

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-102:
Colorado Commission Decision No. C24-0052

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

PHASE II DECISION: (1) ADDRESSING RESOURCE SELECTION AND THEREBY MODIFYING PUBLIC SERVICE’S CLEAN ENERGY PLAN; (2) ADDRESSING THE ADDITIONAL TRANSMISSION INVESTMENTS IDENTIFIED IN PHASE II; (3) ESTABLISHING PERFORMANCE INCENTIVE MECHANISMS FOR UTILITY-OWNED GENERATION; (4) ADDRESSING THE 2024 JUST TRANSITION SOLICITATION; AND (5) ADDRESSING RELATED MATTERS

Mailed Date: January 23, 2024

Adopted Date: December 6, 13, 20, 2023

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I. BY THE COMMISSION

A. Statement

1. In accordance with § 40-2-125.5(4), C.R.S., the electric resource plan (ERP) filed by Public Service Company of Colorado (Public Service or the Company) on March 31, 2021, includes a Clean Energy Plan (CEP) to reduce the Company's carbon dioxide (CO₂) emissions by a target of 80 percent by 2030 as compared to 2005 levels. As set out in Decision No. C22-0459 (the Phase I Decision)¹ and Decision No. C22-0559 (addressing applications for rehearing, reargument, or reconsideration)² the Commission approved certain elements of the Company's CEP, including the Coal Action Plan that transitions Public Service away from its remaining coal facilities. The Commission also authorized Public Service to use Phase II of this Proceeding to further implement the requirements for approval of a CEP such that the Commission could continue evaluation of, among other things, the additional clean energy plan activities, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I) and (3)(a)(II), and whether the CEP is in the public interest and consistent

¹Issued August 3, 2022.

² Issued September 21, 2022.

with the clean energy target in § 40-2-125.5(3)(a)(I). The Commission's decisions in Phase I and Phase II of this ERP proceeding thus implement a bold clean energy policy that helps avoid the worst impacts of climate change while allowing Coloradoans to enjoy the benefits of reliable clean energy at an affordable cost.

2. Throughout the course of Phase II, Public Service showcased its preferred resource portfolio of new utility resources to be acquired through 2027 and, in response to party and public comments, its updated preferred portfolio of resources. In accordance with the Commission's Phase I directives, the Company also presented numerous alternate portfolios for consideration. Although the Company's preferred resource portfolio³ projects sufficient emission reductions to exceed statutory requirements, comments point out that not only might these projected reductions in emissions be overstated, but that the costs to customers would be significant – pointing to, among other major concerns, billions of dollars in modeled transmission investment changes between Phase I and II, and significant utility ownership in gas resources presented in the Company's updated preferred plan.

3. Building on our determinations in Phase I, we find that modifying the Company's CEP by selecting an alternative resource portfolio (the Alternative Portfolio)⁴ is necessary considering statutory and public interest concerns.

4. The Alternative Portfolio exceeds Colorado's goals in emission reductions and protects reliability of the electrical system, according to the Company's analysis. At the same time,

³ As detailed below, in the 120-Day Report, Public Service presented its Preferred Portfolio, and this Preferred Portfolio is what comments from intervenors address. In its Response Comments, the Company presents an Updated Preferred Portfolio. Apart from a few minor modifications (*e.g.* replacing a wind project with a different wind project) the Updated Preferred Portfolio and the Preferred Portfolio are identical. The benefits of the Alternative Portfolio set forth throughout this Phase II decision apply both to the Preferred Portfolio and the Updated Preferred Portfolio.

⁴ As discussed below, the Alternative Portfolio is the Inverse 1324 (\$0CO₂) Plan that Public Service included in the 120-Day Report. (*See* 120-Day Report (Appendix S) Rev. 1, p. 26).

the Alternative Portfolio—which includes fewer new utility-owned resources than the Company’s preferred resource portfolio and is thus better tailored to the developing capabilities of the Company’s system—will reduce costs to customers, especially considering factors such as the curtailment of generated renewable energy.

5. This case propels Colorado’s transition towards greater reliance on renewable resources, takes massive strides towards emission reductions, and continues on a path towards 100 percent clean energy resources; however, the Company maintains that system reliability currently requires at least some new natural gas-fired generation resources. Like the Company’s updated preferred portfolio, the Alternative Portfolio includes nearly half the amount of gas resources predicted in the Phase I Settlement modeling, which was supported by a majority of parties with diverse interests, including some environmental advocates.⁵ Moreover, and unlike the Company’s updated preferred plan, the Alternative Portfolio better allows for technological advancements and flexibility by deferring certain resource acquisitions, reducing the amount of Company-owned gas resources, and significantly increasing the amount of storage on the electrical system. For similar reasons, the Alternative Portfolio creates the opportunity to better optimize transmission upgrades during resource procurement in future proceedings.

6. Particularly given the billions of dollars in discrepancies of modeled transmission costs, granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio with the Phase I authorizations also allows us to better support Colorado customers and communities. Through directed modeling and filing considerations, we include further direction to support transitioning communities through the 2024 Just Transition Solicitation. As we remain dedicated to supporting the economic changes facing our state’s

⁵ Phase I Settlement (Attachment D), p. 2.

transitioning communities, optionality and opportunity through ongoing, robust, competitive bidding is essential to continue selecting optimal resources to support Colorado's needs. In recognition that affordability of energy bills remains a significant focus, we also include direction on performance incentive mechanisms that further incentivize Public Service to reduce the costs of the new Company-owned generation and promotes fairness and transparency within the competitive bidding process.

7. On balance, the Phase I and Phase II Decisions together provide a measured approach to reliability and cost considerations, while taking exponential strides towards a clean energy future that supports Colorado citizens. These decisions propel the Company towards an 86 percent reduction in emissions by 2030 as well as the goal of providing its customers with energy from 100 percent clean energy resources by 2050.

8. Thus, through this Decision we find that modification of the proposed CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest. Consistent with the Phase I Decision and determinations in this Phase II order, we direct Public Service to pursue this modified CEP and its Alternative Portfolio of resources with further due diligence and contract negotiations and to file applications for Certificates of Public Convenience and Necessity (CPCNs) for all Company-owned generation resources arising from the modified CEP. We further direct that all Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM set forth below.

9. In addition, we make several directives regarding transmission investments as well as future proceedings, including the 2024 Just Transition Solicitation proceeding and the

application Public Service will file regarding the attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment (RESA).

B. Discussion

1. Electric Resource Planning

10. The Commission's ERP Rules, set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq.*, serve two primary functions. First, the rules require a regular, periodic examination of an electric utility's energy sales and demand forecasts as compared to an assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

11. As established in the ERP Rules, for decades Colorado electric utilities have used competitive bidding to procure additional resources to meet identified future resource needs. An ERP thus describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals (RFPs), including the inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, the social costs of emissions, discount rates, etc.), and how it will apply resource selection criteria.

12. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources.⁶ In Phase II, the Commission issues a final decision regarding the utility's preferred cost-effective plan for pursuing the acquisition of particular resources.

⁶ Rule 4 CCR 723-3-3617(c) describes the contents of the Commission's Phase I decision in more detail.

13. Phase II begins after the Commission issues its Phase I decision. Public Service issues its RFPs, receives competitive bids and utility-owned proposals, and files a report no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) (120-Day Report). The 120-Day Report presents an evaluation of all proposed resources, based on the criteria established in the Phase I decision (*e.g.*, the base modeling inputs and assumptions to be used in developing optimized resource portfolios and the sensitivities that “re-price” optimized portfolios using alternative values for selected inputs and assumptions).

14. At the end of Phase II, the Commission issues a final decision that approves, conditions, modifies, or rejects the utility’s preferred cost-effective resource plan. Rule 3613(h) describes the contents of a Phase II decision as follows:

Within 90 days after the receipt of the utility’s 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility’s preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S., the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado’s energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

15. Upon the conclusion of Phase II, and consistent with Rule 3613(h), upon the issuance of this Phase II Decision, Public Service will continue its due diligence and contract negotiations, as appropriate, and file applications for CPCNs in accordance with § 40-5-101, C.R.S., for each of the Company-owned projects arising from approval of the modified CEP.

These projects will be entitled to a presumption of prudence per Rule 3617(d), supported primarily through the determinations of need in Phase I and Phase II, the use of competitive bidding, and the implementation of bid evaluation and selection pursuant to our Phase I decision. Given the magnitude of this ERP Proceeding and the complexity associated with the CEP considerations set forth below, the Commission waives the 90-day deadline to issue a Phase II decision as contemplated by Rule 3613(h).

2. Clean Energy Plans Pursuant to SB 19-236

16. While longstanding statutes, the Commission's rules, and competitive bidding processes are foundational to the Colorado's utility resource planning process, recent legislative changes, including Senate Bill (SB) 19-236 further overlay CEP considerations on Public Service's current ERP.

17. SB 19-236 enacts § 40-2-125.5(1) that declares the statewide importance of promoting cost-effective clean energy and new technologies and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." Specifically, § 40-2-125.5(3) requires that, in addition to the other requirements of the section, Public Service shall meet the following clean energy targets:

- (I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels; and
- (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generation from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest and consistent with the requirements of this section.

18. The statute further requires that the first ERP following January 1, 2020, must include a CEP that “will achieve the clean energy target set forth in subsection (3)(a)(I)” and will “make progress toward the [100 percent] clean energy goal set forth in subsection (3)(a)(II).”⁷ Subsection 4 further specifies what a CEP must include (*e.g.*, a plan of actions and investments projected to achieve compliance with the clean energy targets set forth in subsection (3)(a)(I) and (3)(a)(II), the projected costs of the CEP’s implementation, and workforce transition and community assistance plans).

19. Subsection 4(d) includes that the Commission “shall approve the [CEP] if the commission finds it to be in the public interest and consistent with the [80 percent target], and the commission may modify the plan if the modification is necessary to ensure the plan is in the public interest.” In evaluating whether a CEP submitted is in the public interest, the Commission is directed to consider the following factors, “among other relevant factors as defined by the commission”:

- (I) Reduction in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
- (II) The feasibility of the [CEP’s] impact on the reliability and resilience of the electric system. The commission shall not approve a plan that does not protect system reliability.
- (III) Whether the [CEP] will result in a reasonable cost to customers, as evaluated on a net present value basis.⁸

20. If the Commission approves a CEP that achieves an emission reduction of at least 75 percent from 2005 levels, then the relevant utility is provided with a “safe harbor” from any

⁷ § 40-2-125.5(4)(a).

⁸ § 40-2-125.5(4)(d)(III).

additional emission reduction regulations that the Air Quality Control Commission (AQCC) might develop for the power sector through 2030.⁹

21. As a general matter, the Colorado Department of Public Health and Environment (CDPHE) is tasked with calculating whether a proposed CEP will meet these clean energy targets. In particular, the division of administration in the CDPHE must describe the methods of measuring CO2 emissions and verify the projected CO2 emission reductions of the CEP.¹⁰ The statute goes on to state that the division of administration, in consultation with the AQCC, must determine whether the CEP will meet the 2030 clean energy targets, and will report to the Commission the division's calculation of CO2 emission reductions attributable to any approved CEP.¹¹

22. SB 19-236 also sets forth accounting requirements to track the costs of the CEP. For instance, § 40-2-125.5(4)(a)(III) states the utility must “clearly distinguish” between the set of resources necessary to meet customer demands in the resource acquisition period (RAP) and the additional CEP activities—such as the retirement of existing generating facilities—that may be undertaken to meet the clean energy target of 80 percent emission reduction by 2030. Moreover, the CEP must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions.¹² Likewise, the CEP must list the “actions and investments” necessary to meet the clean energy target and describe the effect of such actions and investments on the safety, reliability, renewable energy integration, and resiliency of the electric system.¹³

23. The statute goes on to direct the utility to collect revenues for the additional CEP activities through a CEPR assessed on a percentage basis on all retail customer bills.¹⁴ This CEPR

⁹ § 25-7-105(1)(e)(VIII)(C), C.R.S.

¹⁰ § 40-2-125.5(4)(b).

¹¹ § 40-2-125.5(4)(c)(I).

¹² § 40-2-125.5(4)(a)(VI)

¹³ § 40-2-125.5(4)(a)(IV)—(V).

¹⁴ § 40-2-125.5(5)(a)(II)

is limited to a maximum electric retail rate impact of 1.5 percent of the total annual electric bill for each customer for implementation of the approved additional clean energy plan activities and “may be established as early as the year following approval of a clean energy plan by the commission.”¹⁵

24. SB 19-236 requires that the ERP containing the CEP use a RAP extending through 2030. If the CEP calls for the accelerated retirement of any generating facilities, the CEP must include a workforce transition plan for impacted utility workers. Similarly, the CEP must include a plan to pay community assistance to any local government or school district whose voters previously approved projects, the costs of which are expected to be paid for from property taxes that the accelerated retirement directly impacts.¹⁶

25. While the statute requires the utility to use a competitive bidding process to procure any energy resources to fill the cumulative resource need derived from the ERP and CEP, the Commission shall also allow the utility to own a target of 50 percent of the energy and capacity developed or acquired to meet the resource need “if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact.”¹⁷

26. As discussed in our Phase I Decision, several of the statutory findings required for an approved CEP could not be made in the Phase I Decision but must wait until Phase II. For instance, the actions and investments required to fill the additional resource need for the CEP, the projected cost to implement the CEP, and the cost and rate impact of the 50 percent utility ownership target could not be known until after the 120-Day Report. The Phase I Decision permitted Public Service to issue the RFP and proceed to Phase II and established the framework in which bids will be evaluated and selected, setting important Phase II assumptions regarding the

¹⁵ § 40-2-125.5(5)(a)(I).

¹⁶ § 40-2-125.5(4)(a)(VII).

¹⁷ § 40-2-125.5(5)(b).

treatment of the Company's remaining coal-fired power plants, and ensuring that the 120-Day Report contains the information required to make the statutory findings necessary to reach an approved CEP.

27. The Commission did not anticipate, and no party requested, a fully litigated hearing in Phase II.¹⁸ Rather, through its usual Phase II process, the Commission can address the necessary statutory findings in this Phase II Decision (*e.g.*, upon consideration of the 120-Day Report, the parties' comments to the 120-Day Report, and the IE Report). As the parties assert in their Joint Brief Addressing Phase II Topics, (filed on August 2, 2021) SB 19-236 might change the objectives of the ERP process, but it does not direct any changes to the process itself.¹⁹

3. Procedural Background

28. A complete procedural history through Phase I of this Proceeding is provided in the Phase I Decision.

29. The parties in this Proceeding consist of the following: Public Service; Staff of the Colorado Public Utilities Commission (Staff); the Office of Utility Consumer Advocate (UCA); the Colorado Energy Office (CEO); the City of Boulder (Boulder); the Colorado Energy Consumers (CEC); Climax Molybdenum Company (Climax); Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Colorado Solar and Storage Association and Solar Energy Industries Association (jointly COSSA/SEIA); the International Brotherhood of Electrical Workers, Local No. 111 (Local 111); Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly,

¹⁸ This is consistent with the position of the parties. (Joint Brief Addressing Phase II Topics, p. 8 (arguing that the statutory findings required to approve a CEP do not necessitate a Phase II hearing)).

¹⁹ Joint Brief Addressing Phase II Topics, p. 13.

RMELC and CBCTC);²⁰ Holy Cross Electric Association, Inc. (Holy Cross); CORE Electric Cooperative (CORE); Western Resource Advocates (WRA); Vote Solar; Walmart Inc. (Walmart); Colorado Renewable Energy Society (CRES); Natural Resources Defense Council and Sierra Club (collectively, the Conservation Coalition); the City and County of Denver (Denver); the Board of County Commissioners of Pueblo County (Pueblo County); the City of Pueblo and Board of Water Works of Pueblo (jointly Pueblo City and Water); Onward Energy Management (Onward); and the Colorado Oil and Gas Association (COGA). The Commission also granted Black Hills Colorado Electric, LLC (Black Hills) leave to participate as an *amicus curiae* in this Proceeding.²¹

30. In addition, in Decision No. C21-0343-I,²² the Commission granted the Unopposed Motion for Limited Participation that CDPHE filed on April 29, 2021. As such, CDPHE is participating in this Proceeding as a neutral verifier.

31. In response to Decision No. C21-0404-I,²³ in which the Commission solicited briefs from the parties regarding Phase II procedures, on August 2, 2021, Public Service, Staff, UCA, CEO, CIEA, COSSA/SEIA, RMELC and CBCTC, Local 111, Conservation Coalition, Interwest, Onward, Pueblo County, Pueblo City and Water, Walmart, and WRA jointly filed a brief arguing that no Phase II hearing is required. Vote Solar was the only party to file a separate Phase II brief, in which it states that it “does not believe Senate Bill 19-236 requires a Phase II hearing” but argues that “additional evidentiary hearing process may nonetheless be necessary in Phase II if Public Service Company of Colorado proposes any portfolios in its 120-Day Report that include gas plants located in, or near, any disproportionately impacted communities.”²⁴

²⁰ Local 111, RMELC, and CBCTC collectively refer to themselves as the Labor Interests.

²¹ The Commission denied the Motions to Intervene filed by Ms. Leslie Glustrom and the Coalition of Ratepayers. (Decision No. C21-0315-I, pp. 16-22.)

²² Issued June 9, 2021.

²³ Issued June 23, 2021.

²⁴ Vote Solar’s Phase II Brief, p. 1.

32. On September 30, 2021, the Office of Just Transition (OJT) filed a motion to intervene out of time, or in the alternative, to participate as *amicus curiae*. On October 25, 2021, the Commission granted OJT's motion to intervene out of time, allowing OJT to participate as a party in this Proceeding.²⁵

33. On August 3, 2022, the Commission issued the Phase I Decision addressing Public Service's ERP and CEP and approving, in part, the Updated Non-unanimous Partial Settlement Agreement (Phase I Settlement) filed on April 26, 2022.²⁶ Among other things, the Phase I Decision directed Public Service to issue RFPs for an all-source, competitive bidding process to meet its resource need.

34. On September 21, 2022, the Commission issued Decision No. C22-0559 addressing applications for rehearing, reargument, or reconsideration of the Phase I Decision.

35. On December 1, 2022, Public Service issued its 2022 All-Source RFPs.

36. On March 31, 2023, Public Service filed its "30-Day Report" describing bids received in response to its competitive bid solicitation.

37. On March 31, 2023, Public Service filed an unopposed motion to, among other things, extend by 50 days the time to file the 120-Day Report. By Decision No. C23-0246-I,²⁷ the Commission granted the Company's motion and extended the deadline for the 120-Day Report as well as all associated deadlines.

²⁵ Decision No. C21-0666-I, issued October 20, 2021.

²⁶ The Phase I Settlement was supported by the following parties: Public Service, Staff, UCA, CEO, RMELC and CBCTC, COSSA/SEIA, Pueblo County, Holy Cross, Pueblo City and Water, Walmart, Boulder, Denver, COGA, Local 111, the OJT, CIEA, Onward, Interwest, Conservation Coalition, and WRA.

²⁷ Issued on April 13, 2023.

38. On July 27, 2023, Public Service filed the Motion for Second Extension requesting an additional 24-day extension of time within which to file the 120-Day Report. By Decision No. C23-0522-I,²⁸ the Commission granted the Motion for Second Extension.

39. On September 5, 2023, Public Service together with the Independent Evaluator (IE) and Staff filed a Motion that requested a third extension of time for the Phase II deadlines. On September 5, 2023, various parties representing the interests of independent power producers (IPPs) filed a Response to the Joint Motion for Third Extension (Joint IPP Interests Response). The Joint IPP Interests Response was specifically filed by COSSA/SEIA, CIEA, and Interwest. These parties argued that the IPP projects will be prejudiced by the additional requested delay, which could postpone final decisions in this matter through March of 2023 to consider requests for rehearing, reargument, and reconsideration. By Decision No. C23-0594-I²⁹ and Decision No. C23-0647-I,³⁰ the Commission granted, in part, and denied, in part, the requested Phase II extensions. While the Commission recognized the significant complexity of this Phase II process relative to past ERPs, it agreed with other parties regarding the urgency of issuing a Phase II decision.

40. Ultimately, the Company filed the 120-Day Report on September 18, 2023, approximately 80 days after the Company was initially scheduled to file the 120-Day Report.³¹ Public Service would subsequently file corrections to the 120-Day Report on October 18, 2023.

²⁸ Issued on August 8, 2023.

²⁹ Issued September 7, 2023.

³⁰ Issued September 27, 2023.

³¹ The original deadline for the 120-Day Report was June 29, 2023. (Decision No. C23-0246-I, ¶ 4).

41. On October 5, 2023, the Commission issued Decision No. C23-0672-I, that required the Company, and invited other parties, to submit comments outlining a potential risk sharing mechanism for Company-owned generation.

42. On October 18, 2023, the Air Pollution Control Division of the CDPHE filed the Phase II Clean Energy Plan Verification Report.

43. On October 20, 2023, in response to Decision No. C23-0672-I, Public Service submitted a proposal for risk-sharing mechanisms regarding Company-owned generation resources. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

44. On October 21, 2023, the IE filed its report (the IE Report).

45. On November 8, 2023, intervenor comments on the 120-Day Report were filed.

46. On November 20, 2023, Public Service filed its Response Comments to the 120-Day Report.

47. On December 6 and 13, 2023, the Commission commenced deliberations. On December 13, 2023, the Commission also issued Decision No. C23-0841-I, directing Public Service to set forth certain information related to the cost-to-construct performance incentive mechanism (PIM) and the operational PIM. In addition, we instructed the Company to consider and potentially refile the Highly Confidential Exhibit 1 to the Response to Decision No. C23-0672-I.

48. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing the specific information requested, and a corresponding narrative on the identified highly confidential document.

49. The Commission resumed deliberations on December 20, 2023, and concluded deliberations that same day.

50. In addition to the public comment hearings and written comments provided in Phase I, throughout Phase II of this Proceeding, the Commission received numerous written public comments that the Commission reviewed and retains in the administrative record.

C. Phase I Decision and Public Service CEP

51. In the Phase I Decision, the Commission set the framework in which Public Service may proceed to issue RFPs for an all-source, competitive bidding process to meet its resource need and advance its CEP toward final consideration and approval. The Commission's rulings on topics such as the Company's coal action plan, workforce transition and community assistance, best value employment metrics (BVEMs), and the CEPR paved the way for the development of a CEP in Phase II that complies with the requirements of SB 19-236 and advances the establishment of a bold clean energy policy for Colorado.

52. The following list summarizes the primary rulings the Commission made in its Phase I Decision that relate to the Company's CEP and the requirements of SB 19-236:

- a) Consistent with the Phase I Settlement, the resource acquisition period (RAP) for the Company's ERP/CEP extends through 2030 per § 40-2-125.5(4)(a)(I).
- b) Subject to certain exceptions, starting in 2024, the Company must retire all RECs in the year generated, per § 40-2-125.5(3)(a)(III).
- c) In the 120-Day Report, the Company will clearly distinguish between the set of resources necessary to meet customer demands in the resource acquisition period and the additional clean energy plan activities that may be undertaken to meet the clean energy target in § 40-2-125.5(3)(a)(I), per § 40-2-125.5(4)(a)(III).
- d) In the 120-Day Report, the Company will set forth the actions and investments required to meet the clean energy target of § 40-2-125.5(3)(a)(I).
- e) The Company will set forth a proposal for the CEPR as part of the 120-Day Report that enables us to consider the appropriate timing for Public Service to initiate the CEPR via an advice letter filing.
- f) The suite of portfolios the Company will present in the 120-Day Report will allow the Commission to evaluate whether the proposed level of utility ownership comes at a reasonable cost and rate impact per § 40-2-125.5(5)(b).

- g) Consistent with the Phase I Settlement, the 120-Day Report will include the information necessary for the Commission to consider BVEM in conjunction with our other Phase II decisions.
- h) The Company will include the projected costs of both workforce transition plans and community assistance plans in the Phase II modeling. The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years following retirement (or conversion) for Hayden 1 and Hayden 2, and Pawnee (the Brush Coal plant), respectively, and ten years for Pueblo Unit 3, and will be offset by any new investment in the respective community.³²
- i) Public Service will file post-Phase II updated Just Transition Plans (JTPs) for the Hayden coal plants, the Brush Coal Plant, and Pueblo Unit 3.³³ Regarding the Pueblo Unit 3 in particular, no later than June 1, 2024, Public Service will file a JTP that includes a standalone competitive solicitation. To the extent not otherwise addressed in the Phase I Settlement, this 2024 Just Transition Solicitation (the 2024 JTS) shall be treated as an interim ERP under Rule 3603(a). While the focus of the 2024 JTS is the replacement of Unit 3 and the Pueblo community, the 2024 JTS is not geographically limited to the Pueblo area nor is the resource need limited to replacing Unit 3.³⁴
- j) The Phase II modeling will allow the Commission to evaluate both the social cost of carbon (SCC) and the social cost of methane (SCM), consistent with the spirit of § 40-3.2-106.

53. In addition, the Phase I Decision ruled on such things as the provisions in the Company's model PPA, the inputs and assumptions to be used in the Phase II modeling, and the portfolios and sensitivities that the Company will present in the 120-Day Report.

D. Phase II Filings

1. 120-Day Report

54. The 120-Day Report summarizes the results of the Public Service's Phase II modeling and puts forth the Company's Preferred Portfolio for Commission approval. Under the Preferred Portfolio, the Company would move forward with developing numerous generation resources and associated transmission infrastructure. While the relevant details of the 120-Day

³² Phase I Settlement, pp. 18-19.

³³ Phase I Settlement, p. 19.

³⁴ Phase I Decision, pp. 40, 42; Phase I Settlement, pp. 27-31.

Report and the subsequent Updated Preferred Plan (UPP) will be discussed below, we highlight here some of the major components.

55. Public Service's Preferred Portfolio contains about half as much gas-fired generation resources as what the Phase I modeling predicted (628 MW versus 1,176 MW).³⁵ Conversely, the Preferred Portfolio adds almost twice as much renewable generation and six times as much storage as was anticipated in Phase I.³⁶ As to the storage specifically, Public Service states that the Preferred Portfolio takes advantage of the IRA tax benefits for storage, and uses storage to "effectively utilize otherwise curtailed renewable energy, provide critical ancillary services, and meet peak demand in the evenings when solar generation declines."³⁷

56. Regarding emissions reductions, Public Service estimates that the Preferred Portfolio will achieve 87.4 percent reduction in CO₂ emissions by 2030—far exceeding the 80 percent clean air target.³⁸ Public Service acknowledges, however, that "in addition to all of the normal variance in forecasting, the modeling process itself leads to structural optimism in emissions reduction potential" and that "real time operations will likely have less optimistic results than those predicted by the models."³⁹ The Company states that it "believes we would likely achieve an 80%-85% reduction."⁴⁰

57. The emissions reductions are due largely to the Coal Action Plan and the renewable resources the Preferred Portfolio adds as replacement and new utility resources. Indeed, Public Service states that the Preferred Portfolio is "the largest portfolio ever advanced through the ERP

³⁵ 120-Day Report, p. 36.

³⁶ 120-Day Report, p. 36.

³⁷ 120-Day Report, p. 36.

³⁸ 120-Day Report, p. 38.

³⁹ 120-Day Report, p. 23.

⁴⁰ 120-Day Report, p. 24.

process.”⁴¹ Public Service estimates that through 2055 the Preferred Portfolio has a net present value (NPV) of approximately \$44.2 billion. Included in this total price is an estimated \$2.82 billion in transmission investments. By far the most significant portion of the total transmission investment is an estimated \$2.2 billion needed for Denver Metro Transmission Network Upgrades.⁴²

58. The Preferred Portfolio includes higher levels of Company-owned resources compared to past ERPs. Out of the 7,192 MW of nameplate capacity additions that would be acquired under the Preferred Portfolio, Public Service would own 66.6 percent of the capacity and 69.7 percent of the energy. The Company argues that the higher ownership percentage is a direct result of the more equitable tax credit policy for clean energy resulting from the historic IRA.⁴³

2. CDPHE Verification

59. On October 18, 2023, CDPHE filed the Phase II CEP Verification Report. In its Verification Report, CDPHE opines that the GHG emissions reduction calculations for each portfolio submitted in this Phase II of Proceeding No. 21A-0141E are expected to be 80 percent or more below 2005 baseline levels. CDPHE further states that the portfolios “would be expected to achieve the minimum percent reduction levels required by the statutes for the CEP and Safe Harbor.”⁴⁴

60. In its Phase II CEP Verification Report, CDPHE lists the expected 2030 emissions reductions for each of the submitted portfolios. Of note, the expected emissions reductions for the Preferred Portfolio is 87 percent.⁴⁵

⁴¹ 120-Day Report, p. 22.

⁴² 120-Day Report, p. 130.

⁴³ 120-Day Report, p. 40-41.

⁴⁴ CDPHE Phase II CEP Verification Report, p. 6.

⁴⁵ CDPHE Phase II CEP Verification, pp. 4-6.

3. IE Report

61. On October 21, 2023, the IE filed its Report in this Proceeding. In its Report, the IE attests that the Phase II process was conducted fairly and without bias. The IE states: “The IE can attest to the results of the evaluation and fidelity to the protocols and that the Phase I assumptions were used in evaluation. The IE also was unable to identify any bias towards or against any technology or respondent, including the options presented for the [Public Service] self-owned assets.”⁴⁶

62. That said, the IE also raised several recommendations for future ERP proceedings that the IE asserts will allow the process to better accommodate the large number of bids and increasing reliance on renewable resources. For example, the IE states that “inadequate time was allotted for the transmission analysis” and suggests changes going forward that allow for a better understanding of the transmission requirements associated with the proposed generation projects.⁴⁷

4. Intervenor Comments

63. Numerous intervenors submitted comments on the 120-Day Report, including Staff, CEO, the UCA, CEC, CIEA, COSSA/SEIA, Interwest, WRA, the Conservation Coalition, Boulder, CRES, the OJT, and the Labor Interests.

64. Several parties, such as CEO, WRA, CRES, and Conservation Coalition, cite concerns with the Phase II modeling process and recommend selecting an alternative portfolio with fewer gas resources or simply removing some or all of the gas resources from the Preferred Portfolio.⁴⁸ Conversely, UCA argues that the Phase II modeling shows that eliminating gas-fired

⁴⁶ IE Report, p. 35.

⁴⁷ See IE Report, p. 37.

⁴⁸ CEO’s Comments, pp. 13-14; WRA’s Comments, pp. 15-17; CRES’s Comments, p. 2; Conservation Coalition’s Comments, pp. 12-13.

capacity is extremely expensive.⁴⁹ CEC similarly argues that the Commission should approve a less-costly portfolio that meets but does not greatly exceed the required emissions reductions.⁵⁰

65. Some parties, including Boulder and UCA, suggest that the existing resources in the Preferred Portfolio could be replaced with other resources that they perceive to be lower-priced.⁵¹

66. Other parties representing IPP interests, like CIEA, argue that the Commission should choose an alternative portfolio that better balances how many resources will be owned by Public Service versus IPPs.⁵² Conversely, the Labor Interests argue that there is a positive relationship between portfolios with high BVEM and portfolios with high Company-ownership numbers.⁵³

67. At a high level, the parties have mixed opinions regarding the transmission investments presented in the 120-Day Report—some raise serious concerns while others argue the Commission should approve and expedite the transmission. Likewise, several parties raise cost and emissions concerns about the Hayden Biomass project, while other parties argue that the project should be included in any approved portfolio.

68. Out of the intervenors that filed comments, it appears that the Labor Interests, COSSA/SEIA, the OJT, and Pueblo County, do not oppose adoption of the Preferred Portfolio as presented.⁵⁴

⁴⁹ UCA's Comments, p. 17.

⁵⁰ CEC's Comments, pp. 12-13.

⁵¹ See UCA's Comments, pp. 20-24; Boulder's Comments, pp. 14-15.

⁵² CIEA's Comments, pp. 12-15.

⁵³ Labor Interests' Comments, pp. 2.

⁵⁴ See, e.g., Labor Interests' Comments, pp. 2; COSSA/SEIA's Comments, pp. 1-2.

69. For its part, Staff raises concerns that Public Service's Preferred Portfolio is too aggressive, too costly, and not well supported. Staff states that the Preferred Portfolio contains unexpectedly large generation and transmission investments and high levels of expected curtailments that together could lead to potentially large rate impacts for customers.⁵⁵ Staff encourages the Commission to consider selecting one of five smaller portfolios that would reduce expected curtailments, enable the Commission to defer some of the proposed projects, and to further analyze alternatives for the proposed transmission investments.

5. Comments from the Northern Cheyenne Nation

70. At the CWM on October 25, 2023, William Walksalong presented comments on behalf of the Northern Cheyenne Nation regarding the potential impacts to the Sand Creek Massacre National Historic Site. As described more below, tribal leaders urged the Commission to protect the Sand Creek Massacre National Historic Site as sacred grounds and its view shed from the encroachment of energy development.

6. Public Comments

71. After Public Service filed the 120-Day Report, the Commission received numerous public comments. Many of these public comments argue against the Preferred Portfolio's inclusion of three new-build gas facilities that Public Service would own. At a high level, these comments urge the Commission to reject the new natural gas plants, citing concerns regarding stranded costs, climate change, and air pollution. The Commission also received more substantive public comments from Leslie Glustrom, Advanced Energy United, Sustainable Resilient Longmont, and 350 Colorado that similarly argue for modifications to the Preferred Portfolio, including not approving the proposed gas facilities in the Preferred Portfolio.

⁵⁵ Staff's Comments, pp. 5-7.

72. In addition, the Commission received several comments from organizations and local governments like Upstate Colorado, Alamosa County, the City of Alamosa, Kiowa County, Prowers County, Baca County, and Pueblo County that support the Preferred Portfolio on the basis of emissions reductions and economic development. Of these supportive comments, several public comments specifically support the inclusion of the Hayden Biomass facility in the Preferred Portfolio, arguing that it will provide important economic benefits to Moffat and Routt Counties, which will be impacted by the closure of coal-fired power plants. Northwest Colorado Development Council, Routt County, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden are some of the entities that submitted these types of comments specifically addressing the Hayden Biomass facility.

73. Since the Commission had its initial Phase II deliberations on December 6, 2023, we have continued to receive and review numerous public comments. At a high level, the majority of these most recent public comments urge the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility for natural gas, or concerns that the resources will become stranded. Several of the public commenters argue that the Alternative Portfolio is more expensive on a dollar per MW basis than the Company's UPP.

7. Public Service's Response Comments and the UPP

74. In its Response Comments, Public Service responds to criticisms and concerns raised by intervenors and public commentators and presents an UPP that modifies a few of the proposed generation projects. Aside from the modifications to a few of the generation projects, however, the Company largely maintains its initial position in the 120-Day Report.

75. For example, in response to arguments that the Commission should reduce or eliminate the amount of gas resources included in the portfolio, Public Service asserts that—due to reliability concerns—the Company “cannot become comfortable with any level of reduction in dispatchable resources.”⁵⁶ Public Service argues that adjusting the portfolio by eliminating gas units or using questionable short-term power purchase agreement (PPA) extensions makes the portfolio less reliable and the Company “cannot compromise on reliability.”⁵⁷

76. As for arguments that the UPP has too many utility-owned resources or is too large, the Company argues that all of the selected clean energy projects are either build-own-transfer, PPA, or were purchased from IPPs by the Company earlier in the commercial lifecycle. Public Service agrees that the UPP is large but asserts that the size of the portfolio is ultimately driven by economics and state energy policy goals.⁵⁸

77. Turning to the concerns raised about the approximately \$2.8 billion in transmission investments, Public Service states that the ultimate decision before the Commission is approval of a generation portfolio and that “approval of a resource portfolio does not constitute a final approval of the transmission projects presented in the 120-Day Report.”⁵⁹ Public Service maintains, however, that to achieve the State’s emissions reduction goals, the Company must begin moving forward with the transmission investments needed to support the CEP.⁶⁰

78. As for the proposed resource modifications under the UPP, in response to concerns that Bid 1029 could impact the Sand Creek Massacre National Historic Site due to its proximity, in the UPP, Public Service recommends that the Commission approve a specific backup bid for

⁵⁶ Public Service’s Response Comments, p. 29.

⁵⁷ Public Service’s Response Comments, pp. 27-29.

⁵⁸ Public Service’s Response Comments, pp. 33-34.

⁵⁹ Public Service’s Response Comments, p. 66.

⁶⁰ Public Service’s Response Comments, p. 65.

Bid 1029 while still allowing Bid 1029 to move forward. Similarly, the Company proposes that the Commission conditionally approve the Hayden Biomass project but further analyze the costs, emissions reductions, workforce and community benefits, tax benefits, and viable alternatives in a follow-on CPCN proceeding.⁶¹

79. The Company proposes a few other changes to the resources in the UPP, but the suggested changes result from problems with the original resources as opposed to intervenor concerns.⁶²

80. As compared to the Preferred Portfolio, the UPP adds 329 MW of nameplate capacity. This increase is comprised of an additional 101 MW of solar resources and an additional 228 MW of additional wind resources. The UPP is also \$288 million more expensive on a present value revenue require (PVRR) basis.⁶³ Regarding the price increase, Public Service asserts that the \$288 million increase is caused by unavoidable changes to bids that appear in virtually all portfolios. Thus, the Company asserts that all of the other portfolios would increase by the same amount, meaning there is little to no impact on the differences between plans.⁶⁴ The percentage of resources that the Company would own decreases slightly in the UPP from 66.6 percent of capacity to 62.7 percent.⁶⁵

E. Modification of the CEP's Resource Portfolio

81. As described above, the statute prescribes when the Commission must approve a CEP and when the Commission may modify the CEP. Specifically, the Commission may modify the plan if the modification is necessary to ensure the plan is in the public interest. In evaluating

⁶¹ Public Service's Response Comments, pp. 19-20.

⁶² Public Service's Response Comments, pp. 18-24.

⁶³ Public Service's Response Comments, p. 9.

⁶⁴ Public Service's Response Comments, p. 9.

⁶⁵ Public Service's Response Comments, p. 9.

whether a CEP submitted to the Commission is in the public interest, the Commission shall consider (1) emissions reductions, (2) the CEP's impact on reliability and resilience of the electric system,⁶⁶ and (3) the cost of the CEP on a NPV basis. The statute also permits the Commission to consider "other relevant factors."

82. A CEP includes "clean energy plan activities that may be undertaken to meet the clean energy target... which may create an additional resource need for the [CEP]."⁶⁷ Public Service's CEP is thus comprised of several components, including the Coal Action Plan, the workforce transition and community assistance plans,⁶⁸ and the "investments required to fill the additional resource need,"⁶⁹ (*i.e.*, the portfolio of resources procured through the competitive solicitation). In this Proceeding, significant clean energy plan activities involve the conversion of the Brush plant from coal to gas and the lower capacity values of Pueblo Unit 3.⁷⁰ The UPP represents a portion of Public Service's CEP as proposed by the Company.

83. Given that the Company's preferred resource portfolio comprises a portion of the total CEP, the selection of an alternative resource portfolio does not replace the overall CEP. Because the Commission maintains the other important elements of the CEP—like the Coal Action Plan—the selection of an alternative portfolio is a modification to the overall CEP.

84. While the Commission recognizes that Company proposals in Phase I and II in this Proceeding have made progress towards Colorado's energy transition, there are significant

⁶⁶ The statute makes clear that the Commission "shall not approve a plan that does not protect system reliability." (§ 40-2-125.5(4)(d)(III), C.R.S.)

⁶⁷ § 40-2-125.5(4)(a)(III), C.R.S.

⁶⁸ § 40-2-125.5(4)(a)(VII), C.R.S.

⁶⁹ § 40-2-125.5(4)(a)(IV), C.R.S.

⁷⁰ Although the Coal Action Plan includes the early retirement of the Hayden and Craig coal plants, the coal actions are not technically part of the CEP because they are also included in the reference ERP portfolio.

concerns raised by parties and public commenters regarding the UPP.⁷¹ For instance, Staff argues that given the large price tag of the Preferred Portfolio as well as the concerns Staff has about the Phase II modeling process, the Commission should reduce the size of the resource portfolio or delay decisions until further analysis and support can be provided.⁷² Regarding its modeling concerns, Staff notes that Public Service's decision to increase the generic price of most renewables for years 2029 and 2030 might be causing the model to over-value acquisitions in the near-term.⁷³ Similarly, the reliability rubric the Company implemented in Phase II arguably prohibited the model from "backsliding" or removing resources after dispatchable resources were added. Staff states that the reliability rubric "introduced constraints into the capacity expansion step that fundamentally render the process suboptimal as it is no longer able to truly optimize the portfolio."⁷⁴ Staff goes on to suggest that the reliability rubric's constraints made the Commission-ordered demand response sensitivity ineffective.⁷⁵

85. In addition, Staff notes that the Preferred Portfolio likely fails to account for high levels of curtailment and the resulting increase in costs and emissions. Staff argues that the model likely fails to capture significant levels of curtailments for several reasons, including the model's limitations regarding simplified commitment logic and the inability to capture curtailments from perturbations in the system as well as the timing mismatch between when generation will come online and when the transmission will be ready to serve the new generation. Staff ultimately concludes that the "the level and costs of curtailments portrayed by the model cannot be trusted"

⁷¹ Because Public Service presented the UPP after intervenors submitted their Comments on the 120-Day Report, intervenors address the Preferred Portfolio rather than the UPP. The differences between the UPP and the Preferred Portfolio, however, are largely immaterial as to the concerns that the intervenors raise.

⁷² Staff's Comments, p. 6.

⁷³ Staff's Comments, p. 28.

⁷⁴ Staff's Comments, p. 30.

⁷⁵ Staff's Comments, pp. 34-35.

and that the Preferred Plan “may saddle customers with extra costs for renewable energy that does not reduce emissions because it is never delivered.”⁷⁶ In contrast, Staff notes that other portfolios presented in the 120-Day Report achieve comparable levels of emission reductions with much lower levels of curtailments and higher levels of storage.⁷⁷

86. UCA also criticizes the Phase II modeling process and is especially critical of the May Valley Longhorn Extension (MVLE) and the most expensive part of the Denver Metro Area transmission upgrades—the Harvest Mile Chambers-Sandown-Cherokee (HCSC) project. UCA recommends that the Commission reject the HCSC, the MVLE, and the wind projects that UCA argues necessitate the transmission projects.⁷⁸

87. Other parties, such as Conservation Coalition and CRES argue that the Commission should not approve any of the gas resources in the Preferred Portfolio.⁷⁹ CEO similarly recommends the Commission not approve 200 MW of the 628 MW of gas included in the Preferred Portfolio. CEO argues that it is unclear whether an additional 200 MW of new gas generation will actually be necessary and recommends that the Commission address this proposed new gas in future ERPs, including the 2024 JTS and the 2026 ERP.⁸⁰ WRA suggests that the Commission select the lower dispatchable portfolio, which has 504 MW of new gas generation—124 MW less than the Preferred Portfolio.⁸¹ WRA also suggests modifying the Preferred Portfolio by reducing reliance on new construction and instead utilizing available existing generation.⁸²

⁷⁶ Staff’s Comments, pp. 31-32, 34.

⁷⁷ Staff’s Comments, p. 32.

⁷⁸ See UCA’s Comments, pp. 29-30.

⁷⁹ Conservation Coalition’s Comments, p. 10; CRES’s Comments, p. 2. Relatedly, the Commission has received numerous public comments urging the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility, or concerns that the resources will become stranded.

⁸⁰ CEO’s Comments, p. 14.

⁸¹ WRA’s Comments, pp. 15-16.

⁸² WRA’s Comments, pp. 16-17.

88. CIEA raises several concerns with the Phase II modeling, arguing that the Company used a heavy-handed approach to manipulate the model.⁸³ Many of CIEA's recommendations are aimed at the goal of achieving a higher proportion of PPA resources in the Company's resource mix—both in this Proceeding and in future ERPs. CIEA asserts there have been “huge project cost overruns at the [Company-owned] Cabin Creek, Comanche, and Pawnee stations” and that customers are seeing less value than anticipated from two Company-owned wind projects.⁸⁴ CIEA argues that given the high percentage of Company-owned projects in the Preferred Portfolio, Public Service might be biting off more than it can chew.⁸⁵ CIEA reasons that PPA resources can help insulate ratepayers from both capital cost overruns and performance issues with generators. Noting that all of the gas resources in the Preferred Portfolio would be owned by Public Service, CIEA recommends that the Commission select an alternative resource portfolio that replaces some of the Company-owned gas-fired projects with existing PPA gas resources.⁸⁶ CIEA argues that PPA resources “should be at least 50% of Public Service's resource mix to balance ratepayer and shareholder risks.”⁸⁷

89. CEC argues that there are too many red flags and unknowns for this Commission to approve the Preferred Portfolio as presented. CEC notes that Preferred Portfolio will far exceed the clean air targets established by SB 19-236 and argues that the Commission should not approve a plan that goes “above and beyond” statutory requirements to the detriment of customers, particularly given the current affordability concerns.⁸⁸ For instance, CEC notes that the Preferred

⁸³ CIEA's Comments, pp. 26-28.

⁸⁴ CIEA's Comments, p. 13.

⁸⁵ CIEA's Comments, pp. 9-10.

⁸⁶ CIEA's Comments, pp. 16-18.

⁸⁷ CIEA's Comments, pp. 13-15.

⁸⁸ CEC's Comments, pp. 12-13.

Portfolio is approximately \$600 million more expensive than the \$0CO₂ Least Cost Plan, and the \$0CO₂ Least Cost Plan still exceeds SB19-236 bold emission reduction targets.⁸⁹

90. Given these concerns, and considering the record as a whole, we find that modification of the CEP in the selection of an alternative portfolio is necessary to ensure the plan is in public interest based on the three enumerated statutory factors as well as “other relevant factors” that the Commission defines.

91. As noted above, Staff recommends for several reasons that the Commission focus its consideration on five “portfolios of interest.”⁹⁰ We agree with Staff and, consistent with the discussion below, determine that the Inverse 1324 (\$0CO₂) Plan best represents an “Alternative Portfolio” that incorporates the necessary modifications to Public Service’s CEP to support the public interest findings required by SB 19-236.

92. Compared to the Preferred Portfolio set forth in the 120-Day Report, the Alternative Portfolio has 1,338 MW lower nameplate additions (7,192 MW – 5,854 MW). More specifically, the Alternative Portfolio has 19 MW fewer biomass, 41 MW more gas resources, 350 MW fewer solar resources, and 1,706 MW fewer wind resources. However, the Alternative Portfolio has 678 MW more storage resources.⁹¹ The Alternative Portfolio also requires fewer transmission investments and is \$194 million less expensive on a NPV basis. Regarding curtailments, the Phase II report suggests that in 2028 the Alternative Portfolio will result in 1,629 GWh of modelled curtailments, compared to 5,433 GWh of modelled curtailments in the Preferred Portfolio.⁹² Moreover, the Company states in its Phase II Report that the modelled curtailment is the “best

⁸⁹ CEC’s Comments, pp. 12-13.

⁹⁰ Staff’s Comments, p. 11.

⁹¹ See Staff’s Comments, p. 49.

⁹² See Staff’s Comments, p. 49.

possible case scenario [rather] than a realistic expectation of [the curtailment level that]...would occur in real-time operations.”⁹³ This uncertainty over actual curtailment levels further supports the more cautious approach taken with the Alternative Portfolio.

93. In addition, unlike three of the five portfolios of interest, the Alternative Portfolio was included in the 120-Day Report and thus was reviewed by the IE and CDPHE. As noted by Staff and confirmed by CDPHE, the emissions reductions resulting from the Alternative Portfolio exceed the 2030 greenhouse gas reduction targets. While the Alternative Portfolio has somewhat lower interim emissions reductions compared to the Preferred Portfolio, consistent with the Company’s statements that the modeling does not capture curtailments resulting from transmission congestion and other perturbations in the system, Staff argues that it is unclear that the higher emissions reductions in the Preferred Portfolio “would bare out in reality” given the concerns regarding curtailments and the deliverability of the renewable energy.⁹⁴

94. Moreover, the smaller size of the Alternative Portfolio addresses concerns raised by Staff and others that the Preferred Portfolio is too large due to factors such as the repricing of generic resources in the Phase II modeling and the no “backsliding” component of the Reliability Rubric modeling. Likewise, the smaller size ameliorates Staff’s concerns about new generation coming online before the 2029/2030 in service date (ISD) for major transmission projects that Public Service indicates are necessary to take full advantage of the renewable resources.⁹⁵ Finally, the Alternative Portfolio reduces the Company’s ownership percentage so that it is expected to be

⁹³ See 120-Day Report, at p. 95.

⁹⁴ Staff’s Comments, p. 63.

⁹⁵ Staff’s Comments, p. 61.

closer to the 50 percent IPP and 50 percent PPA statutory expectations.⁹⁶ Given the Company's significant upcoming investments in transmission through the Colorado Power Pathway and issues identified by intervenors of the Company's struggles to adhere to project budgets and timelines in different instances, a better balance between Company and IPP ownership presents an opportunity to decrease the risk of performance issues by a single entity impacting overall performance of the CEP.

95. Considering the statutory factors and additional public interest considerations raised in comments by parties and the public, based on this record and supported by party filings, we find that the Alternative Portfolio better aligns with Colorado's multi-faceted goals to achieve significant emission reductions and progress towards 100 percent emission reductions in the future, all while ensuring reliability and protecting affordability for ratepayers. Addressing specific factors below—and as supported by policy direction throughout our Phase II Decision that also includes PIMs and directives for the 2024 JTS—we find that modification of the CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest.

1. Emission Reductions

96. The statute requires the Commission to consider the emissions reductions associated with the CEP. Because the Alternative Portfolio is included in the 120-Day Report, CDPHE evaluated it along with all of the other Phase II portfolios in the Phase II Clean Energy Plan Verification Report. CDPHE opines that the emissions reduction calculations for each of the Phase II portfolios are expected to be 80 percent or more below 2005 baseline levels.

⁹⁶ To be clear, the Commission does not find that SB 19-236 in any way sets a floor or a ceiling for Company-ownership. The Commission does, however, find persuasive arguments from CIEA and others that more balanced levels of PPA and Company-owned resources help insulate ratepayers from potential cost overruns and performance issues.

Regarding the Alternative Portfolio in particular, CDPHE estimates that the expected 2030 emissions reductions will be 86 percent by 2030.⁹⁷ Thus, the Alternative Portfolio is expected to exceed the 80 percent emissions reductions set forth in the statute and makes progress towards achieving the goal of 100 percent clean energy resources by 2050.

97. As presented in the Phase II modeling, the UPP arguably achieves slightly greater emissions reductions, especially in the interim years prior to 2030. However, Public Service admits that these emissions reductions estimates are optimistic and that the model does not include curtailments caused by transmission congestion or perturbations in the system.⁹⁸ Thus, it is questionable how accurate these emissions reductions predictions are, especially in the interim years before Public Service has finished building the transmission upgrades the Company states are necessary to reliably deliver power.⁹⁹ In other words, these modeled interim emissions reductions are unlikely to materialize if Public Service cannot construct the majority of the associated transmission investments until 2030.¹⁰⁰ Moreover, it is these same transmission upgrades that resulted in the \$2.2 billion “surprise” in Phase II, as discussed more below. We find it unsettling to rely on predictions that are speculative, at best, on transmission availability in the UPP that result in the seemingly higher emissions reductions. Given that the transmission modeling results changed dramatically between Phase I and II with costs escalating billions of dollars beyond the Company’s initial estimates, we cannot depend on emission reduction predictions tied explicitly to those same transmission needs.

98. Throughout this Proceeding and in selecting the Alternative Portfolio, the Commission has considered the PVRR of both the social cost of carbon (SCC) and the social cost

⁹⁷ CDPHE Phase II CEP Verification, pp. 4-6.

⁹⁸ 120-Day Report, p. 95.

⁹⁹ 120-Day Report, pp. 130-133.

¹⁰⁰ See Staff’s Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).

of methane (SCM), which also helps in our considerations on emission reductions. The Alternative Portfolio significantly reduces the SCC and SCM compared to Public Service's ERP or business-as-usual portfolio.¹⁰¹ For the capacity expansion phase of the modeling, the Alternative Portfolio does not include the social cost of emissions.¹⁰² Post-modeling, however, in the 120-Day Report the SCC and SCM associated with the Alternative Portfolio are both presented.¹⁰³ Moreover, the Coal Action Plan, which is critical to emissions reductions, is hardwired into the Alternative Portfolio. While there are other portfolios that have still greater reductions in SCC and SCM, notwithstanding the uncertainties around curtailment impacts to those figures, the Alternative Portfolio exceeds the 80 percent emissions reductions set forth in the statute while balancing other factors such as costs, reliability, and future optionality.

99. While the Alternative Portfolio—like other portfolios the Company claims protect reliability¹⁰⁴—includes over 600 MW of gas resources, these gas resources do not impede Colorado's emissions reductions goals. Rather, the new gas resources are all equipped with both fast start and fast shutdown capability, which allows the units to sit idle most of the time while providing essential operating reserves and ancillary services.¹⁰⁵ The Commission reluctantly recognizes that there does not appear to be a path forward that excludes or significantly reduces the need for new gas resources, given the Company's repeated assertions that it cannot support any reduction in gas resources based on the Company's reliability analysis¹⁰⁶ and the lack of modeling demonstrating the contrary within the record.

¹⁰¹ 120-Day Report (Appendix S) Rev. 1, pp. 1, 26.

¹⁰² 120-Day Report, p. 97.

¹⁰³ 120-Day Report (Appendix S) Rev. 1, p. 26.

¹⁰⁴ Public Service argues that the No New Gas and No Gas Portfolios are not reliable. The Lower Dispatchable portfolio includes somewhat fewer gas resources (504 MW), but the Company has raised reliability concerns with this portfolio as well. (Public Service's Response Comments, pp. 29-30).

¹⁰⁵ 120-Day Report, pp. 80-81, 126.

¹⁰⁶ Public Service Response Comments, p.29

100. Moreover, as discussed more below, rather than simply eliminating 200 MW of gas-fired resources as argued by some parties and sacrificing reliability, the Alternative Portfolio reduces the amount of Company-owned gas resources, increasing the Company's ability to fully transition away from carbon emitting resources as we approach 2050 and reducing risk of stranded assets to ratepayers. This reduction in Company ownership provides continued opportunities to further accelerate towards 100 percent renewable resources by not tying the Company – and Colorado – to the full amount of utility-owned gas-fired resources presented in the UPP.

101. Under SB 19-236, the CEP must achieve 80 percent emissions reductions by 2030 while working towards 100 percent clean energy by 2050, and the Commission must consider reliability and affordability when determining whether the CEP is in the public interest. The Alternative Portfolio with its 669 MW of gas resources provides this balanced, transitional plan that SB 19-236 contemplates. Even though the gas resources will be run infrequently with the vast majority of the energy coming from wind and solar resources, the units provide an important insurance policy during sustained periods of hot or cold weather – including in extreme circumstances given the realities of climate change.¹⁰⁷ Providing this backup option and permitting the integration of substantial additions of new clean energy resources allows Public Service to retire its remaining coal plants and several of its older gas units.¹⁰⁸

102. In sum, when considering emission reductions, the Alternative Portfolio exceeds Colorado's ambitious emission reduction goals, sets the state towards a path for 100 percent renewable resources, all while continuing to avoid extreme costs and outages.

¹⁰⁷ 120-Day Report, pp. 22-23, 80-81.

¹⁰⁸ 120-Day Report, pp. 22-23, 80-81.

2. Reasonable Cost to Customers

103. The statute requires the Commission consider if the CEP will result in a reasonable cost to customers on an NPV basis. The NPV of the UPP is \$44,479 million while the NPV of the Alternative Portfolio as presented is \$43,997 million.¹⁰⁹ However, in its Response Comments, Public Service states that the \$288 million NPV increase from the Preferred Portfolio to the UPP is a result of unavoidable changes that would appear in virtually all portfolios.¹¹⁰ Assuming that the same incremental change appears in the Alternative Portfolio, the updated NPV of the Alternative Portfolio is \$44,285 million ($\$43,997 + \$288 = \$44,285$). Even using this updated NPV, the Alternative Portfolio is \$194 million less expensive than the UPP ($\$44,479 - \$44,285 = \$194$).

104. While the Alternative Portfolio is preferable to customers on an NPV basis as contemplated in SB 19-236, another relevant factor the Commission must consider is the cost to customers as experienced through increased rates. Intervenors such as Staff, UCA, and CEC have raised alarms regarding the Preferred Portfolio's impact on rates. For instance, Staff states that the rate increase attributable to the Preferred Portfolio for the single year from 2026 to 2027 is just over 10 percent.¹¹¹ As discussed more below, the rate analysis the Company provides in the 120-Day Report only includes the impact of the CEP and fails to include other planned investments such as \$4.5 billion in projected distribution investments through 2028, an additional \$800 million in generation projects outside of the CEP, as well as investments in wildfire mitigation, transportation electrification, distributed solar, and others.¹¹² Staff asserts that the impact of real time operations, construction schedules, system curtailments, and other factors will likely result in

¹⁰⁹ Public Service's Response Comments, p. 9; 120-Day Report (Appendix S) Rev. 1, p. 26.

¹¹⁰ Public Service's Response Comments, p. 9.

¹¹¹ Staff's Comments, p. 19.

¹¹² See Staff's Comments, p. 19.

higher rate impacts than the Company's calculations suggest.¹¹³ Given the importance of maintaining affordability, the Commission must consider these costs to customers more generally and not limit our consideration to the NPV comparison of the various resource portfolios.

105. An example of a cost to customers that does not explicitly appear in the NPV considerations is the likely cost of curtailments that the modeling fails to capture. Although the NPV estimates do include the costs of curtailments included in the modeling, the Company admits as discussed above that the model's curtailment forecasting is "more a 'best possible case scenario' than a realistic expectation of what would occur in real time operations."¹¹⁴ Public Service notes that "a large percentage of curtailment" is caused by perturbations in the system from transmission issues or reliability events and that these curtailments "are not captured in the model."¹¹⁵ The curtailments resulting from transmission issues are especially concerning given that under the UPP the Company will be connecting vast amounts of new renewable generation years before most of the associated transmission upgrades can be constructed.¹¹⁶ The Company indicates that while the transmission investments are being built, Public Service will maintain reliable service using tools such as curtailments and redispatch.¹¹⁷ Thus, the NPV calculations do not reflect significant amounts of curtailments that the modeling fails to capture, but these missing curtailments will result in additional costs that customers must pay.

106. The Alternative Portfolio cuts modeled curtailments from 15 percent in the UPP to 5 percent,¹¹⁸ and curtailments that the model does not capture will likely also be reduced due to a decreased reliance on yet-to-be-built transmission and an increased investment in storage. By way

¹¹³ Staff's Comments, p. 19.

¹¹⁴ 120-Day Report, p. 95.

¹¹⁵ 120-Day Report, p. 95.

¹¹⁶ See Staff's Comments, pp. 43-44.

¹¹⁷ 120-Day Report, p. 134.

¹¹⁸ See Staff's Comments, p. 49.

of analogy, Public Service predicts that the UPP will have 6,043 GWh of curtailments in 2028,¹¹⁹ but the Alternative Portfolio is only predicted to have 1,629 GWh of curtailments in 2028.¹²⁰ It is reasonable to assume that curtailments that the model fails to capture will follow similar trajectories resulting in significant additional costs savings in the Alternative Portfolio.

107. Put simply, the Alternative Portfolio will achieve the state's ambitious clean energy targets while mitigating the risk that ratepayers will be required to pay for resources that have less incremental value because they are significantly curtailed.

108. Another category of costs that does not appear in the NPV calculations are the potential costs associated with Company-owned gas generation assets, including construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. On this last point, several parties including UCA, WRA, Conservation Coalition, and Boulder, as well as numerous public comments, raised concerns that the new gas resources will become stranded assets. The Alternative Portfolio is again preferable to the UPP in this regard because it contains a substantial decrease in Company-ownership of new gas capacity. Specifically, the UPP contains 628 MW of new build gas resources, all of which are Company-owned.¹²¹ The Alternative Portfolio contains 669 MW of new build gas resources, but of this 669 MW, 219 MW is a PPA resource with a 20-year term.¹²² By diversifying the ownership of the gas resources, the Alternative Portfolio reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources.

¹¹⁹ Public Service's Response Comments, Attachment 2, p. 1.

¹²⁰ 120 Day Report (Appendix T), p. 23.

¹²¹ Public Service's Response Comment, p. 9.

¹²² 120-Day Report (Appendix S) Rev. 1, p. 26.

109. Finally, yet another cost that is not included in the NPV estimates is the risk that a larger, more sprawling resource portfolio like the UPP will eliminate opportunities to take advantage of future technology developments or reductions in price in some of the newer technologies. As discussed more below, acquiring a smaller portfolio of resources in this Proceeding creates more optionality in future proceedings for efficiencies and cost savings, including through a more robust use of demand side resources. In other words, the Alternative Portfolio reduces the risk that customers will pay for generation and transmission resources that could have been avoided through better use of developing technologies.

110. As we consider costs, we believe that least-cost options presented in the Phase II report may be unworkable for Colorado. We find unpersuasive arguments raised during Phase II that the Commission should select the Least Cost Portfolio. While the Least Cost Portfolio is slightly less expensive on a NPV basis than the Alternative Portfolio,¹²³ the Company has raised reliability concerns with the portfolio because it does not include the strategically located gas resources the Company asserts are necessary for transmission support.¹²⁴

111. Similarly, we reject arguments that selecting a larger portfolio to reduce emissions at any cost is appropriate. It is critical that we examine costs and emissions together, and in conjunction with reliability as required by statute. Not only is the diverse technical makeup of the Alternative Portfolio needed for the reliability needs raised by the Company and discussed more below, but because of the increase in storage in the Alternative Portfolio, modifying the CEP to move forward with this portfolio also allows further development with not only load but storage capacity that could help increase efficiencies and reduce costs in the future. In addition,

¹²³ The Least Cost Portfolio has a PVRR of \$43,984 million, which is \$13 million less than the Alternative Portfolio's PVRR or 43,9997. (120-Day Report, p. 38; 120-Day Report (Appendix S) Rev. 1, p. 26).

¹²⁴ 120-Day Report, pp. 39-40; Public Service's Response Comments, p. 29.

overinvesting in the system could price electricity out of competition with other fuels, jeopardizing beneficial electrification efforts.¹²⁵ To help ensure that Colorado can continue to decarbonize all sectors of the economy—many parts of which will rely on the electrical system as the backbone of the transition—it is essential to provide electrical service at a reasonable cost and rate impact.

112. Finally, CRES and certain public commentors note that Public Service’s NPV cost numbers were calculated using the Company’s weighted average cost of capital (WACC) as the discount rate, and they urge the Commission to use a lower discount rate. CRES argues that using the WACC as the discount rate will have the effect of discounting future fuel and other costs sharply. Moreover, CRES states that in enacting SB 23-291, the legislature has directed the Commission in C.R.S. § 40-2-139 to use a discount rate for future fuel costs that does not exceed the long-term rate of inflation. CRES recommends that the Commission direct the Company to resubmit the NPV values in accordance with what is now Colorado law.¹²⁶

113. We note that the appropriate use of discount rates was litigated in Phase I. The Phase I Decision put forward a compromise to help mitigate the substantive concerns raised by CRES, requiring Public Service to provide in Phase II the annual nominal cash flows associated with each portfolio so that the parties and the Commission could calculate the NPV calculation using various discount rates.¹²⁷ As such, this Commission believes it is important to understand the potential cost and other resource choice impacts that might occur at lower discount rates, but

¹²⁵ Numerous public commenters argue that the Alternative Portfolio is more expensive than the UPP on a dollars per MW basis. This argument only looks at the nameplate capacity of the respective portfolios and does not account for important distinctions in how different resources contribute to the electrical system. For example, a 300 MW solar facility will be of no value to the electrical system after the sun sets. A 300 MW solar plus storage facility, however, is able to help serve load after the sun sets and, in this way, can be more useful to the electrical system, even though it has the same nameplate capacity as the solar facility. Thus, the addition of storage resources to a portfolio can contribute value in ways that are not reflected in the amount of nameplate capacity.

¹²⁶ CRES’s Comments, pp. 2-3.

¹²⁷ Phase I Decision, ¶ 211.

declines to upset the compromise position we adopted in the Phase I decision particularly since the Company did provide the requested Excel worksheet as Appendix W to the 120-Day Report.

114. Likewise, we reject CRES's argument that the Commission is required in this Phase II process to use an alternative discount rate per SB 23-291's amendment to C.R.S. § 40-2-139, which would further extend the Phase II process with additional modeling and process by relitigating issues resolved in Phase I. CRES is correct that, going forward, the requirement imposed by the amended § 40-2-139, C.R.S. imposes a duty on the Commission that, if it relies on the use of a discount rate when calculating NPV of future carbon-based fuel costs, the rate must not exceed the long-term rate of inflation. However, the law does not consider or include the necessary Phase I and II process or other clarifications.

115. A law is presumed prospective unless the legislature "clearly and unequivocally expressed" ¹²⁸ intent for the statute to apply retrospectively. Generally, when the cause of action "accrues prior to the effective date of an amending statute," the prior statute controls. ¹²⁹

116. Here, Public Service filed its application in this Proceeding in March 2021. At that time, and at the time of the Phase I order, the statute did not include the updated language, which went into effect in August 2023. The party evidence and record overall, including the expectation of the Company when it filed the application, were set well before the 2023 legislative session. The issue was fully concluded through the Phase I Decision issued in 2022. To change the required scope of the considerations at this late phase is not required and counters long-standing precedent. ¹³⁰

¹²⁸ *Edelstein v. Carlile*, 33 Colo. 54, 57, 78 P. 680, 681 (1904)

¹²⁹ *United Bank of Denver Nat. Ass'n v. Wright*, 660 P.2d 510, 511 (Colo. App. 1983); *Diversified Veterans Corp. Ctr. v. Hewuse*, 942 P.2d 1312, 1314 (Colo. App. 1997) (holding that the imposition of penalties involves substantive rights and liabilities and is therefore governed by the law in effect on the date of the party's injury).

¹³⁰ *See, e.g., United Bank of Denver Nat. Ass'n v. Wright*, 660 P.2d at 511.

117. Phase I is complete and has always been the appropriate phase for determination of the applicable discount rate. In enacting its statute in 2023, the Legislature is presumed to understand this process, and the Commission certainly will be required to apply the statute in future ERP Phase I decisions that direct the necessary considerations of discount rate determinations. The Commission is not, however, required to alter its Phase II process and extend already tight timelines for further modeling, analysis, and to expand the record. Indeed, if it did, these actions would potentially put at risk the time-sensitive bidding process.

118. Nevertheless, as the Commission did in its Phase I order in considering updates to statute subsequent to the 2021 ERP application filing by directing the Company to include the social cost of methane in its Phase II information, the Commission is in no way precluded from recognizing the statutory considerations and discussing the spirit and application based on the record. The Commission generally has a broad delegation of power to regulate utilities from the Colorado legislature.¹³¹ Where the legislature has not directly prohibited the Commission from considering certain factors, the Commission generally can exercise its power over rates and utilities as it sees fits.¹³² Specifically, when approving resource plans, the Commission can consider “other relevant factors, as determined by the commission.”¹³³ The legislature grants the Commission broad power here to determine what factors are appropriate to use to compare bids in a resource plan.¹³⁴ Recognizing these statutory provisions, the record here indicates that the Alternative Portfolio would still be the most appropriate selection.

119. No parties to this Proceeding submitted analysis during Phase II showing the PVRR of various portfolios using a lower discount rate, although certain public commentators submitted

¹³¹ See *City of Montrose v. Pub. Utils. Comm’n*, 629 P.2d 619, 622 (Colo. 1981).

¹³² See § 40-3-102, C.R.S.

¹³³ § 40-3.2-106(3)(c), C.R.S.

¹³⁴ § 40-3.2-106(3)(c), C.R.S.

analysis regarding the impact of different discount rates on the NPV of fuel costs. Regardless, even assuming that certain that a lower discount rate makes the Alternative Portfolio more expensive on a NPV basis compared to the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio, this does not justify the selection of a different portfolio. First, the Commission is still prohibited from selecting a portfolio that fails to protect reliability. Public Service states in its Response Comments: “neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law.”¹³⁵ Public Service has also raised concerns with the reliability of the lower dispatchable portfolio. Moreover, while one of the enumerated statutory factors is the cost on a NPV basis, the statute permits the Commission to also consider other relevant factors. One such unenumerated factor the Commission is considering is the cost to customers more generally. Through this lens, the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio all require significantly more resource acquisitions in the short term that will have significant consequences for the affordability of electric service. This factor weighs in favor of granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio.

3. Reliability and resilience of the electric system

120. The statute also requires the Commission to consider the impact of the CEP on the reliability and resilience of the electric system and prohibits the Commission from approving a plan that does not protect system reliability. Based on modeling in this record, the Alternative Portfolio is just as reliable, if not more so, than the UPP.

121. As presented by the Company, gas-fired generation resources are a key factor in ensuring reliability. In response to arguments that the Commission should reduce the amount of

¹³⁵ 120-Day Report, p. 60.

gas resources, Public Service asserts that it “cannot become comfortable with any level of reduction in dispatchable resources.”¹³⁶ In addition to the total amount of gas resources included in the portfolio, Public Service asserts that two gas resources within the UPP are strategically located and necessary to provide transmission support: Bid 989 in the Denver Metro area and a new gas resource in the Alamosa area. Regarding Bid 989, the Company states that it “is the only bid submitted that includes firm dispatchable generation providing supportive benefit to the transmission constraint” in the Denver Metro area.¹³⁷ Similarly, the Company notes that, after a 2026 retirement of an existing gas resource, there will be no firm dispatchable resources located in the San Luis Valley. The Company asserts that it is essential from a reliability perspective to continue to have firm dispatchable generation in the region.¹³⁸

122. The Alternative Portfolio slightly increases the amount of gas resources included in the UPP and retains the two gas resources that Public Service argues are strategically located and necessary to provide transmission support.¹³⁹ The only modification the Alternative Portfolio makes to the gas resources in the UPP is to Bid 1000, which the Company does not flag as being necessary for transmission support.¹⁴⁰ Bid 1000 is a Company-owned project with two 200 MW combustion turbines (CTs). The Alternative Portfolio would eliminate one of the 200 MW CTs in Bid 1000 and replace it with a 219 MW CT (Bid 235) that is owned by an IPP. As set forth above, this change provides valuable diversification benefits that, among other things, reduces the risk of stranded assets that customers face from Company-owned gas resources. In addition, Public Service has raised no reliability concerns with Bid 235. Indeed, Bid 235 is included in the backup

¹³⁶ Public Service’s Response Comments, p. 29.

¹³⁷ 120-Day Report, p. 39.

¹³⁸ 120-Day Report, p. 39.

¹³⁹ 120-Day Report (Appendix S) Rev. 1, p. 26. While the Alternative Portfolio replaces the UPP’s Alamosa gas resource with a slightly larger gas resource that is also located in the Alamosa area.

¹⁴⁰ 120-Day Report, p. 29.

portfolio and is the only gas bid that the Company includes in its Prospective New Load portfolio.¹⁴¹ Thus, the Alternative Portfolio maintains or increases the reliability of the UPP in that it retains the two strategically located gas resources, slightly increases the total amount of gas resources, and replaces a Company-owned gas resource with a PPA resource that the Company has found to be reliable.¹⁴²

123. Furthermore, the Company ran both the Alternative Portfolio and the Preferred Portfolio (which closely resembles the UPP) through an “extreme summer” scenario that—according to the Company—“provides useful information on the reliability of the portfolios under extreme events.”¹⁴³ Under this extreme summer scenario, the Alternative Portfolio performed better than the Preferred Portfolio.¹⁴⁴ Thus, we are left to conclude that the Alternative Portfolio is not only reliable based on Public Service’s own metrics, it appears to be more reliable than the UPP.

124. Although the UPP and the Alternative Portfolio have comparable levels of gas-fired generation, we acknowledge the arguments from several parties and numerous members of the public that the Commission should only approve a resource portfolio with fewer or no new gas resources. We share their disappointment that the Phase II competitive resource solicitation failed to result in any viable portfolio with fewer gas resources and again urge the Company to come

¹⁴¹ 120-Day Report, p. 55; Public Service’s Response Comments, p. 27.

¹⁴² Pursuant to the Phase I Settlement and the Phase I Decision, the model PPA for dispatchable resources was amended to, among other things, require that gas resources have backup fuel on site necessary to allow the facility to run continuously for a minimum of five days at maximum load on the alternative fuel. Firm gas transportation contracts could serve as a substitute for the requirement to have a backup alternative fuel on site. (Phase I Decision, pp. 106-06; 120-Day Report, pp. 122-23). In the 120-Day Report, Public Service confirms that “[a]ll bids that were advanced to EnCompass modeling are compliant with the requirement for either onsite backup fuel storage or firm gas transportation contracts” but that the model did not select the fuel oil storage bids due to economics. (120-Day Report, p. 125). The Commission reiterates its interest in having five days of backup fuel onsite for the new gas resources.

¹⁴³ 120-Day Report, p. 77.

¹⁴⁴ Corrected Table 19 of 120-Day Report, p. 1.

forward in future proceedings, including the 2024 JTS, with more developed demand side resources and other reliability solutions that do not involve new gas resources. As described above, the requirement to include at or near the amount of gas resources in the Alternative Portfolio stemmed from the Company's reliability determinations and their direct modifications to the modeling in Phase II, as a result. The Commission is disappointed that specific, locational reliability concerns were not clearly communicated in Phase I, which could have been informative to potential bidders and provided additional options.

125. We therefore find that granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio, including its gas resources, is in the public interest. First, SB 19-236 prohibits the Commission from approving a plan that does not protect system reliability. Thus, we cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability.

126. Other modeled resource portfolios with fewer gas resources than the Alternative Portfolio were presented by Public Service—including the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio. None of these portfolios, however, represent a better option than the Alternative Portfolio. Public Service states in its Response Comments that “neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law.”¹⁴⁵ In addition, we note the No New Gas portfolio and the No Gas portfolio are significantly larger and more costly than the Alternative Portfolio.

127. As for the Lower Dispatchable portfolio, it is much larger than the Alternative Portfolio (7,163 MW instead of 5,835 MW) and more expensive on a NPV basis (\$45,315

¹⁴⁵ 120-Day Report, p. 60.

compared to 43,997).¹⁴⁶ Moreover, as compared to the Alternative Portfolio, the Lower Dispatchable portfolio simply reduces the amount of PPA gas resources by selecting a smaller CT (Bid 1061). The Company-owned gas resources are essentially unchanged.¹⁴⁷ In addition, the Company argues in its Response Comments that it has reliability concerns with Bid 1061.¹⁴⁸ Thus, on this record we find that the Alternative Portfolio is superior to the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio.¹⁴⁹

128. Even though we would have preferred selecting a portfolio with fewer or no gas resources, we find it useful to consider the total amount of gas resources in the context of what was originally anticipated in Phase I of this Proceeding. Based on the inputs and assumptions established in the Phase I Settlement, the modeling predicted that the competitive solicitation could lead the Company to acquire 1,372 MW of gas additions.¹⁵⁰ The vast majority of the parties in this Proceeding joined the Phase I Settlement, including CEO, WRA, and Conservation Coalition. Thus, we conclude that the 669 MW of gas resources in the Alternative Portfolio are well within the guardrails established in Phase I.

129. While we find on this record that the Alternative Portfolio and its gas resources are in the public interest, we acknowledge the numerous concerns that parties raised regarding how Public Service tested for reliability in the Phase II modeling and the manual adjustments the Company made regarding gas resources. In particular, we share the concerns raised by parties

¹⁴⁶ 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.

¹⁴⁷ 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.

¹⁴⁸ Public Service's Response Comments, p. 30.

¹⁴⁹ For similar reasons, we reject CIEA's arguments that the Commission select a portfolio that use the annuity tail instead of the replacement chain modeling. As between the Alternative Plan and the Alternative Plan with the annuity tail, the new 219 MW PPA CT (Bid 235) is replaced with three short-term extensions of existing PPA CTs, but the Company-owned gas resources remain essentially the same. The record before us better supports the reliability of Bid 235 as compared to the extensions of the existing PPA CTs. Moreover, because the annuity tail version is just a sensitivity, its projected emissions have not been reviewed by CDPHE.

¹⁵⁰ Public Service's Response Comments, p. 28 (citing Phase I Settlement (Attachment D), at Table 3 and noting that the 1,372 MW of gas additions is over a longer RAP).

such as Staff, COSSA/SEIA, and Conservation Coalition regarding the Company's reliability rubric.¹⁵¹ We also question whether the Company adequately communicated to bidders the importance of strategically located gas resources. It is our expectation that the Company will strive to resolve these issues prior to the 2024 JTS. Nevertheless, while these concerns further support our decision to select a tailored resource portfolio, we are unconvinced that these concerns warrant additional Phase II modeling or the manual removal of gas resources from the modeled portfolios.

4. Future Technology Development

130. Another related factor that the Commission considers when evaluating the CEP is the impact of future technology developments. For instance, the Alternative Portfolio includes a much higher percentage of storage resources than the UPP. This significantly expanded level of storage may be critical to future efforts to incorporate still greater amounts of renewables without unreasonable levels of curtailments while reducing the need for gas resources.

131. Colorado's bold clean energy targets necessitate a rapid shift in the electrical system, which in turn requires us to think about our electrical system in a different way. We cannot attempt to build Colorado's future, low-emission electrical system by continuing to build the system as we have in the past. Simply building increasing amounts of generation resources as the UPP would do results in high curtailments and high costs. In contrast, modifying the CEP to include the Alternative Portfolio helps the Commission start building a different type of electrical system that takes advantage of developing technologies in several ways. Efficient and cost-effective planning of such a system will rely on a variety of components: flexible supply, flexible demand, participation in larger geographic markets, energy efficiency and acquisition of

¹⁵¹ See, e.g., Staff's Comments, pp. 29-30; COSSA/SEIA's Comments, pp. 14-15; Conservation Coalition's Comments, pp. 10-13.

clean resources. While other dockets are addressing regional markets, demand flexibility and energy efficiency, in this CEP we address clean resources and flexible supply, placing a greater emphasis on supply management through increased storage capacity. As an example, energy storage resources in the Alternative Portfolio represent 32 percent of new capacity,¹⁵² compared to just 16 percent in the UPP.¹⁵³ In this way, the Alternative Portfolio marks the first step in a new approach to resource planning for a modern, efficient, and cost-effective grid.

132. In addition, the modification of the CEP to include the Alternative Portfolio results in a smaller, less aggressive resource acquisition. Although it is likely that our selection of a smaller resource portfolio in this Proceeding will result in a larger acquisition in the 2024 JTS, deferral of some of the new generation resources will also provide additional time for the Commission to better understand and take advantage of developing technologies that might reduce the cost of, or eliminate the need for, new generation and transmission resources. In this vein, the Alternative Portfolio's acquisition of a PPA gas resource reduces the amount of gas resources that Public Service would otherwise own.¹⁵⁴ This gives Public Service more flexibility if future technology improvements render gas resources unnecessary. Moreover, advancements in various types of distribution system management are particularly promising for ensuring that the distribution system is more capable of the dynamic load management that will be more important as beneficial electrification advances. The Commission also expects that more robust and innovative demand response programs will be a critical part of the future electrical system. As more items like electric vehicles, heat pumps, and heat pump water heaters come onto the grid, the management of these loads will become increasingly important, but also increasingly possible.

¹⁵² Staff's Comments, p. 11.

¹⁵³ Public Service's Response Comments (Attachment 1), p. 1.

¹⁵⁴ See 120-Day Report (Appendix S) Rev. 1, p. 26.

To ensure that the Commission is being good stewards of ratepayer funds, we need the Company and their planning processes to evolve away from overbuilding resources and instead look for ways to enable more dynamic management of both supply resources and demand resources.

133. Several parties similarly argue that the Commission should continue examining how new technological developments could be used to meet system needs instead of traditional generation and transmission investments. For instance, WRA suggests that the need for some of the Denver Metro transmission upgrades could instead be addressed by load management programs. WRA states that investment in transmission system upgrades to alleviate the Denver Metro constraint may be needed but recommends that the Company develop without delay load management programs in the metro area. WRA also recommends that the Company improve distributed energy resource (DER) programs and interconnection rules, with financial incentives to ensure the growing DER capacity provides benefits to the grid.¹⁵⁵

134. Similarly, noting that the Company's proposal for metro Denver transmission upgrades was "significantly influenced by the lack of cost-effective bids [for generation] in the Denver metro area," COSSA/SEIA asserts that the Company should consider alternatives to conventional transmission upgrades, including non-wires alternatives such as virtual power plants (VPPs).¹⁵⁶ CEO likewise encourages the exploration of non-wires alternatives associated with the proposed upgrades in its new Distribution System Plan as well as additional details in the 2024 JTS.¹⁵⁷ CRES argues that with the new storage contained in the Preferred Portfolio, together with the fact that long-term storage technologies are evolving quickly, the Commission should not

¹⁵⁵ WRA's Comments, p. 22.

¹⁵⁶ COSSA/SEIA's Comments, pp. 22.

¹⁵⁷ CEO's Comments, pp. 29-30.

approve the proposed gas resources until Public Service has gained significant experience operating its system with the large amount of storage that will be added in the coming years.¹⁵⁸

135. Staff asserts that Public Service never mentioned the possibility of demand side or other generation solutions to alleviate the \$2.1 billion in transmission in the Denver Metro area. Staff notes that demand response solutions, aggregation of customer-sited generation and storage, and the use of electric vehicles to deliver grid benefits are being discussed in the Commission's Distribution System Plan proceedings and VPP Miscellaneous Proceeding. Staff argues that it is unclear whether solutions such as Time-of-Use rates, critical peak pricing, additional demand response, VPPs focused on this period, managed charging, Vehicle-to-Grid programs, strategically located storage at Community Solar Gardens, etc. could prove to be more cost-effective solutions than what the Company proposes.¹⁵⁹

136. Future development also implicates changing needs for workforce labor and development. Despite the many positive attributes of the Alternative Portfolio, we have not lost sight of best value regarding employment of Colorado labor and the impacts the Alternative Portfolio will have on the long-term economic viability of Colorado communities.¹⁶⁰ As set forth more below, the 120-Day Report assigns a BVEM score to each portfolio and the Alternative Portfolio's BVEM score is slightly lower than the UPP's BVEM score. Although it is disappointing that the Alternative Portfolio has a lower BVEM score, just as deferral of some of the new generation resources will provide additional time for the Commission to take advantage of developing technologies, the Alternative Portfolio allows time for better evaluation of BVEM for those resources that will be acquired in future solicitations. Notably, the BVEM scores appear

¹⁵⁸ CRES's Comments, p. 2.

¹⁵⁹ Staff's Comments, p. 41.

¹⁶⁰ See generally § 40-2-129(1)(a), C.R.S.

to track to some degree with the percentage of utility ownership, so as IPPs prepare for future solicitations, they should take special care to improve BVEM performance to ensure that in future solicitations the Commission does not see lower BVEM scores as a reason to disturb the ownership balance between the utility and IPPs. Ultimately, we believe that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns, outweigh the lower BVEM score.

137. In sum, the prospect of future technology developments weighs in favor of modifying the CEP to include the resources in the Alternative Portfolio. The composition of the Alternative Portfolio itself with the large amounts of storage will likely be key for the future low emissions electrical system. Likewise, the more tailored acquisition of resources provides the Commission with more opportunities to evaluate quickly advancing technologies such as distribution management and new demand response programs and balances the risk that some of these new technologies could reduce the need for future generation and transmission investments.

5. Transmission Concerns

138. The transmission concerns that have arisen in Phase II are another factor that contributes to the finding that granting Public Service authority to move forward with acquiring the resources in the Alternative Portfolio is necessary for the public interest. The Company presents several categories of transmission costs, but all are overshadowed by the \$2.2 billion in investments for transmission network upgrades to the Denver Metro area.¹⁶¹ In Phase I of this Proceeding, the Company identified a need in the Denver Metro area, but only estimated the need

¹⁶¹ 120-Day Report, p. 130.

at a capital cost of “approximately \$250 million”.¹⁶² Therefore, the Phase II modeling did not consider the new and significantly larger cost or how to minimize or avoid it as part of the resource selection process. Moreover, as noted above, the majority of the transmission investments are not scheduled to be completed until 2030, years after many of the resources in UPP would otherwise come online,¹⁶³ exacerbating concerns regarding both the modelled and actual levels of curtailments that will occur in the UPP.

139. As discussed in more detail elsewhere in this Decision, several parties raise concerns about the \$2.2 billion investment in transmission upgrades that Public Service states is necessary for the Denver Metro area and question whether the selection of resources could be better optimized to reduce the transmission upgrades. For example, Staff states that there “seems to be a fundamental problem that the modeling process does not integrate transmission planning in a meaningful way” and notes that Public Service “has not provided any analysis of the amount and type of metro area generation that would be needed to reduce this transmission network upgrade cost or the amount by which it could be reduced.”¹⁶⁴ Staff argues that the \$2.2 billion surprise raises several questions including whether the transmission costs would be substantially different under any other generation portfolio, whether there are cost effective Denver Metro bids, and whether demand side or other generation resources could reduce the overall cost and need for the transmission network upgrades.¹⁶⁵

140. Among the other parties that raise transmission concerns, CEC argues that the estimated \$2.2 billion in transmission upgrades for the Denver Metro area is “shocking” and notes that this current estimate is almost nine times larger than the estimate provided in Phase I. CEC

¹⁶² HE 107 p. 50-51

¹⁶³ Staff’s Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).

¹⁶⁴ Staff’s Comments, p. 40.

¹⁶⁵ Staff’s Comments, pp. 39-41.

asserts that this change fundamentally alters the facts the Commission and stakeholders relied on in Phase I.¹⁶⁶ UCA similarly argues that in the Preferred Portfolio Public Service intertwines generation and transmission projects to provide a circular basis for one another, which significantly expands Company ownership, costs, and capacity beyond what was contemplated in the Phase I Settlement.¹⁶⁷

141. In the 120-Day Report, the Company cites several factors driving the need for large investments in the Denver Metro area, including population growth, the scale and location of new generation that the Company is acquiring in the Preferred Portfolio, and the lack of cost-effective bids in the Denver Metro area.¹⁶⁸ In its Response Comments, Public Service recognizes that “additional work remains to better integrate transmission and generation planning” but argues against the idea that material cost savings could be obtained with further analysis of the transmission costs or tweaks to the resource portfolio.¹⁶⁹ As support, the Company notes that a 30 percent reduction in the size of the resource portfolio only results in a 20 percent reduction in modeled transmission costs.¹⁷⁰

142. The large and unexpected costs of the transmission investments, the timing of the investments compared to the associated generation, and the analysis that resulted in the proposed transmission investments all support the selection of the Alternative Portfolio. The costs associated with curtailments is discussed above, but the UPP creates a timing mismatch in which the majority of the transmission resources will be put into service years after the generation resources. In addition, we share Staff’s questions as to whether alternatives exist that could reduce

¹⁶⁶ CEC’s Comments, pp. 5-7.

¹⁶⁷ UCA’s Comments, pp. 11-15.

¹⁶⁸ 120-Day Report, pp. 131-32.

¹⁶⁹ Public Service’s Response Comments, pp. 68-69.

¹⁷⁰ Public Service’s Response Comments, p. 69.

the overall costs and need for the network upgrades. While we cannot determine on this record whether the transmission network upgrades in the Denver Metro area will be necessary in the future,¹⁷¹ the Alternative Portfolio defers certain resource acquisitions. At the very least, the deferrals provide more opportunities to further evaluate the proposed transmission network upgrades and enable the Commission – and Colorado as a whole – to have greater confidence that the acquisition of new resources minimizes transmission investments and is in the public interest.

6. Conclusion

143. Granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio instead of the UPP will likely reduce costs to customers, especially when the Commission considers costs more generally. Such costs include those that are likely to result from the curtailments that the model fails to capture and the potential future costs associated with Company-owned gas resources in the UPP (*e.g.*, decommissioning). At the same time, the Alternative Portfolio is just as reliable as the UPP, and perhaps more so. While the modeling shows that the UPP achieves greater emissions reductions than the Alternative Portfolio, the Alternative Portfolio still exceeds the state's ambitious clean energy targets, while leaving open the possibility for more cost effective emission reductions in the future. Furthermore, the emissions reductions in the UPP, and especially the interim emissions reductions, appear to be optimistic given the likely impact of curtailments that the modeling presented in the 120-Day Report does not fully incorporate. Finally, pursuing a smaller, more tailored portfolio of resources is necessary for the public interest because it creates an opportunity to investigate how to better optimize transmission upgrades during resource selection and provides more opportunities to take advantage of

¹⁷¹ While the estimated cost of the transmission investments is still quite large in Alternative Plan, it is approximately \$397 million less than the associated transmission investments in the UPP (\$2,353 - \$1,956 = \$397). (*Compare* Public Service's Response Comments, p. 9, *with* 120-Day Report (Appendix S) Rev. 1, p. 26.)

developing technologies that might reduce or eliminate investments in traditional generation and transmission assets. Given the point in this Proceeding in which the significantly higher transmission costs were disclosed and the opportunity to take advantage of other technologies to limit ratepayer expenses, including the UPP in the approved CEP cannot be found to be in the public interest, as the UPP leaves too many unanswered questions and opportunities for optimization still on the table. As discussed throughout this decision, modifying the CEP by including the Alternative Portfolio is necessary to ensure the plan is in the public interest.

144. To reach an approved CEP that meets Colorado’s needs, we find that modification of the presented CEP to include the Alternative Portfolio is necessary to ensure the approved CEP is in the public interest. With its CEP activities—including the Coal Action Plan that is critical for reducing emissions—and the plans for workforce transition and community assistance, the modified CEP moves Colorado significantly forward in its clean energy transition.

F. Transmission

1. Phase II Changes in Transmission Investments

145. In Phase I of this Proceeding, Public Service explained that it would need to make transmission investments in four areas to accommodate the new generating resources to be procured: 1) Denver Metro network upgrades, 2) grid strength reinforcement, 3) reactive power/voltage support, and 4) generator interconnections. At that time, Public Service provided a “preliminary and illustrative” cost estimate of \$250 million for the Denver Metro upgrades, and a “rough” estimate of the combined costs for voltage support and grid strength of \$150 to \$250 million.¹⁷²

¹⁷² Hearing Exhibit 107, Direct Testimony and Attachments of Hari Singh, pp. 50-59.

146. In the 120-Day Report, the Company states that the transmission analysis it conducted to support the CEP is its most thorough transmission analysis for an ERP ever, involving numerous power flow studies, scenario modeling and “tabletop exercises” to develop project scoping and cost estimates. The Company states that 1) the scale and (largely remote) location of the new generation the Company will procure via this ERP, 2) the planned generation retirements the ERP entails, and 3) the lack of bids for new or existing generation located within the Denver Metro area transmission constraint all combine to require significant evolution of, and investment in, the transmission system to maintain reliable delivery of power to load centers.¹⁷³

147. More specifically, the Company states that its existing substations lack the space for expansions necessary to eliminate overloads and expand the system’s capacity, and that it has identified significant needs for new substations and new transmission lines. Moreover, it states that siting, permitting, and the need for extensive undergrounding in the Denver Metro area add cost and complexity to many of the network upgrade projects it has identified. Given these siting challenges, the Company states that its planning approach has been to create long-term ratepayer value by considering not only what upgrades are needed for its Preferred Portfolio, but also designing to accommodate future renewable development and growth in electricity demand.¹⁷⁴

148. The Phase II cost estimates for grid strength/voltage support and the MVLE are consistent with the estimates for those costs in Phase I of this Proceeding. However, the Company adds a new, previously unreported category of transmission investments in Phase II—the San Luis Valley (SLV) network upgrades with an estimated cost of \$176 million. In addition, in Phase II the estimated costs of the Denver Metro upgrades increase from \$250 million to \$2,146 million.

¹⁷³ 120-Day Report, pp. 128-134.

¹⁷⁴ 120-Day Report, pp. 128-134.

While Public Service asserts that its Phase II costs are not CPCN-level estimates, the Company states that its “process improvements” give it a higher confidence in these estimates than in those provided in previous ERPs.¹⁷⁵

149. The Company claims that the need for Metro Denver upgrades have greatly expanded in Phase II and that the Phase II analysis identified substantial network upgrades needed within the SLV as well. The Company states that “[w]hile the smaller portfolio of transmission projects contemplated in Phase I may have alleviated transmission overloads within a short time window, the customer value of a smaller transmission portfolio would be quickly overwhelmed by additional load growth and resource acquisitions, requiring costly and difficult upgrades to new transmission facilities.”¹⁷⁶ The Company stated reasons for the higher costs of the transmission investments include the following: siting and permitting challenges and the need for undergrounding many facilities in the Denver Metro area, the scale and location of new generation that will be acquired in this Proceeding, and the lack of cost-effective generation bids in the Denver Metro area.¹⁷⁷

2. Party Comments

150. Staff reiterates that Public Service’s transmission power flow analysis—conducted at the tail end of the Phase II modeling—estimates that almost \$3 billion in transmission investment is needed to support the Preferred Portfolio (in addition to the approximately \$1.7 billion investment recently approved in the CPP). Staff states that this estimated \$4.5 billion in transmission investments is perhaps “Staff’s largest concern with the Company’s Preferred

¹⁷⁵ 120-Day Report (Appendix Q), p. 3.

¹⁷⁶ 120-Day Report (Appendix Q), p. 11.

¹⁷⁷ 120-Day Report (Appendix Q), p. 12.

Plan.”¹⁷⁸ Staff reviews the Company’s explanation of the necessary transmission upgrades but states that it is left with more questions than answers. Staff recommends that 1) the Commission make clear that “the Commission is in no way approving the transmission projects presented and described in the Report;” 2) the Commission add consideration of improved integration between transmission and resource planning and modeling to the recently-opened transmission pre-rulemaking docket 23M-0472E; 3) the Commission consider directing the Company to file a standalone transmission planning application; and 4) that the Commission consider options for implementing an independent transmission monitor.¹⁷⁹

151. Staff acknowledges the concern that some of its recommendations could further delay transmission investments needed to deliver renewable energy. Given that many of the ISDs for the transmission investments are in 2029 and 2030, however, Staff argues that such delays might be avoidable.¹⁸⁰

152. CEO, UCA, and CEC similarly criticize the transmission network upgrade proposals the Company presents in the 120-Day Report. For example, CEO recommends the Commission clarify that it is not providing a presumption of prudence on the proposed Denver Metro transmission network upgrades until additional information is provided. Specifically, CEO recommends the Company provide more information on the degree to which upgrades are necessary for reliability, as compared to planning for future growth.¹⁸¹ UCA complains that the Company did not inform the Commission in the CPP proceeding that additional billions of dollars would be needed to deliver power from the CEP and states that had it

¹⁷⁸ Staff’s Comments, p. 8.

¹⁷⁹ Staff’s Comments, pp. 44-45.

¹⁸⁰ Staff’s Comments, p. 45.

¹⁸¹ CEO’s Comments, pp. 29-30.

been aware of the magnitude of the transmission upgrade needs the Company now claims, it would have approached the proceeding differently.¹⁸²

153. In contrast, other parties such as CIEA and COSSA/SEIA generally support the Company's proposed transmission investments.¹⁸³ In fact, COSSA/SEIA suggests that the transmission investments should be designed to accommodate continued growth in renewable energy development.¹⁸⁴

154. In its Response Comments, Public Service maintains that transmission projects will be necessary for any generation portfolio to achieve the aggressive emission reductions the State requires.¹⁸⁵ In response to party comments recommending that the Commission not provide final approval of the network upgrade projects, the Company notes that it has not sought such approval, and reiterates its recommendation that the Commission schedule a Commissioners' Information Meeting (CIM) on CEP-related transmission in the first quarter of 2024 where the Company can further detail its broader transmission plans and analysis, and answer Commissioner questions. Following this, the Commission and parties can vet transmission projects through CPCN filings.¹⁸⁶

155. The Company urges the Commission to deny the Staff recommendations to require a transmission planning proceeding and an independent transmission monitor. Public Service claims that "[t]hese recommendations are vague and would unnecessarily slow down the energy transition by requiring parties to expend valuable time and resources on processes with little, if any, incremental benefit."¹⁸⁷

¹⁸² UCA's Comments, pp. 14-15.

¹⁸³ *See, e.g.*, CIEA's Comments, pp. 19-20.

¹⁸⁴ COSSA/SEIA's Comments, pp. 20-21.

¹⁸⁵ Public Service's Response Comments, pp. 65-66.

¹⁸⁶ Public Service's Response Comments, pp. 66-67.

¹⁸⁷ Public Service's Response Comments, pp. 67-68.

156. The Company expresses strong disagreement with Staff's suggestion that generating resources should be delayed to future ERPs in recognition of the time it will take to put the new transmission assets into service (and the likely curtailment this will cause). The Company argues that the State's policy objectives do not allow for this delay, and it encourages the Commission to approve the UPP now. It claims that delaying approval of generation assets will only result in increased bid prices for generation and increase both the cost and siting difficulties for transmission.¹⁸⁸ Public Service further argues that using tools such as curtailment and redispatch in the short term as transmission buildout is completed is superior to delaying the acquisition of resources.¹⁸⁹

157. Responding to party arguments that some of the transmission upgrades are unnecessary, the Company notes that none of these parties conducted detailed transmission planning analyses and refers to their contentions as conjecture. The Company asserts that the transmission portfolio is a reasonable set of solutions and states that it sought to upgrade existing transmission facilities wherever possible instead of constructing new greenfield transmission lines.¹⁹⁰

3. Findings and Conclusions regarding Transmission

158. We share the serious concerns expressed by parties regarding the large, unexpected cost increases in transmission investments. After nearly three years of process, it was incredibly frustrating to see such a major failure of planning and estimating come to light so late in this Proceeding, upending the understandings of this Commission and many of the parties about the cost to integrate resources associated with this solicitation. Public Service will need to improve

¹⁸⁸ Public Service's Response Comments, pp. 72-73.

¹⁸⁹ Public Service's Response Comments, pp. 73-74.

¹⁹⁰ Public Service's Response Comments, pp. 70-72.

its transmission modelling and cost estimation processes in in future ERP proceedings to allow the Commission and relevant stakeholders a better ability to assess the critical links between generation and transmission resources. As noted above, the concern around transmission that arose in Phase II of this Proceeding was one of the factors that compelled us to select a smaller, more tailored resource portfolio.

159. In addition, the Commission emphasizes that the proposed transmission network upgrades, grid strength reinforcements, and reactive power/voltage support investments presented in the 120-Day Report are not part of the approved CEP. We are neither approving (or denying) these transmission actions here nor entitling the investments to any sort of presumption of prudence (or prejudice). Substantially more process will be required to fully assess the need for, alternatives to, and cost of remedial actions on the transmission grid in light of significant transition that this Proceeding initiates. Not only does the Company note that it is not seeking approval of those actions here, but the Commission has made clear it is modifying the CEP such that these actions are still to-be-determined with possible alternative solutions.

160. Moreover, as presented, the transmission network upgrades appear designed to accommodate future renewable development and growth in electricity demand, not *just* the CEP and its emissions reduction goals. Likewise, the alleged need for some of the proposed transmission upgrades may simply be the result of an aging system and changing dynamics. Though prudence only attaches to the “approved CEP,” Company filings continue to emphasize that the transmission network upgrades presented here are not part of its CEP.

161. In the context of the shocking cost increases associated with the new transmission and concerns regarding the analysis and vetting of the proposed alternatives to the transmission investments, the Commission agrees with Staff that we simply do not have enough information or

reliable modeling to authorize the spending on another \$2.8 billion in transmission investments at the current time.¹⁹¹ While the Commission recognizes that a prudency determination was not sought by the Company in this Proceeding, we are wary to approve a suite of resources that all but lock in the future need for significant additional future system expenses without first vetting alternatives to mitigate those costs. The Commission needs to see a more holistic picture of the various transmission projects arising from this Proceeding, including what investments are necessary and how the various transmission investments work together with other system requirements and constraints. This additional review of the proposed transmission projects is necessary even if Rule 3206 technically would not require a CPCN for some of the individual transmission projects in other circumstances. Accordingly, we waive Rule 3206 as to the transmission projects arising from this Proceeding; we emphasize that it is incumbent upon Public Service to provide a fulsome and comprehensive description of all transmission projects necessary to accommodate power delivery and maintain reliable service from the approved CEP. Thus, the Company is requested to bring forward one or more CPCN or other filings regarding transmission projects raised in this Proceeding. However, and particularly given our emphasis that selecting the Alternative Portfolio presents the opportunity that not every transmission project raised will ultimately be pursued, we leave it to the Company's discretion on how best to present this type of analysis to the Commission; *i.e.*, both in timing and type of filings made, but also with regard to the number or combination of filings.

162. The Commission does not oppose the Company's offer in its Response Comments to make a presentation on expected transmission requirements in a CIM. As a general matter, we are particularly interested in additional information regarding the differences in transmission plans

¹⁹¹ Staff's Comments, p. 45.

between the UPP and the Alternative Portfolio as well as any explanation the Company can provide regarding the failure to better anticipate the significant transmission needs in the Denver Metro area. Likewise, the Commission is interested in learning from Public Service how the Company's planning processes will improve and any innovative ways to approach future ERP proceedings so that the optimization of costs includes transmission investments, and to avoid similar major discrepancies between Phase I and Phase II expectations presented in modeling. Nevertheless, we recognize that when the Company proposed the transmission CIM, it did so in the context of the UPP rather than the Alternative Portfolio. Given the significant changes associated with the Alternative Portfolio and timing concerns with the upcoming filing of the 2024 JTS, we refrain from directing a transmission CIM at this time but invite the Company to determine the appropriate time and forum to address our concerns.

163. In addition, we find merit in Staff's proposal that the scope of Proceeding No. 23M-0472E (*i.e.*, regarding review of the provisions addressing transmission CPCN and planning in the Commission's Rules Regulating Electric Utilities, 4 CCR 723-3, in anticipation of future rulemaking) should be specifically defined to include consideration of improved processes for integrating transmission planning into generation resource plan proceedings and modeling. It is reasonable to expect that a previously unknown \$2 billion in additional expenses is an important variable to optimize around by reevaluating what different resource acquisition decisions would or could have been made to bring the entire portfolio of resource and transmission needs to a reasonable and optimized cost for ratepayers. As appropriate we will address these considerations in the context of Proceeding No. 23M-0472E, including through future order in that proceeding.¹⁹²

¹⁹² Staff and interested stakeholders are encouraged to bring forward proposals in the context of that proceeding. The Commission will address any necessary direction directly in the context of the pre-rulemaking proceeding.

164. We similarly find merit in Staff's recommendation to consider options for implementing an independent transmission analyst. The Commission sees value in having some independent transmission and power flow modeling expertise among Staff, CEO, and UCA with which the Company could collaborate. The presence of such outside expertise could help accelerate approvals and lessen the overwhelmingly negative reactions of "surprises," such as the \$2.2 billion in transmission network upgrades for the Denver Metro area. We see the primary role of this independent transmission analyst as building up the analytical capabilities of parties, particularly Staff, UCA, and CEO, regarding power flow modeling and other transmission issues.

165. Accordingly, we direct Staff to initiate a stakeholder process with UCA and CEO and in conferral with Public Service. The objective of the stakeholder process would be for Staff to bring forward a scope of work for hiring an independent transmission analyst. While we will leave it to the stakeholders to work through the details, this scope of work could be based on the IE contracting approach the Commission uses in ERP proceedings in which the Company contracts with the outside expert. Our expectation is that the analyst would work integrally with Staff. Ultimately, however, the independent transmission analyst must maintain independence from the Company.

166. Regarding timing, Staff should bring forward the proposed scope of work as soon as reasonably feasible but no later than through initial filings at the commencement of the 2024 JTS proceeding. Ideally, the independent transmission analyst could assist with the modeling in Phase I of the 2024 JTS. It would be ideal in Phase I of the process to have the help of an expert third-party to identify approximate quantities of certain resource types in targeted geographic areas to test assumptions about total costs for different portfolios, inclusive of both generation and transmission costs. We acknowledge the short timeframe this creates but find that time is of the

essence to ensure that the relevant state agencies have this type of expertise available during Phase I of the 2024 JTS to inform the parameters of the Phase II portfolios, given the shortcomings of this Proceeding.

167. As should be evident from our decisions on items such as the selection of the Alternative Portfolio and the directive for Staff to produce a scope of work for an independent transmission analyst, it is our expectation that the Company will look for better ways to model and analyze transmission costs in Phase I of the 2024 JTS. Part of these efforts should focus on mechanisms to provide reliable electrical service through dynamically managing both supply resource and demand resources—as opposed to simply building more generation and transmission resources.

168. We aspire for the independent transmission analyst discussed above to be engaged during Phase I of the 2024 JTS to bolster the analytical capabilities of Staff, CEO, and UCA regarding the integration of transmission and generation resources. However, given the possibility that the independent transmission analyst cannot be engaged in time for Phase I, as a backstop we direct Public Service to include certain portfolios in its direct case. Specifically, Public Service must present—at a bare minimum—one or more portfolios that examine minimizing transmission costs by increasing resources interconnecting in the Denver Metro area or using capacity on existing transmission lines, including capacity that will become available as thermal generating units retire. Broadly communicating the geographic areas for resource development anticipated to minimize transmission costs could also increase the likelihood of bidders to provide additional options in these target areas.

G. Performance Incentive Mechanisms

1. Background and Party Comments

169. After the filing of the 120-Day Report, in Decision No. C23-0672-I¹⁹³ the Commission directed the Company to submit comments outlining a potential symmetric risk sharing mechanism that would apply to Company-owned projects. The goal of this project-specific mechanism would be to better align customer and utility incentives, treat Company-owned generation projects in ways that are at least somewhat closer to the risks that are routinely imposed on IPP projects, and to ensure reasonable costs for customers.¹⁹⁴ While the Commission required a response from Public Service, it also invited comments from the intervenors.¹⁹⁵

170. On October 20, 2023, Public Service filed its Response to Decision No. C23-0672-I. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

171. Public Service proposes two complimentary risk-sharing proposals or PIMs, with possible variations for both PIMs. The first is a cost to construct PIM intended to incentivize the Company to complete projects within its estimated capital expenditures that formed the basis of its Phase II bids. The Company proposes either (1) a dead band with sharing approach, or (2) a fixed capital cost approach. For either of these two approaches, the Company recognizes that the Commission could implement the PIM on either a project specific basis or on a portfolio basis.¹⁹⁶

172. The second PIM is an “operational performance” PIM modeled after the Commission’s suggested Levelized Energy Cost (LEC) metric identified in Appendix P to the 120-Day Report. Noting that the committed energy and weather adjustment provisions of PPA

¹⁹³ Issued October 6, 2023.

¹⁹⁴ Decision No. C23-0672-I, p. 3.

¹⁹⁵ Decision No. C23-0672-I, p. 4.

¹⁹⁶ Response to Decision No. C23-0672-I, pp. 6-7.

allow IPPs some flexibility in how much energy their projects produce, the Company argues that a 15 percent dead band around the Appendix P LEC is appropriate.¹⁹⁷ The Company further argues that the operational PIM should not seek to manage curtailments but that this is better addressed in the emissions reduction PIM.¹⁹⁸ In fact, the Company argues that any operational PIM should include curtailed volumes in the calculation of the LEC in part because this avoids creating a perverse incentive to favor Company-owned generation when determining which units to curtail.¹⁹⁹

173. The Company asserts that the combination of these two PIMs should meet the Commission's expectation regarding cost discipline regarding both capital investment and operational performance.²⁰⁰

174. Under Staff's proposed PIM for utility-owned generation, Public Service would be required to recover the costs of Company-owned renewable generation assets entirely through the electric commodity adjustment (ECA) as opposed to base rates.²⁰¹

175. Other intervenors suggest various other types of PIMs in their comments to the 120-Day Report. For example, Boulder's suggestions include a PIM for Company-owned projects that would use as a baseline the cost of seemingly lower priced bids as well as a PIM to address the capacity factors for gas resources.²⁰² COSSA/SEIA suggests that the Commission consider deploying a PIM that would incentivize the on-time construction and deployment of new

¹⁹⁷ Response to Decision No. C23-0672-I, p. 11.

¹⁹⁸ Response to Decision No. C23-0672-I, pp. 12-13.

¹⁹⁹ Response to Decision No. C23-0672-I, p. 13.

²⁰⁰ Response to Decision No. C23-0672-I, pp. 1-2.

²⁰¹ Staff Response to Risk Sharing Mechanism, p. 14.

²⁰² Boulder's Comments, pp. 14-15.

transmission assets.²⁰³ Conservation Coalition in turn proposes a mechanism in which the Company would bear any incremental costs for hydrogen conversion of its gas plants.²⁰⁴

176. In its Response Comments, the Company appears to argue that the cost to construct PIM should only be a fixed capital cost approach based on the total portfolio. Without much explanation, Public Service states that to facilitate approval of a PIM framework in this Proceeding, there should be no dead band for the construction capital cost PIM. Instead, the baseline should be set at the approved portfolio capital budget/point cost estimate.²⁰⁵

177. For the operational PIM, the Company argues in its Response Comments that the baseline should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs. Public Service states that this is necessary to avoid double penalty or double reward.²⁰⁶ In addition, the Company states that the evaluation period for projects subject to the operational PIM should occur on three-year intervals beginning with the first through third full calendar years of project operation. As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027, and extend through December 31, 2029. Public Service argues that this promotes administrative efficiency and better addresses annual variation in weather, maintenance patterns and other performance drivers.²⁰⁷

178. In contrast, Public Service vehemently opposes Staff's proposal, stating that "[t]he magnitude and ramifications of this proposed sea change are difficult to overstate."²⁰⁸ Public Service asserts that Staff's PIM would "essentially deregulate generation in the state" in

²⁰³ COSSA/SEIA's Comments, pp. 20-21.

²⁰⁴ Conservation Coalition's Comments, pp. 16-17.

²⁰⁵ Public Service's Response Comments, pp. 81-82.

²⁰⁶ Public Service's Response Comments, p. 82.

²⁰⁷ Public Service's Response Comments, p. 82.

²⁰⁸ Public Service's Response Comments, p. 83.

that it would reconstitute the Company as an IPP in all but name.²⁰⁹ The Company argues that Staff's proposal would increase the risks conferred to the Company with little incremental benefit and no opportunity to price that risk into its bids. Public Service asserts that, if implemented, Staff's proposal "would require the Company to reassess its project commitments, increasing the cost and delaying the delivery of this plan, or whatever is left of it."²¹⁰

179. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing additional point costs and capacity factors data in connection with the Alternative Portfolio and setting forth the Company's proposed sharing percentages for the operational PIM in a non-confidential format.

2. Findings and Conclusions

180. The Commission appreciates that the Company has "sharpened its pencil" and is willing to "stand behind its pricing and performance metrics as bid."²¹¹ Given the significant amount of Company-owned generation projects in the portfolio of resources Public Service will acquire,²¹² this confidence and willingness to share risks is an important component of our decision to move forward with the Alternative Portfolio. In other contexts, costs, performance, or scheduling issues have increased costs for customers relative to the initial estimates the Company provided, and material changes to the cost and performance metrics of a project could impact the justification of the need determinations made in the ERP process.²¹³ More generally, competitive solicitation is the lynchpin of Colorado's ERP process, and a successful competitive solicitation

²⁰⁹ Public Service's Response Comments, p. 83.

²¹⁰ Public Service's Response Comments, p. 86.

²¹¹ Response to Decision No. C23-0672-I, p. 4.

²¹² Of the 5,835 MW that the Alternative Portfolio contemplates acquiring, Public Service would own 53.7 percent of the capacity resources and 67.3 percent of the energy resources. (120-Day Report (Appendix S), Rev. 1, p. 26.)

²¹³ See Decision No. C23-0672-I, pp. 2-3.

relies upon some degree of certainty that, after winning at a lower price, bidders will not be able to materially increase the price of their bids without consequences. To date, the Commission has not had a mechanism in place to hold the Company to their bids and performance, in a similar way to the IPP contracts, which has increasingly become a point of concern. In Phase I of this Proceeding, the Company put forth a plan to convert the Brush Coal Plant to burn natural gas at a capital cost of \$44 million. The Commission and parties relied upon the information provided by the Company to make decisions in Phase I of this Proceeding, broadly considered the Company's Coal Action Plan, which was agreed to be carried forward into the Phase II modeling. Several months later, the Company put forth a CPCN application to complete the conversion at the significantly increased cost of \$85 million. The Commission finds a compelling need to ensure that the pricing relied upon during this Proceeding will not be significantly altered after the fact without a meaningful sharing of risk with the Company. The Company-ownership PIMs that Public Service proposes help ensure that the Commission is making informed resource acquisition decisions, promoting fairness amongst the bidders and the Company, and providing necessary protections to ratepayers.²¹⁴

181. Accordingly, as part of the Commission's approval of the planned acquisition of Company-owned generations projects consistent with the Alternative Portfolio, we adopt a cost to construct PIM and an operational PIM for all Company-owned generation projects arising from this Proceeding.²¹⁵ These cost to construct and operational PIM are based on the Company's proposals, subject to the modifications detailed below.

²¹⁴ See Decision No. C23-0672-I, pp. 2-3.

²¹⁵ The cost to construct PIM applies to all Company-owned generation projects from this Proceeding, including Bid 1029. As set forth below, however, the operational PIM only applies to Company-owned LEC projects.

a. Cost to Construct PIM

182. Starting with the cost to construct PIM, we reject the Company's arguments that the cost to construct PIM should be applied on a portfolio basis. Rather, the cost to construct PIM shall be a project-specific PIM for each Company-owned project in the Alternative Portfolio. Applying this PIM on a portfolio level would be inconsistent with how IPP bids are treated and contrary to the underlying principles of the competitive solicitation that each project must stand on its own.

183. The baseline for each cost to construct PIM will be the point cost for capital costs to construct the particular generation project that was used in the Company's Phase II bid. In its Response to Decision No. C23-0672-I, Public Service states that "each Company-owned bid has a point cost for capital cost to construct that can serve as a baseline for PIM evaluation purposes."²¹⁶ During the course of Phase II, the Company provided the point costs for all relevant Company-owned projects.

184. Under the cost to construct PIM, there would be a five percent dead band around the baseline in which Public Service earns no incentive or disincentive. Outside of the five percent dead band, however, the Company and ratepayers would share any cost overruns or savings based on three symmetrical tiers. Specifically, for a total variance of more than 5.0 percent through 10.0 percent above or below the baseline, 40 percent of the cost overruns or savings would be allocated to Public Service. For a variance of more than 10.0 percent through 15.0 percent above or below the baseline, 50 percent of the cost overruns or savings would be allocated to Public Service. For any variance above or below 15.0 percent of the baseline, 60 percent of the cost overruns or savings would be allocated to Public Service.

²¹⁶ Response to Decision No. C23-0672-I, p. 6.

185. The sharing percentage will be applied to the overage and not on the total project amount. Also, there will be no deduction due to the 5 percent dead band or any other previous tiers. For example, if a project with a \$100 million point cost is actually constructed for \$114 million, Public Service would incur a \$7 million disincentive; *i.e.*, the 14 percent overage means that 50 percent of additional costs are allocated to Public Service (50 percent of \$14 million is \$7 million). The same calculation would be used if Public Service was able to construct the project for only \$86 million. In that scenario, the Company would earn a \$7 million incentive. Resolution of the appropriate PIM assessment (*i.e.* the calculation of any incentive or disincentive) will occur in the first rate case following the ISD of the relevant generation project.

b. Operational PIM

186. Turning to the operational PIM, the baseline will be the LEC for the relevant project set forth in the corrected Appendix P. The operational PIM will be applied on a project-specific basis. Except for LCC-based projects like standalone storage and gas, the operational PIM will apply to all Company-owned generation arising from this Proceeding. Regarding the exclusion of LCC-based projects, we find persuasive the Company's argument that including such project could have an unintended consequence of incentivizing the overuse of dispatchable resources in order to avoid penalties or to accrue incentives.²¹⁷

187. The Commission rejects the 15 percent dead band that Public Service proposes for the operational PIM and will replace it with a 5 percent dead band around the LEC baseline. This narrower dead band is supported by—among other things—CIEA's Comments. CIEA asserts that the Company either exaggerates or obscures the true costs and risks of its proposal when compared to PPA arrangements. CIEA points out that IPPs have no dead band around their bid

²¹⁷ Response to Decision No. C23-0672-I, p. 12.

price and suggests that the Company should not have the benefit of a dead band either.²¹⁸ While we do not agree that removing the dead band altogether is appropriate, we agree with CIEA that the intent of the PIM is to set the Company's bidding risk on par with IPPs more readily. Establishing the mechanism here with a narrower dead band than proposed by the Company better aligns these goals.

188. Aside from the narrower dead band, the basic calculation structure for assessing the incentive or disincentive under the operational PIM would generally match the Company's proposal. Specifically, for variances of more than 5 percent through 10 percent above or below the baseline, 20 percent of the costs or savings would be allocated to Public Service. For variances of more than 10 percent through 15 percent above or below the baseline, 30 percent of the costs or savings would be allocated to Public Service. For variances of more than 15 percent through 20 percent above or below the baseline, 40 percent of the costs or savings would be allocated to Public Service. For variances of more than 20 percent through 25 percent above or below the baseline, 50 percent of the costs or savings would be allocated to Public Service. And finally, for any variance more than 25 percent above or below the baseline, 60 percent of the costs or savings would be allocated to Public Service.²¹⁹

189. Regarding the timing of performance evaluations, the Commission agrees with the Company that performance evaluation for projects should be conducted on a three-year rolling average after the third full operational year is complete and on a similar cadence thereafter.²²⁰

²¹⁸ CIEA's Comments (Attachment A), p. 5-6.

²¹⁹ See Public Service's Response to Decision No. C23-0841, pp. 2-3.

²²⁰ In its Response Comments, Public Service provides the following example of this timing: "As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027 and extend through December 31, 2029." (Public Service's Response Comments, p. 82).

This approach will stagger the performance reviews so that a subset of projects (*e.g.*, all those with 2026 ISDs) is evaluated each year.

190. We similarly agree with Public Service's arguments that the baseline of the operational PIM should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs.²²¹ Excluding the effect of construction capital expenditures is necessary to avoid double penalty or double reward.

191. In connection with the establishment of the operational PIM, all projects subject to the operational PIM in this Proceeding will receive cost recovery through the appropriate rider (RESA or ECA) from the ISD of the project until the project is rolled into base rates.

192. While we direct that the operational PIM as described above apply to all Company-owned LEC projects arising from this Proceeding, we recognize that certain considerations warrant further exploration in future proceedings. For instance, we invite interested stakeholders and the Company to explore whether an operational PIM could be crafted in which the baseline is derived from the project's estimated capacity factor as opposed to the estimated LEC. This would essentially exclude factors such as the capital construction costs and the Company's estimated WACC. We welcome a more robust consideration of this approach in the upcoming 2024 JTS.

193. Similarly, we reiterate the importance of timing as a performance metric,²²² and have a strong interest in evaluating in the follow-on CPCN proceedings a mechanism to incentivize timely completion of Company-owned projects, in accordance with the timing anticipated in the modeling and bidding processes. For example, one possibility would be to commence the LEC

²²¹ Public Service's Response Comments, p. 82.

²²² See Decision No. C23-0672-I, ¶ 6.

calculations on the as-bid ISD of the Company-owned project. Thus, if the as-bid ISD of a project was May of 2026 but the project experienced delays and did not commence operations until October 2026, this six-month delay would decrease the project's achieved LEC as compared to the as-bid baseline LEC. While we do not adopt this structure as part of this Decision, we intend to evaluate in the follow on CPCN proceedings how best to align the Company's incentives regarding the completion of generation projects.

194. Regarding curtailments, we likewise intend to continue evaluating in the follow on CPCN proceedings how exactly the operational PIM should account for curtailments. To be clear, we do not intend for the operational PIM to somehow shift the risk of curtailments on to the Company. The issue of appropriately disincentivizing curtailments across the entire electrical system is better addressed elsewhere, including possibly through the emissions reduction PIM that the Phase I Decision contemplates. In this way, we largely agree with the Company's position that the operational PIM should not seek to manage curtailments.²²³ Nevertheless, there are unresolved details regarding how to make the operational PIM appropriately indifferent to curtailments, and we intend to address these details in the follow on CPCN proceedings.

c. Extraordinary Circumstances

195. Finally, as to both the cost to construct PIM and the operational PIM, the Commission finds merit in Public Service's argument that the Company should be able to petition the Commission for relief in the event of extraordinary circumstances. In other words, Public Service can seek relief from the Commission for any amounts assessed to the Company under either the cost to construct PIM or the operational PIM, with the Company bearing the burden of establishing the existence of extraordinary circumstances and the impact of any such

²²³ Response to Decision No. C23-0672-I, pp. 12-13.

circumstances on unit construction.²²⁴ We clarify that the starting point for the definition of “extraordinary circumstances” could be similar to the definition of “force majeure” in the Model PPA for Wind and Solar.²²⁵ That said, in the proceeding in which the Company attempts to establish the existence of extraordinary circumstances, the parties—including the Company—may advocate for modifications to the definition of “extraordinary circumstances” as appropriate, recognizing that Company-owned projects may not have identical extraordinary issues to the Model PPA.

d. Other proposed PIMs

196. We decline to implement Staff’s proposed PIM in this Proceeding given our adoption of a cost to construct PIM and operational PIM. Nevertheless, we are intrigued about the possibilities offered by Staff’s PIM. As Staff notes, under its PIM, cost recovery increases in direct proportion to the amount of renewable energy the assets produce while also tying cost recovery to Public Service’s Phase II bids. Likewise, the PIM would account for both capital construction costs and performance of the assets.²²⁶ The Commission sees Staff’s PIM as a potential avenue to engage in performance based regulation (PBR) on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking, providing a potential opportunity to realign utility incentives to benefit ratepayers.

197. Many of Public Service’s arguments against Staff’s PIM are focused on why it should not be applied to the Company-owned projects arising from this Proceeding. Arguments that Staff’s PIM “moves the goalposts” after submission of Phase II bids and that Staff’s PIM has many unresolved details might be legitimate as to this Proceeding but are far less

²²⁴ Response to Decision No. C23-0672-I, p. 15.

²²⁵ Hearing Exhibit 101, Attachment AKJ-3 (Volume 3.2), pp. 142-43.

²²⁶ Staff’s Response to Decision No. C23-0672-I, pp. 14-15.

persuasive regarding future implementation of Staff's PIM. Given the Commission's longstanding interest in PBR and the fact that the Commission has already approved a similar approach for one of Black Hills' wind projects,²²⁷ the Company's claims that Staff's PIM would essentially deregulate generation in Colorado seem exaggerated.

198. The Commission intends to evaluate in the 2024 JTS whether Staff's PIM can be applied to the Company-owned projects arising from that proceeding. As such, we request that Public Service confer with Staff on its proposed PIM²²⁸ prior to the 2024 JTS in an attempt to reach consensus. Regardless of the outcome of the conferral, we invite the parties in the 2024 JTS to raise this issue for our continued consideration.

199. As for the remaining proposed PIMs, including those that Boulder, COSSA/SEIA, and Conservation Coalition put forth in their comments, we decline to adopt these concepts in this Proceeding. Although the expedited nature of this Phase II process did not allow for the development of a robust record for these proposals, we invite the parties to consider bringing these proposals forward in the PIM stakeholder process that the Phase I Decision contemplates and through future proceedings.

H. The Sand Creek Massacre National Historic Site and Bid 1029

200. Bid 1029 is included in the Preferred Portfolio, the UPP, and the Alternative Portfolio and is a 500 MW Company-owned wind project with an in-service date of 2026. Although the Commission does not know the precise location of Bid 1029, it appears to be close to and possibly adversely impacts, the Sand Creek Massacre National Historic Site view shed.

²²⁷ Staff recounts that Black Hills recovers the cost of the Peak View wind farm exclusively through the ECA and RESA for the first ten years of commercial operation. (Staff's Response to Decision No. C23-0672-I, p. 9).

²²⁸ This conferral should include further evaluation of whether Staff's PIM could be modified to apply to LCC-based projects instead of only LEC-based projects.

201. On October 25, 2023, elder and tribal administrator Mr. William Walksalong of the Northern Cheyenne Nation spoke at the Commissioner's weekly business meeting. Through comments, tribal representatives requested that the Commission protect from energy development the viewshed of the Sand Creek Massacre National Historic Site given its sacred importance to several tribal nations. In addition, Mr. Walksalong asked that the Commission ensure that energy development not disturb any human remains or cultural artifacts from the area around the Sand Creek Massacre National Historic Site. Mr. Walksalong noted that the massacre spilled well-beyond the boundaries of the Sand Creek Massacre National Historic Site that Congress has designated. Consequently, he urged the Commission to require utilities and developers to consult tribal representatives as to how to proceed should remains or artifacts be discovered in the course of construction.

202. In its comments, Staff recommends the Commission not approve Bid 1029 as part of this Proceeding. Staff asserts that a preliminary viewshed analysis indicates that wind turbines from Bid 1029 might impact the Sand Creek Massacre National Historic Site's viewshed. Staff also ran its own modeling runs that forced the model to exclude Bid 1029 and suggests that the Commission could approve a 200 MW solar plant (Bid 375) or a 603 MW wind plant (Bid 1024) in place of Bid 1029.²²⁹

203. CEO also recognizes concerns regarding Bid 1029 but does not suggest that the Commission exclude it from the approved CEP. Rather, CEO recommends the Commission direct the Company to include additional information in subsequent CPCNs, including discussions between the Company and Tribal governments regarding the proposed projects, the status of those

²²⁹ Staff's Comments, p. 58-59.

discussions, and any outcomes or results of such discussions.²³⁰ CEO argues that approach will allow the Commission to take action in the instant proceeding consistent with the presentation by the Northern Cheyenne Nation and also rely on the existing CPCN process to consider alternatives and proposed impacts when making a determination on specific resource proposals.²³¹

204. In its Response Comments, Public Service argues that Bid 1029 has “strong economics” and was included in almost all portfolios. Thus, the Company maintains that it would be premature to set this bid aside. Public Service does, however, acknowledge Staff’s concerns and states that the identified impacts are important to work through and address. Indeed, the Company states that it is already engaged with these issues. Ultimately, Public Service asks that the Commission allow Bid 1029 to move forward and states that the Company would then provide an update on efforts to mitigate the impacts of concern in the follow on CPCN proceeding.²³²

205. The Commission agrees with the positions of Public Service and CEO and rejects Staff’s proposal to exclude Bid 1029 from the approved CEP. We emphasize, however, that allowing the Company to include Bid 1029 in the Alternative Portfolio is in no way an approval of the project, which must necessarily be vetted through continued stakeholder and community considerations. In this vein, we adopt Public Service’s suggestion to approve a backup bid for Bid 1029 so that the Company can pivot to a different project if stakeholder processes, including the Company’s further discussions with the Northern Cheyenne Nation, do not resolve concerns. In addition, we adopt CEO’s recommendation and direct Public Service to include additional information in subsequent CPCN proceedings, including discussions between the Company and Tribal governments.

²³⁰ CEO’s Comments, pp. 26.

²³¹ CEO’s Comments, pp. 26.

²³² Public Service’s Response Comments, pp. 23-24.

206. Resolution of this issue will require collaboration of the interested stakeholders, and we are encouraged by indications that Public Service is already engaging with the Northern Cheyenne Nation regarding Bid 1029. In this instance, Public Service needs to take the lead and work with interested stakeholders, including the Northern Cheyenne Nation, to address potential impacts to the Sand Creek Massacre National Historic Site.

207. As to the precise backup for Bid 1029, in its Response Comments Public Service recommends that the Commission approve Bid 1018. However, Bid 1018 is unavailable as a backup because it is located on the MVLE, which the Alternative Portfolio does not include. Ultimately, we permit the Company discretion to select an appropriate backup for Bid 1029 pursuant to the approved backup selection process set forth in this Decision. We note, however, that Bid 1016 (a 554 MW Company-owned wind bid) appears to be a good candidate.

I. Hayden Biomass

208. Bid 1031 is a 19 MW Company-owned biomass project that Public Service proposes as a Section 123 resource.²³³ The proposed project is located near Hayden, Colorado to support workforce transition as part of the planned retirement of the Hayden coal units.²³⁴

209. Public Service states that it would employ 26 full-time employees, thus reducing workforce transition costs associated with the early retirement of the Hayden coal plants. Public Service further asserts that the project, which is anticipated to use primarily forest waste from fire prevention activities and debris from pine beetle outbreaks, is carbon neutral and would reduce air emissions, including particulate matter, carbon monoxide, volatile organics, and

²³³ Public Service also states that it “complies with the spirit of” the portfolio development framework for HB 21-1324. (120-Day Report, p. 52).

²³⁴ In its Response Comments, Public Service intentionally presents the bid name with the bid ID as public information.

nitrogen oxides.²³⁵ In comparing the Preferred Portfolio with the Hayden biomass project to a reoptimized portfolio without the project, the portfolio excluding biomass adds 19 MW gas and 200 MW solar and is \$257 million less in PVRR.²³⁶

1. Party Comments

210. The Labor Interests argue that the Hayden biomass project should belong in any Commission-approved portfolio, listing its benefits as including 26 well-paid jobs and a high total BVEM rating for its construction phase. The Labor Interests add that the Hayden biomass unit represents an innovative technology under both Section 123 and HB 21-1324, noting that wind and solar projects have often dominated discussions about innovation despite patterns of low-paying jobs post-construction.²³⁷

211. CEO supports the inclusion of the Hayden biomass plant in the Commission-approved CEP primarily because of its just transition benefits. CEO acknowledges, however, that Public Service “does not provide information on the salaries or the estimated tax benefits” and requests that the Company provide more details about the public benefits of the project “so the Commission has a full record on which to make its Phase II decision.”²³⁸ CEO also notes the relatively high cost of the biomass plant, concluding that the Hayden biomass project increases the PVRR of the Preferred Portfolio by \$257 million.²³⁹ CEO recommends that if the Commission does not approve the Hayden Biomass project here, the Commission direct the Company to evaluate the project in future ERPs for additional consideration.²⁴⁰

²³⁵ 120-Day Report, p. 40.

²³⁶ 120-Day Report, p. 138.

²³⁷ Labor Interests’ Comments, pp. 11-14.

²³⁸ CEO’s Comments, p. 23.

²³⁹ CEO’s Comments, p. 22.

²⁴⁰ CEO’s Comments, pp. 17.

212. OJT endorses CEO's Comments as to the just transition issues, including the evaluation of the Hayden biomass project.²⁴¹ OJT opines that the biomass project would employ a third of the coal plant's current workforce, generate a "significant, though yet-unspecified, amount of property tax revenues," and create long-term supply chain jobs in the region for timber harvesting and processing.²⁴² However, OJT also requests that Public Service provide more specific information on the expected local economic and employment benefits, including information about jobs retained or created and property and other tax revenues generated.²⁴³

213. Public comments from entities such as the Moffat County Board of County Commissioners, the Routt County Board of County Commissioners, the City of Craig, Northwest Colorado Development Council, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden also expressed support for the Hayden biomass project, citing the risk that not replacing the coal plant will lead to cascading effects in the form of losing high-paying jobs and reducing funding for important government services.

214. In contrast, certain other parties recommend the Commission reject the Hayden biomass project and potentially reconsider it in an alternative proceeding, mostly pointing to the upcoming 2024 JTS. For example, CEC asserts that the Company has not established that the project is the best solution for the Hayden community, nor that it is worth the additional expense or necessary for emissions reductions.²⁴⁴

215. Staff argues that the Hayden biomass project is very high cost and is overall uneconomic, with unclear information about jobs benefits and tax revenue replacement.

²⁴¹ OJT's Comments, p. 3.

²⁴² OJT's Comments, p. 6.

²⁴³ See OJT's Comments, pp. 3, 6.

²⁴⁴ CEC's Comments, pp. 13-14.

Staff asserts that the Hayden biomass plant is not designed as a closed-loop facility and thus will not enjoy access to a full production tax credit, meaning that the cost of the biomass unit presented in the 120-Day Report is artificially low. Staff states that it conferred with the Company, which agreed with this critique.²⁴⁵ Staff also raises concerns that the Hayden biomass project is not sufficiently novel or scalable to be a Section 123 project.²⁴⁶ Staff suggests that the Commission consider alternatives to the biomass facility in future proceedings.²⁴⁷

216. Similar to Staff, WRA raises concerns not only about cost, but also about environmental claims made about the Hayden biomass project. Referencing recent studies, WRA asserts that emissions from the harvesting stage strongly erode any potential emissions benefit, and inefficiencies mean electricity generation with woody biomass can be more carbon-intensive per MWh than coal-generated electricity.²⁴⁸ WRA argues that Public Service's assertions about the Hayden biomass project being greenhouse gas neutral are incorrect as a matter of practice—biomass electricity generation produces carbon dioxide—and also that the Company has failed to provide information demonstrating that emissions released from combustion are less than would have been emitted without being converted to electrification, pursuant to § 40-2-124(1)(a)(IV).²⁴⁹ Moreover, WRA states that the 120-Day Report provides insufficient information about planned forest management practices and leaves open the idea that other fuel would be used besides that from fire prevention and pine beetle kill.²⁵⁰

217. Like Staff and WRA, Conservation Coalition raises concerns that greenhouse gas emissions from the biomass project will exceed the Company's estimates. Conservation Coalition

²⁴⁵ Staff's Comments, p. 53.

²⁴⁶ Staff's Comments, pp. 51-52.

²⁴⁷ Staff's Comments, p. 51.

²⁴⁸ WRA's Comments, pp. 9-10.

²⁴⁹ WRA's Comments, p. 11.

²⁵⁰ WRA's Comments, p. 12.

argues that the Commission can consider additional measures for the Hayden community in the 2024 JTS, noting that the last unit at Hayden is not scheduled to retire until 2028.²⁵¹ Additionally, public comments from entities like 350 Colorado similarly urge the Commission to find other ways to meet just transition needs due to environmental risks associated with the proposed biomass project, including air pollutant emissions and the potential that salvage logging and deforestation activities may be required to meet fuel needs.

218. In its Response Comments, Public Service reiterates that the Hayden biomass project contributes to three policy objectives: developing clean firm dispatchable capacity with wildfire mitigation benefits, making progress towards emissions reduction goals, and providing just transition benefits. The Company states that not providing new workforce opportunities for communities affected by energy transition is “not a viable path.”²⁵² However, Public Service also recognizes that questions about cost and tax credit eligibility are legitimate, and therefore proposes alternative procedural pathways, including conditional approval of the project with additional analysis in a follow-on CPCN filing or consideration within the Hayden JTP filing.²⁵³

2. Findings and Conclusions

219. In its Phase I Decision, the Commission approved provisions of the Phase I Settlement specifying that Public Service will make follow-on JTP filings for each area with an affected coal plant after the Phase II final decision.²⁵⁴ For purposes of Phase II modeling, JTP costs will include costs associated with workforce transition and community assistance.

²⁵¹ Conservation Coalition’s Comments, pp. 15-16.

²⁵² Public Service’s Response Comments, p. 19.

²⁵³ Public Service’s Response Comments, pp. 19-20.

²⁵⁴ Phase I Settlement, ¶ 109.

220. Regarding the Hayden 1 and Hayden 2 coal plants, the estimated costs of the community assistance is the projected lost property tax revenues for six years following retirement of the respective plant, but these costs may be offset by other investments in the community.²⁵⁵

221. The Commission takes seriously its role in supporting a just transition for workers and communities that are impacted by the closure of coal units as part of creating a cleaner energy system. The labors and skills of these communities helped propel Colorado's economy and the reliable electricity we have enjoyed for generations. We have a commitment to do what we can to ensure these communities are not left behind in the energy transition, and this might go beyond even the six-year commitment that was contemplated in the Phase I Settlement. Regarding the closures of Hayden 1 and Hayden 2, we recognize the transmission resources that will be made available in the near future as well as the potential expansion of these transmission resources into the western market. In short, the Commission is hopeful that there will be opportunities for resource development that benefit both local communities and ratepayers in general.

222. Nevertheless, we decline to approve the Hayden biomass project in this Proceeding. We do not have in front of us a complete proposal that allows us to determine whether the project is in the public interest. For example, we are concerned by Staff's assertion that the Company will not qualify for closed-loop biomass tax credits, which leaves the actual cost of the project uncertain, and we are troubled by the potential environmental impacts of the plant that WRA and others raise. Moreover, even CEO and OJT seem to acknowledge that the current proposal lacks important information regarding workforce transition and community benefits. The Hayden biomass project would cost ratepayers approximately \$257 million in PVRR before upward

²⁵⁵ Phase I Settlement, p. 19.

adjustments due to tax credit miscalculations, and this is for a relatively small 19 MW project that would replace what has been hundreds of MW of capacity from the Hayden coal plants.²⁵⁶

223. While we decline to approve the Hayden biomass project here, in the event Public Service develops clearer answers to the questions raised by parties about the environmental, financial, workforce, and community benefits of the plant, we encourage the Company to bring this or another just transition proposal forward for further consideration as part of the 2024 JTS. The 2024 JTS proceeding²⁵⁷—as opposed to the Hayden JTP or a standalone CPCN—will allow the Commission and stakeholder to evaluate the costs and benefits of the biomass project, if rebid, more holistically with other alternatives, including potentially other bids from IPPs that could provide similar tax, employment, and other benefits to the local community. We conclude that reconsidering this or other similar projects in a full competitive solicitation will be the best way to maximize benefits to both the Hayden community and to ratepayers more generally.

224. To effectuate this, Public Service shall confer with relevant stakeholders and determine whether it makes sense to bring forward the Hayden JTP within 120 days of the Phase II decision, consistent with approved provisions of the Phase I Settlement, or to postpone that filing. In conferral with settling parties, and particularly those affected by the potential Hayden JTP filing, since the Hayden Biomass project or other beneficial projects could potentially be reevaluated in the 2024 JTS, we permit flexibility on whether the Hayden JTP should be filed 120 days following the Phase II decision or at a later date.

²⁵⁶ See CEO's Comments, p. 22 (comparing Preferred Portfolio with Hayden biomass to the Preferred Portfolio without Hayden biomass).

²⁵⁷ The Commission emphasizes that the primary focus of the 2024 JTS is the replacement of Unit 3 and the corresponding impacts to the Pueblo community. Nevertheless, as an interim ERP the 2024 JTS also provides an opportunity to evaluate more holistically the various resource opportunities in the Hayden community.

J. Backup Bids

225. In the 120-Day Report, the Company proposes three tools to mitigate the risks associated with potential project failure: extensive due diligence, right of first offer (ROFO), and backup bids. Public Service further notes that the 2024 JTS allows for a more rapid opportunity to course correct than the standard four-year ERP cycle typically provides.²⁵⁸ Regarding the backup bids, Public Service states that these bids are intended to be pre-approved by the Commission as a set of projects to be “next in line” to replace a project in the approved portfolio if it fails.

1. Party Comments

226. Staff is generally supportive of the establishment of a pool of back-up resources. However, Staff is concerned that approving a backup pool of bids that includes both Company-owned and PPA bids may create perverse incentives for the Company in negotiating projects. For instance, Staff questions whether the Company’s PPA negotiations with an IPP would be impacted if the IPP project would be replaced with a Company-owned project.²⁵⁹

227. Staff recommends that the Commission consider a back-up bid replacement process in which additional process is required for Company-owned backup bids. If a failed project is being replaced by a PPA project, the Company should notify the Commission of such a failure and the steps it intends to take to address the failure, but the Company need not seek Commission approval prior to commencing negotiations. If a failed project is being replaced by a Company-owned project, however, the Company would be required to do the following: (a) notify the Commission and provide additional evidence and detail regarding the steps taken to attempt to

²⁵⁸ 120-Day Report, pp. 44-46.

²⁵⁹ Staff’s Comments, p. 66.

remediate the failed project; (b) retain the burden to prove that the Company-owned project was the prudent replacement; and (c) provide robust alternatives analysis as part of the follow-on CPCN proceeding. Regarding the available pool of backup bids, Staff recommends that any project included in the Company's inverse Preferred Portfolio that is not ultimately approved in this Proceeding should be eligible for inclusion in the back-up pool.²⁶⁰

228. Similar to Staff, CIEA approves of the backup bid concept and recommends that the Commission approve the backup bid projects as contingency projects. However, CIEA asserts that it will be important for the Commission to clarify the back-up bid process and list clear criteria to avoid controversy in the implementation of Phase II.²⁶¹

229. COSSA/SEIA also raises concerns with perverse incentives that could arise when an IPP project fails but focuses its concern on the Company's ROFO. The ROFO is a provision in the model PPA that allows the Company to step into a failed IPP project and take over development. COSSA/SEIA recommends that the Commission require the Company to first use its identified list of backup bids before deploying the ROFO, as the latter guarantees that the Company's ownership share will grow after a project fails. COSSA/SEIA argues that allowing for ROFO to be used prior to backup bids could incentivize the Company to slow-walk PPA negotiations, placing IPP projects in peril, with the knowledge that the Company can simply offer to buy the developer out if or when the project goes south.²⁶²

230. In its Response Comments, the Company agrees that some of the intervenor recommendations have merit but argues for the importance of maintaining price integrity and

²⁶⁰ Staff's Comments, p. 66.

²⁶¹ CIEA's Comments, pp. 24-25.

²⁶² COSSA/SEIA's Comments, pp. 18-20.

allowing for flexibility to move to a backup bid for timely replacement.²⁶³ The Company argues that, to the extent practicable, the Company will try to select “like for like” backup bids both in terms of technology and ownership. More specifically, Public Service argues that it should be able to move forward with an IPP backup bid after a simple notice provided to the Commission and when the backup bid is Company-owned, the Company should only be subject to a “limited-scope” CPCN process similar to any other Company-owned project in an approved resource plan.²⁶⁴

231. Public Service argues against adopting an approach set forth by Staff and others in which the Company would be required to undergo more process when it replaces an IPP project with a Company-owned project. The Company acknowledges the “academic” concerns about perverse incentives but argues that its commitment to strive for “like for like” replacements and the Company’s conduct in this Proceeding should comfort the Commission.²⁶⁵ Public Service further argues that a limited scope CPCN is appropriate because Company-owned replacement projects would need to move quickly in order to meet resource needs.

232. Public Service also argues the presumption of prudence under Rule 3617(d) should apply to all backup bids as they move forward, providing regulatory certainty for these projects.

233. Finally, in its Response Comments, Public Service notes two resource modifications in the UPP: (1) replacing a Company-owned solar plus storage project (Bid 0476) with an IPP solar plus storage project (Bid 0303), and (2) replacing a Company-owned wind project (Bid 0045) with a different Company-owned wind project (Bid 1024). The Company also requests that the Commission approve a specific backup for Bid 0044. Bid 0044 is an IPP wind

²⁶³ Public Service’s Response Comments, pp. 39-40.

²⁶⁴ Public Service’s Response Comments, p. 42.

²⁶⁵ As an example of the Company’s conduct, Public Service notes that in the UPP the Company proposes to replace a Company-owned bid (Bid 0467) with an IPP bid (Bid 0303). (Public Service’s Response Comments, p. 42).

bid that might not be able to move forward at its as-bid price. The Company requests that the Commission approve Bid 0254 as its backup. Bid 0254 is also an IPP wind project.²⁶⁶

234. Because the resource modifications in the UPP impact the backup bid portfolio, Public Service provides an updated portfolio of backup bids set forth in Table 3 of its Response Comments.²⁶⁷

2. Findings and Conclusions

235. At the outset, the Commission expressly approves the updated list of backup bids set forth in Table 3 of the Company's Response Comments. Recognizing that the backup bids in Table 3 were compiled in anticipation of the UPP and not the Alternative Portfolio, however, we clarify that the Company may use its discretion to adjust the portfolio of backup bids as necessary given the authorizations we have attached to the Alternative Portfolio. For instance, consistent with Staff's recommendation to include projects from the inverse Preferred Portfolio, it would be reasonable to include as a backup bid any bid within the UPP that is not in the Alternative Portfolio.

236. In addition, we agree with the Company's position and confirm that the presumption of prudence set forth in Rule 3617(d) applies to any backup bid that moves forward in accordance with the Commission's approved process for selecting backup bids.

237. Regarding the selection of backup bids, the Commission finds merit in the concerns raised by Staff, CIEA, and COSSA/SEIA that there should be more process in place for when Public Service selects a Company-owned backup bid or when the Company uses its ROFO to buy-out a failing IPP bid. We find persuasive the arguments regarding perverse incentives and worry that without additional process, the selection of a Company-owned backup bid or the

²⁶⁶ See Public Service's Response Comments, p. 6.

²⁶⁷ Public Service's Response Comments, p. 27.

exercise of the Company's ROFO could give rise to the appearance of bias. While the Commission acknowledges the benefits of allowing the Company discretion to quickly pivot to a backup bid, these benefits must be balanced with guardrails that protect customers, enhance fairness amongst bidders, and increase transparency. Conversely, the Commission disagrees with suggestions from CIEA that the Commission should establish clear criteria for the selection of backup bids or mandate like-for-like replacements. Apart from concerns regarding the selection of a Company-owned bid instead of an IPP project, we believe that Public Service should have the flexibility to use its discretion to select the most appropriate backup bid.

238. Accordingly, we generally adopt Staff's suggested approach in which—among other things—Public Service retains the burden of proving that any Company-owned backup project was the prudent replacement and would need to provide a robust alternatives analysis as part of the follow-on CPCN proceeding.²⁶⁸ The additional protections set forth in Staff's approach also apply when the Company exercises its ROFO and when the Company replaces a Company-owned project with a Company-owned backup. That said, we emphasize that the additional process set forth in Staff's proposal must move quickly, especially in instances in which the replacement is like for like.

239. Finally, we clarify that the backup bid selection process set forth above does not apply to the two replacement projects the Company proposed as part of the UPP. Specifically, the Company may replace Bid 0476 with Bid 0303 and may replace Bid 0045 with Bid 1024. The Company already explains the need for replacement and the economics of alternative backup bids in its Response Comments. Moreover, the concerns that the Company would have perverse incentives during PPA negotiations do not apply at this point in the process. For the same reasons,

²⁶⁸ See Staff's Comments, p. 66.

we approve Bid 0254 as the backup bid for Bid 0044 if Bid 0044 cannot move forward. Acknowledging that the Company's Response Comments presumed the selection of the UPP, as opposed to the Alternative Portfolio, we clarify that the Company has the flexibility to make the necessary resource modifications consistent with the Company's Response Comments.

K. Section 123 Resources

240. In the 120-Day Report, Public Service states five bids qualified as Section 123 Resources pursuant to the criteria established in the Phase I Decision.²⁶⁹ In addition to the Hayden biomass project, Bids 0011, 0106, 0269, and 0552 were considered as Section 123 Resources. Other than the Hayden biomass, only Bid 0011 was sometimes selected in the Phase II portfolios.²⁷⁰ While Public Service included the Hayden biomass project in its Preferred Portfolio, the Company rejected the other Section 123 resources for various reasons, including cost, project risk, and location. Regarding Bid 0106 (a hydrogen fuel cell project) and Bid 0269 (a long-duration storage project), the Company states that there could be long term benefits if these projects are successful. Public Service states that the Company would be interested in moving forward with these projects if the Commission were to approve them *in addition to* the other projects in the Preferred Portfolio.²⁷¹

241. CEO supports the Commission approving Bid 0106 (the hydrogen fuel cell project). CEO argues that pursuing this project as a firm resource would help the state continue its development of hydrogen as a pathway to decarbonization. While CEO acknowledges the project involves certain risks, CEO argues that the potential benefits outweigh these risks, noting that the

²⁶⁹ Public Service notes that one additional project claimed Section 123 but did not meet the Phase I Decision's criteria.

²⁷⁰ 120-Day Report, p. 139.

²⁷¹ 120-Day Report, pp. 150-51.

State intends to continue pursuing the development of hydrogen. Alternatively, if the Commission does not believe it is the right time to approve the project, CEO recommends that the Commission “direct Public Service to pursue a similar project in either the Just Transition Plan or through its next ERP in 2026.”²⁷²

242. In its Response Comments, Public Service maintains that it does not recommend approval of the project as part of this Phase II ERP. However, the Company states that it appreciates and shares CEO’s interest in pursuing the hydrogen fuel cell project and that Public Service is interested in exploring the viability of the project. Public Service goes on to state that it sees opportunities to pursue Bid 0106 or other hydrogen projects as part of proceedings conducted pursuant to HB 23-1281, the upcoming 2024 JTS, or through a separate filing.²⁷³

243. Pursuant to § 40-2-123(1)(a), C.R.S., the Commission shall:

give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado’s energy security, economic prosperity, insulation from fuel price increases, and environmental protection, including risk mitigation in areas of high wildfire risk as designated by the state forest service.

244. As required, the Commission has fully considered Section 123 Resources. This consideration began in Phase I when the Commission approved a modeling approach for Section 123 Resources and adopted guidelines proposed by Public Service to define these resources, emphasizing that they must be new, innovative, not commercialized, and could not include standalone wind, solar, or lithium-ion storage.²⁷⁴ This framework enabled the efficient presentation of Section 123 Resources in the 120-Day Report, which in turn allowed the

²⁷² CEO’s Comments, pp. 18-20.

²⁷³ Public Service’s Response Comments, pp. 110-11.

²⁷⁴ Phase I Decision, ¶ 501.

Commission and stakeholders to evaluate the various risks and potential benefits of the Section 123 Resources.

245. We have considered the beneficial attributes of all of the Section 123 Resources, including Bid 0106 which CEO supports. We further note that the Alternative Portfolio includes Bid 0011 which, while proposed as a Section 123 Resource, was included based on economic modeling. As to the question of whether additional Section 123 Resources should be pursued at this time, however, we agree with Public Service's position set forth above in its Response Comments. Given uncertainty ranging from tax credits to the implementation of HB 23-1281, it would be premature to approve additional projects here, including Bid 0106. Should hydrogen projects be included as bids within the 2024 JTS, they can be more appropriately considered there. Accordingly, no further Section 123 Resources are approved here, and we look forward to consideration of innovative technologies in the 2024 JTS.

L. Prospective New Load

246. In its 120-Day Report, Public Service states that large loads, such as the demand and energy requirements of new data centers, are developing at a faster pace than historic trends. The Company thus requests that the Commission approve a "Prospective New Load Preferred Plan" (PNL) portfolio to accommodate potential new load of 300 MW beginning in January 2026. Public Service states that at least some of this 300 MW new load would be better described as "more likely" than "possible." The Company recommends the Commission allow it to use the backup bid pool to serve this load if needed. Public Service specifically puts forth four additional bids that would be included in the PNL portfolio: two storage projects, as solar project, and a 219 MW gas project.²⁷⁵

²⁷⁵ 120-Day Report, pp. 55-57.

247. Several parties, including CEO, Conservation Coalition, Interwest, Staff, and WRA raise concerns about the PNL portfolio, particularly its inclusion of 219 MW of new gas generation. CEO and Staff suggest that the new load is speculative and could fail to materialize, and with Conservation Coalition and WRA, recommend that new load be addressed as part of the load forecast in the 2024 JTS.²⁷⁶ Staff asserts that two large wholesale loads have announced the intention to leave the Company's system but remain in the Company's load forecast, which cuts against the arguments that additional generation resources will be necessary. Likewise, Staff critiques the Company's demand response sensitivity analysis, arguing that aggressive demand side solutions would mitigate concerns regarding new load.²⁷⁷ CEO adds that if the Commission does approve the PNL portfolio, it should ensure ratepayer protections if the new load fails to emerge. For example, CEO suggests that if new load does not emerge, shareholders should be responsible for the cost of additional new gas generation instead of ratepayers.²⁷⁸

248. In its Response Comments, the Company maintains that that the PNL portfolio has value in this Proceeding and as a general resource planning matter in the current environment. Public Service acknowledges intervenors' comments that new load is speculative but states that it has more information than intervenors and reiterates the challenge associated with new, large loads developing at a faster pace than before. Public Service agrees, however, that should additional resources not be approved for procurement here, it is reasonable to revisit the issue in the 2024 JTS.²⁷⁹

²⁷⁶ Staff's Comments, pp. 53-54; CEO's Comments, pp. 15-16; WRA's Comments, pp. 19-20; Conservation Coalition's Comments, p. 14.

²⁷⁷ Staff's Comments, pp. 53-54.

²⁷⁸ CEO's Comments, p. 16.

²⁷⁹ Public Service's Response Comments, p. 106.

249. We take the risk that new load is increasing seriously,²⁸⁰ but we decline to approve the PNL portfolio. We agree with Staff's assertion that based on what is currently publicly known, these load additions are speculative and could be offset by future load departures and more effective efforts around demand response. Moreover, given that the new load is speculative but would directly result in adding a new gas resource, it deserves both the full vetting of a Phase I process, through which such questions of appropriate load forecasts and sensitivities are traditionally considered, and consideration as to the impact of new large loads that might seek economic development rates on state emissions targets.

M. Clean Energy Plan Rider (CEPR)

250. Section 40-2-125.5(5), C.R.S. authorizes Public Service to initiate a CEPR, capped at a maximum rate of 1.5 percent of customers' total electric bill, to collect new revenues to fund the approved, additional clean energy plan activities that are undertaken to meet the clean energy target applicable to the Company. However, the statute also prescribes limitations on what the CEPR can fund.

251. In Phase I, the Commission rejected the complex, counterfactual modeling proposal put forward by Public Service in support of the approval and prospective implementation of its CEPR. The Commission further declined to move forward with Public Service's presumption that the Company could apply RESA funding to offset CEP costs, even as the Commission approved certain related provisions of the Phase I Settlement that relate to reporting and treatment of over- and under-collections. Instead, the Commission directed Public Service to file significantly more detail on anticipated cost recovery mechanisms in the 120-Day Report and to file an

²⁸⁰ To address this risk, we encourage Public Service to work to ensure that it has additional firm dispatchable resources as close to construction ready as reasonably possible.

application in a separate future proceeding presenting its methodology for defining and assigning costs related to additional clean energy activities as between the CEPR and the RESA, no later than one year in advance of beginning to recover costs attributable to the CEPR.

1. Public Service's New CEPR Proposals and Party Comments

252. In its 120-Day Report, Public Service completely revises its cost recovery methodology as compared to the proposals the Company presented in Phase I of this Proceeding. For instance, the Company compared its Preferred Portfolio to the reference case and identified the following incremental actions and investments: acquisition of clean energy resources, the Brush Coal Plant gas conversion, reduction of Pueblo Unit 3 operations, gas storage, transmission, and community assistance and workforce transition plans. Out of these, Public Service states that clean energy resources, Brush Coal Plant conversion costs from 2025-2030,²⁸¹ and community assistance and workforce transition plans should be considered clean energy plan activities that are eligible for CEPR recovery (noting that community assistance and workforce transition costs are statutorily also eligible to be recovered through other riders). Public Service explains that, pursuant to § 40-2-125.5(5)(b)(III), the Company will exclude transmission, fuel costs for Pueblo unit 3 operations, and gas storage, and proposes they be collected from other cost recovery mechanisms, such as the ECA, the Transmission Cost Adjustment, and base rates.²⁸²

253. To attribute the costs of clean energy plan activities to the CEPR, Public Services proposes to sort resources into energy or capacity and then to stack them from lowest to highest based on accredited capacity and levelized cost of energy or capacity calculated using Encompass, the model used for bid evaluation and selection.²⁸³ This approach results in three solar and storage

²⁸¹ The Brush Coal Plant conversion costs are also being considered within Proceeding No. 22A-0563E.

²⁸² 120-Day Report, pp. 168-69.

²⁸³ 120-Day Report, p. 169.

resources being identified as attributable to the CEP in the “energy resource stack” and no resources being identified as attributable to the CEP in the “capacity resource stack.” Public Service suggests refining this methodology and extending it to CEPR/RESA interactions through the post-Phase II application. Public Service also adds that the exact costs for community assistance and workforce transition will be evaluated in future JTP filings.²⁸⁴

254. Public Service requests that the Commission authorize it to file an advice letter to initiate the CEPR for collections purposes beginning either January 1, 2024, or January 1, 2025, depending on when the Phase II Decision is issued. Public Service forecasts that by starting collections at 1.4 percent in 2024, it would be over-collected by \$6.3 million in 2030, and it would be under-collected by \$19.3 million in 2030 if it began collections at 1.5 percent in 2025.²⁸⁵

255. UCA raises concerns about the Company’s approach, including that the presentation of levelized energy costs for resource stacking does not match costs presented in appendices, and therefore the bids may be incorrectly sorted as to cost recovery mechanism. UCA further argues that the costs associated with the early retirement of Hayden 1, Hayden 2, Craig 2, and the entire costs of the Brush Coal Plant conversion should be considered CEP costs, and therefore the under-collections for the CEPR will be higher than Public Service anticipates.²⁸⁶

256. Public Service argues that UCA has not correctly applied updated modeling values and explains that only the conversion of the Brush Coal Plant from coal to gas would be considered an additional clean energy plan activity. With regard to the RESA, Public Service states that the methodology it used to distinguish between the ERP and the CEP will also be used to distinguish between clean energy resources and eligible energy resources. The Company reiterates that it

²⁸⁴ 120-Day Report, pp. 170-72.

²⁸⁵ 120-Day Report, pp. 172-73.

²⁸⁶ UCA’s Comments, pp. 27-28.

intends to file the application presenting its methodology for defining and assigning costs between the RESA and CEPR promptly after the final Phase II decision, consistent with the Phase I decision. Accordingly, Public Service reiterates its request that the Commission approve the establishment of the CEPR at the full 1.5 percent in its Phase II decision, with collections to begin as soon as possible upon filing of an advice letter.²⁸⁷

2. Findings and Conclusions

257. We conclude that further process is still required to determine whether the CEPR should be initiated at the full 1.5 percent as proposed by Public Service in its 120-Day Report. Nevertheless, we generally agree with, and approve, its categorization of actions and investments which should be considered additional clean energy plan activities, including those that may be recoverable through the CEPR,²⁸⁸ as the Company's new proposals are clearer and will avoid the inappropriate levels of complexity that were present in the counterfactual Phase I proposal.²⁸⁹ That said, given its late introduction, the balance of the Company's latest CEPR proposals has not been fully vetted by stakeholders and questions remain as to variations between data tables and appendices. Moreover, the application of this methodology for RESA/CEPR cost recovery is less clear than its applicability for ERP/CEP questions. Finally, the Commission has selected the Alternative Portfolio instead of the UPP, necessitating greater clarity on cost recovery (*e.g.*, whether the resource stack changes and results in different allocations between cost recovery mechanisms).

²⁸⁷ Public Service's Response Comments, pp. 98-100.

²⁸⁸ To clarify, consistent with the discussion above, transmission investments as presented in the 120-Day Report are not considered additional clean energy plan activities.

²⁸⁹ We note that while the Commission deferred the specifics of cost recovery for early retirement for Craig 2, Hayden 1, and Hayden 2, it approved the provisions of the Phase I Settlement that affirmed that they should be excluded from CEPR recovery (*i.e.*, they would be included within the reference case for modeling purposes), (Phase I Decision, ¶ 63; Phase I Settlement, ¶¶ 27-28). *See also* Proceeding No. 22A-0515E.

258. Given the timing of this Phase II Decision, pursuant to § 40-2-125.5(b)(II), C.R.S., the earliest the CEPR would be able to be placed into effect is January 1, 2025. Accordingly, we direct the Company, as part of its application regarding attribution of costs between the CEPR and RESA as still required by the Phase I Decision, to address the recovery of specific activities within the categories set forth above, based on the approved resource portfolio. The application should also address the appropriate level for the CEPR to be initiated on January 1, 2025.

N. Best Value Employment Metrics

259. The Phase I Settlement established a multistep process in the Phase II bid evaluation to ensure consideration of BVEM in accordance with § 40-2-129(1)(a), C.R.S. First, the RFP directed bidders to include quantitative information with bid packages that addressed the BVEM statutory requirements, including access to apprenticeships and industry-standard wages and benefits. Second, a bid incorporating a Project Labor Agreement (PLA) was deemed to meet threshold BVEM standards. Third, the Company agreed to screen bids based on BVEM and disqualify those that did not provide sufficient BVEM. Fourth, the Company would retain a labor economist to score the bids for advancement to computer modeling. The Phase I Settlement goes on to specify that the Company will provide a cumulative BVEM score for each portfolio in the 120-Day Report.²⁹⁰ Finally, one of the required Phase II portfolios was a “high PLA portfolio.”

260. In the 120-Day Report, Public Service confirms that it implemented this multi-step BVEM process during Phase II. The Leeds School of Business at the University of Colorado-Boulder was hired as a labor economist and provided scoring of 166 bids. The Company states that it disqualified bids with insufficient BVEM information. In addition, the

²⁹⁰ Phase I Settlement, ¶ 69.

Company notes that Appendix K to the 120-Day Report contains the BVEM documentation that the bidders provided.²⁹¹

261. The Labor Interests describe the challenging history of Colorado's efforts to account for the employment impacts of resource planning through the Phase II solicitation and modeling process. The Labor Interests describe the quantitative scoring provided by the labor economist as a positive evolution in the consideration of BVEM but remain concerned that BVEM was less emphasized after bids were advanced to modeling. Ultimately, however, the Labor Interests support the Preferred Portfolio including the Hayden biomass unit as having a strong BVEM score that matches or exceeds other modelled portfolios and offers an imperfect, but positive, middle ground. The Labor Interests note the positive relationship between utility ownership and BVEM due to Public Service's involvement in collective bargaining.²⁹² They further add that SB 23-292 is a recent and strong statement in support of robust and protective labor policies which will have a significant impact on all phases of energy generation in the future.²⁹³

262. Staff argues that the RFP informed the bidders of the categories and subcategories of information that would be used to develop the BVEM score, however, it did not specify the weighting of these categories and subcategories to the bidders. Staff is concerned that the approach incentivizes detail over quality. Staff suggests that the BVEM scoring methodology could use improved documentation as verifying the methodology is challenging due to lack of sufficient information. That said, Staff notes that it checked for consistency of BVEM scoring across

²⁹¹ 120-Day Report, pp. 159-60.

²⁹² Labor Interests' Comments, pp. 7-8.

²⁹³ Labor Interests' Comments, pp. 8.

different bids and found it to be consistent and objective.²⁹⁴ WRA likewise supports utilization of a BVEM scoring methodology in future ERPs.²⁹⁵

263. In its Response Comments, Public Service agrees with the Labor Interests that the BVEM scoring methodology in this ERP is an improvement and should be continued, with iterations. Public Service specifically supports using a similar BVEM scoring methodology in future ERPs, including the 2024 JTS.²⁹⁶

264. As noted earlier, the Commission has considered the employment of Colorado labor and its positive impacts on the long-term economic viability of Colorado communities throughout this ERP proceeding pursuant to § 40-2-129, C.R.S. These considerations began in Phase I of this Proceeding when the Commission approved the multistep process in the Phase II bid evaluation regarding BVEM and continued in Phase II in our review of the 120-Day Report, the relevant party comments, and the cumulative BVEM score for all portfolios. In addition to BVEM, the Commission must consider and balance many factors in its decision regarding the optimal resource portfolio, including emissions reductions, costs, and reliability. The consideration of these combined factors culminates in a Phase II decision.

265. The Alternative Portfolio has a slightly lower BVEM score (48 percent) than the UPP's BVEM score (52.7 percent). Nevertheless, we find that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns as detailed above, outweigh the lower BVEM score.

²⁹⁴ Staff's Comments, p. 68.

²⁹⁵ WRA's Comments, pp. 25-29.

²⁹⁶ Public Service's Response Comments, pp. 106-07.

266. As Labor Interests set forth, the process of evolving a qualitative concept like BVEM into a meaningful component of bid evaluation has been a long and thoughtful process, with a significant amount of evolution demonstrated through the Phase I Settlement and Phase II. In such a sweeping and significant process as an ERP, even though moving incrementally can be frustrating, nuanced iterations are often the best course of action.

267. Moreover, the Alternative Portfolio includes slightly fewer resources and therefore will provide time for the application of BVEM to continue to evolve. This also means that resources that are deferred now could be brought into the future ERPs through an even more robust process, which is necessary to comply with additional statutory requirements in § 40-2-129, C.R.S.²⁹⁷

268. We also agree with Labor Interests that the thoughtful work performed by the labor economist in this Proceeding represents an enhancement of how BVEM can be incorporated into decision-making. However, Staff also raises valid points in that the methodology could be more clearly articulated for bidders. In this vein, we would be interested in seeing proposed changes to the model PPAs in the 2024 JTS aimed at clarifying standards for BVEM to ensure that IPPs and the Company are competing on a level playing field regarding BVEM. We encourage the collaboration of Labor Interests in this effort, such that work on the model PPAs will account for the role that the IRA can play in producing projects with high BVEM scores by incorporating factors such as the IRA's prevailing wage requirements. We also note that high BVEM scores generally track high utility ownership percentages and express our desire that IPPs that are interested in building projects in Colorado should improve their BVEM to ensure they stay competitive with Company-owned bids in this regard.

²⁹⁷ These new requirements in § 40-2-129, C.R.S., are effective January 1, 2024.

O. In Service Date Extensions

269. In connection with the delays in this Proceeding associated with Public Service's filing of the 120-Day Report, CIEA argues that the Commission should allow IPPs to have a corresponding extension of the ISDs of their projects. CIEA specifically proposes that all projects in the selected portfolio as well as backup bids with ISDs in 2026 and 2027 (spilling into 2028 by up to 75 days if necessary) should have a one-time election to extend the ISDs up to 75 days. CIEA argues that this will address the acute issues in the market and Public Service's delays in the Phase II process in a straightforward and transparent manner.²⁹⁸ In addition, CIEA requests that backup bids should be granted an ISD extension equal to the number of days after the Phase II Decision when the backup bid gets approved to move to the selected portfolio.²⁹⁹

270. In its Response Comments, the Company supports CIEA's recommendations and agrees that all project developers should have the opportunity to extend the ISD of their approved projects and backup bids commensurate with the extended Phase II timeline. The Company further recommends the Commission acknowledge that delays in generation resource ISDs due to transmission-related delays, such as delays associated with interconnection, backfeed, and substation construction, shall be considered reasonable.³⁰⁰

271. Likewise, Public Service asserts that backup bids should be allowed an extension of their commercial operation date (COD) by the number of days after the Phase II Decision that the backup bid is approved to move to the selected portfolio. The Company supports this COD extension because selected backup bids will see a delay in their selection given their backup bid

²⁹⁸ CIEA's Comments, pp. 41-42

²⁹⁹ CIEA's Comments, pp. 41-42.

³⁰⁰ Public Service's Response Comments, pp. 103-04.

status, and the COD extension increases the likelihood that the backup projects will come to fruition.³⁰¹

272. In accordance with CIEA's recommendations, we authorize Public Service to extend ISDs upon application by IPPs by up to 75 days as well as any delays in transmission assets to which individual projects interconnect. No support should be required of the IPP for ISD delays of 75 days or fewer. Before granting an ISD extension greater than 75 days, the Company should be directed to obtain a thorough and credible explanation from the IPP detailing how delays related to completion of Public Service transmission projects prevented it from achieving its proposed ISD. We likewise adopt the ISD extension for backup bids that Public Service sets forth in its Response Comments.

P. Repricing

273. CIEA also requests that the Commission clarify that Public Service can allow IPPs to reprice their projects if delays in transmission project completion cause cost increases through no fault of the IPP. CIEA asserts that IPPs "cannot be expected to maintain as-bid pricing through material delays in transmission upgrade and interconnection processes."³⁰² CIEA similarly argues that backup bids are likely to be stale by the time Public Service calls upon such bids to move forward. Accordingly, CIEA argues that the Commission should allow an opportunity for limited repricing of backup bids to keep up with inflation.³⁰³

274. Public Service argues against the suggestion that backup bids should be provided a repricing opportunity, arguing that doing so could impugn the integrity of the process. However, the Company does support allowing price increases in the limited circumstance where a

³⁰¹ Public Service's Response Comments, pp. 40-41.

³⁰² CIEA's Comments, p. 22.

³⁰³ CIEA's Comments, p. 25.

transmission cost estimate is different than the estimate provided as part of the RFP. Public Service states that this should be the only basis for repricing and should be equally applicable to any bid with which the Company moves forward.³⁰⁴

275. The Commission agrees with Public Service's position and denies CIEA's request to allow backup bids to reprice. The one exception is that repricing is allowed for backup bids in the case where the transmission costs provided in the RFP have changed, consistent with Public Service's proposal in its Response Comments.

Q. 2024 Just Transition Solicitation

276. Given the various issues that have arisen in Phase II of this Proceeding, several intervenors argue that the Commission should issue various directives to Public Service to improve the ERP process. As discussed below, these proposed improvements cover topics including modeling, the ability of IPPs to negotiate the terms of Model PPAs during Phase II, and the appropriate amount of Company ownership.

1. Modeling Improvements

277. Staff, CIEA, Interwest, Conservation Coalition, and WRA all put forth various proposals aimed at improving the modeling process of bids in the 2024 JTS. Relatedly, CEO suggests process improvements for the 2026 ERP. For example, CIEA's proposals include asking the Commission to reject the use of the things like the best-in-class modeling and the reliability rubric for use in the 2024 JTS.³⁰⁵ CIEA also argues that the annuity method of modeling portfolios should be used going forward and that Public Service should be required to analyze the failure of

³⁰⁴ Public Service's Response Comments, p. 41.

³⁰⁵ CIEA's Comments, pp. 6-7, 29-31.

the model and possible solutions, including a process for returning to the Commission in the event of model failures.³⁰⁶

278. Interwest requests that the Commission require a full analysis of both the computer system used in this ERP as well as an estimate of what computer system would have been able to run the modeling software in the timeframe required under the ERP rules.³⁰⁷ For future ERPs, Interwest argues that the curtailment projections must be more flexible and consider the likelihood that curtailments will be reduced over the long term.³⁰⁸

279. Conservation Coalition proposes numerous directives for the Commission to issue regarding the 2024 JTS. As an example of some of these proposals, Conservation Coalition argues that the Company should be required to provide the modeling input and output files to all parties and provide written explanation for all manual adjustments made to the modeling. Conservation Coalition also recommends that the Commission require the use of round-trip modeling, building all portfolios to the same minimum level of reliability, and running a scenario in which, the model replaces all 2-hour storage with 4-hour storage. Similarly, Conservation Coalition argues that Public Service should be required to conduct capacity accreditation studies and planning reserve studies in the same software tool and database to ensure consistency.³⁰⁹

280. WRA's proposals include things such as how generic prices should be used, requirements for the IE, and—more broadly—a different approach to ERP solicitations that uses sequential, rolling solicitations. WRA also proposes that Public Service develop and propose a

³⁰⁶ CIEA's Comments, pp. 30-31.

³⁰⁷ Interwest's Comments, p. 11.

³⁰⁸ Interwest's Comments, p. 12.

³⁰⁹ Conservation Coalition's Comments, pp. 18-20.

transparent scoring system for non-price factors, such as environmental compliance and community support.³¹⁰

281. Arguing for higher-level changes to the ERP process, CEO raises concerns that the ERP process fails to develop a set of portfolios that are significantly different in terms of the resources considered or even the relative cost. Citing its proposals in Proceeding No. 19R-0096E for requiring electric utilities to submit various types of plans with their ERPs, CEO recommends that the Commission direct the Company to include scenario-type analysis as part of the 2026 ERP. CEO also encourages the Commission to re-open its ERP rules and adopt new rules that are more relevant to today's utility environment and that will help Colorado achieve its climate goals.³¹¹

282. Staff proposes that the Company explain in the 2024 JTS how it will update the effective load carrying capability (ELCC) and planning reserve margin (PRM) studies with the goal of accurately modeling portfolio level ELCC interactions to create reliable portfolios in EnCompass. Staff also recommends that Public Service work with Staff prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.³¹²

283. In its Response Comments, the Company does not oppose Staff's recommendation to include an explanation in the Pueblo JTP filing as to how it plans to improve the accuracy of modeling portfolio level ELCC interactions.³¹³ However, Public Service appears to disagree with

³¹⁰ WRA's Comments, pp. 25-29.

³¹¹ CEO's Comments, p. 30.

³¹² Staff's Comments, p. 74.

³¹³ Public Service's Response Comments, p. 104.

Staff's recommendation that the Company be required to work with Staff in the interim to develop more robust modeling processes.³¹⁴

284. Regarding Conservation Coalition's recommendation that the Company conduct capacity accreditation studies and planning reserve studies in the same software tool, Public Service states that, as part of the Phase I Settlement, the Company has already committed to utilize the same modeling software and inputs for ELCC and PRM studies in future resource planning cycles and will also survey best practices in other jurisdictions when developing its methodology for these studies. The Company thus argues that the Phase II Decision does not need to reiterate this requirement.³¹⁵

285. As for the arguments about increased information sharing, process improvements, and transparency, the Company asserts that no directives addressing these issues should be issued in this Proceeding. While Public Service acknowledges that there is always room for improvement in the resource planning and intervenor participation process, the Company argues that such issues are more appropriately resolved a part of a robust Phase I process in the 2024 JTS and the 2026 ERP.³¹⁶

286. The Commission hereby adopts Staff's recommendations and will require Public Service to explain how the Company plans on accurately modelling portfolio level ELCC interactions in connection with its updated ELCC and PRM studies. We further direct the Company to confer with Staff and other interested parties prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.

³¹⁴ Public Service's Response Comments, p. 112.

³¹⁵ Public Service's Response Comments, pp. 104-05.

³¹⁶ Public Service's Response Comments, pp. 111-12.

287. In contrast, we decline to adopt in this Phase II Decision the numerous other modeling and process proposals, including those proposed by party commenters that are expressly discussed above. Some of these proposals closely resemble topics that were adjudicated in Phase I (*e.g.*, making the modeling files available for other parties).³¹⁷ More generally, the Commission finds that it would be premature on this Phase II record to specify how the next ERP process will resolve these modelling and process issues. Nevertheless, as referenced above, we take seriously the numerous concerns that parties raised regarding how Public Service conducted the Phase II modeling, including the manual adjustments the Company made in Phase II and how difficult it was for the parties to analyze the impact of these adjustments. Likewise, we share many of the parties' concerns regarding the model's shortcomings as to issues such as curtailments and the interaction between new generation and transmission. While resolution of these issues for purposes of future ERP proceedings will benefit from a more robust record than is available to us during this Phase II, many of these concerns contribute to our decision to modify the CEP to include the Alternative Portfolio.

2. Non-Negotiable PPA Terms

288. Interwest asserts that the negotiating process on the model PPAs was not explained in advance and put some bidders at a significant and unexpected disadvantage. Interwest states that Public Service found several redlines to model PPAs unacceptable during the due diligence process, prior to actual PPA negotiations, but necessary to advance in the bid selection process. Interwest recommends that the Commission consider language in the Phase II decision specifying that only after a bid is selected should the PPA negotiations start, and Public Service should be

³¹⁷ Phase I Decision, ¶ 513.

prohibited from using the threat of bid elimination to force bidders to accept terms that this Commission has specifically intended to be negotiable.³¹⁸

289. COSSA/SEIA similarly recommends that the Commission mandate that the Company identify which model PPA terms it considers non-negotiable, and that this be litigated in Phase I of future ERP proceedings so that all parties would enter Phase II on the same page about which terms are open to negotiation.³¹⁹

290. CIEA claims that many IPPs felt bullied to identify model PPA-changes they would accept or forego the opportunity to raise such issues later in contract negotiation and were pressured to adopt Public Service's position just to remain in the evaluation process. CIEA recommends that the Commission direct a new approach that limits Public Service's ability to negotiate PPA terms with bidders during the bid evaluation process.³²⁰

291. In Public Service's Response Comments, the Company argues that the Commission should reject recommendations that would restrict the Company's ability to negotiate PPA terms with bidders during the bid evaluation process. The Company argues that to the extent bidders do not submit compliant bids, the Company must retain the ability to work with bidders to bring bids into compliance and ensure a viable and comparable bid pool. The Company does, however, support recommendations from CIEA and COSSA/SEIA that non-negotiable model PPA provisions be clearly set forth in its Phase I 2024 JTS filing and be formalized in the Commission's Phase I decision. Public Service states that doing so will provide additional clarity to bidders and

³¹⁸ Interwest's Comments, pp. 9-10.

³¹⁹ COSSA/SEIA's Comments, pp. 15-18.

³²⁰ CIEA's Comments, pp. 32-35 ().

would help mitigate the need for extensive PPA contract discussions during the bid evaluation process.³²¹

292. The Commission agrees with the IPP intervenors and the Company that there should be more clarity for bidders regarding what terms of the model PPA contracts are negotiable. We accordingly adopt Public Service's position and require the Company to clearly set forth the non-negotiable PPA terms in its Phase I 2024 JTS filing with the expectation that such terms will be formalized in the Commission's Phase I decision approving model PPAs.

293. As noted by Interwest and Public Service, "Colorado does not have a 'conforming bid' policy whereby bidders have to bid to the model agreements 'as-is.'"³²² However, having the Company and IE attempt to determine on an *ad hoc* basis during the bid evaluation process which terms of the PPAs are negotiable is a challenging situation. We acknowledge that it may be time for Colorado to move towards a conforming bid policy, especially considering that the Commission already addresses many core issues of the model PPAs in Phase I and the fact that in Phase II the Company and IE are called upon to equitably evaluate numerous bids. To be clear, the Commission is not in this Decision adopting any type of conforming bid policy, but we invite party feedback regarding adopting this type of approach in the future.

3. Company Ownership

294. Interwest takes issue with the high percentage of Company ownership in the portfolios presented in the 120-Day Report, arguing that it is outside of what was expected by virtually all parties. Interwest suggests that this calls into question the validity of the agreements in the Phase I Settlement regarding the amount of replacement capacity from the 2024 JTS that

³²¹ Public Service's Response Comments, p. 105.

³²² See 120-Day Report, p. 86; Interwest's Comments, p. 9.

Public Service would own. Interwest requests that the Commission consider whether Public Service achieved the letter and spirit of the law, whether the Phase I Settlement provisions regarding the ownership of Unit 3's replacement capacity are still valid, and whether action is necessary now to ensure compliance in future ERPs.³²³

295. CIEA similarly recommends that the Commission use the 2024 JTS to course correct and rebalance the resource ownership of IPPs and the Company in the total capacity mix of the system.³²⁴

296. Public Service urges the Commission to reject suggestions that the ownership percentage allowed in the 2024 JTS be adjusted to account for the high ownership the Company proposes in this Proceeding. Public Service argues that this recommendation could lock the Commission into higher-cost and uneconomic outcomes.³²⁵

297. The 2024 JTS is an interim ERP that will largely be governed by the Commission's ERP rules. We find that it would be inappropriate in this Phase II to attempt to set bounds around the Company ownership levels of the approved portfolio coming from the 2024 JTS. Moreover, we note that the selection of the Alternative Portfolio significantly reduces the amount of Company-owned capacity resources approved as part of this Proceeding as compared to the UPP.

4. Just Transition Bids

298. UCA expresses disappointment that there were no bids for wind, solar, storage or solar plus storage at Craig or Hayden. UCA claims that such bids would have contributed to the just transition plan. UCA argues that these type of JTP bids should be encouraged at Craig and

³²³ Interwest's Comments, p. 9.

³²⁴ CIEA's Comments, p. 18.

³²⁵ Public Service's Response Comments, pp. 33-34.

Hayden and other west slope locations as well as in the Pueblo area. UCA goes on to suggest that such bids could even be required from Public Service.³²⁶

299. Although we refrain from creating any sort of requirement for certain bids, we agree with UCA's sentiments about the benefits of bids at Craig, Hayden, and Pueblo and encourage such bids in the upcoming 2024 JTS. We further encourage bids within the Denver Metro area to the extent such bids can mitigate the need for additional transmission investments.

300. The 2024 JTS offers the state an important opportunity to continue acquiring renewable resources to achieve even greater emissions reductions while addressing some of the issues that arose in this Proceeding. Consistent with the Phase I Settlement Agreement, however, we reiterate that the 2024 JTS is the proceeding that will acquire a suitable replacement for the capacity that will be lost when Unit 3 retires and that all parties should work to ensure that the Pueblo community and benefits to the community are the focus of this replacement.³²⁷ In this vein, we note that nothing in this Phase II Decision impacts the Company's commitment in the Phase I Settlement to "make payments to Pueblo County annually from 2031 through 2040 ... in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County."³²⁸

³²⁶ UCA's Comments, p. 20.

³²⁷ See Phase I Decision, p. 43; Phase I Settlement, ¶ 43.

³²⁸ Phase I Settlement, ¶ 42.

5. Discount Rates

301. Conservation Coalition suggests that the Commission direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the June 2024 JTS.³²⁹

302. While consideration of lower discount rates does not warrant the selection of a different resource portfolio in this Proceeding (as set forth above), we find merit in the Conservation Coalition's request that Public Service attempt to reach consensus with stakeholders on the related issue of discounting the social cost of emissions. Accordingly, we grant Conservation Coalition's request and direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the 2024 JTS. This conferral should include the impacts of SB 23-291 regarding the appropriate discount rate to use for fuel costs.

6. Comprehensive Rate Analysis

303. In the 120-Day Report, Public Service states that "the average bill impact for the Preferred Plan is expected to grow less than the historical rate of inflation."³³⁰ Staff, UCA, and CEC argue, however, that the costs presented in the 120-Day Report are likely to be artificially low.³³¹ Staff in particular states that there is additional anticipated investment that is not included in the Company's rate impact analysis. Staff asserts that the Company's statement regarding the cumulative average growth rates was carefully worded to include only the incremental rate impact of the CEP, not the rate impact of the entirety of the Company's planned investments including

³²⁹ Conservation Coalition's Comments, pp. 21-22.

³³⁰ 120-Day Report, p. 34.

³³¹ Staff's Comments, p. 19; UCA's Comments, pp. 5-7; CEC's Comments, pp. 15-16.

distribution system investment, other transmission system investment, and additional electric generation not included in this Proceeding.³³²

304. Given the importance of affordability, the Commission and interested stakeholders should have access to a consistent view of Public Service's capital expansion plan for the Colorado electrical system and what this plan means for ratepayers. Accordingly, the Commission directs Public Service to provide in the 2024 JTS a comprehensive long-term rate analysis that fully includes all of the projected investments the Company is communicating to the financial community, including for new distribution investment, wildfire mitigation, transmission upgrade, transportation electrification, distributed solar, and other electricity business investments.³³³ This comprehensive rate analysis should also include an analysis that better quantifies the actual levels of resource curtailment above the modelled levels and, in format, should be similar to the rate forecast models the Company has recently presented in rate cases.

305. We emphasize that this comprehensive rate analysis shall not be limited to projects that have received official regulatory approval or projects that have final cost estimates. Rather, this comprehensive rate analysis shall include all projected investments in the Colorado electric system that Public Service is communicating to the financial community and any that are reasonably expected.

R. Miscellaneous Issues for Future Proceedings

1. Equity Directives

306. In its Comments on the 120-Day Report, Staff notes the importance of evaluating ERP proceedings through an equity lens. Staff further notes that as part of the solicitation that the

³³² Staff's Comments, p. 19.

³³³ Consistent with prior filing expectations, documents are expected to be as robust as possible and in executable format.

Company performed in this Proceeding, all bidders were required to provide information on the assessment of, and plan for continuing to monitor local community, disproportionately impacted (DI) community, and state reaction to the bidder's proposed project, and a plan to work with the local community and DI communities on project issues. In addition, as part of the 120-Day Report, the Company provided maps that identify which projects are located in DI communities.³³⁴

307. After assessing the information that was received in this Proceeding, Staff makes a series of recommendations that the Commission could take in future proceedings to continue to improve the Commission's consideration of equity issues. For example, Staff argues that in the future, the 120-Day Report should include a more detailed analysis of community/state reaction, which goes beyond identifying the DI communities. Staff also suggests that the Commission consider developing rules that (1) identify key metrics that should be reported by bids in DI communities to help understand impacts and benefits of bids on DI communities, and (2) define a process for tracking stakeholder engagement in bids approved in the resource plan in DI communities. Finally, Staff recommends that the Commission consider specifying how it will consider equity metrics in decision making and document the consideration of energy equity issues in written decisions prior to approvals for Resource Plans, Plan amendments, and CPCNs.³³⁵

308. In a similar vein, CEO notes with approval how the Company mapped the bids in this Proceeding relative to DI Communities. CEO encourages a similar presentation of mapping in the Company's next ERP and notes the expectation that the Commission will continue to consider how it will use such mapping in its decision making going forward.³³⁶

³³⁴ Staff's Comments, pp. 69-70.

³³⁵ Staff's Comments, pp. 71-72.

³³⁶ CEO's Comments, pp. 24-25.

309. In its Response Comments, the Company expresses appreciation for Staff's recommendations as the consideration of equity issues in resource planning continues to evolve. The Company notes that it has expanded the scope and reach of its community engagement efforts and expects to continue this expansion. Public Service further expects that the presentation and evaluation of equity issues will continue to improve, similar to how the BVEM bid information and evaluation process has improved. Public Service states that it welcomes and encourages continued discussion in the next ERP Phase I process and in future Just Transition Plan proceedings to ensure meaningful consideration of equity issues but that the Company does not believe specific requirements need be prescribed in rules.³³⁷

310. We acknowledge and appreciate the considerations from Staff and CEO regarding how to continue improving the Commission's consideration of equity issues in future ERP proceedings and rulemakings. At this juncture, however, we will leave it to the relevant stakeholders to work out the appropriate specifics on when and how best to further advance the consideration of equity issues in resource planning. We note that in Proceeding No. 22M-0171ALL the Commission has an ongoing and far-reaching pre-rulemaking underway aimed at improving equity outcomes in the State through reforms to practices, outreach, and rules. The Commission encourages stakeholders to provide comments within that pre-rulemaking proceeding where we are diligently collecting concepts on what rules should be considered and addressed in order to promote equity.

2. CPCN Prioritization

311. CIEA and Conservation Coalition both encourage the Commission to proactively manage the applications for CPCNs that the Company will eventually file for each utility-owned

³³⁷ Public Service's Response Comments, pp. 107-08.

generation asset included in the approved resource portfolio. For instance, noting the large amount of expected CPCN filings, CIEA recommends that there be a priority established for 2024 CPCNs based on the value to ratepayers of the various projects. Denver metro transmission projects with 2030 ISDs could be delayed to later but generation projects that are critical to system or local reliability should be prioritized.³³⁸

312. Similarly, the Conservation Coalition suggests that the Commission consider how it can reduce the litigation burden to parties (and the burden on the Commission) of the CPCNs arising from this Proceeding. The Conservation Coalition specifically recommends one of two solutions for consolidating the various CPCNs. The first proposal is to require the Company to confer with all parties and file a reporting containing the proposals for how best to consolidate and minimize the number of CPCN applications. The Commission would then issue an order in this Proceeding addressing consolidation. The second proposal is to simply order the Company to consolidate its CPCN applications based on some criterion or criteria (*e.g.*, technology type or ISD).³³⁹

313. In its Response Comments, Public Service argues that it has the responsibility to timely file CPCNs and that the Company will need some flexibility to do so. However, the Company proposes providing updates to interested parties and the Commission on the status of CPCN filings in its Annual ERP Reports that it files every year on March 31 as well as in its annual Rule 3205 and Rule 3206 reports. Public Service argues that these existing reporting venues provide the appropriate opportunity for the Company to update stakeholders on CPCN filing

³³⁸ CIEA's Comments, pp. 8, 35-36.

³³⁹ Conservation Coalition's Comments, pp. 22-23.

readiness as well as the anticipated filing dates, sequencing, and grouping of generation and transmission CPCNs moving forward post-Phase II.³⁴⁰

314. We adopt Public Service’s position set forth in its Response Comments and direct the Company to provide additional updates to interested stakeholders regarding the Company’s CPCN prioritization via the existing reporting venues. At this juncture, the Commission will not attempt to dictate the form or timing of Public Service’s CPCN and other applications.

3. Voluntary Additional Emissions Reduction Program

315. Boulder recommends the Commission direct Public Service and interested communities and customers to explore acquiring additional resources to support development of a voluntary customer product that generates additional emissions reductions. Boulder asserts that “communities comprising at least 35 percent of Public Service retail sales seek ‘100% renewable energy’ or zero emissions electricity by 2030.”³⁴¹ Given the importance of decarbonizing the electricity sector as soon as possible to support decarbonization in other sectors like buildings and transportation, Boulder argues that “the time is now to develop next-generation voluntary customer products that quantify incremental emissions reductions.”³⁴²

316. Boulder acknowledges that the Phase I Settlement contains a commitment for Boulder and Public Service to work together to develop such a voluntary program. Boulder indicates that, based on preliminary modeling, it appears that acquiring additional renewable resources could generate incremental emissions reduction but at the significant risk of curtailments. In addition, according to Boulder, the preliminary modeling showed that incremental

³⁴⁰ Public Service’s Response Comments, pp. 100-02.

³⁴¹ Boulder’s Comments, p. 17.

³⁴² Boulder’s Comments, p. 17.

costs of such additional resources “suggests that new voluntary emissions reduction products must be available to all Public Service customers and not limited to one community or customer.”³⁴³

317. Boulder asserts that the bids received in Public Service’s solicitation provide options for the development of a new voluntary emissions reduction product that would enable communities and customers to progress towards their 100 percent renewable energy goals. Boulder suggests that bids included in the Preferred Portfolio could be expanded to add generation or storage, and this expansion could be funded by communities and customers participating in the voluntary emissions reduction program. Boulder also asserts that there are bids that were not included in the Preferred Portfolio, including Section 123 Resources, the acquisition of which could be supported by customers interested in a voluntary emissions reduction program.

318. The Commission understands that certain communities and organizations would prefer to exceed the environmental attributes of Public Service’s general resource mix via a more robust, voluntary offering and believe such a program is feasible. We are interested in better understanding what steps the Commission could put in place to provide such a voluntary program for customers and communities and how the tracking would work to ensure that the program would not dilute the environmental attributes of the general resource mix or unfairly allocate costs.

319. Accordingly, we direct Public Service and Staff of the Commission³⁴⁴ to work together with interested parties to discuss this topic at a CIM. The discussion could include information regarding what stakeholders are interested in, what attributes are desired, the potential structure of such a program, the status of Public Service’s efforts on this topic, and what the next steps are. We are hopeful that this CIM could be convened in late February or early March.

³⁴³ Boulder’s Comments, p. 18.

³⁴⁴ This could be either Trial Staff or staff of the Commission’s Research and Emerging Issues group.

S. Requests not Explicitly Addressed

320. The Commission has weighed the information and filings from all parties and public commentors in balancing its policy and reaching the various decisions set out in this Phase II Decision. To the extent this Phase II Decision does not expressly address requests made by Public Service or an intervening party, such requests are denied. However, these requests were considered in balancing our considerations and reaching our ultimate conclusions in this Proceeding.

II. ORDER**A. The Commission Orders That:**

1. After consideration of the statutory factors and other relevant factors, modifications to the Clean Energy Plan (CEP) presented by Public Service Company of Colorado (Public Service) are necessary to ensure that the Commission's approval of the CEP is in the public interest.

2. In accordance with the discussion above, we authorize Public Service to pursue the modified CEP and the acquisition of the resources included in the Alternative Portfolio with further due diligence and contract negotiations. Public Service shall further file applications for Certificates of Public Convenience and Necessity for all Company-owned generation resources arising from the modified CEP. Public Service's actions, consistent with this Decision, shall be presumed to be prudent at the time of cost recovery consistent with 4 *Code of Colorado Regulations* (CCR) 723-3-33617(d) of the Commission's Rules Regulating Electric Utilities.

3. All Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM, in accordance with the discussion above.

4. The proposed transmission network upgrades, grid strength reinforcements, reactive power investments, and voltage support investments presented in the 120-Day Report are not part of the approved CEP. Additional review of the proposed transmission projects is necessary and, accordingly, 4 CCR 723-3-3206 is waived as to the transmission projects arising from this Proceeding, in accordance with the discussion above.

5. In accordance with the discussion above, Staff of the Colorado Public Utilities Commission (Staff) shall also initiate a stakeholder process with the Colorado Office of Utility Consumer Advocate and the Colorado Energy Office and in conferral with Public Service to bring forward a scope of work for hiring an independent transmission analyst as soon as reasonably feasible but no later than the commencement of the 2024 Just Transition Solicitation (JTS) proceeding. If this independent transmission analyst cannot be engaged in time for Phase I of the 2024 JTS, we direct the Company to include certain transmission-related portfolios in its direct case, in accordance with the discussion above.

6. As part of its application regarding attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment, the Company shall address the recovery of specific activities based on the approved resource portfolio and the appropriate level for the CEPR to be initiated on January 1, 2025, in accordance with the discussion above.

7. With respect to the 2024 JTS, Public Service shall confer with Staff prior to the 2024 JTS to develop more robust modeling processes, clearly set forth the Company's proposed non-negotiable PPA terms in its Phase I 2024 JTS filing and provide in the 2024 JTS a comprehensive long-term rate analysis in addition to our other directives in accordance with the discussion above.

8. Public Service and Staff of the Commission shall work together to present at an upcoming Commissioners Information Meeting the interest in, potential structure of, and current efforts to develop a voluntary emissions reduction program, in accordance with the discussion above.

9. The 90-day deadline for a written Phase II Decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan set forth in 4 CCR 723-3-3613(h) is waived.

10. To the extent requests are not addressed in this Decision, they are denied.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS
December 6, 13, and 20, 2023.**

(S E A L)



ATTEST: A TRUE COPY

Rebecca E. White

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-103:
2025 Xcel ERP Annual Progress Report



2021 ELECTRIC RESOURCE PLAN & CLEAN ENERGY PLAN

Annual Progress Report
Proceeding No. 21A-0141E

March 31, 2025

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ATTACHMENTS:

Attachment A – Loads and Resources Table and Forecast Update

Attachment B – Comanche 3 O&M and Capital Forecast (2025-2029)

Attachment C – Hayden O&M and Capital Forecast (2025-2029)

Attachment D – Craig 2 O&M and Capital Forecast (2025-2029)

Attachment E – Benefits of the SPP WEIS Market for Public Service

I. INTRODUCTION & PROCEDURAL BACKGROUND

Public Service Company of Colorado (“Public Service” or the “Company”) presents this annual progress report including updates and information in accordance with Rule 3618(a) of the Colorado Public Utilities Commission’s (“Commission”) Electric Resource Planning (“ERP”) rules. In addition to certain information required by Rule 3618(a), this report provides an update on the resources approved as part of the 2021 Electric Resource Plan and Clean Energy Plan (“2021 ERP & CEP”) in the Company’s most recent ERP (Proceeding No. 21A-0141E). Additionally, this report presents information required through various Settlement Agreements and Commission decisions, including the following:

- Section D of the Settlement Agreement approved by Decision No. R20-0108 in Proceeding No. 19A-0409E (Valmont & Manchief CPCN) requiring a detailed loads and resources table;
- Paragraph 86 of Decision No. C22-0459 in Proceeding No. 21A-0141E (2021 ERP & CEP) requiring certain information regarding Comanche Unit 3 planned overhauls and operations and maintenance (“O&M”) costs;
- Paragraphs 28 and 34 of Decision No. C23-0362 in Proceeding No. 22A-0515E (Coal Asset Cost Recovery) requiring certain capital expenditure, O&M, and decommissioning cost information for Hayden 1, Hayden 2, and Craig 2 (as available);
- Paragraph 40 of the Updated Settlement Agreement in Proceeding No. 21A-0141E regarding cumulative emissions reductions compared to the adjusted baseline developed in the Clean Energy Plan Guidance and appendices (included in the Company’s Direct Case as Attachment LWQ-1);
- Section V of the Settlement Agreement approved by Decision No. R24-0194 in Proceeding No. 22A-0563E (Pawnee Conversion CPCN) regarding certain information on the status of the Pawnee conversion project;
- Section 3.3 of the Settlement Agreement approved by Decision No. R22-0826 in Proceeding No. 22AL-0270E (Southwest Power Pool Western Energy Imbalance Services Market (“SPP WEIS”) Cost Recovery) regarding market participation and performance in the SPP WEIS and certain information regarding carbon dioxide emissions;
- Paragraphs 313-314 of Decision No. C24-0052 in Proceeding No. 21A-0141E (“Phase II Decision”) requiring an update on CPCN filing readiness as well as the anticipated filing dates, sequencing, and grouping of generation and transmission CPCNs moving forward post-Phase II; and
- Paragraph 40 of the Updated Settlement Agreement in Proceeding No. 21A-0141E regarding REC retirement processes.

A. 2021 Electric Resource Plan and Clean Energy Plan

Public Service filed its 2021 ERP & CEP on March 31, 2021 in Proceeding No. 21A-0141E. The Company's Clean Energy Plan was filed as part of the ERP pursuant to the requirements of Senate Bill 19-236 ("SB 19-236") enacted by the General Assembly and signed into law by Governor Polis in the 2019 legislative session. SB 19-236 provides an explicit and detailed process for developing and filing a CEP to achieve an 80 percent carbon dioxide emissions reduction by 2030 and establishes the framework for the Company to seek 100 percent clean energy resources by 2050.

The Commission issued Decision No. C22-0459 on August 3, 2022 approving the Updated Comprehensive Non-Unanimous Settlement Agreement ("USA") in large part, including the Coal Action Plan, and addressing all other Phase I issues. The Commission addressed issues raised in Applications for Rehearing, Reargument, or Reconsideration ("ARRR") in Decision No. C22-0559 mailed on September 21, 2022 (collectively, these two decisions are generally referred to as the "Phase I Decision").¹

The Commission issued Decision No. C24-0052 on January 23, 2024 ("Phase II Decision") in which, among numerous other decision points, the Commission approved an alternative resource portfolio ("Alternative Portfolio")² for the reasons discussed in the Phase II Decision. The Phase II Decision authorized Public Service to pursue the acquisition of more than 5,800 MW of new storage and generation projects that were included in the approved resource portfolio with further due diligence and contract negotiations and directed Public Service to file applications for Certificates of Public Convenience and Necessity ("CPCN") for all utility-owned resources within the approved resource portfolio. The Phase II Decision also established a framework for a cost-to-construct ("CtC") performance incentive mechanism ("CtC PIM") and an Operational PIM for each utility owned generation project in the approved resource portfolio.

On February 12, 2024, Public Service and several other parties filed an ARRR of Decision No. C24-0052. On March 6, 2024, the Commission held deliberations on the ARRRs and issued Decision No. C24-0161 addressing ARRRs on March 13, 2024 ("ARRR Decision") regarding several issues, including challenges to the approved resource portfolio, replacement bids, proposed modifications to the established CtC PIM, and the appropriate process for selecting backup projects. On May 2, 2024, the Commission issued Decision No. C24-0292 ("Second ARRR Decision") addressing discrete issues raised by Commission Staff.

On September 6, 2024, Public Service filed the CEP Delivery Plan ("CEPD Plan"), which sought approval to allow bidders to adjust the costs of their bids to reflect geopolitical and supply chain constraints that threaten the viability of projects approved in Phase II of the 2021 ERP & CEP. As discussed in detail in that filing, the objective of the CEPD Plan was to solution for market challenges and geopolitical circumstances affecting project

¹ A more detailed summary of the procedural background can be found in the Company's 2024 ERP Annual Report filed on March 29, 2024 in Proceeding No. 21A-0141E.

² The Alternative Portfolio is the Inverse 1324 (\$0CO2) Plan that Public Service included in the 120-Day Report. (See Appendix S, Rev. 1, p. 26 of the 120-Day Report).

delivery, while balancing the need for project developer relief (both for the Company and for independent power producers (“IPPs”)), and the need to minimize impacts on customers.

On January 14, 2025, the Commission issued Decision No. C25-0024 (“CEPD Plan Decision”) approving potential cost increases of 1 percent and 6 percent, respectively, for solar/storage and wind projects, subject to demonstration of need in a future filing. The Commission further approved the extension of the Plains End purchase power agreement (“PPA”), and an as-bid presumption of prudence for 400 MW of new thermal generation. The CEPD Plan Decision denied the Company’s request for a rebuttable presumption of prudence in the construction a third thermal unit but did not foreclose the option to bring forward the project for reconsideration in a future application.

As discussed in Section E below, the Company is continuing to diligently pursue contract negotiations and follow-on CPCN filings to bring CEP projects online.

B. 2024 Just Transition Solicitation

Public Service filed its most recent ERP—the 2024 Just Transition Solicitation (“2024 JTS” or “JTS”)—on October 15, 2024 in Proceeding No. 24A-0442E in accordance with the USA approved in Proceeding No. 21A-0141E, which requires, in applicable part, that the Company file the JTS to continue the clean energy transition with a focus on advancing a just transition.³ The JTS seeks to identify and develop a framework to meet the Company’s energy and capacity needs through 2031. The 2021 ERP & CEP accelerated the Company’s efforts in retiring coal-fired generation with clean energy and thermal replacement and was the first resource plan to focus on a specific emissions reduction target. The 2024 JTS will take another significant step in balancing energy policy objectives to reduce emissions and facilitate a just transition.

As set forth in the Company’s Direct Testimony, the JTS has multiple, and sizeable, objectives with intersecting components, including: (1) implementing an 80 percent emissions reduction by 2030; (2) maintaining reliability while meeting load growth needs, managing complexities, and seizing opportunities; (3) finding the new “gold standard” ERP process that meets the dynamic needs of the system today and in the future; and (4) delivering a just transition. The JTS seeks to complete the effort of meeting the 2030 emissions targets set forth by Senate Bill 19-236 and will also advance the effort to fully transition the Public Service system off of coal. The JTS also addresses the challenge of meeting a new era of heightened demand growth with an electric system that is increasingly reliant on clean but weather-dependent energy generation. The JTS balances the need to protect Colorado workers and communities most impacted by the clean energy transition, while still maintaining the focus on reliability and affordability.

On February 21, 2025, the Company filed Supplemental Direct Testimony to provide the information requested by the Commission in Decision No. C24-0956-I (“Decision”) (issued 3 December 31, 2024). On March 13, 2025, the Commission held a joint technical

³ Paragraph 45 of the USA established a June 1, 2024 filing date, which was subsequently extended to October 15, 2024 by Decision No. C24-0513.

conference scheduled in both Proceeding No. 24A-0442E (the JTS) as well as in Proceeding No. 24A-0547E (the Company's 2025-2029 Distribution System Plan ("DSP")) to address questions regarding modeling and forecasting. The Commission has scheduled an evidentiary hearing in June 2025.⁴

II. ANNUAL PROGRESS REPORT REQUIREMENTS

Commission Rule 3618(a) requires the Company to file annual progress reports to its most recent ERP in order to "inform the Commission of the utility's efforts under the approved plan and the emerging resource needs and potential utility proposals that may be part of the utility's next electric resource plan filing." Annual progress reports are also to contain the following for a running ten-year period beginning at the report date:

1. An updated annual electric demand and energy forecast;
2. An updated evaluation of existing generation resources;
3. An updated evaluation of planning reserve margins and contingency plans;
4. An updated assessment of need for additional resources; and
5. An updated report of the utility's plan to meet the resource need and the resources the utility has acquired to date in implementation of the plan.

A. Updated Annual Electric Demand and Energy Forecast

The Company's most recent annual electric demand and energy forecast is provided in Table 2-11.15 of the Company's JTS Volume 2 Technical Appendix and is summarized in Table 1 below. A discussion of the load forecast and methodology is available in Section 2.2 of the JTS Volume 2 Technical Appendix.

Table 1 – Demand and Energy Forecast (Base Case)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	20234
Annual Native Load										
Energy Sales (GWh)	35,762	35,852	38,383	42,132	47,251	52,943	57,938	61,787	64,362	66,614
Summer Native Load										
Peak Demand (MWh)	7,327	7,039	7,348	7,732	8,437	9,123	9,720	10,141	10,464	10,736

B. Updated Evaluation of Existing Generation Resources

Table 2 below includes the Company's evaluation of existing generation resources as set forth in the 2024 JTS and shows the Net Dependable Capacity in megawatts ("MW") of thermal units and the calculated accredited capacity of renewables by adjusting the nameplate capacity by the effective load carrying capability ("ELCC").

⁴ Pursuant to Decision No. C25-0064-I, Answer Testimony is due April 18, 2025; Rebuttal Testimony is due May 23, 2025; and an evidentiary hearing is scheduled June 10-13, 17-18, 20 and 23-24 on an as-needed basis.

Table 2 – Summer Net Dependable Capacity (MW) and Assumed ELCC Levels

PSCo Summer L&R Table (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Owned Coal	1,462	663	661	567	412	412	-	-	-	-
Purchased Coal	-	-	-	-	-	-	-	-	-	-
Total Coal-Fired Generation	1,462	663	661	567	412	412	-	-	-	-
Owned Gas Steam	230	695	693	462	463	463	480	480	480	480
Owned Gas Combined Cycle	1,710	1,703	1,699	1,689	1,690	1,690	1,753	1,753	1,753	1,753
Purchased Gas Combined Cycle	293	121	-	-	-	-	-	-	-	-
Owned Gas Combustion Turbine	833	782	716	711	712	712	738	738	738	738
Purchased Gas Combustion Turbine	676	673	420	213	213	213	221	-	-	-
Total Gas-Fired Generation	3,743	3,975	3,528	3,076	3,078	3,078	3,193	2,971	2,971	2,971
Owned Storage	234	195	215	205	224	230	210	210	210	210
Purchased Storage	155	123	136	129	142	146	133	133	133	133
Purchased Biomass	-	-	-	-	-	-	-	-	-	-
Owned Hydro	12	12	12	12	12	12	12	12	12	12
Purchased Hydro	16	16	5	-	-	-	-	-	-	-
Owned Solar	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Purchased Solar	378	307	310	262	196	189	188	182	181	180
Purchased BTM Solar	144	150	149	113	101	107	127	136	145	154
Purchased Community Solar	52	55	62	54	59	72	92	100	108	115
Owned Wind	166	180	176	233	234	220	235	235	235	235
Purchased Wind	453	482	458	501	502	469	499	445	403	370
2021 ERP/CEP Resources	-	457	1,500	2,105	2,118	2,115	2,059	2,057	2,056	2,055
Demand Response	352	335	372	341	387	409	417	429	442	454
Market Purchase	-	-	-	-	-	-	-	-	-	-
Total Renewable/Other Generation	1,962	2,313	3,395	3,954	3,973	3,969	3,971	3,939	3,925	3,919
TOTAL ACCREDITED CAPACITY	7,167	6,951	7,585	7,597	7,463	7,459	7,163	6,911	6,896	6,890

C. Updated Planning Reserve Margins and Contingency Plans

1. Planning Reserve Margin

Pursuant to the USA and the 2021 ERP & CEP Phase I Decision, the Company updated its Planning Reserve Margin (“PRM”) study and effective load carrying capability (“ELCC”) study for the 2024 JTS. The combined updated study entitled, “*2024 Public Service Company of Colorado Resource Adequacy Study: Analysis of Planning Reserve Margin Requirements & Effective Load Carrying Capability*” (“2024 RA Study”) was developed by Energy & Environmental Economics, Inc. (“E3”) and is included as Attachment ZM-1 to the Direct Testimony of Zachary Ming in pending Proceeding No. 24A-0442E.

The 2024 RA Study evaluated every hour of years 2024 through 2031 for the capacity required to expect no more than 1 loss of load event (“LOLE”) in 10 years. The inputs to the study included 44 historical years of weather correlated demand, wind, and solar hourly profiles and the last five years of generator outage profiles to capture the variability in resource availability and demand.

The 2024 RA study separates the year into two seasons, summer (May to October inclusive) and winter (November to April inclusive) and calculates seasonal PRM values as the quantity of required perfect capacity to reliably serve peak load in each season. This study shows that a PRM requirement between 6.3% to 6.4% in the summer over the period from 2025 to 2031 and 9.0 to 14.5% in the winter over the same period, expressed in using an ELCC accounting convention, is required to achieve Public Service’s reliability standard of a LOLE of 0.1 days per year. The PRM results of the 2024 RA Study are summarized in Table 3 below.

Table 3 – 2025-2031 Assessment of Reliability Need

		2025	2026	2027	2028	2029	2030	2031
Target Planning Reserve Margin Requirement (%)	Annual	6.1%	5.8%	5.8%	5.8%	5.9%	6.0%	5.9%
	Summer	6.4%	6.3%	6.4%	6.4%	6.4%	6.4%	6.3%
	Winter	9.0%	9.1%	10.4%	11.9%	13.3%	14.5%	13.3%

2. Contingency Plan

The Company's contingency plan is discussed in Section 2.6 of the Volume 2 Technical Appendix filed as part of the Company's 2024 JTS. In addition to the contingency measures outlined in Section 2.6 of Volume 2, the Company proposes to implement a pre-construction development asset ("PCDA") contingency option intended to provide flexibility to quickly develop generation and capacity resources to address near-term system uncertainty caused by project failures and system load growth. PCDA will be a means to acquire but defer construction of some generation and capacity resources in the Phase II process. The concept essentially provides a low-cost option that limits customer cost exposure while supporting developers with some assurance their costs associated with developing a project will be returned.

In its 2021 ERP & CEP Phase I Decision, the Commission noted that there is growing uncertainty due to future climate extremes, supply chain disruptions, inflation, a greater reliance on intermittent resources, and the future costs and performance of clean energy technologies. To mitigate these near-term concerns and create optionality, in its Phase I Decision, the Commission requested that the Company explore acquiring PCDA's for gas-fired resources like combustion turbines ("CTs")⁵ as part of its contingency plan required by Rule 3609(c) in the 120-Day Report.

As discussed in the 120-Day Report in Proceeding No. 21A-0141E, few bidders selected the PCDA option in the bid package and no bids were recommended by the Company or approved by the Commission for this PCDA structure in the 2021 ERP & CEP.⁶ Nevertheless, the Company views this type of structure as a positive step in resource procurement and has therefore brought forward the PCDA process in the 2024 JTS.⁷

⁵ Paragraph 59 of Decision No. C22-0559 limited the optionality opportunity provided through pre-construction development assets to gas-fired resources (i.e., eliminating wind, solar, and storage resources).

⁶ In future proceedings, the Company may also include a proposal to seek milestone payment recovery or similar structure if necessary to maintain the viability of certain Company-owned and/or IPP projects as contemplated by Decision No. C24-0161, at ¶71.

⁷ See Hearing Exhibit 103, Direct Testimony of Justin M. Tomljanovic, at Section V.

D. Updated Need for Additional Resources

The Company's most recent L&R as of the filing of the JTS was provided in Section 2.9 of the JTS Volume 2 Technical Appendix. Table 2.9-1 and Table 2.9-2 provided the 2024 JTS Phase I L&R projection of resource capacity need using the Base Case forecast for summer and winter, respectively, and are reproduced as Table 4 and Table 5 below.⁸ The JTS L&Rs presented below use the updated PRM and ELCC conventions referenced in Section C above and discussed in more detail in the Company's Phase I JTS filing in Proceeding No. 24A-0442E.

Additionally, pursuant to the terms of the Settlement Agreement approved by Decision No. R20-0108 in Proceeding No. 19A-0409E, Attachment A provides a more detailed L&R that includes a detailed breakdown of the changes in the forecast and resource need as compared to the most recent ERP Annual Update (filed on March 29, 2024) and a narrative explanation surrounding the drivers for any such changes.

Table 4 – Summer Load & Resources Table (MW)

	PSCo Summer L&R Table (MW)	2025	2026	2027	2028	2029	2030	2031	2032	
1	Owned Coal	1,462	663	661	567	412	412	-	-	
2	Purchased Coal	-	-	-	-	-	-	-	-	
3	Total Coal-Fired Generation	1,462	663	661	567	412	412	-	-	
4	Owned Gas Steam	230	695	693	462	463	463	480	480	
5	Owned Gas Combined Cycle	1,710	1,703	1,699	1,689	1,690	1,690	1,753	1,753	
6	Purchased Gas Combined Cycle	293	121	-	-	-	-	-	-	
7	Owned Gas Combustion Turbine	833	782	716	711	712	712	738	738	
8	Purchased Gas Combustion Turbine	676	673	420	213	213	213	221	-	
9	Total Gas-Fired Generation	3,743	3,975	3,528	3,076	3,078	3,078	3,193	2,971	
10	Owned Storage	234	195	215	205	224	230	210	210	
11	Purchased Storage	155	123	136	129	142	146	133	133	
12	Purchased Biomass	-	-	-	-	-	-	-	-	
13	Owned Hydro	12	12	12	12	12	12	12	12	
14	Purchased Hydro	16	16	5	-	-	-	-	-	
15	Owned Solar	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2	
16	Purchased Solar	378	307	310	262	196	189	188	182	
17	Purchased BTM Solar	144	150	149	113	101	107	127	136	
18	Purchased Community Solar	52	55	62	54	59	72	92	100	
19	Owned Wind	166	180	176	233	234	220	235	235	
20	Purchased Wind	453	482	458	501	502	469	499	445	
21	2021 ERP/CEP Resources	-	457	1,500	2,105	2,118	2,115	2,059	2,057	
22	Demand Response	352	335	372	341	387	409	417	429	
23	Market Purchase	-	-	-	-	-	-	-	-	
24	Total Renewable/Other Generation	1,962	2,313	3,395	3,954	3,973	3,969	3,971	3,939	
25	TOTAL ACCREDITED CAPACITY	7,167	6,951	7,585	7,597	7,463	7,459	7,163	6,911	A
26	Native Load Forecast - Spring 2024 (Base)	7,426	7,139	7,450	7,835	8,540	9,228	9,828	10,227	
27	Estimated TOU Impact	(99)	(100)	(101)	(103)	(104)	(106)	(108)	(86)	
28	FIRM OBLIGATION LOAD	7,327	7,039	7,348	7,732	8,437	9,123	9,720	10,141	B
29	Target Planning Reserve Margin	469	442	469	492	540	586	617	644	
30	CORE & HCEA Backup Reserves	16	4	4	4	4	4	4	4	
31	TOTAL PLANNING RESERVE MARGIN TARGET	485	446	473	496	543	590	621	647	C
32	Actual Reserve Margin	(161)	(88)	236	(135)	(974)	(1,663)	(2,556)	(3,230)	A - B
33	CAPACITY POSITION: LONG/(SHORT)	(646)	(534)	(237)	(631)	(1,517)	(2,253)	(3,177)	(3,878)	A - B - C

⁸ The columns in each table present the capacity position in the given reliability season. Summer refers to the capacity position relative to the gross peak occurring in the period of July through August, and Winter refers to the position relative to the gross peak occurring in the period of December through February.

Table 5 – Winter Load & Resources Table (MW)

	PSCo Winter L&R Table (MW)	2025	2026	2027	2028	2029	2030	2031	2032	
1	Owned Coal	1,437	655	655	566	411	411	-	-	
2	Purchased Coal	-	-	-	-	-	-	-	-	
3	Total Coal-Fired Generation	1,437	655	655	566	411	411	-	-	
4	Owned Gas Steam	224	672	678	454	452	452	452	487	
5	Owned Gas Combined Cycle	1,808	1,797	1,799	1,795	1,786	1,786	1,786	1,925	
6	Purchased Gas Combined Cycle	303	130	-	-	-	-	-	-	
7	Owned Gas Combustion Turbine	907	849	770	768	764	764	764	824	
8	Purchased Gas Combustion Turbine	710	706	707	421	213	213	213	-	
9	Total Gas-Fired Generation	3,953	4,154	3,954	3,439	3,215	3,216	3,216	3,236	
10	Owned Storage	148	146	142	152	150	173	187	191	
11	Purchased Storage	98	96	87	94	93	108	117	120	
12	Purchased Biomass	-	-	-	-	-	-	-	-	
13	Owned Hydro	4	4	4	4	5	5	5	5	
14	Purchased Hydro	8	8	8	-	-	-	-	-	
15	Owned Solar	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	
16	Purchased Solar	0	27	51	28	60	39	14	0	
17	Purchased BTM Solar	0	5	11	24	38	22	-	(0)	
18	Purchased Community Solar	0	2	5	11	22	12	-	(0)	
19	Owned Wind	105	101	89	109	169	198	214	224	
20	Purchased Wind	286	270	239	233	363	420	456	426	
21	2021 ERP/CEP Resources	-	-	484	1,002	1,488	1,630	1,698	1,749	
22	Demand Response	77	80	79	111	123	155	182	193	
23	Market Purchase	-	-	-	-	-	-	-	-	
24	Total Renewable/Other Generation	726	738	1,199	1,767	2,511	2,762	2,874	2,908	
25	TOTAL ACCREDITED CAPACITY	6,116	5,547	5,809	5,772	6,136	6,389	6,090	6,145	A
26	Native Load Forecast - Spring 2024 (Base)	5,593	5,803	5,673	6,170	6,636	7,489	8,212	8,873	
27	Estimated TOU Impact	3	3	3	3	3	3	20	21	
28	FIRM OBLIGATION LOAD	5,596	5,806	5,676	6,173	6,639	7,492	8,232	8,893	B
29	Target Planning Reserve Margin	485	522	514	645	790	995	1,197	1,183	
30	CORE & HCEA Backup Reserves	22	5	5	6	7	8	9	8	
31	TOTAL PLANNING RESERVE MARGIN TARGET	506	528	519	651	797	1,002	1,206	1,191	C
32	Actual Reserve Margin	520	(259)	133	(401)	(503)	(1,104)	(2,143)	(2,749)	A - B
33	CAPACITY POSITION: LONG/(SHORT)	13	(787)	(386)	(1,052)	(1,301)	(2,106)	(3,348)	(3,940)	A - B - C

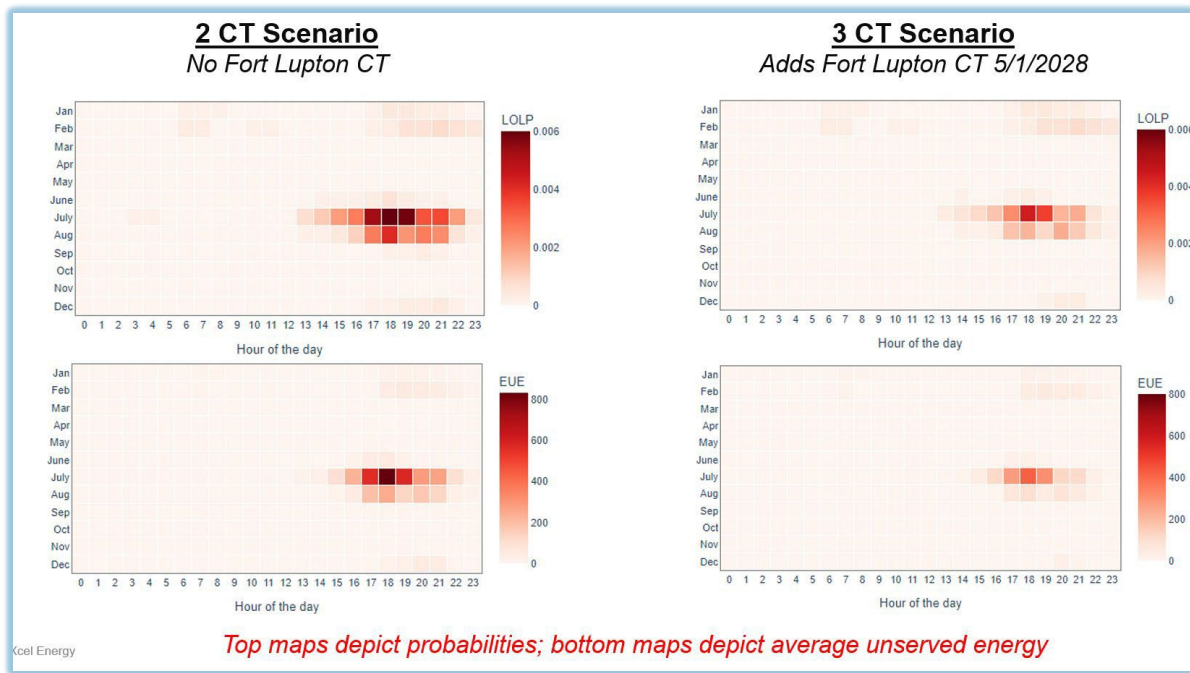
1. Resource Adequacy Update

On February 11, 2025, following the issuance of the Commission's CEPD Plan Decision, the Company filed a Letter on Resource Adequacy ("RA Letter") in Proceeding No. 21A-0141E expressing concerns.

As discussed in detail in the RA Letter, resource adequacy is a paramount concern for Public Service. The electric system is bringing on ever-increasing amounts of weather-dependent energy generation in efforts to meet energy policy goals. The electric system is also losing firm generation that is available 24 hours per day, 7 days per week, and the Company must take sufficient actions to secure replacement for the retiring generation over the medium- and long-term. Short-term actions and patches are not solutions for the long run. In recent summers Public Service has been looking to the market for firm energy purchases and solutions. This is not an option the Company can continue to rely on as western power markets get tighter and other energy providers experience the same demand growth the Company is forecasting in the Public Service territory.

The Company reiterates that real-time operations and resource planning are not the same. Loads and resources tables, such as those presented above, are merely a snapshot in time and are not the singular basis to perform the planning and selection of resources. When the Company evaluates its ability to reliably serve customers, we use tools such as loss of load probability and expected unserved energy. An evaluation of the Company's ability to reliably serve our customers shows that, with the approved CEPD Plan resources inclusive of the Plains End resource approved by Decision No. C25-0024, we do not meet industry standard reliability metrics, nor the reliability assumptions used in the 2021 ERP & CEP. Figure 1 below presents heat maps reproduced from the RA Letter that visually depict the system with three new thermal assets as compared to two.

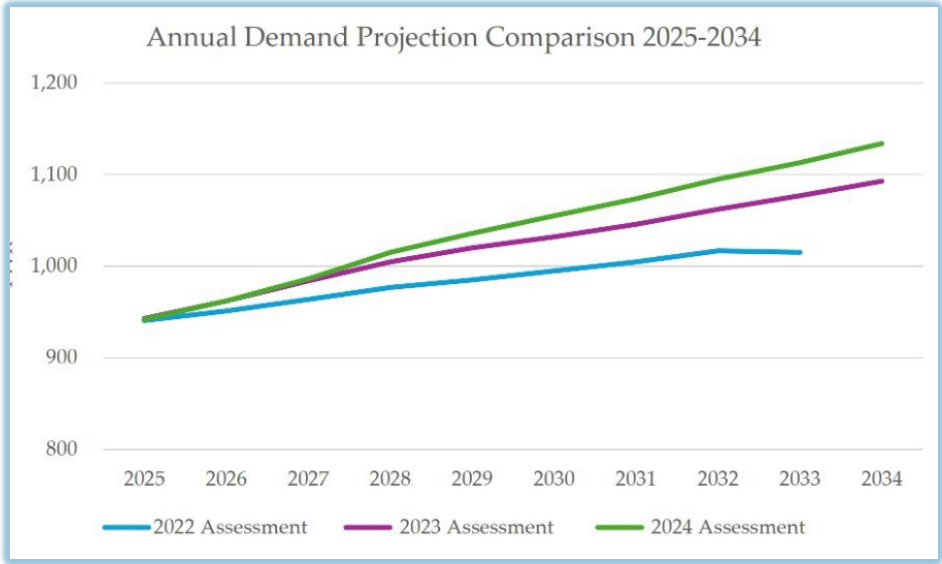
Figure 1 – 2 CT Scenario and 3 CT Scenario Heat Maps



The western energy landscape is different than when Proceeding No. 21A-0141E began, and when the competitive solicitation commenced, and has continued to evolve over the nearly four years that the 2021 ERP & CEP proceeding has been in progress. Recent data from the Western Electricity Coordinating Council's ("WECC") 2024 Western Assessment of Resource Adequacy illustrates these changes, as shown in Figure 2 below. WECC also notes recent uncertainties in bringing new resources online: "Between 2018 and 2023, approximately 76% of the proposed resource additions came online in the year scheduled. In 2023, only 53% of the new generation resources scheduled to come online that year actually came online; the rest were delayed or cancelled."⁹

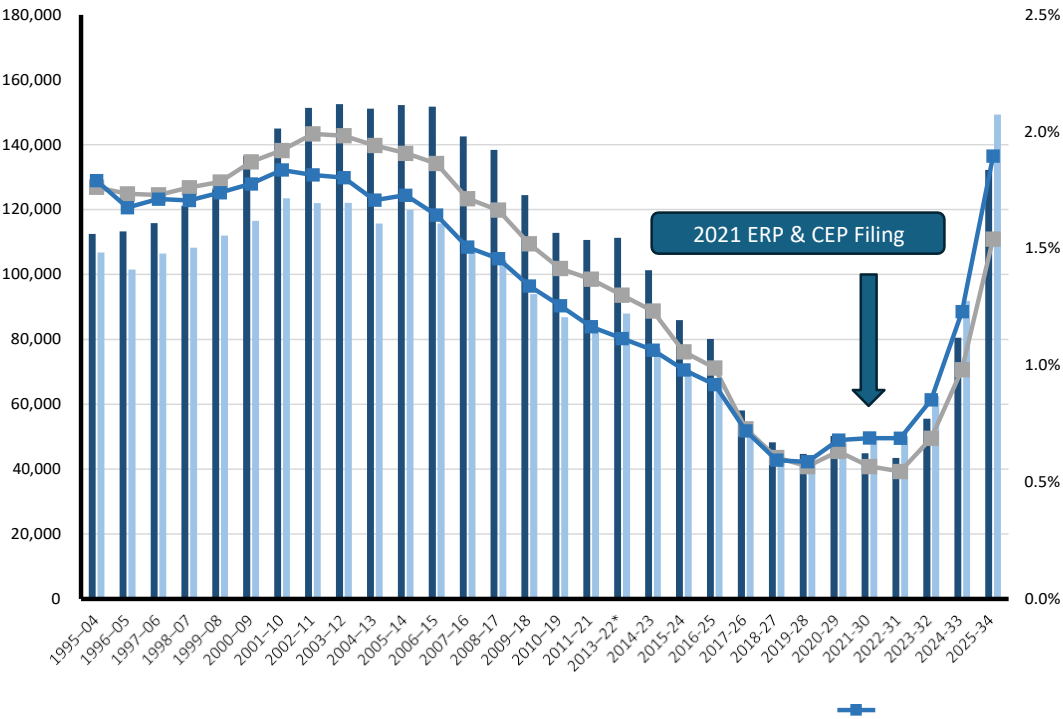
⁹ <https://feature.wecc.org/wara/>.

Figure 2 – Annual Demand Projection Comparison 2025-2034



This issue is not Western-only in scope, as the ten-year national demand growth forecasts in Figure 3 below from the North American Electric Reliability Corporation (“NERC”) show.

Figure 3 – NERC: Ten-Year U.S. Demand Forecasts 1995-2025



The Commission recognizes Public Service has the responsibility to maintain reliability. The resources brought forward by the Company in the CEPD Plan are needed in order to ensure the reliable operation of the electric system over the long-term for our customers and for the state as a whole. Accordingly, Public Service will be bringing forward a CPCN Application(s) for the thermal assets it needs to meet resource adequacy needs, including the Fort Lupton CT (Bid 0989) anticipated to be filed in late Q2 or Q3 2025, and will potentially be taking other actions deemed necessary to maintain industry standard resource adequacy. Further, the Company has modeled, and fully expects to need, more thermal resources in the JTS in Proceeding 24A-0442E, but that proceeding cannot deliver resources in time to meet needs in the relatively near-term (e.g., by the end of 2028).

E. Status of Acquisition of Generation Resources from the 2022 All-Source Solicitation Approved in Phase II of the 2021 ERP & CEP

In this section, the Company provides an update on the status of the implementation of the Alternative Portfolio approved by the Commission's Phase II Decision. The Alternative Portfolio, as approved by Decision No. C24-0052 and further modified by the ARRR Decision, was comprised of 20 generation resources, including nine Company-owned generation projects and eleven independent power producer ("IPP") generation projects. The Phase II Decision authorizes Public Service to pursue the acquisition of the resources included in the Alternative Portfolio with further due diligence and contract negotiations and directs Public Service to file applications for CPCNs for all Company-owned generation resources arising from the approved Alternative Portfolio.

The composition of the approved Alternative Portfolio has Table 6 below provides a list of CEP projects that are planned to come online during the CEP RAP as of the date of this annual report filing. The list is expected to change based on ongoing PPA negotiations and the evaluation of potential backup projects.

Table 6 – Current CEP Projects

Bid ID	Technology	MW	Ownership
1002	Solar	335	Own
0474	Solar	200	PPA
0782	Solar	400	PPA
1010	Solar + Storage	325/200	Own
0303	Solar + Storage	300/100	PPA
0589	Storage	200	PPA
0249	Storage	199	PPA
0251	Storage	199	PPA
0282	Storage	250	PPA
0467	Storage	250	PPA
1085	Storage	200	Own
0295	Wind	500	PPA
1024	Wind	603	Own
1029	Wind	500	Own
1015	Wind	450	Own
0011	Gas	50	Own
1000	Gas	400	Own

1. Status of Acquisition of PPA Generation Resources

As ordered in the Phase II Decision, the Company is pursuing the acquisition of the approved PPA generation resources referenced in Table 6 above with further due diligence and contract negotiations. Pursuant to Paragraph 95 of Decision No. C25-0024 in Proceeding No. 21A-0141E, the Company is providing monthly updates on the status of negotiations with IPPs for all PPA and build-transfer projects. The first status report was filed on February 5, 2025 (Rev. 1 was filed on February 10, 2025) and the most recent status report was filed on March 3, 2025.¹⁰ The Company will file its next monthly status report in accordance with the April 5, 2025 deadline.

As detailed in the status reports, the Company has continued negotiations with all IPPs for projects included in the Approved Portfolio as well as the majority of IPPs with projects in the backup bid pool.¹¹ To date, one build-transfer contract has been signed

¹⁰ The Company's March 3, 2025 filing also included a motion for an extension of the Rule 3613(i) deadline, which was approved by Decision No. C25-0181-I.

¹¹ The Company has excluded from the status reports, updates on projects for which bids were withdrawn or negotiations had failed prior to the Clean Energy Plan Delivery plan decision issued on January 14, 2025 as contract negotiations had ceased and withdrawals had occurred prior to the decision date.

(Bid 1085)¹² and the Company has reached final terms on two PPA contracts which are in the process of being signed (Bids 0589 and 0782). Several others are nearing completion pending final resolution of language related to the implementation of Component 1, Stage 2 of the Clean Energy Plan Delivery Plan (“CEPD”) and other potential impacts from recent federal tariff and permitting actions.

2. Status of Acquisition of Company-owned Generation Resources

Decision No. C24-0052 directs the Company to file follow-on CPCNs for the Company-owned generation resources that are part of the Approved Portfolio. The Phase II Decision further states, “[a]t this juncture, the Commission will not attempt to dictate the form or timing of the Company’s CPCN[s] and other applications.”¹³ Therefore, the Company has evaluated, and will continue to evaluate, what it believes is the most appropriate form and timing of the follow-on CPCN filings. The Commission directed the Company to provide additional updates to interested stakeholders regarding the Company’s prioritization of the follow-on CPCN filings via existing reporting venues, including the Annual ERP Progress Report filed every year pursuant to Rule 3618(a), as well as its annual Rule 3205 and Rule 3206 reports.¹⁴ Accordingly, the Company provides a summary discussion and Table 7 below regarding the current status of CPCN filings.

Generation CPCNs

As of the date of this filing, the Company has made two follow-on CPCN filings for Company-owned generation resources and anticipates making at least two additional CPCN filings as described below.

First, on March 25, 2024, the Company filed an Application in Proceeding No. 24A-0141E for: (1) a CPCN for the Rocky Mountain 325 MW solar plus 200 MW storage project and associated interconnection facilities, including an approximately 4.3-mile generation tie line (“Rocky Mountain Gen-Tie”) (collectively, “Rocky Mountain” or the “Rocky Mountain Project”); and (2) a CPCN for the 335 MW Arroyo 2 solar project and associated interconnection facilities (“Arroyo 2” or the “Arroyo 2 Project”). The Rocky Mountain Project and the Arroyo 2 Project are identified in Table 6 above as Bid ID 1010 and Bid ID 1002, respectively.

By Decision No. C24-0525 (issued July 23, 2024), the Commission approved the CPCNs, and the Unopposed Comprehensive Settlement Agreement (“Settlement Agreement”) submitted in the Proceeding. Pursuant to the terms of the Settlement

¹² The Company notes that while the contract has been signed, additional items regarding the execution of the contract have been identified. The Company and developer are working diligently and collaboratively, to address these questions.

¹³ Decision No. C24-0052, at ¶314.

¹⁴ *Id.*

Agreement, following commercial operation, Public Service will provide reporting annually as part of the Company's ERP annual reports.¹⁵

Second, on March 17, 2025, the Company filed an Application in Proceeding No. 25A-0112E requesting approval of three CPCNs to construct, own, and operate three wind generation resources, including the: (1) 450 megawatt ("MW") Cheyenne Ridge II wind project (Bid 1015); (2) 603 MW Singing Grass wind project (Bid 1024); and (3) 500 MW Towner wind project (Bid 1029) (collectively, the "Facilities"). In the alternative, should the Commission decide not to approve a CPCN for the Towner Project, the Company requests approval of a CPCN for the 550 MW Heartstrong Project (approved backup Bid 1016).

In the CPCN Application and supporting Direct Testimonies, the Company presents updated cost estimates and updated commercial operation dates ("COD") for the Facilities. The Company explains the drivers behind project cost and COD variances and explains why approval of the CPCNs is in the public interest. The Company also presents the NPV of the Facilities based on the updated cost estimates. Additionally, and as directed by the Commission, the Company addresses the engagement it undertook with the Northern Cheyenne Tribe ("Tribe") and interested stakeholders regarding potential impacts of the Towner Project on the viewshed of the Sand Creek Massacre National Historic Site ("SCMNHS"). As detailed in the Company's Direct Testimonies, Public Service and the Tribe have successfully resolved matters of mutual interest and concern regarding potential impacts to the viewshed of the SCMNHS in a manner that the Towner Project continues to be more cost effective than the approved Heartstrong backup bid.

Third, in Q2 2025, the Company anticipates filing a CPCN Application for the 400 MW gas resource (Bid 1000).

Finally, the Company is continuing negotiations with Bid 0011, a build-transfer dispatchable generator based on the Commission's direction in the CEPD Plan Decision. Negotiations are expected to conclude in Q2 2025 with a CPCN following this summer. Additionally, as noted above, the Company and developer of Bid 1085 are negotiating regarding the scope of the build-own transfer storage project and will file a follow-on CPCN Application at the appropriate time when all of the necessary project information is known.

Additionally, as noted above, the Company will be filing for the third CT from the CEPD Plan filing and is continuing to evaluate potential backup bids and will file a CPCN Application for any proposed Company-owned backup bids as necessary (either combined with Bid 1085 or as a separate CPCN Application(s), but the anticipated timing of such a filing is unknown at this time.

¹⁵ Settlement Agreement at ¶ 15.

Transmission CPCNs

In the Phase II Decision, the Commission left it to the Company's discretion regarding how best to present the required transmission analysis to the Commission both in terms of timing and type of filings made, but also with regard to the number or combination of filings. On December 20, 2024, the Company filed a CPCN Application in Proceeding No. 24A-0560E requesting approval of CPCNs for the following two transmission projects: (1) the Denver Metro Transmission Network Improvement Project ("Denver Metro Project"); and (2) the Leetsdale-Elati 230 kV Underground Transmission Upgrade Project ("Leetsdale-Elati Project") (together, the "Projects").

The Denver Metro Project was identified as part of the Company's transmission planning study for the 2021 ERP & CEP. While the Leetsdale-Elati Project was identified prior to the 2021 ERP & CEP transmission planning study analysis to address upgrades to this line that were identified as needed prior to the finalization of an approved resource portfolio, it was incorporated into the 2021 ERP & CEP transmission analysis underpinning the Denver Metro Project and is foundational to that transmission plan. As discussed throughout the Company's Direct Case, the Projects will not only enhance system resilience and reliability in the Denver metro area but enable the Company to reliably deliver the 5.5 gigawatts of new generation resources contemplated in the Company's 2021 ERP & CEP to the Company's major load centers.

The Company also continues to evaluate the remaining transmission needs associated with the Approved Portfolio of resources, including grid strength reinforcement and dynamic reactive/voltage support facilities, transmission network upgrades in the San Luis Valley, and interconnection facilities. The Company expects to bring forward CPCNs for grid strength reinforcement and reactive/voltage support devices in 2025. These devices are needed to ensure the Company can maintain safe and reliable transmission service as new clean energy resources are interconnected to the transmission system, and the Company is in the process of studying the appropriate solutions and locations. When evaluating the San Luis Valley, the Company is reconsidering system needs in light of potential changes to the Approved Portfolio of resources. Due to certain project failures, there may no longer be a need for new transmission network upgrades in the San Luis Valley area as initially forecasted in the 120-Day Report. Finally, the Company expects to make filings throughout 2025 for interconnection facilities for the approved generation projects from the 2021 ERP & CEP. Studies, design, and cost estimation for these projects is still underway.

Summary of Anticipated CPCN Filings

Table 7 below summarizes the status of CPCN filings to date and estimated timing of forthcoming CPCN filings. The Company notes that the ultimate sequencing and timing of the remaining filings will be based on ongoing consideration of administrative efficiency, as well as consideration of construction timing, contract terms and negotiations, completion of associated studies necessary for each filing, and other issues that may influence the actual scope and timing of the various filings.

Table 7 – Status of Filings and Estimated Filing Dates

Anticipated Filing	General Scope	Status
Generation CPCN Application	Rocky Mountain (Bid 1010) & Arroyo 2 (Bid 1002)	Filed on March 25, 2024; CPCNs approved by Decision No. C24-0525 issued July 23, 2024
Transmission CPCN Application	Denver Metro Transmission Upgrades	Filed on December 20, 2024 in Proceeding No. 24A-0560E
Generation CPCN Application	Company-owned Wind Projects: Cheyenne Ridge II (Bid 1015), Singing Grass (Bid 1024), Towner (Bid 1029), and Heartstrong backup bid (Bid 1016) ¹⁶	Filed on March 17, 2025 in Proceeding No. 25A-0112E
Transmission Voltage Control Application(s)	Voltage control devices needed to maintain system stability and reliability	Anticipated filing(s) in 2025
Generation CPCN Application	Bid 1000	Anticipated filing in Q2 2025
Generation CPCN Application	Bid 1085 and/or Bid 0011	TBD pending ongoing negotiations regarding project scope
Generation CPCN Application	Company-owned backup bids as necessary	TBD based on the timing and need of backup bid activation

F. Pawnee Natural Gas Conversion Project Status

Background

On December 20, 2022, the Company filed a CPCN Application in Proceeding No. 22A-0563E for the conversion of Pawnee from coal to natural gas operations as required by Paragraph 31 of the Settlement Agreement and Paragraph 63 of the Phase I Decision in Proceeding No. 21A-0141E. On June 6, 2023, the Commission referred the matter to an Administrative Law Judge (“ALJ”) and on June 29, 2023, the ALJ scheduled an evidentiary hearing for November 7 and 9, 2023 and established a procedural schedule. On October 26, 2023, the Company filed a Settlement Agreement representing a comprehensive resolution of the Proceeding and set forth terms regarding approval of the CPCN, performance incentive mechanism (“PIM”), operational matters, timing of the conversion, reporting, and best value employment metrics (“BVEM”). Decision No. R24-0194, issued on March 29, 2024, approved reporting provisions of the Settlement Agreement. Accordingly, the Company provides this second update on the status of the Pawnee Conversion as set forth by the terms of the Settlement Agreement.

Conversion Status

As of March 10, 2025, the Pawnee Conversion project is approximately 70 percent complete and is currently expected to be converted and online in the Fall of 2025. To date, the project has spent approximately \$24.5 million, or just over 30 percent of the baseline budget.

For converting the boiler, the boiler conversion design by Babcock Power Services, Inc. is complete, and all remaining Issued for Construction (“IFC”) drawings will be released by April 2025. Equipment has begun delivery to site and is expected to be complete by September 2025. A Request for Proposal (“RFP”) was issued for boiler conversion installation in December 2024 and bids were due January 20, 2025. A conformed contract is expected to be executed in March 2025. Construction is expected to start in May 2025.

For the wastewater treatment, the supply of the equipment was awarded to Evoqua Water Technologies, LLC in May 2024. The design by Barr Engineering Co. is complete with IFC drawings released in March 2025. Delivery of equipment is expected to begin in July 2025. A contract was awarded to MasTec Industrial Corp (“MasTec”) for the Civil and Foundations work in October 2024 and work began in February 2025. An RFP was issued for the installation of the wastewater treatment equipment in November 2024, and the contract is expected to be executed in March 2025.

For other balance of plant equipment, the Distributed Control System (“DCS”) equipment vendor, Emerson Process Management, is approximately ninety percent

¹⁶ The Company is seeking a CPCN for the Towner Project; however, should the Commission decide not to approve a CPCN for the Towner Project, the Company requests approval of a CPCN for the Heartstrong Project, the approved backup bid to Towner.

complete with the design with expected delivery in August 2025. The long-lead electrical equipment will be awarded to Rexel USA Inc. in March 2025, and the pre-engineered metal building for wastewater treatment equipment was awarded to MasTec in February 2025.

In April 2024, Morgan County informed the Company that the existing Special Use Permit for Pawnee has language for only coal operation. In July 2024 the County clarified an amendment would be necessary to modify existing permit and then further clarified in October 2024 that it would be a Major Amendment. An application was submitted and presented to County Commissioners in January and February 2025. The application was approved with conditions on February 4, 2025.

The Company anticipates the project will be complete and online prior to the end of 2025.

III. OTHER ANNUAL PROGRESS REPORT REQUIREMENTS

This section addresses various reporting requirements as set forth in certain Settlement Agreement, Commission Decisions, and/or informal commitments made by the Company to provide additional information in this Annual Progress Report.

A. COMANCHE UNIT 3 PLANNED OVERHAULS AND O&M COSTS

In Decision No. C22-0459, the Commission summarized the recommendation of Western Resource Advocates (“WRA”) to require Public Service to report on planned overhauls of Comanche Unit 3. The Commission adopted WRA’s recommendation in Paragraph 52 of its Phase I Decision, which states in applicable part:

52. We find WRA’s request to be reasonable. Indeed, given the plant’s pending retirement, its historical operational problems detailed in the record, and proposed operational changes such as economic dispatch, we establish enhanced reporting requirements for Unit 3 beyond what WRA expressly requests. In the annual progress reports Public Service files under Rule 3618, the Company shall include Unit 3’s planned overhauls with the associated estimated capital expenditures. In addition, the Company must include the actual O&M expenditures for Unit 3, broken down by fixed and variable costs.¹⁷

Accordingly, Attachment B provides the Company’s forecasted O&M budget and planned overhaul budget for 2025-2029, the forecasted capital expenditures for 2025-2029 (the Company develops its capital and O&M budgets based on a 5-year forecast), and actual O&M expenditures for 2024. As noted previously in the Company’s Annual Progress Report filed on March 29, 2024, the Company does not differentiate actual O&M costs between fixed and variable costs; rather, the O&M costs are broken down by major cost categories. Variable O&M costs are costs that vary based on energy production and are comprised of commodities, inclusive of chemicals (e.g., lime, ammonia, sulfuric acid, mercury sorbent, etc.), variable water costs and electricity costs. Fixed O&M includes labor (base, non-productive, overtime and premium), benefit loadings (pension, insurance, incentive, payroll taxes), consulting, contract labor, contributions & dues, employee expenses, facility costs, materials, postage, rents, regulatory and other fees, transportation and miscellaneous.

¹⁷ Paragraph 52 of Decision No. C22-0459 also requires the Company to present Comanche Unit 3 planned and unplanned capital expenditures as well as past and projected future O&M expenditures in the Pueblo Just Transition interim ERP and the 2026 ERP, and to include a narrative describing Comanche Unit 3 planned overhauls when the Company submits the proposal for the O&M and capital cost PIM 60 days after the 120-Day Report.

B. HAYDEN 1 & 2 AND CRAIG 2 COST REPORTING

Paragraphs 28 and 34 of Decision No. C23-0362 in Proceeding No. 22A-0515E addressing cost recovery associated with the early retirements of coal generation assets Craig 2, Hayden 1, and Hayden 2, and the retiring coal portion of Pawnee (“Coal Asset Cost Recovery Proceeding”), require the Company to report certain information for Hayden 1 & 2, and Craig 2 (to the extent such information is reasonably available to the Company),¹⁸ respectively, in its ERP Annual Progress Reports (beginning in this 2024 annual report), including the following:

1. each unit’s planned overhauls with the associated estimated capital expenditures,
2. the actual O&M expenditures for each unit, broken down by major cost categories,
3. annual year-end net book value (“NBV”), and
4. current estimate of decommissioning costs.

Accordingly, regarding Hayden 1 & 2, the Company provides Attachment C, which includes: O&M actual costs for 2024; the forecasted capital expenditures for 2025-2029; the O&M project and overhaul budget for 2025-2029; and NBV and dismantling estimate as of December 31, 2024. As noted in Attachment C, these costs represent Public Service’s portion of the common, Unit 1, and Unit 2 costs at Hayden Station.

Regarding Craig 2, the Company provides information that is reasonably available in Attachment D, which includes: O&M actual costs for 2024; the forecasted capital expenditures for 2025-2029; and NBV and dismantling estimate as of December 31, 2024. As noted in Attachment D, these costs represent Public Service’s portion of the common and Unit 2 costs at Craig Station.

C. CUMULATIVE EMISSIONS REDUCTIONS

Paragraph 40 of the USA approved by Decision No. C22-0459 requires the Company to report the cumulative carbon emissions reductions as an annual million short tons value compared to the adjusted baseline developed in the Clean Energy Plan Guidance and appendices.¹⁹ Table 8 below provides the cumulative emissions of the Alternative Portfolio approved in Phase II of Proceeding No. 21A-0141E. The Company notes, however, that these emissions reductions may change as the approved resources are

¹⁸ In Decision No. C23-0362, at ¶33, the Commission acknowledged that even if Public Service does not have the same ability to access information for Craig 2 as it does for the plants it operates, additional reporting of the information that is reasonably available provides important transparency.

¹⁹ Included in the Company’s Direct Case filing in Proceeding No. 21A-0141E as Attachment LWQ-1.

updated consistent with the Commission's Phase II and ARRR decisions. Emissions forecasts will also be affected by actual in-service dates and project replacements.

Table 8 – Cumulative Emissions Reductions of Approved Alternative Portfolio

	2024	2025	2026	2027	2028	2029	2030
Carbon (Tons)	15,161,940	14,550,692	7,557,927	6,323,128	5,774,633	3,546,451	3,751,349
% CO2 Reduction	-44.4%	-46.6%	-72.3%	-76.8%	-78.8%	-87.0%	-86.2%

D. SPP WESTERN ENERGY IMBALANCE SERVICES MARKET

Public Service joined the Southwest Power Pool's Western Energy Imbalance Services market ("SPP WEIS") in April 2023. On June 14, 2022, Public Service filed an advice letter and supporting testimony in Proceeding No. 22AL-0270E requesting recovery of certain costs associated with joining SPP WEIS. On November 15, 2022, the Company filed a Unanimous Comprehensive Settlement Agreement, which was approved by Decision No. R22-0826. In relevant part, Section 3.3 of the approved Settlement Agreement requires certain additions to future ERP Annual Update reports, including information regarding (1) the Company's participation and performance in the SPP WEIS market as detailed in Section 3.3.1 of the Settlement Agreement, and (2) information regarding carbon emissions as detailed in Section 3.3.2 of the Settlement Agreement.

Please see Attachment E, which provides updated information since the Company's last ERP Annual Report regarding the benefits of Public Service's participation in the SPP WEIS, including economic sale and purchase margins, estimated avoided curtailment of the Company's wind and solar resources, and the impact on carbon emissions.

E. REC RETIREMENT

Paragraph 17 of the USA in Proceeding No. 21A-0141E addresses the Renewable Energy Credits ("RECs") retirement process and provides that the Company will follow a method similar to that which the Company uses to comply with the Renewable Energy Standard ("RES"), with RECs retired by June 1 of the following year. Paragraph 17 further requires that for energy purchases used to serve customer load that is assigned a market-based, eGRID, or system emissions rate that reflects the use of renewable energy, the Company will provide the energy mix reflected by the emission rate in its ERP annual reports to the extent information regarding the energy mix is available. The Company also commits to make good-faith efforts in conjunction with interested parties to study solutions to best capture the levels of such renewable energy, and to consider whether and how associated retirements of RECs may be accomplished with appropriate regulatory

approvals and cost recovery and the Company will report on progress in these efforts, to the Commission, in the annual ERP reports.

The Company plans to comply with the 2024 RES requirements by retiring RECs in the year they were generated, which aligns with the USA. In other words, only 2024 vintage stamped RECs will be retired; no RECs of older vintages nor RECs carried forward or banked will be utilized for RES compliance. A RES/REC retirement report will be filed annually by June 1 for the prior years' reporting activity (for example, 2024 reporting will be filed by June 1, 2025). Public Service's 2024 energy mix can be found on page 5 of the Company's Form 10-K at this link: [PSCo 2024 Form 10k](#).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-104:
PacifiCorp 2015 IRP Update



2015 Integrated Resource Plan Update

Let's turn the answers on.

March 31, 2016



Pacific Power
Rocky Mountain Power

This 2015 Integrated Resource Plan Update Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):

Wind Turbine: Marengo II

Solar: Residential Solar Install

Transmission: Populus to Terminal Tower Construction

Demand-Side Management: Wattsmart Flower

Thermal-Gas: Lake Side I

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EXECUTIVE SUMMARY

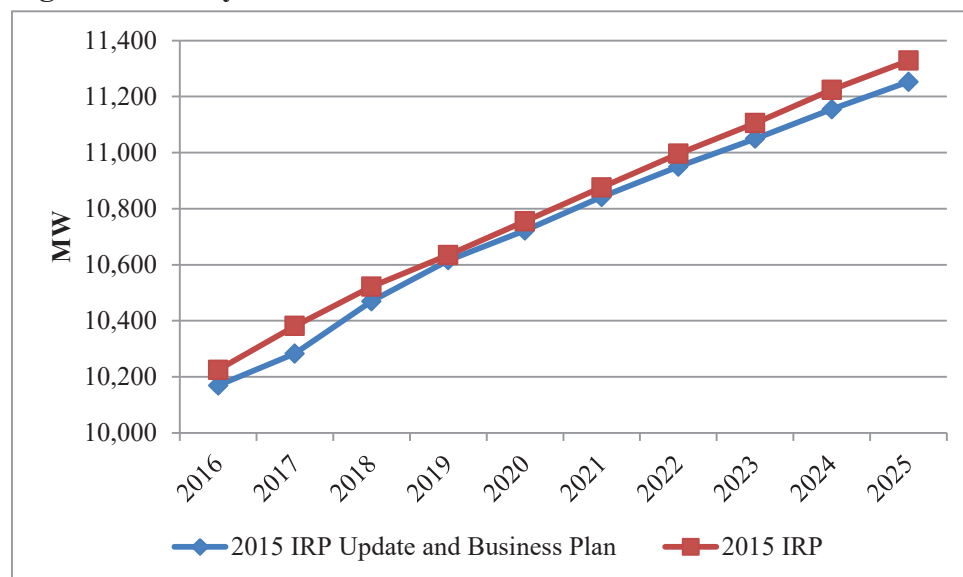
PacifiCorp submitted its 2015 Integrated Resource Plan (2015 IRP) to state regulatory commissions in March 2015. That plan provides a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks for customers. This 2015 IRP Update describes resource planning and procurement activities that occurred since the 2015 IRP was filed, presents an updated load and resource balance, presents an updated resource portfolio consistent with changes in the planning environment, presents an updated action plan, and provides a status update on the action plan filed with the 2015 IRP. In presenting the updated load and resource balance and updated resource portfolio, PacifiCorp shows changes relative to the 2015 IRP and relative to its fall 2015 ten-year business plan (Business Plan), which covers the 2016 to 2025 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2015 IRP acknowledgement process.

2015 IRP Update Highlights

PacifiCorp's long-term planning process involves balanced consideration of cost, risk, uncertainty, supply reliability/delivery, and long-run public policy goals. The following summarizes the key highlights of PacifiCorp's 2015 IRP Update:

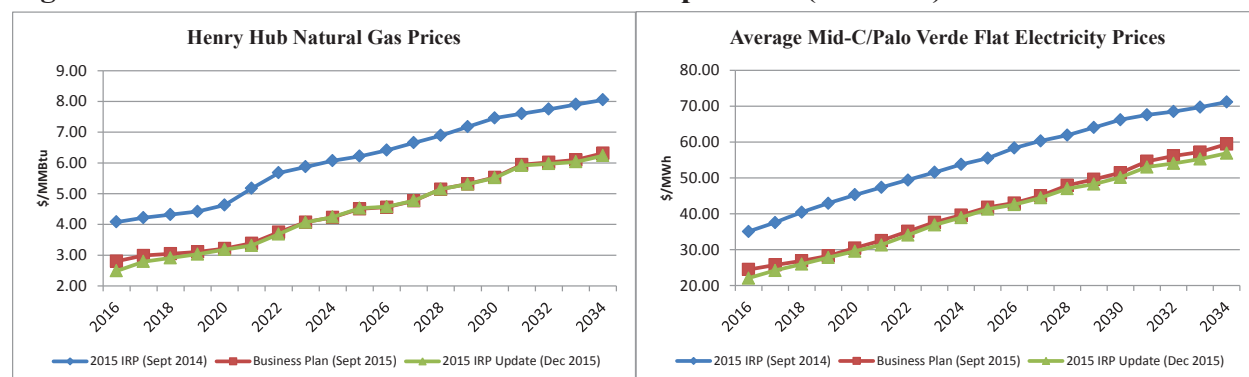
- As shown in Figure ES.1 PacifiCorp's most recent coincident system peak load forecast, used for the Business Plan and the 2015 IRP Update, is down relative to the 2015 IRP. On average, across the front ten years of the planning period, the coincident system peak is down by about 54 MW relative to the 2015 IRP.

Figure ES.1 – System Coincident Peak Load



- Figure ES.2 shows that forecasted natural gas and energy prices have declined from those assumed in the 2015 IRP. Domestic gas price forecasts continue to be driven down by growth in unconventional shale gas plays. This in turn (combined with lower forecast regional loads) impacts forward market power prices.

Figure ES.2 – Power and Natural Gas Price Comparisons (Nominal)



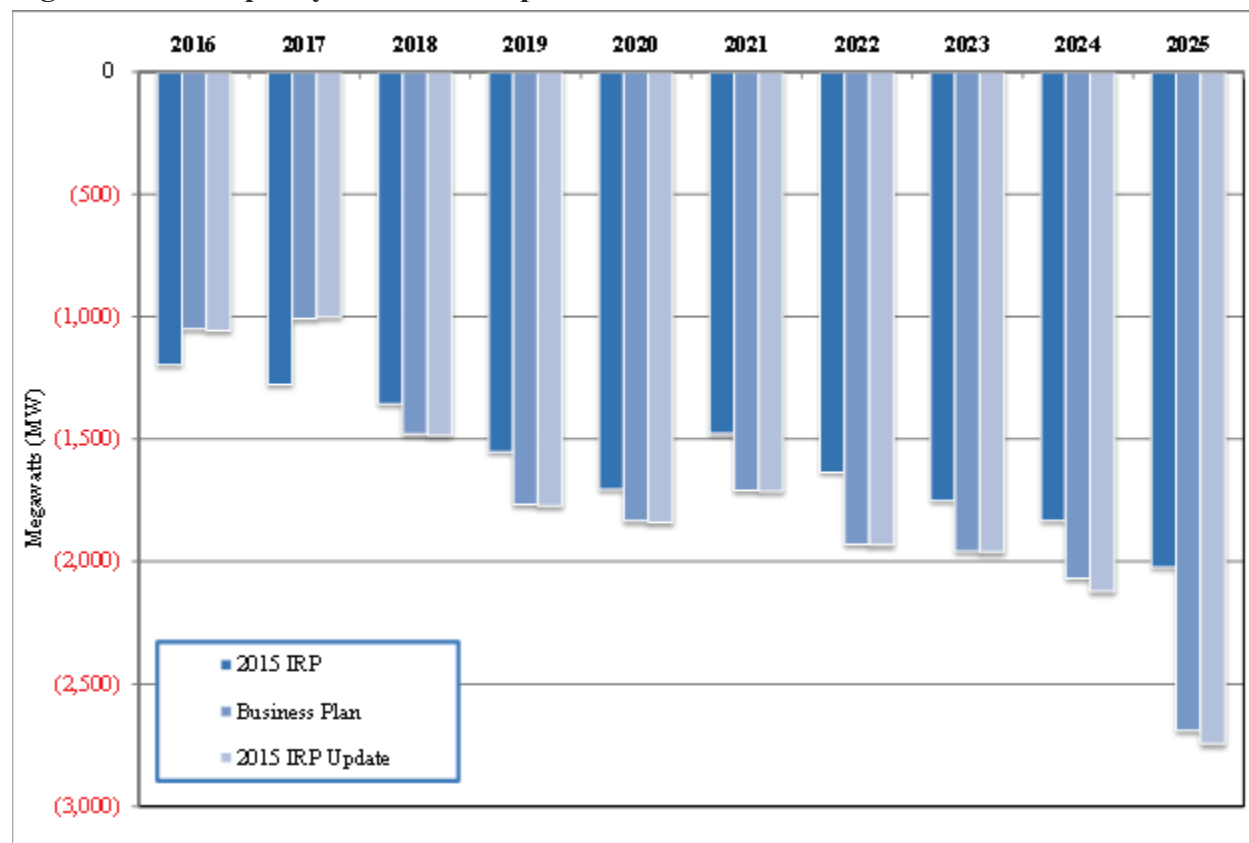
- PacifiCorp's updated resource portfolio continues to show that customer loads over the front ten years of the planning horizon will be met with front office transactions (firm market purchases) and energy efficiency. Over the front ten years of the planning period (2016 through 2025), accumulated acquisition of incremental energy efficiency resources meets 87% of projected load growth.
- PacifiCorp refreshed its analysis of Regional Haze compliance alternatives for Naughton Unit 3, which was assumed to convert to a natural gas-fired facility by mid-2018 in the 2015 IRP. With reduced load, lower market prices, and increased costs for gas conversion, the refreshed analysis shows that retiring Naughton Unit 3 at the end of 2017 is a lower cost alternative than the assessed gas conversion approach. As such, the capacity of the converted Unit 3 is no longer included in the 2015 IRP Update resource portfolio after year-end 2017. However, recognizing that Naughton Unit 3 is an important generation resource to the state of Wyoming and PacifiCorp's customers, PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2017.
- The state of Arizona issued a regional haze state implementation plan (SIP) requiring, among other things, the installation of SO₂, NO_x and particulate matter controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. The U.S. Environmental Protection Agency (EPA) approved in part, and disapproved in part, the Arizona SIP and issued a federal implementation plan (FIP) requiring the installation of selective catalytic reduction (SCR) equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. With respect to the Cholla FIP requirements, the court has placed the appeals in abeyance while parties attempt to agree on an alternative compliance approach. In October 2015, EPA acknowledged receipt of the state of Arizona's re-assessed regional haze SIP that commits to ceasing operation of Cholla Unit 4 as a coal fueled

resource in April 2025, in lieu of installation of SCR. EPA is currently expected to propose its final action on the Arizona SIP in mid-2016 and commence the public comment process. Similar to Naughton Unit 3, with reduced load, lower market prices, and expected costs for gas conversion, PacifiCorp has assumed Cholla Unit 4 will cease operation at the end of 2024 for capacity planning purposes in the 2015 IRP Update.

- After PacifiCorp filed its 2015 IRP, EPA issued its final rule for the Clean Power Plan (CPP). On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the U.S. Supreme Court, the stay will remain in effect until the U.S. Supreme Court takes action to either deny the petition, or, if the U.S. Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation is scheduled for June 2, 2016 before the D.C. Circuit Court of Appeals. In the 2015 IRP Update, PacifiCorp assumes a mass-based emission target to limit CO₂ emission from its affected generation facilities covered by the CPP.
- On March 8, 2016, Oregon Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition Plan, was signed into law, which, among other things, doubles the Oregon renewable portfolio standard (RPS) target to 50% by 2040. In October 2015, California Senate Bill No. 350 (SB 350) was signed into law, which among other things, expands California's RPS targets to 50% by 2030. Considering these updated RPS targets, renewable energy credit (REC) banking provisions and the market potential for RECs, PacifiCorp can meet its state RPS obligations through the planning horizon with REC purchases. However, PacifiCorp has identified the potential for a near-term, time-sensitive opportunity that may reduce state RPS compliance costs over time through the acquisition of renewable resources that can take full advantage of federal income tax deductions and credits passed in December 2015. PacifiCorp has updated its action plan to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives.

Load and Resource Balance Update

Figure ES.3 summarizes the 2015 IRP Update capacity load and resource balance, prior to acquiring any new resources and making firm market purchases, alongside the load and resource balance from the 2015 IRP and the Business Plan. The load and resource balance has decreased by an average of 209 MW, relative to the 2015 IRP, in 2016 and 2017 reflecting to changes in the load forecast, hydro generation and qualifying facility contracts. The projected load and resource balance position is shorter beginning in 2018, relative to the 2015 IRP, primarily due to the assumed early retirement of Naughton Unit 3 at the end of 2017 and Cholla Unit 4 at the end of 2024. This is partially offset by the addition of new wind and solar qualifying facility contracts. The 2015 IRP Update load and resource balance shows is shorter by 128 MW in 2018 rising to 720 MW by 2025.

Figure ES.3 – Capacity Position Comparison

Resource Portfolio Update

Table ES.1 reports the 2015 IRP Update resource portfolio and differences relative to the 2015 IRP Preferred Portfolio.¹ The table shows the resource mix targeted to achieve a 13% planning reserve margin in each reported year. As compared to the 2015 IRP Preferred Portfolio, changes in the resource mix for the 2016-2025 planning period reflect those needed to meet capacity needs associated with the assumed early retirement of Naughton Unit 3 and Cholla Unit 4. As was the case in the 2015 IRP Preferred Portfolio, PacifiCorp continues to plan to meet its customers' needs largely through the acquisition of cost-effective energy efficiency (Class 2 Demand Side Management) resources and FOTs over the next ten years.

¹ A comparison of the portfolio changes relative to the Business Plan is presented in Chapter 5.

Table ES.1 – Comparison of 2015 IRP Update with 2015 IRP Preferred Portfolio (Megawatts)**2015 IRP Update**

Resource	Capacity (MW)											10- year Total
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2016-2025
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	143	128	138	146	158	142	149	155	161	162	135	1,476
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	39	39
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,062
Existing Unit Changes												
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	(667)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Total	685	1,031	886	960	1,403	1,345	1,120	1,215	1,126	1,155	1,227	

FOT in resource total are 10-year averages

2015 IRP Update less 2015 IRP Preferred Portfolio

Resource	Capacity (MW)											10- year Total
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2016-2025
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	10	(11)	(8)	(0)	5	8	12	11	15	14	12	58
DSM - Load Control	-	-	-	-	-	-	-	(5)	(11)	-	39	23
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	37	(34)	(157)	224	311	224	202	269	205	239	670	215
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	(337)	-	-	-	-	-	-	(387)	(724)
Total	47	(45)	(164)	(113)	315	232	214	275	209	252	333	

FOT in resource total are 10-year averages

IRP Action Plan

PacifiCorp has updated its action plan to reflect changes in the planning environment since the IRP was filed in March 2015. Specifically, PacifiCorp updated action item 1a (Renewable Portfolio Standard Compliance) to issue RFPs for REC and near-term resource procurement opportunities that can be used to meet RPS requirements in Oregon, Washington, and California. The updated action plan also removes action item 1c (Oregon Solar Capacity Standard), which was eliminated when SB 1547-B was signed into law. As it relates to coal resource actions, action item 4a (Naughton Unit 3) has been updated consistent with PacifiCorp's most recent analysis summarized in Confidential Appendix B. Table ES.2 presents the updated action plan. Chapter 6 of the 2015 IRP Update provides a status update of PacifiCorp's 2015 IRP action plan items.

Table ES.2 – 2015 IRP Update Action Plan

Action Item	1. Renewable Resource Actions
1a	<u>Renewable Portfolio Standard Compliance</u> - Issue a request for proposals (RFP) in spring 2016 seeking bids for new renewable resources that qualify for the Oregon, Washington, and/or California RPS and that can take full advantage of federal income tax deductions and credits renewed or extended in December 2015. - Issue a RFP in 2016 for current year and forward vintage RECs that qualify for the Oregon, Washington, and/or California RPS. - Complete the concurrent evaluation, selection, and contracting process for both the renewable resource RFP and REC RFP by fall 2016.
1b	<u>Renewable Energy Credit Optimization</u> On a quarterly basis, and through calendar year 2016, issue reverse RFPs to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.
Action Item	2. Firm Market Purchase Actions
2a	<u>Front Office Transactions</u> - Acquire economic short-term firm market purchases for on-peak summer deliveries from 2016 through 2017 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: - Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a

	competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.												
Action Item	3. Demand Side Management (DSM) Actions												
3a	<u>Class 1 DSM</u> – Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.												
3b	<u>Class 2 DSM</u> • Acquire cost effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp’s implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP. <table><tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr><tr><td>2016</td><td>584</td><td>139</td></tr><tr><td>2017</td><td>616</td><td>146</td></tr><tr><td>2018</td><td>634</td><td>146</td></tr></table> *Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource.	Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)	2016	584	139	2017	616	146	2018	634	146
Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)											
2016	584	139											
2017	616	146											
2018	634	146											
Action Item	4. Coal Resource Actions												
4a	<u>Naughton Unit 3</u> • Continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2017.												
4b	<u>Dave Johnston Unit 3</u> • The portion of EPA’s final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals. • If following appeal, EPA’s final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027.												

	If following appeal, EPA’s final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.
4c	<u>Wyodak</u> - Continue to pursue the Company’s appeal of the portion of EPA’s final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. - If following appeal, EPA’s final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
4d	<u>Cholla Unit 4</u> Continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025.
Action Item	5. Transmission Actions
5a	<u>Energy Gateway Permitting</u> - Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: - For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. - For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. - For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.
5b	<u>Wallula to McNary 230 kilovolt Transmission Line</u> Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.

CHAPTER 1 – INTRODUCTION

This 2015 IRP Update describes resource planning activities that occurred after the 2015 IRP was filed in March 2015, presents an updated load and resource balance, an updated resource portfolio consistent with changes in the planning environment, presents an updated action plan, and provides a status update on the action plan filed with the 2015 IRP. In presenting the updated load and resource balance assessment and updated resource portfolio, PacifiCorp shows changes relative to the 2015 IRP and relative to its fall 2015 ten-year business plan (Business Plan), which covers the 2016 to 2025 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2015 IRP acknowledgement process.

In support of its business planning process, PacifiCorp refined the 2015 IRP Preferred Portfolio to reflect updates to forecasted loads, resources, market prices, and other model inputs. PacifiCorp's business planning process also considers capital expenditure and operating cost constraints with input from the business units (Pacific Power, Rocky Mountain Power, and PacifiCorp Transmission). Consideration of both capital and operating cost constraints is critical to ensure that PacifiCorp's business plan is financially supportable and affordable to customers. The 2015 IRP Preferred Portfolio served as the primary basis in establishing the resource portfolio for the Business Plan. A similar process has been completed to develop the load and resource balance and resource portfolio for this 2015 IRP Update, which considers updates to forecasted loads, resources, market prices, and other model inputs since the intervening Business Plan resource portfolio was developed.

The 2015 IRP Update also addresses recommendations and requirements identified by PacifiCorp's state regulatory commissions during the 2015 acknowledgement process. These include requests from the Washington Utilities and Transportation Commission (WUTC)² and Public Utility Commission of Oregon (OPUC)³ regarding assumptions related to the use of renewable energy attributes for compliance with both state renewable portfolio standards (RPS) and the Clean Power Plan (CPP). The WUTC also requested PacifiCorp analyze its future resource needs for Washington RPS compliance based on the same allocation methodology used to allocate renewable energy generation to Washington. The OPUC also requested a study that replaces base case DSM with accelerated DSM and to report the impact on the resource portfolio. The Public Service Commission of Utah (PSCU)⁴ requested an explanation, as necessary, of the interaction of requirements from the Federal Energy Regulatory Commission (FERC) Order 1000 and any Energy Gateway Project. PSCU also directed PacifiCorp to present an analysis on whether the available historical cooling degree day information is still an appropriate predictor of future normal conditions in the load forecast.

This report first describes the current planning environment, load updates, resource updates, state and federal policy updates, and Energy Gateway transmission planning and project completion forecast (Chapter 2). Next, Chapters 3 and 4 describe the changes to key inputs and assumptions

² Acknowledgement letter in PacifiCorp's 2015 Electric Integrated Resource Plan, Docket UE-140546, dated November 13, 2015.

³ Order No. 16-071 in PacifiCorp's 2015 Integrated Resource Plan, Docket LC 62, dated February 29, 2016.

⁴ Report and Order in PacifiCorp's 2015 Integrated Resource Plan, Docket No. 15-035-04, dated January 8, 2016.

relative to those used for the 2015 IRP. The updated resource portfolio is then presented along with a status update on the 2015 IRP Action Plan (Chapters 5 and 6, respectively). Appendix A provides additional load forecast details. Confidential Appendix B presents PacifiCorp's updated Naughton Unit 3 analysis.

CHAPTER 2 – PLANNING ENVIRONMENT

Business Plan Development

The 2015 IRP Preferred Portfolio served as the basis for the resource assumptions used in PacifiCorp's fall 2015 ten-year business plan (Business Plan), which covers the 2016 to 2025 planning horizon. Changes in the portfolio reflect updates to forecasted loads, resources, market prices, and other model inputs. PacifiCorp's business planning process also considers capital expenditure and operating cost constraints to ensure that the resulting business plan is financially supportable and affordable to customers.

Federal Policy Update

New Source Performance Standards for Carbon Emissions – Clean Air Act § 111(b)

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On August 3, 2015, the U.S. Environmental Protection Agency (EPA) issued a final rule limiting carbon emissions from coal- and natural gas-fired power plants. New natural gas fueled power plants can emit no more than 1,000 pounds of carbon dioxide (CO₂) per megawatt-hour (MWh). New coal fueled power plants can emit no more than 1,400 pounds of CO₂/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards.

Carbon Emission Guidelines for Existing Sources – Clean Air Act § 111(d)

EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating carbon emissions from existing power plants on August 3, 2015. Under the final rule, states would be required to submit compliance plans by September 6, 2016. However, a state may seek an extension to September 6, 2018 to submit a state plan. On August 3, 2015, EPA also issued a proposed federal plan and model trading rules for public comment. The public comment period closed January 21, 2016. Under section 111(d) of the Clean Air Act, states are required to develop standards of performance, which are the degree of emission limitation achievable through the application of the best system of emission reduction (BSER).

In the final rule, EPA set forth emission reduction goals for each state based on EPA's formulation of BSER, which is made up of three building blocks: (1) heat rate improvements at existing coal-fueled resources; (2) increased utilization of natural gas resources; and (3) increased deployment of zero-emitting resources. States would be required to meet the emission reduction goal by 2030, as well as interim goals, which would be met over three interim compliance periods: 2022-2024, 2025-2027, and 2028-2029. Utilizing its formulation of BSER, EPA established uniform national interim and final carbon emission performance standards as 1,305 lb CO₂/MWh for coal-fired power plants and 771 lb CO₂/MWh for natural gas-fired power plants, which in turn were utilized to establish projected mass-based and rate-based compliance targets for individual states.

Under the final rule, states have a number of implementation options: states may choose to adopt the rate-based standard and apply them on a subcategory or state-specific blended rate basis, or, alternatively, states may choose to adopt the standards as a mass-based state goal. In the final rule, EPA provided state mass-based goals that it stated are equivalent to the rate-based emissions goals. Under a mass-based implementation program, compliance would be demonstrated through reported stack emissions and the retirement of carbon allowances. Under a rate-based implementation program, compliance would be demonstrated through the use of megawatt-hour credits referred to as emission rate credits (ERCs) from renewable energy and, potentially, energy efficiency. States also have the option to trade with other affected resources in other states implementing similar approaches (e.g., rate state with other rate states or mass state with other mass states) so long as those states meet certain “trading ready” minimum requirements.

The federal plan proposal also includes model rules for rate-based and mass-based trading programs for potential use by any state in developing its state plan. The mass-based federal plan proposal includes a proposed allowance allocation methodology and a method for states to address leakage through allowance set-asides. For this 2015 IRP Update, PacifiCorp developed its updated resource portfolio with mass-based emission targets aligned with EPA’s proposed allowance allocation methodology. PacifiCorp will develop additional CPP scenarios in coordination with its stakeholders during the 2017 IRP public process.

On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the U.S. Supreme Court, the stay will remain in effect until the U.S. Supreme Court takes action to either deny the petition, or, if the U.S. Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation is scheduled for June 2, 2016 before the D.C. Circuit Court of Appeals.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants considered harmful to public health and the environment. For a given NAAQS, EPA and/or a state identifies various control measures that once implemented are meant to achieve an air quality standard for a certain pollutant, with each standard rigorously vetted by the scientific community, industry, public interest groups, and the general public.

Particulate matter (PM), sulfur dioxide (SO₂), ozone (O₃), nitrogen dioxide (NO₂), carbon monoxide (CO), and lead are often grouped together, because under the Clean Air Act, each of these categories is linked to one or more NAAQS. These “criteria pollutants”, while undesirable, are not toxic in typical concentrations in the ambient air. Under the Clean Air Act, they are regulated differently from other types of emissions, such as hazardous air pollutants and greenhouse gases. Within the past few years, EPA established new standards for PM, SO₂, and NO₂.

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. Under the final rule, EPA will designate areas in the country as being in “attainment” or “nonattainment” of the revised standards by October 2017. State

compliance dates will be set depending on the ozone level in the area. PacifiCorp facilities will only be impacted to the extent they are located in an ozone nonattainment area.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as the Best Available Retrofit Technology (BART), for industrial facilities meeting certain regulatory criteria with emissions that have the potential to impact visibility. These pollutants include fine PM, NO_x, SO₂, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines as well as establishing BART emissions limits for those facilities. States are also required to periodically update or revise their implementation plans to reflect current visibility data and the effectiveness of the state's long-term strategy for achieving reasonable progress toward visibility goals. States are currently required to submit the next periodic update by July 31, 2018. However, this date may be extended as EPA has proposed that this date be changed to July 31, 2021.

The regional haze rule is intended to drive additional emissions reductions, particularly from facilities operating in the Western United States. This includes the states of Utah and Wyoming where PacifiCorp operates generating units, as well as Arizona where PacifiCorp owns but does not operate a coal unit, and in Colorado and Montana where PacifiCorp has partial ownership in generating units operated by others, but are nonetheless subject to the regional haze rule.

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO₂, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO₂ portion of the Utah regional haze SIP and disapproved the NO_x and PM portions. EPA's approval of the SO₂ SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_x and PM SIP. PacifiCorp and the state's appeals were dismissed. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, recognizing NO_x controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On January 14, 2016, EPA issued a proposed rule including two co-proposals: one to approve the SIP in its entirety and one to partially approve and partially disapprove the revised Utah SIP and propose a FIP. The public comment period on EPA's proposed action closed March 14, 2016.

On January 10, 2014, EPA issued a final action in Wyoming requiring installation of the following NO_x and PM controls at PacifiCorp facilities:

- Naughton Unit 3 by December 31, 2014 - selective catalytic reduction (SCR) equipment and a baghouse
- Jim Bridger Unit 3 by December 31, 2015 - SCR equipment

- Jim Bridger Unit 4 by December 31, 2016 - SCR equipment
- Jim Bridger Unit 2 by December 31, 2021 - SCR equipment
- Jim Bridger Unit 1 by December 31, 2022 - SCR equipment
- Dave Johnston Unit 3 - SCR within five years or a commitment to shut down in 2027
- Wyodak - SCR equipment within five years

Different aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak. PacifiCorp requested, and was granted, a stay of EPA's action as it pertains to Wyodak pending resolution of the appeals. With respect to Naughton Unit 3, in its final action EPA indicated support for the conversion of the unit to natural gas and that it would expedite action relative to consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. PacifiCorp has obtained a construction permit and revised regional haze BART permit from the state of Wyoming to convert Naughton Unit 3 to natural gas in 2018. Wyoming has not yet submitted a revised regional haze SIP incorporating this alternative compliance approach to EPA.

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of SO₂, NO_x and PM controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. With respect to the Cholla FIP requirements, the court has placed the appeals in abeyance while parties attempt to agree on an alternative compliance approach. In October 2015, EPA acknowledged receipt of the state of Arizona's alternate compliance approach for Cholla for review and final action. EPA is currently expected to propose their final action in mid-2016 for public comment.

The state of Colorado issued a regional haze SIP requiring, among other things, the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. Environmental groups appealed EPA's action, in which PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation, other than PacifiCorp, entered into a settlement agreement which requires installation of SCR equipment at Craig Unit 1 in 2021. The revised SIP, as reflected in the settlement, is currently pending EPA approval. PacifiCorp opposed the settlement agreement between the EPA and other parties to the litigation.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. In June 2015, the U.S. Supreme Court found that EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the D.C. Circuit Court of Appeals ruled that MATS may be enforced as EPA modifies the rule to comply with the

Supreme Court decision. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs have historically been considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA issued a final rule in December 2014 to regulate CCRs for the first time. Under the final rule, EPA will regulate CCRs as non-hazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. The final rule was effective October 19, 2015. Under the final rule, surface impoundments and landfills utilized for CCRs may need to close unless they can meet more stringent regulatory requirements. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCRs. Prior to the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCRs and hence are not subject to the final rule.

Water Quality Standards

Cooling Water Intake Structures – The federal Water Pollution Control Act (“Clean Water Act”) establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the “best technology available for minimizing adverse environmental impact” to aquatic organisms. In May 2014, EPA issued a final rule, effective October 2014, under § 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule established requirements for electric generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the U.S. and use at least 25% of the withdrawn water exclusively for cooling purposes. PacifiCorp’s Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S. for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The rule includes impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility’s cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility) standards. The standards will be set on a case by case basis to be determined through site-specific studies and will be incorporated into each facility’s discharge permit.

Effluent Limit Guidelines – EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines) in 1974 with subsequent revisions in 1977 and 1982. On November 3, 2015, EPA finalized revised effluent limit guidelines. The rule does not allow the discharge of bottom ash or fly ash transport water, and directly impacts the Wyodak, Dave Johnston, and Naughton facilities.

2015 Tax Extender Legislation

On December 18, 2015, President Obama signed tax extender legislation (H.R. 2029) that retroactively and prospectively extended certain expired and expiring federal income tax deductions and credits.

Bonus Depreciation – Fifty percent bonus depreciation was extended for property acquired and placed in service during 2015, 2016, and 2017. For property acquired and placed in service during 2018, 40% of the eligible cost of the property qualifies for bonus depreciation. For property acquired and placed in service during 2019, 30% of the eligible cost of the property qualifies for bonus depreciation. For property placed in service after December 31, 2019, there will be no bonus depreciation.⁵

Production Tax Credit (Wind) – The production tax credit (PTC), currently 2.3 cents per kilowatt-hour (inflation adjusted), has been extended and phased out for wind property for which construction begins prior to January 1, 2020 as follows:

- 2015 – 100% retroactive
- 2016 – 100% (construction begins prior to January 1, 2017)
- 2017 – 80% (construction begins prior to January 1, 2018)
- 2018 – 60% (construction begins prior to January 1, 2019)
- 2019 – 40% (construction begins prior to January 1, 2020)

Production Tax Credit (Geothermal and Hydro) – The PTC for geothermal and hydro were granted a two year extension as follows (no phase-out period was adopted):

- 2015 – 100% retroactive
- 2016 – 100% (construction begins prior to January 1, 2017)

30% Energy Investment Tax Credit (Wind) – The investment tax credit (ITC) has been extended and phased out for wind property for which construction begins prior to January 1, 2020 as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins prior to January 1, 2017)
- 2017 – 24% (construction begins prior to January 1, 2018)
- 2018 – 18% (construction begins prior to January 1, 2019)
- 2019 – 12% (construction begins prior to January 1, 2020)

30% Energy Investment Tax Credit (Solar) – The ITC has been extended steps down for solar property for which construction begins prior to January 1, 2022 as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins prior to January 1, 2017)

⁵ There is an exception for long production period property (generally property with a construction period longer than one year and a cost exceeding \$1 million). Costs incurred on long production period property may qualify for bonus depreciation if physical construction has begun prior to the placed in service date of the bonus phase-out.

- 2017 – 30% (construction begins prior to January 1, 2018)
- 2018 – 30% (construction begins prior to January 1, 2019)
- 2019 – 30% (construction begins prior to January 1, 2020)
- 2020 – 26% (construction begins prior to January 1, 2021)
- 2021 – 22% (construction begins prior to January 1, 2022)
- 2022 – 10% (construction begins on or after January 1, 2022)

State Policy Update

California

Pursuant to the authority of the Global Warming Solutions Act, in October 2011, the California Air Resources Board (CARB) adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of GHG allowances was held in California in November 2012 and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances, and purchase the required amount of allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously-established 2050 target.

In 2002, California established a Renewable Portfolio Standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, in October 2015, Governor Jerry Brown signed into law Senate Bill 350 which requires utilities to procure 50 percent of their electricity from renewables by 2030. The California Public Utilities Commission is currently developing rules to implement this new program.

Oregon

In 2007, the Oregon Legislature passed HB 3543 Global Warming Actions which establishes GHG reduction goals for the state that (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2009, the Legislature passed SB 101 which requires the Oregon Public Utility Commission (OPUC) to report to the Legislature before November 1 of each even-numbered year on the estimated rate impacts for Oregon's regulated electric and natural gas companies associated with meeting the GHG reduction goals of 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

On July 3 2013, the Oregon Legislature passed Senate Bill 306 which directs the legislative revenue officer to prepare a report examining the feasibility of imposing a clean air fee or tax as

a new revenue option. The report includes an evaluation of how to treat imported and exported energy sources. A final report was published December 2014.

In 2007, Oregon enacted Senate Bill 838 establishing an RPS requirement in Oregon. Under Senate Bill 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition Plan, into law. Senate Bill 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fired resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged: 27% by 2025, 35% by 2030, 45% by 2035 and 50% by 2040. The bill changes the Renewable Energy Certificate (REC) life to five years while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new, long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

Washington

In November 2006, Washington voters approved Initiative 937, the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15% of their energy from renewable resources by 2020. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington State Legislature approved the Climate Change Framework E2SHB 2815, which establishes state GHG emissions reduction limits. Washington's emission limits are to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. In July 2015, Governor Inslee released an executive order which directed the Washington Department of Ecology to develop new rules to reduce carbon emissions in the state. Ecology initiated the rulemaking process in September 2015 and proposed a draft of the Clean Air Rule on January 5, 2016. After further stakeholder engagement, on February 26, 2016, the proposed rule was withdrawn in order to make updates. The Department of Ecology anticipates releasing a new proposed rule for public review in spring 2016. The only PacifiCorp resource that would be subject to the proposed Clean Air Rule is the Chehalis natural gas plant.

Utah

In March 2008 Utah enacted the Energy Resource and Carbon Emission Reduction Initiative which includes provisions to require utilities to pursue renewable energy to the extent that it is cost-effective to do so. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

On March 10, 2016, the Utah legislature passed Senate Bill 115 – the Sustainable Transportation and Energy Plan (STEP). The bill supports plans for electric vehicle infrastructure and clean coal research in Utah and authorizes the development of a renewable energy tariff for new Utah customer loads. The legislation establishes a five year pilot program to provide mandated

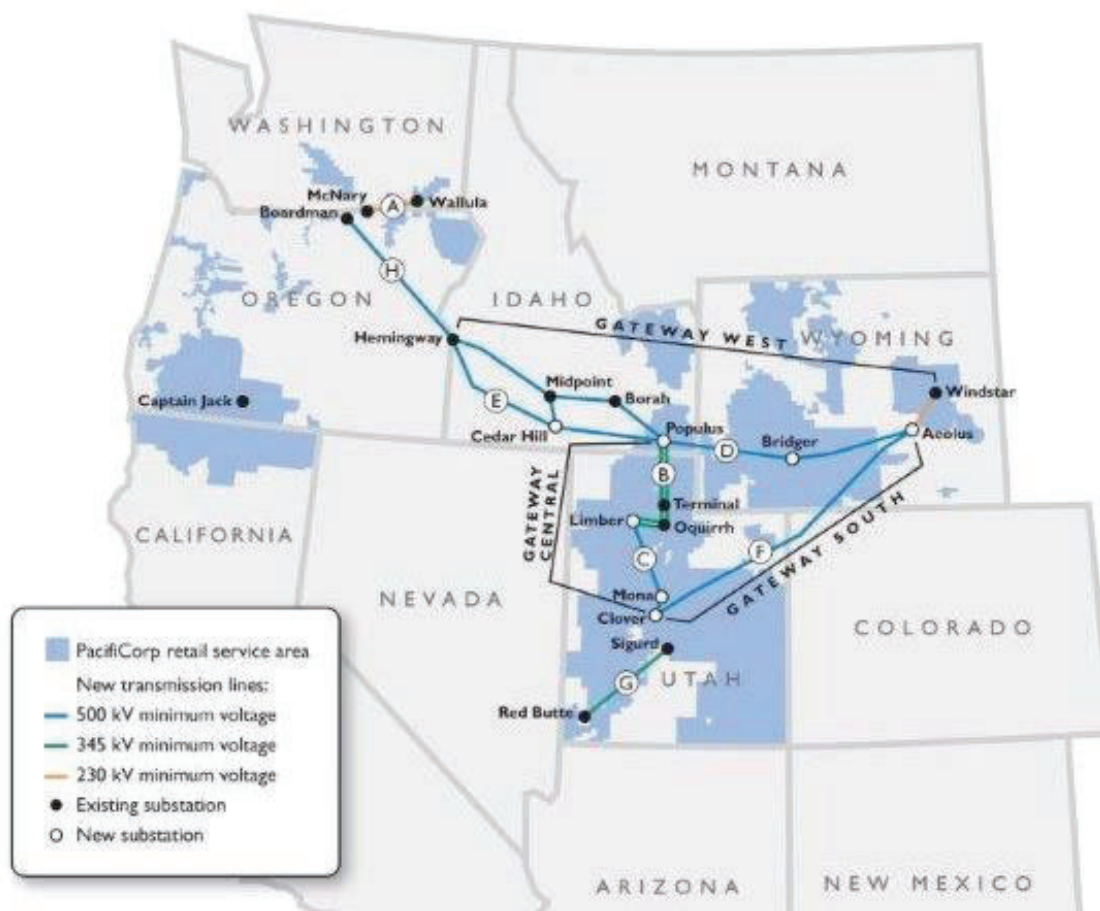
funding for electric vehicle infrastructure and clean coal research, and discretionary funding for solar development, utility-scale battery storage, and other innovative technology and air quality initiatives. The legislation also allows PacifiCorp to recover its variable power supply costs via an energy balancing account, and establishes a regulatory accounting mechanism to manage risks and provide planning flexibility associated with environmental compliance or other economic impairments that may impact PacifiCorp's coal-fueled resources in the future. The deferrals of variable power supply costs will go into effect in June 2016, and implementation and approval of the other programs are required by January 1, 2017. The bill will go into effect no later than May 20, 2016, unless vetoed by Governor Gary Herbert.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted GHG emission performance standards applicable to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emission levels of a state-of-the-art combined-cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO₂/MWh, which is defined as a metric measure used to compare the emissions from various GHG based upon their global warming potential. In March 2013, the Washington Department of Commerce issued a new rule, effective April 6, 2013, lowering the emissions performance standard to 970 lb CO₂/MWh.

Energy Gateway Transmission Program Planning

As discussed in the 2015 IRP, the Energy Gateway transmission project continues to play an important role in PacifiCorp's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. The IRP has incorporated Energy Gateway as part of a solution for delivering the least cost resource portfolio for multiple IRP planning cycles. PacifiCorp continues to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serve customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid.

Figure 2.1 – Energy Gateway Map

This map is for general reference only and reflects current plans. It may not reflect the final routes, construction sequence or exact line configuration.

Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A): This project is required to meet the requirements under PacifiCorp's Open Access Transmission Tariff to provide transmission service to a Point to Point transmission customer when the existing transmission system does not have the capacity to serve the need. In addition, this project is needed to improve reliability and support future resource growth. These requirements will continue to drive the project forward. The OPUC issued a Certificate of Public Convenience and Necessity (CPCN) in September 2011. In 2013, the project was delayed to allow customers to determine their need as it pertains to ongoing projects and ability to move resources to their markets. In 2015, a transmission customer confirmed their need for transmission service requiring the completion of the transmission line agreed to by the parties as terms of the Transmission Service Agreement and to meet requirements of PacifiCorp's Open Access Transmission Tariff. The project is on-track to complete permitting efforts and construction for a 2017 in-service date.

Gateway West (Segments D and E): Under the National Environmental Policy Act, the Bureau of Land Management (BLM) has completed the Environmental Impact Statement (EIS) for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the Record of Decision (ROD) on November 14, 2013, providing a right-of-way grant for all of

Segment D and part of Segment E. The agency chose to defer its decision on the western-most portion of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. A draft supplemental EIS for the deferred portions of the project and the Record of Decision is anticipated in 2016.

Gateway South (Segment F): The BLM’s Notice of Intent was published in the Federal Register in April 2011, followed by public scoping meetings throughout the project area. Comments on this project from agencies and other interested stakeholders were considered as the BLM developed the draft EIS, which was issued in February 2014. A final EIS and the Record of Decision is anticipated in 2016.

Sigurd to Red Butte (Segment G): Project construction is complete and the line was placed in service in May 2015. Sigurd to Red Butte is the third major segment of Energy Gateway to be constructed, following Mona to Oquirrh (Segment C) which was placed in service in May 2013 and Populus to Terminal (Segment B) which was placed in service in November 2010.

Boardman to Hemingway (Segment H): Energy Gateway Segment H represents a significant improvement in the connection between PacifiCorp’s east and west control areas and will help deliver more diverse resources to serve its customers in Oregon, Washington and California. Originally planned as a single circuit 500 kV line from the Hemingway substation south of Boise, Idaho, to the Captain Jack substation near Klamath Falls, Oregon, PacifiCorp has continued to pursue alternative joint-development opportunities on other proposed lines west of Hemingway. Idaho Power leads the permitting efforts on this project and PacifiCorp continues to support the permitting efforts under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The Record of Decision is anticipated in 2016 followed by the Oregon Energy Facilities Siting Council’s final order on the Site Certificate.

Table 2.1 – Energy Gateway Segment In-Service Dates

Segment	2015 IRP	2015 IRP Update
Segment A: Wallula to McNary	2017 – sponsor driven	2017 – sponsor driven
Segment B: Populus to Terminal	Completed Nov 2010	Completed Nov 2010
Segment C: Mona to Oquirrh	Completed May 2013	Completed May 2013
Segment C: Oquirrh to Terminal	June 2021	June 2021
Segment D: Windstar to Populus	2019-2024	2019-2024
Segment E: Populus to Hemingway	2019-2024	2019-2024
Segment F: Aeolus to Mona	2020-2024	2020-2024
Segment G: Sigurd to Red Butte	Completed May 2015	Completed May 2015
Segment H: West of Hemingway	Sponsor driven	

Regional Markets

Energy Imbalance Market

PacifiCorp and the California ISO launched the Energy Imbalance Market (EIM) November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California, covering six states, California, Idaho, Oregon, Utah, Washington, and Wyoming, which uses California ISO advanced market systems that automatically balance supply and demand for electricity every 15 minutes, dispatching the least-cost resources every five minutes. Since the launch of the EIM, NV Energy joined the market December 1, 2015, adding Nevada to the EIM footprint. Puget Sound Energy and Arizona Public Service are scheduled to join October 1, 2016. Portland General Electric is expected to join the EIM October 1, 2017, and other balancing authorities in the west have indicated interest. PacifiCorp continues to work with the California ISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth with the addition of new EIM entities.

As predicted in studies prior to commencement of the market, the EIM has produced significant monetary benefits (\$45.69 million total footprint-wide benefits as of December 31, 2015), quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

Regional ISO

The California ISO is exploring expanding into a regional ISO. PacifiCorp is exploring joining the regional ISO and becoming a full participating transmission owner (PTO). This effort is aimed at reducing costs for consumers, enhancing coordination and reliability of western electric networks, facilitating the integration of renewable resources, reducing emissions, and enhancing regional transmission planning and expansion.

PacifiCorp and the California ISO signed a memorandum of understanding in April 2015 that commits the two entities to explore the benefits of a regional ISO, recognizing that governance and other existing California ISO tariff structures and frameworks would need to accommodate a regional organization. Energy+Environmental Economics (E3) performed an initial analysis of the potential incremental benefits, beyond EIM, of integrating PacifiCorp as a PTO in a regional ISO. The study was released October 2015 and highlights that the full integration of the PacifiCorp and California ISO systems would provide the potential for cost savings.⁶ Specifically, the E3 study quantifies benefits in the following four categories: (1) more efficient unit commitment and dispatch, (2) more efficient over-generation management, (3) lower peak capacity needs, and (4) renewable procurement savings. As described in more detail in the E3 study, under a regional ISO, PacifiCorp and ISO customers could develop capacity plans to meet the combined system coincident peak load, which would be lower than the sum of the non-

⁶ For more background of the E3 benefit study and information:
<http://www.pacificorp.com/about/newsroom/2015nrl/western-grid-integration.html>

coincident peak loads. As it relates to PacifiCorp's updated load and resource balance and resource portfolio, discussed in Chapter 3 and Chapter 5, respectively, this could reduce the need for firm market purchases over the near- to mid-term and displace the need for resources in the long term.

PacifiCorp continues to explore and evaluate the benefits and costs of becoming a PTO in a regional ISO. PacifiCorp will seek approval from each of its state public utility commissions to turn over operational control of its transmission assets to the ISO should further studies confirm net benefits for customers and acceptable governance structure is adopted. Integration as a PTO would result in the following primary impacts to PacifiCorp: (1) integration of PacifiCorp's two balancing authority areas (BAAs) into the regional ISO's BAA (2) turning over operational control of PacifiCorp's networked transmission assets to the regional ISO; (3) becoming subject to all requirements of the ISO tariff, as modified for regional integration, including resource adequacy requirements, transmission access charges, integrated generator interconnection studies, and many others; and (4) participation in the regional ISO's real-time and day-ahead markets.

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CHAPTER 3 – LOAD AND RESOURCE BALANCE UPDATE

Introduction

This chapter presents the update to PacifiCorp's load and resource balance, focusing on the 2016-2025 planning period covered by the fall 2015 ten-year business plan (Business Plan) and 2015 IRP Update. Updates to PacifiCorp's long-term load forecast, resources, and capacity position are presented and summarized in this chapter.

Load Forecast

PacifiCorp's 2015 IRP Update and Business Plan use the same load forecast updated and finalized in October 2015. Relative to the load forecast prepared for the 2015 IRP, PacifiCorp system sales decrease over the planning period. Changes between these two forecasts reflect the changes in economic conditions in the service territory that occurred between September 2014 and October 2015. While economic conditions continue to improve following the most recent recession, projected load growth in the residential and commercial customer classes is offset by weakness in the industrial class. A decline in commodities markets drives declines in industrial sales on the east side of the system, while the projected loss of a large customer drives declines on the west side of the system. Figures 3.1 and 3.2 compare annual load and coincident peak load forecasts, respectively, for the 2015 IRP Update and 2015 IRP. These forecast data exclude load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the resource portfolio. Appendix A includes additional details on the updated load forecast.

Figure 3.1 – Forecasted Annual Load Growth

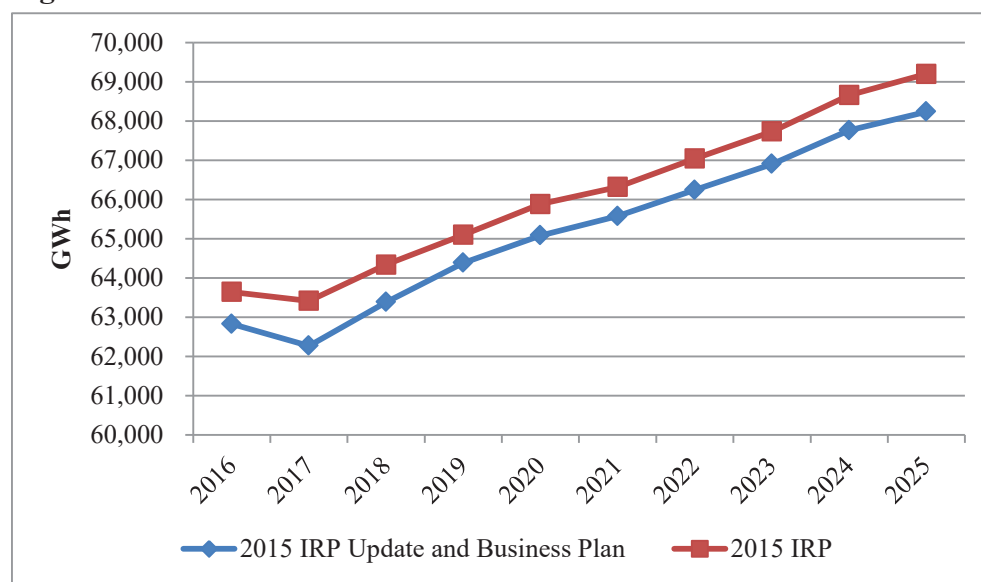
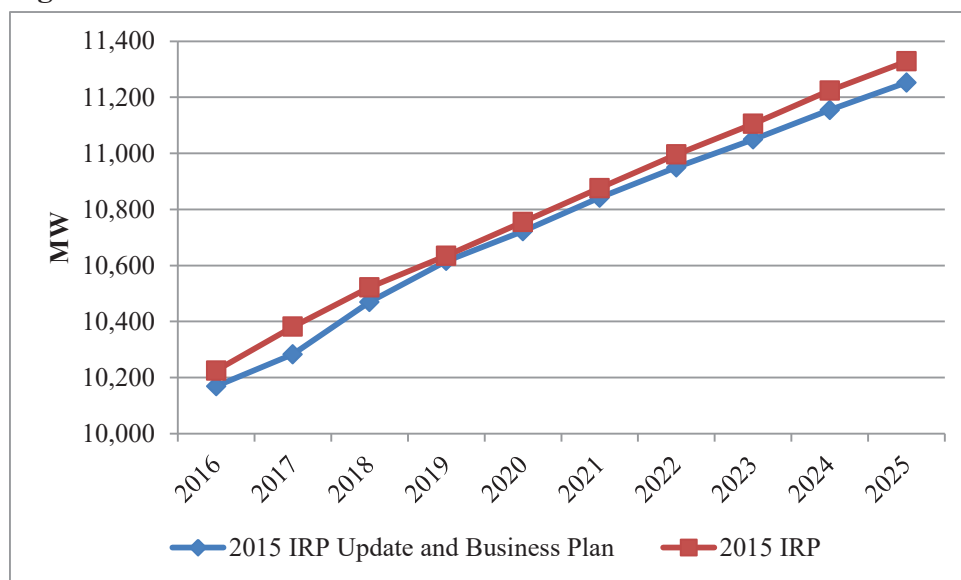


Figure 3.2 – Forecasted Annual Coincident Peak Load

Resource Updates

Existing and Firm Resources

The availability and capacity contribution from existing resources have been updated to reflect changes since assumptions were locked down for the 2015 IRP. Updates to resource capacity assumptions are presented in two steps – changes made between the 2015 IRP and the Business Plan, and changes made between the Business Plan and this 2015 IRP Update.

Changes Made between the 2015 IRP and the Business Plan

- With reduced load, lower market prices, and increased costs for gas conversion, the Business Plan assumes an early retirement of Naughton Unit 3 at the end of 2017 is a lower cost alternative to the assessed natural gas conversion. This assumption aligns with updated analysis of compliance alternatives for Naughton Unit 3 presented in Confidential Appendix B of this 2015 IRP Update. With the assumed retirement of Naughton Unit 3, existing thermal generation capacity is reduced by 337 MW over the period 2018 through 2029.
- With reduced load, lower market prices and uncertainties around state plans for implementing the clean power plan (CPP), the Business Plan assumes Cholla Unit 4 is retired at the end of 2024. PacifiCorp will continue to evaluate the most cost effective compliance alternatives for Cholla Unit 4 in future IRPs. With the assumed retirement of Cholla Unit 4, existing thermal generation capacity is reduced by 387 MW from 2025 and beyond.
- Since assumptions were locked down for the 2015 IRP, 440 MW of additional wind and solar qualifying facility contracts are included in the Business Plan portfolio (representing an increase of 167 MW of capacity at the time of system peak load). Inclusive of capacity assumed in the 2015 IRP, qualifying facility contract capacity from wind and solar projects

expected to come online in the 2015 to 2017 timeframe totals 1,162 MW (representing 409 MW of capacity at the time of system peak load). This increase is partially offset by a reduction of 80 MW (11 MW of capacity at the time of system peak load) due to qualifying facility contract terminations.

- An updated hydro generation forecast reflects current projections for hydro operations accounting for planned water conditions, availability, and market prices. The Klamath River hydro peak contribution is approximately 70 MW higher to reflect its storage capability and ability to hold reserves prior to being decommissioned, assumed to occur at the end of 2020. The increase is offset by a decrease in the Lewis River hydro forecast, in part, to incorporate planned maintenance.
- Updates to interruptible contracts result in an increase in average peak capacity contribution by 20 MW during the 2016-2025 timeframe.

Changes Made between the Business Plan and the 2015 IRP Update

- Since assumptions were locked down for the Business Plan, qualifying facility contract capacity assumptions were updated. The update includes 65 MW of incremental qualifying facility contracts from wind and solar projects (representing an increase of 25 MW of capacity at the time of system peak load). Coupled with the updates applied in the Business Plan, the total amount of qualifying facility contract capacity expected to come online in the 2015 to 2017 timeframe totals 1,227 MW (representing 434 MW of capacity at the time of system peak load).

Tables 3.1 and 3.2 summarize the capacity from wind and solar power purchase agreements with qualifying facilities (QFs) that have or are expected to come online over the 2015 – 2017 timeframe.

Table 3.1 – New Qualifying Facility Wind Contracts Online 2015-2017

Qualifying Facilities	State	2015 IRP Preferred Portfolio		2015 IRP Update	
		Capacity (MW)	L&R Balance Capacity at System Peak (MW)	Capacity (MW)	L&R Balance Capacity at System Peak (MW)
Blue Mountain Power Partners	UT	80	11		
Chopin	OR	10	3	10	3
Latigo Wind	UT	60	9	60	9
Mariah Wind	OR	10	3	10	3
Orem Family Wind	OR	10	3	10	3
Pioneer Wind Park I	WY	80	12	80	12
TOTAL – Purchased Wind		250	39	170	28

Table 3.2 – New Qualifying Facility Solar Contracts Online 2015-2017

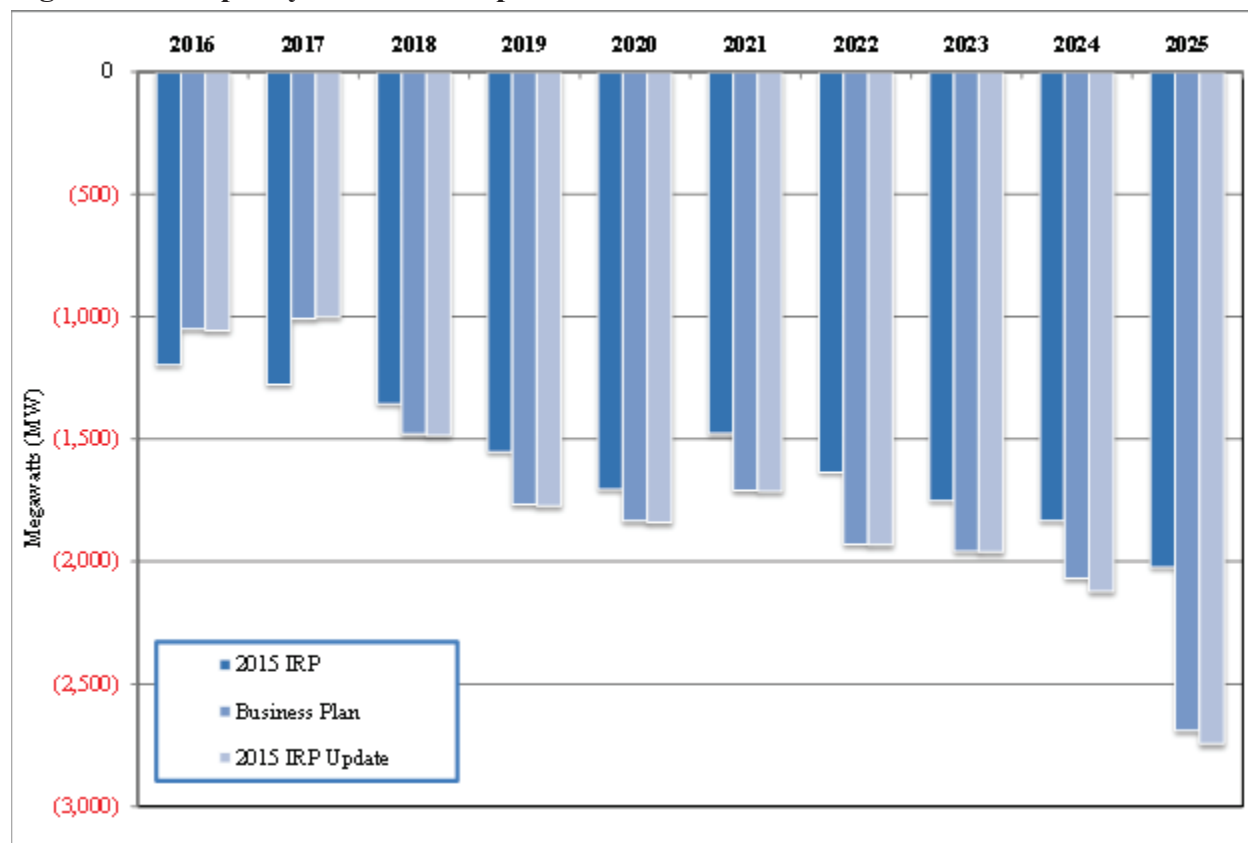
Qualifying Facilities	State	2015 IRP Preferred Portfolio		2015 IRP Update	
		Capacity (MW)	L&R Balance Capacity at System Peak (MW)	Capacity (MW)	L&R Balance Capacity at System Peak (MW)
Adams Solar Center	OR	10	4	10	4
Bear Creek Solar Center	OR	10	4	10	4
Beatty Solar	OR	5	2	5	2
Beryl Solar	UT	3	1	3	1
Black Cap Solar II	OR	8	3	8	3
Bly Solar Center	OR	10	4	9	3
Buckhorn Solar	UT	3	1	3	1
Cedar Valley Solar	UT	3	1	3	1
Chiloquin Solar *	OR			10	3
Collier Solar *	OR			10	4
Elbe Solar Center	OR	10	4	10	4
Enterprise Solar	UT	80	31	80	31
Escalante Solar I	UT	80	31	80	31
Escalante Solar II	UT	80	31	80	31
Escalante Solar III	UT	80	31	80	31
Ewauna Solar *	OR			1	0
Ewauna Solar 2 *	OR			3	1
Fiddler's Canyon Solar 1-3	UT	9	4	9	4
Granite Mountain - East *	UT			80	31
Granite Mountain - West *	UT			50	20
Granite Peak Solar	UT	3	1	3	1
Greenville Solar	UT	2	1	2	1
Iron Springs *	UT			80	31
Ivory Pine Solar	OR	10	4	10	4
Laho Solar	UT	3	1	3	1
Manderfield Solar	UT	2	1		
Milford Flat Solar	UT	3	1	3	1
Milford Solar 2	UT	3	1	3	1
Norwest Energy 2 (Neff) *	OR			10	4
Norwest Energy 4 (Bonanza) *	OR			6	2
Norwest Energy 5 (Arlington) *	OR			3	1
Norwest Energy 7 (Eagle Point) *	OR			10	4
Norwest Energy 9 Pendleton *	OR			6	2

Qualifying Facilities	State	2015 IRP Preferred Portfolio		2015 IRP Update	
		Capacity (MW)	L&R Balance Capacity at System Peak (MW)	Capacity (MW)	L&R Balance Capacity at System Peak (MW)
OR Solar 1, LLC (Sprague River) *	OR			10	4
OR Solar 2, LLC (Agate Bay) *	OR			10	4
OR Solar 3, LLC (Turkey Hill) *	OR			10	4
OR Solar 4, LLC (Bly) *	OR			10	4
OR Solar 5, LLC (Merrill) *	OR			8	3
OR Solar 6, LLC (Lakeview) *	OR			10	4
OR Solar 7, LLC (Jacksonville) *	OR			10	4
OR Solar 8, LLC (Dairy) *	OR			10	4
Pavant Solar	UT	50	20	50	20
Pavant Solar II LLC *	UT			50	20
Quichapa Solar 1- 3	UT	9	4	9	4
South Milford Solar	UT	3	1	3	1
Sprague River Solar	OR	7	3	7	3
Three Peaks Solar *	UT			80	31
Tumbleweed Solar *	OR			10	3
Utah Red Hills Renewable Park	UT	80	31	80	31
Woodline Solar *	OR			8	3
TOTAL – Purchased Solar		566	218	1,057	406

* New since 2015 IRP.

Updated Capacity Load and Resource Balance

Figure 3.3 summarizes the 2015 IRP Update capacity load and resource balance, prior to acquiring any new resources and making firm market purchases, alongside the load and resource balance from the 2015 IRP and the Business Plan. The load and resource balance has decreased by an average of 209 MW, relative to the 2015 IRP, in 2016 and 2017 reflecting to changes in the load forecast, hydro generation and qualifying facility contracts. The projected load and resource balance position is shorter beginning in 2018, relative to the 2015 IRP, primarily due to the assumed early retirement of Naughton Unit 3 at the end of 2017 and Cholla Unit 4 at the end of 2024. This is partially offset by the addition of new wind and solar qualifying facility contracts. The 2015 IRP Update load and resource balance shows is shorter by 128 MW in 2018 rising to 720 MW by 2025.

Figure 3.3 – Capacity Position Comparison

Tables 3.3 through 3.5 summarize the capacity load and resource balance details from the 2015 IRP Update, Business Plan, and 2015 IRP, respectively. As was done in the 2015 IRP, the load and resource balance tables show the system position alongside assumed FOT purchases given current FOT limit assumptions, which were not updated for the 2015 IRP. PacifiCorp will evaluate its FOT limit assumptions as part of the 2017 IRP. Differences between the 2015 IRP and 2015 IRP Update are displayed in Table 3.6, and differences between the 2015 IRP and Business Plan are shown in Table 3.7.

Table 3.3 – System Capacity Load and Resource Balance without Resource Additions, 2015 IRP Update (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	469	463	460	454	447	436	434	381	378
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	6,910	7,044	6,760	6,758	6,752	7,192	7,179	7,167	7,119	6,617
East Total Resources	6,910	7,044	6,760	6,758	6,752	7,192	7,179	7,167	7,119	6,617
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class2 DSM	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)
East obligation	6,707	6,828	6,979	7,104	7,191	7,292	7,381	7,462	7,553	7,624
Planning Reserves (13%)	897	913	933	949	960	973	985	995	1,007	1,016
East Reserves	897	913	933	949	960	973	985	995	1,007	1,016
East Obligation + Reserves	7,604	7,741	7,912	8,052	8,151	8,265	8,366	8,457	8,560	8,640
East Position	(695)	(698)	(1,151)	(1,295)	(1,400)	(1,073)	(1,186)	(1,290)	(1,441)	(2,023)
Available Front Office Transactions	318	318	318	318	318	318	318	318	318	318
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	172	172	172	172	172	118	118	107	107
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	108	177	175	174	176	166	163	155	154	154
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	3,221	3,272	3,282	3,162	3,221	3,043	2,958	3,054	3,062	3,051
West Total Resources	3,221	3,272	3,282	3,162	3,221	3,043	2,958	3,054	3,062	3,051
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
West obligation	3,171	3,163	3,199	3,221	3,240	3,258	3,278	3,296	3,311	3,337
Planning Reserves (13%)	412	411	416	419	421	424	426	429	430	434
West Reserves	412	411	416	419	421	424	426	429	430	434
West Obligation + Reserves	3,583	3,575	3,615	3,640	3,661	3,682	3,704	3,725	3,741	3,771
West Position	(361)	(303)	(333)	(477)	(440)	(639)	(746)	(671)	(679)	(721)
Available Front Office Transactions	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352
System										
Total Resources	10,131	10,316	10,042	9,920	9,973	10,235	10,137	10,221	10,181	9,668
Obligation	9,878	9,992	10,178	10,324	10,431	10,550	10,659	10,758	10,863	10,961
Reserves	1,309	1,324	1,348	1,368	1,381	1,397	1,411	1,424	1,438	1,450
Obligation + Reserves	11,187	11,316	11,527	11,692	11,813	11,947	12,069	12,182	12,301	12,412
System Position	(1,056)	(1,000)	(1,484)	(1,772)	(1,840)	(1,712)	(1,932)	(1,961)	(2,120)	(2,743)
Available Front Office Transactions	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670

Table 3.4 – System Capacity Load and Resource Balance without Resource Additions, Business Plan (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	444	437	435	429	422	412	409	407	403
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	6,910	7,018	6,735	6,733	6,727	7,167	7,155	7,143	7,144	6,643
East Total Resources	6,910	7,018	6,735	6,733	6,727	7,167	7,155	7,143	7,144	6,643
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class2 DSM	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
East obligation	6,704	6,825	6,976	7,101	7,188	7,289	7,378	7,459	7,550	7,621
Planning Reserves (13%)	897	913	932	948	960	973	984	995	1,007	1,016
East Reserves	897	913	932	948	960	973	984	995	1,007	1,016
East Obligation + Reserves	7,601	7,738	7,908	8,049	8,148	8,262	8,362	8,454	8,557	8,637
East Position	(691)	(720)	(1,173)	(1,316)	(1,421)	(1,095)	(1,208)	(1,311)	(1,413)	(1,994)
Available Front Office Transactions	318	318	318	318	318	318	318	318	318	318
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	173	173	173	173	173	118	118	108	108
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	112	190	202	200	202	190	186	179	178	178
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	3,225	3,286	3,309	3,189	3,248	3,068	2,982	3,078	3,087	3,075
West Total Resources	3,225	3,286	3,309	3,189	3,248	3,068	2,982	3,078	3,087	3,075
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
West obligation	3,171	3,164	3,199	3,221	3,241	3,259	3,278	3,297	3,311	3,338
Planning Reserves (13%)	412	411	416	419	421	424	426	429	430	434
West Reserves	412	411	416	419	421	424	426	429	430	434
West Obligation + Reserves	3,583	3,575	3,615	3,640	3,662	3,682	3,704	3,725	3,741	3,772
West Position	(358)	(289)	(306)	(451)	(414)	(615)	(722)	(647)	(655)	(696)
Available Front Office Transactions	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352
System										
Total Resources	10,134	10,305	10,044	9,922	9,975	10,235	10,137	10,221	10,231	9,718
Obligation	9,875	9,989	10,175	10,322	10,429	10,548	10,656	10,756	10,861	10,959
Reserves	1,309	1,324	1,348	1,367	1,381	1,397	1,411	1,424	1,437	1,450
Obligation + Reserves	11,184	11,313	11,524	11,689	11,810	11,944	12,067	12,179	12,298	12,409
System Position	(1,050)	(1,009)	(1,480)	(1,767)	(1,835)	(1,710)	(1,930)	(1,958)	(2,067)	(2,690)
Available Front Office Transactions	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670

Table 3.5 – System Capacity Load and Resource Balance without Resource Additions, 2015 IRP (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,453	6,449	6,448	6,444	6,439	6,434	6,431	6,430
Hydroelectric	114	114	114	114	114	114	114	114	94	94
Renewable	187	187	187	187	187	184	184	177	177	168
Purchase	406	300	300	300	300	272	272	272	272	172
Qualifying Facilities	222	348	347	346	339	337	332	331	280	279
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(732)	(656)	(656)	(656)	(656)	(175)	(175)	(175)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	6,880	6,976	7,031	7,026	7,018	7,462	7,453	7,439	7,396	7,284
East Total Resources	6,880	6,976	7,031	7,026	7,018	7,462	7,453	7,439	7,396	7,284
Load	6,977	7,102	7,208	7,295	7,382	7,448	7,529	7,617	7,640	7,676
Interruptible	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)
Existing Class2 DSM	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
East obligation	6,729	6,854	6,960	7,047	7,135	7,200	7,281	7,370	7,392	7,428
Planning Reserves (13%)	894	910	924	935	947	955	966	977	980	985
East Reserves	894	910	924	935	947	955	966	977	980	985
East Obligation + Reserves	7,623	7,764	7,885	7,982	8,081	8,155	8,247	8,347	8,372	8,413
East Position	(743)	(789)	(853)	(957)	(1,064)	(693)	(794)	(908)	(976)	(1,129)
Available Front Office Transactions	318	318	318	318	318	318	318	318	318	318
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	770	752	775	725	728	643	620	652	646	643
Renewable	170	170	170	170	170	170	115	115	105	105
Purchase	22	22	22	5	5	5	5	5	5	5
Qualifying Facilities	114	140	135	134	120	120	120	115	115	115
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(160)	(160)	(160)	(160)	(160)	(156)	(105)	(105)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	3,163	3,167	3,185	3,119	3,107	3,023	2,993	3,019	3,029	3,025
West Total Resources	3,163	3,167	3,185	3,119	3,107	3,023	2,993	3,019	3,029	3,025
Load	3,237	3,271	3,301	3,323	3,354	3,406	3,429	3,455	3,476	3,506
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
West obligation	3,201	3,235	3,264	3,286	3,317	3,369	3,393	3,419	3,440	3,469
Planning Reserves (13%)	416	421	424	427	431	438	441	444	447	451
West Reserves	416	421	424	427	431	438	441	444	447	451
West Obligation + Reserves	3,617	3,655	3,689	3,714	3,748	3,807	3,834	3,863	3,887	3,920
West Position	(454)	(488)	(503)	(595)	(642)	(784)	(841)	(844)	(858)	(895)
Available Front Office Transactions	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,352
System										
Total Resources	10,043	10,143	10,217	10,144	10,124	10,486	10,446	10,458	10,425	10,310
Obligation	9,930	10,089	10,225	10,333	10,452	10,569	10,674	10,788	10,832	10,897
Reserves	1,310	1,331	1,349	1,363	1,378	1,393	1,407	1,422	1,428	1,436
Obligation + Reserves	11,240	11,420	11,573	11,696	11,830	11,963	12,081	12,210	12,259	12,333
System Position	(1,197)	(1,277)	(1,357)	(1,552)	(1,706)	(1,477)	(1,635)	(1,752)	(1,834)	(2,023)
Available Front Office Transactions	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670

Table 3.6 – System Capacity Load and Resource Balance without Resource Additions, 2015 IRP Update less 2015 IRP (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	0	0	(337)	(333)	(332)	(331)	(329)	(326)	(326)	(713)
Hydroelectric	(5)	(5)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
Qualifying Facilities	82	121	115	114	115	110	105	103	102	99
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	4	4	4	4	4	4	4	4	0	0
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
East Existing Resources	29	68	(271)	(268)	(266)	(271)	(273)	(272)	(277)	(667)
East Total Resources	29	68	(271)	(268)	(266)	(271)	(273)	(272)	(277)	(667)
Load	(14)	(18)	27	65	64	100	108	100	169	204
Interruptible	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Existing Class2 DSM	12	12	12	12	12	12	12	12	12	12
East obligation	(22)	(26)	19	57	56	92	100	92	161	196
Planning Reserves (13%)	3	3	8	13	13	18	19	18	27	31
East Reserves	3	3	8	13	13	18	19	18	27	31
East Obligation + Reserves	(19)	(23)	27	70	70	110	119	110	188	227
East Position	48	91	(298)	(338)	(336)	(381)	(392)	(382)	(465)	(894)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Thermal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	70	74	62	11	65	(20)	(72)	2	(3)	(11)
Renewable	3	3	3	3	3	3	3	3	3	3
Purchase	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Qualifying Facilities	(6)	37	41	39	56	46	43	40	39	39
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(2)	(2)
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
West Existing Resources	59	105	97	44	115	20	(35)	35	33	25
West Total Resources	59	105	97	44	115	20	(35)	35	33	25
Load	(31)	(72)	(66)	(66)	(78)	(112)	(116)	(123)	(130)	(133)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	1	1	1	1	1	1	1	1	1	1
West obligation	(30)	(71)	(65)	(66)	(77)	(111)	(115)	(122)	(129)	(132)
Planning Reserves (13%)	(4)	(9)	(8)	(9)	(10)	(14)	(15)	(16)	(17)	(17)
West Reserves	(4)	(9)	(8)	(9)	(10)	(14)	(15)	(16)	(17)	(17)
West Obligation + Reserves	(34)	(80)	(74)	(74)	(87)	(125)	(130)	(138)	(146)	(149)
West Position	93	185	170	118	202	145	95	173	179	174
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
System										
Total Resources	88	173	(174)	(224)	(151)	(251)	(308)	(237)	(244)	(641)
Obligation	(52)	(97)	(47)	(9)	(20)	(19)	(15)	(30)	32	64
Reserves	(1)	(7)	(0)	5	3	3	4	2	10	14
Obligation + Reserves	(53)	(103)	(47)	(4)	(17)	(15)	(11)	(28)	42	79
System Position	141	277	(128)	(220)	(134)	(235)	(297)	(209)	(286)	(720)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0

Table 3.7 – System Capacity Load and Resource Balance without Resource Additions, Business Plan less 2015 IRP (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	0	0	(337)	(333)	(332)	(331)	(329)	(326)	(326)	(713)
Hydroelectric	(5)	(5)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
Qualifying Facilities	82	95	90	89	90	85	80	79	127	125
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	4	4	4	4	4	4	4	4	0	0
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
East Existing Resources	29	43	(296)	(293)	(291)	(296)	(298)	(297)	(252)	(641)
East Total Resources	29	43	(296)	(293)	(291)	(296)	(298)	(297)	(252)	(641)
Load	(14)	(18)	27	65	64	100	108	100	169	204
Interruptible	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Existing Class2 DSM	9	9	9	9	9	9	9	9	9	9
East obligation	(25)	(29)	16	54	53	89	97	89	158	193
Planning Reserves (13%)	3	2	8	13	13	18	19	18	26	31
East Reserves	3	2	8	13	13	18	19	18	26	31
East Obligation + Reserves	(22)	(26)	24	67	66	107	115	107	184	224
East Position	51	69	(320)	(360)	(358)	(402)	(413)	(404)	(437)	(865)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Thermal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	70	74	62	11	65	(20)	(72)	2	(3)	(11)
Renewable	3	3	3	3	3	3	3	3	3	3
Purchase	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Qualifying Facilities	(2)	51	67	66	83	70	67	63	63	63
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(2)	(2)
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
West Existing Resources	62	119	124	71	142	45	(11)	60	58	50
West Total Resources	62	119	124	71	142	45	(11)	60	58	50
Load	(31)	(72)	(66)	(66)	(78)	(112)	(116)	(123)	(130)	(133)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	1	1	1	1	1	1	1	1	1	1
West obligation	(30)	(71)	(65)	(65)	(77)	(111)	(115)	(122)	(129)	(131)
Planning Reserves (13%)	(4)	(9)	(8)	(8)	(10)	(14)	(15)	(16)	(17)	(17)
West Reserves	(4)	(9)	(8)	(8)	(10)	(14)	(15)	(16)	(17)	(17)
West Obligation + Reserves	(34)	(80)	(73)	(74)	(86)	(125)	(130)	(138)	(146)	(148)
West Position	96	199	197	145	228	170	119	197	203	198
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
System										
Total Resources	91	162	(173)	(222)	(149)	(251)	(309)	(237)	(194)	(591)
Obligation	(55)	(99)	(49)	(12)	(23)	(22)	(18)	(33)	29	62
Reserves	(1)	(7)	(0)	4	3	3	4	2	10	14
Obligation + Reserves	(56)	(106)	(50)	(7)	(20)	(18)	(14)	(31)	39	76
System Position	148	268	(123)	(215)	(129)	(233)	(294)	(206)	(233)	(667)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0

Figures 3.4 through 3.6 summarize the 2015 IRP Update annual capacity position for the system, west balancing area, and east balancing area, respectively.

Figure 3.4 – 2015 IRP Update, System Capacity Position Trend

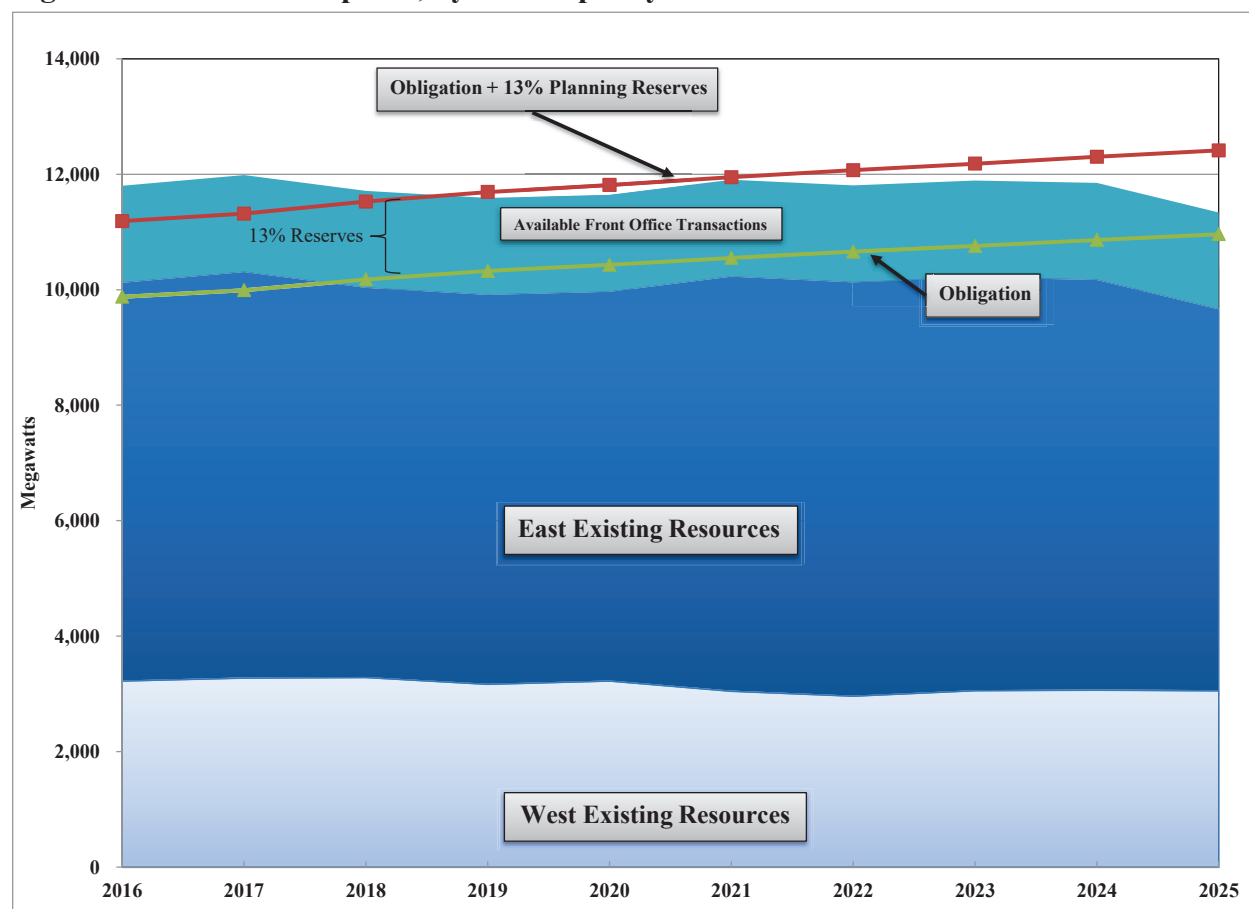
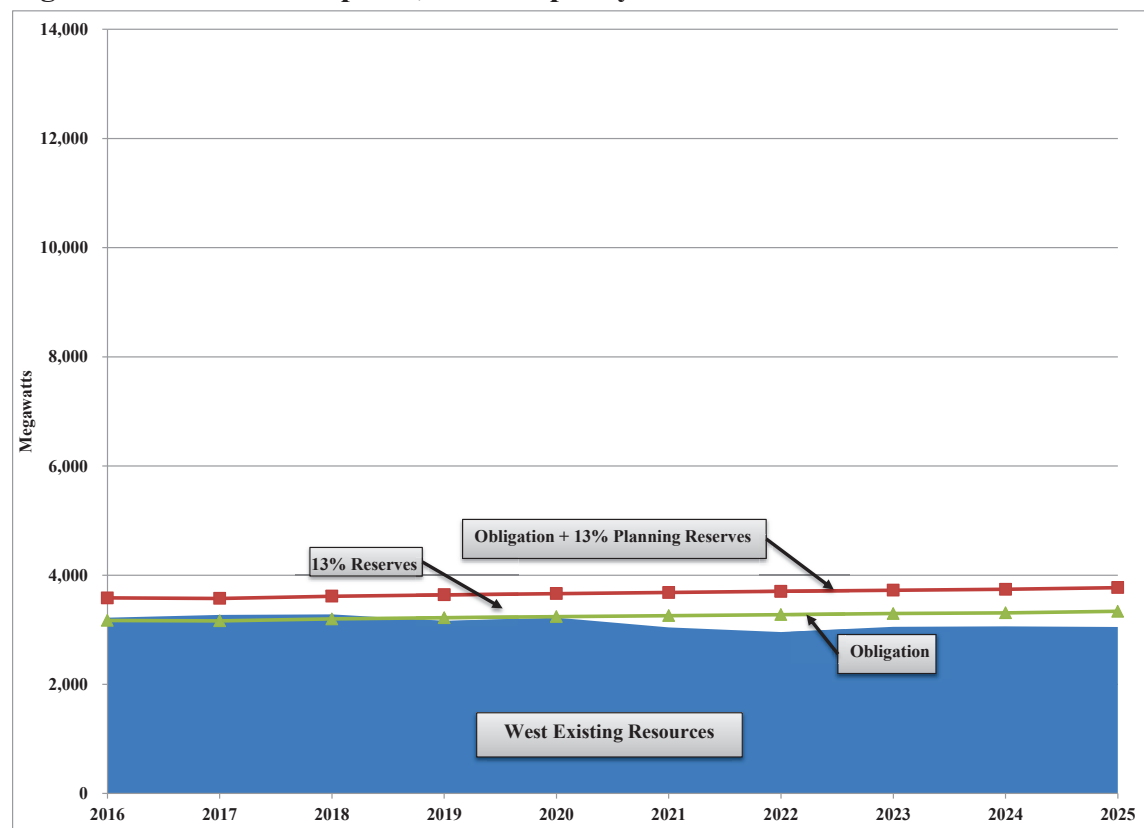
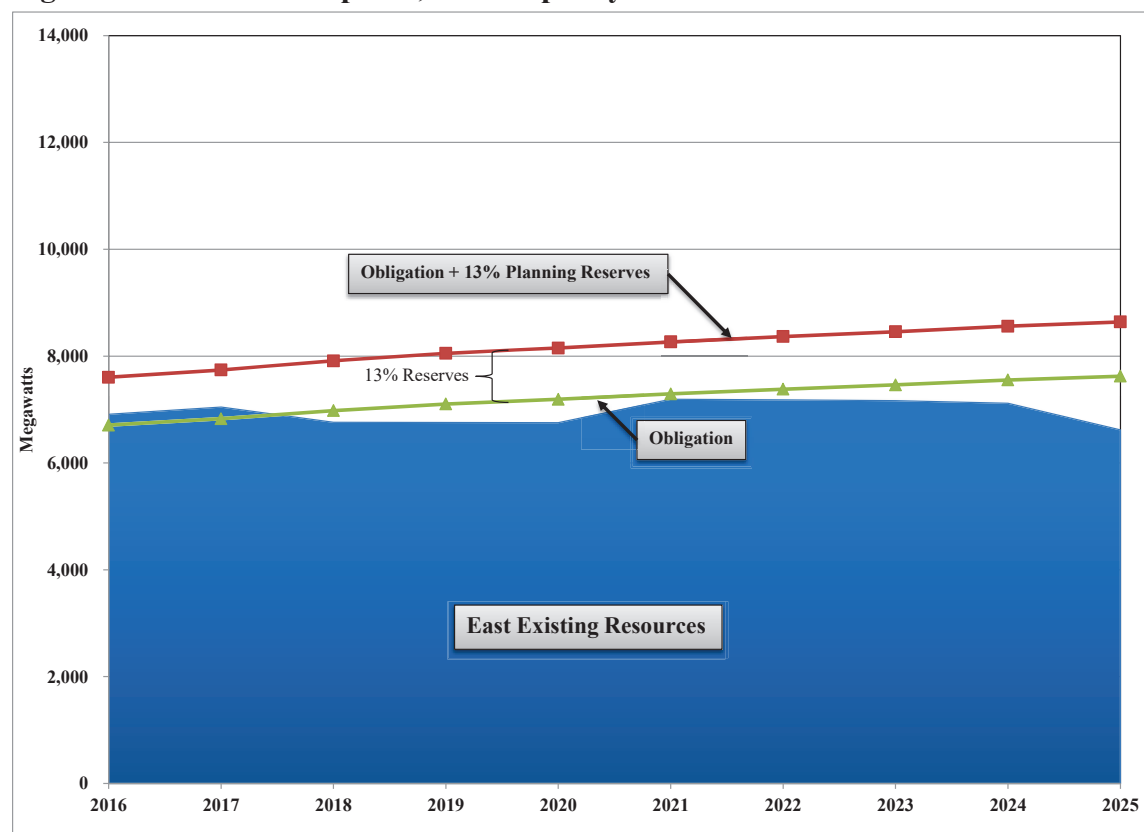


Figure 3.5 – 2015 IRP Update, West Capacity Position Trend**Figure 3.6 – 2015 IRP Update, East Capacity Position Trend**

Changes to the 2015 IRP Update load and resource balance relative to the 2015 IRP are described below:

PacifiCorp West

- Peak loads are lower in the 2015 IRP Update than in the 2015 IRP. This difference is primarily driven by changes in projected sales to several large commercial and industrial customers, including a large industrial customer leaving the system in 2017.
- On average, the addition of incremental wind and solar qualifying facility contracts increase system capacity at the time of peak load by 37 MW over the 2016-2025 timeframe.
- Updated hydro generation forecast reflecting Klamath River hydro facilities' storage capability and the current stream-flow projections result in an average increase of 56 MW in system capacity from 2016 to 2020, and an average decrease of 21 MW over the 2021-2025 timeframe.

PacifiCorp East

- Peak loads are initially lower in the 2015 IRP Update than in the 2015 IRP due to a decline in the oil market driving reductions in industrial sales on the east side of the system. Projected increases in residential and commercial sales increase in the 2015 IRP Update peak forecast as compared to the 2015 IRP starting in 2018.
- The assumed early retirement of Naughton Unit 3 at end of 2017 reduces system capacity by 337 MW from 2018 through 2029. The assumed early retirement of Cholla Unit 4 at end of 2024 reduces system capacity by 387 MW from 2025 and beyond.
- On average, the addition of incremental wind and solar qualifying facility contracts increase system capacity at the time of peak load by 107 MW over the 2016-2025 timeframe, which is partially offset by an average decrease of 50 MW of peak capacity from purchase contracts.
- Updated terms of interruptible contracts are updated to reflect the latest terms, which reduces system capacity by 20 MW.

CHAPTER 4 – MODELING ASSUMPTIONS UPDATE

General Assumptions

In line with the 2015 IRP, the study period for both the fall 2015 ten-year business plan (Business Plan) and the 2015 IRP Update is 2015 through 2034, with a focus on the 2016-2025 planning horizon. Updated resource portfolios were developed assuming a 13% planning reserve margin consistent with the stochastic loss of load probability study included in the 2015 IRP.

PacifiCorp has not made any changes to general inflation assumptions (1.9%) and its discount factor (6.66%) in this 2015 IRP Update. However, PacifiCorp has modified the assumptions regarding the federal production tax credits and federal investment tax credits for qualifying renewable resources, as described in Chapter 2.

Natural Gas and Power Market Price Updates

Portfolio modeling for the 2015 IRP Update was prepared using PacifiCorp's December 31, 2015 official forward price curve (OFPC). OFPCs are produced for both natural gas and power prices by point of delivery. For both natural gas and power, PacifiCorp's OFPCs are developed using forward market prices in tandem with a fundamentals-based price forecast. The first 72 months of the OFPC, beginning with the prompt month, represent broker quotes or settled forward prices per the end-of-quarter quote date, followed by 12 months of blended prices that transition to a market fundamentals-based forecast, starting in month 85.

For the natural gas OFPC, the fundamentals-based component is developed using expert third-party forecasting services with consideration given to underlying supply/demand assumptions, forecast documentation, peer-to-peer forecast price comparisons, date of issuance, location granularity, and forecast horizon. For power, the fundamentals-based component is produced using AuroraXmp® (Aurora), a production cost simulation model. PacifiCorp's fundamentals-based natural gas price forecast is a key driver of Aurora's electricity price forecast.

Natural Gas Market Prices

PacifiCorp's December 2015 natural gas OFPC reflects a fundamentals-based forecast that was issued in November 2015, which is heavily influenced by cost-effective domestic supply expansion largely due to growth in the Marcellus and Utica shale plays.

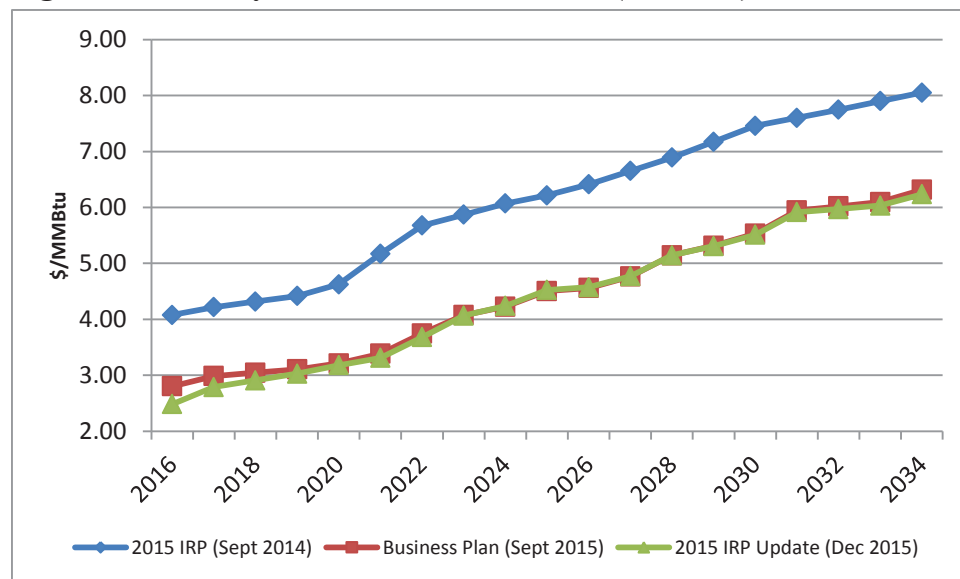
The September 2014 natural gas OFPC, which was used in the 2015 IRP, was based on an expert third-party long-term natural gas price forecast initially issued May 2014 with a front two-year update in August 2014. This price forecast also reflected a considerable portion of domestic natural gas demand being met by unconventional shale production.

In summer 2014, surveyed expert third-party natural gas price forecasters expected 57% to 70% of 2020 production to come from shale, by December 2015 expectations had increased to 62% to

75%. In the course of one year, 2014 to 2015, Marcellus and Utica shale production alone increased from an average of 14.4 billion cubic feet per day (BCF/D) to almost 19 BCF/D.

Figure 4.1 compares the nominal annual Henry Hub natural gas prices from the September 2014 (2015 IRP), September 2015 (Business Plan), and December 2015 (2015 IRP Update) OFPCs.

Figure 4.1 – Henry Hub Natural Gas Prices (Nominal)



Power Market Prices

The natural gas fundamentals forecast described above is a key input to the Aurora model, and consequently, the gas curve shape is reflected in wholesale electricity prices. Figures 4.2 and 4.3 compare the average annual flat and heavy-load-hour electricity prices for the Palo Verde market hub from the September 2014, September 2015 (Business Plan), and December 2015 OFPCs, and Figure 4.4 and 4.5 show the comparison for the Mid-Columbia market hub.

Figure 4.2 – Average Annual Flat Palo Verde Electricity Prices (Nominal)

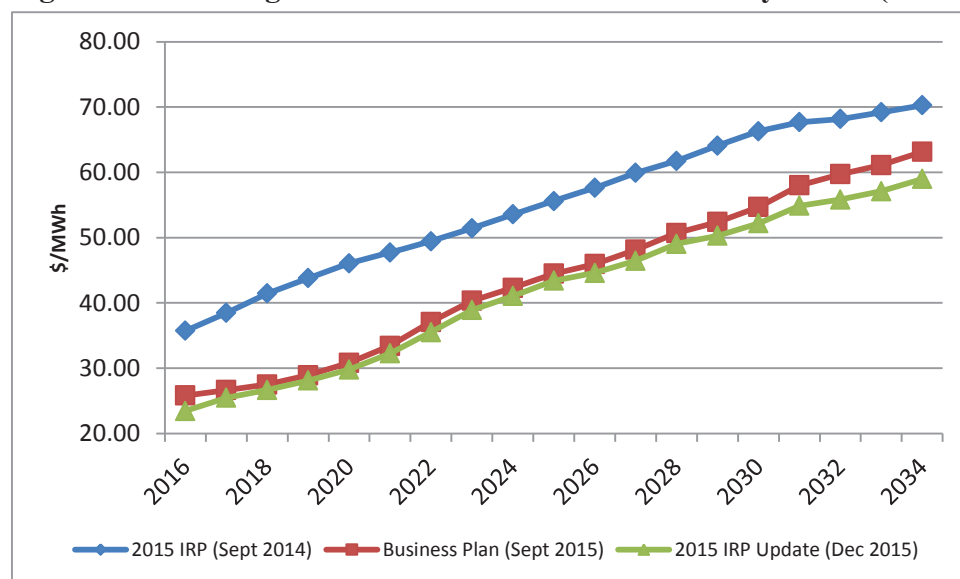


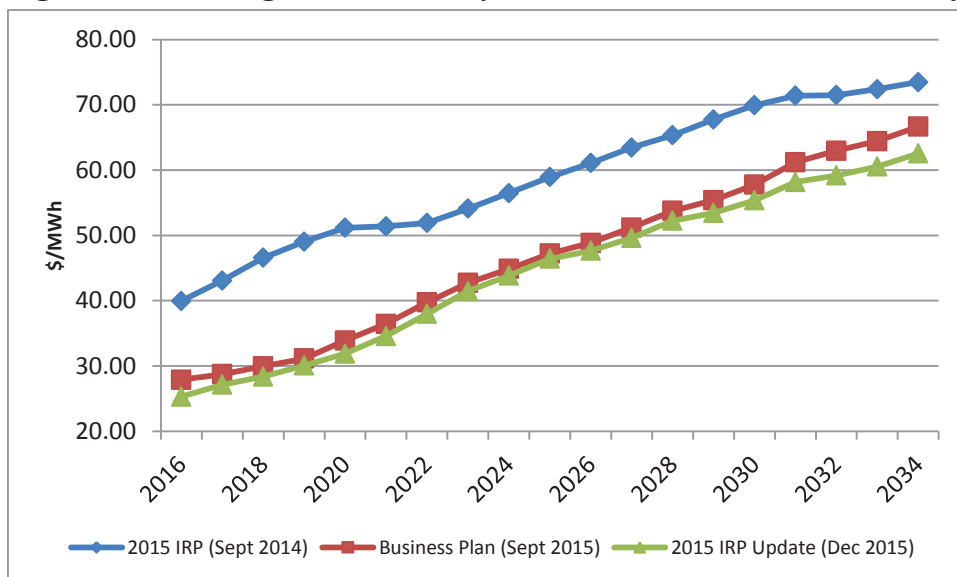
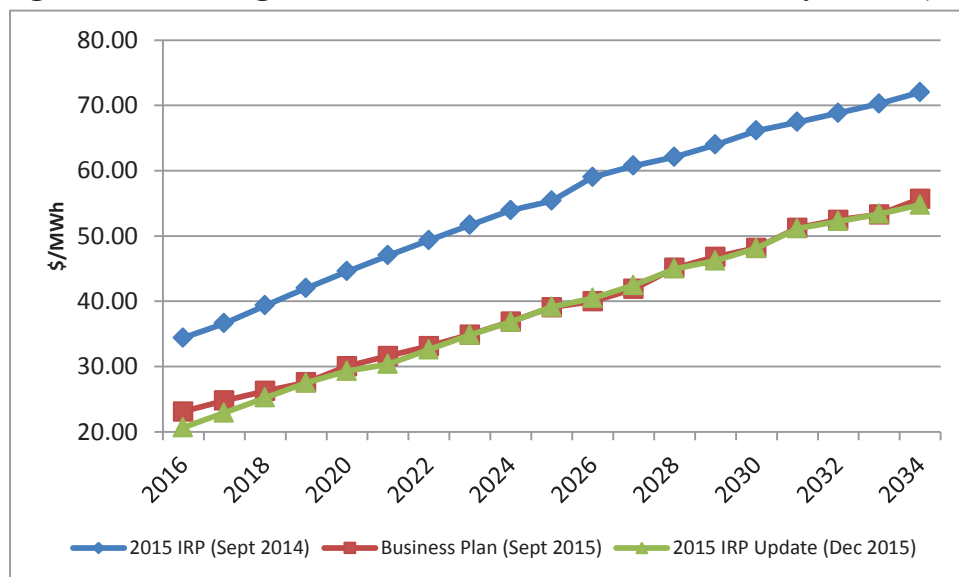
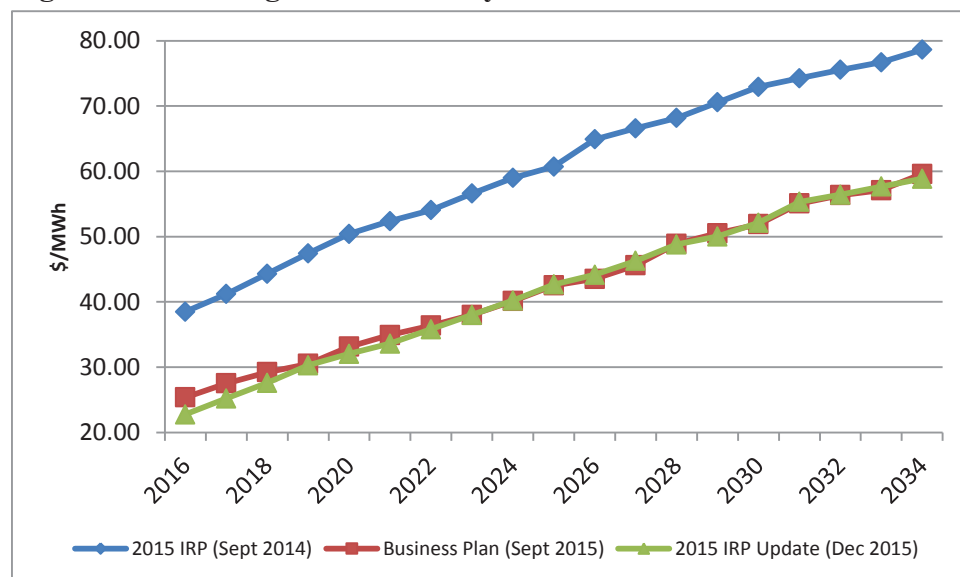
Figure 4.3 – Average Annual Heavy Load Hour Palo Verde Electricity Prices (Nominal)**Figure 4.4 – Average Annual Flat Mid-Columbia Electricity Prices (Nominal)**

Figure 4.5 – Average Annual Heavy Load Hour Mid-Columbia Electricity Prices (Nominal)

Carbon Dioxide Emission Policy

After PacifiCorp filed its 2015 IRP, EPA issued its final CPP, setting emission reduction goals for existing fossil generation. On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the U.S. Supreme Court, the stay will remain in effect until the U.S. Supreme Court takes action to either deny the petition, or, if the U.S. Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation is scheduled for June 2, 2016 before the D.C. Circuit Court of Appeals. In the 2015 IRP Update, considering uncertainty in the timing and details around individual state decisions related to CPP implementation, PacifiCorp assumes a mass-based emission target based on EPA's proposed mass-based FIP to limit CO₂ emissions from its existing affected generation facilities.

Transmission Topology

The transmission topology modeled in the 2015 IRP Update was modified to represent and align transmission rights consistent with the Idaho asset exchange agreement, which was finalized November 4, 2015 between PacifiCorp and Idaho Power Company. In addition to maintaining the 1,600 MW of westbound transfer capability, the Idaho asset exchange agreement now allows PacifiCorp to serve its Goshen load directly from Jim Bridger plant.

Supply-side Resources

The supply side resource costs for 50 MW_{AC} solar photovoltaic (PV) projects are updated to reflect lower market costs for PV modules and mounting structures. A solar option is added for Washington which includes an effective sales tax rate of about 2%. Engineering and owner costs are decreased slightly to reflect increasing levels of certainty for large commercial PV projects.

Projected costs, in real terms, during the 20-year study period continue to reflect a downward trend as in the 2015 IRP. Costs for five-MW fixed tilt solar array projects have not been updated because those projects are being outperformed in the market by larger single axis projects. While costs for solar projects have been reduced for the 2015 IRP Update, there is risk with adding incremental solar resources that have generation profiles aligning with expected output from increasing solar resource penetration levels in California. With increased solar generation, market prices can be very low in the mid-afternoon, particularly during the spring season and other low-load times of the year. Table 4.1 shows the updated costs of solar resources.

Table 4.1 – Updated Cost of Solar Resources, 2014\$ - (50 MW_{AC} Single Axis Tracking)

Location/Technology	2015 IRP Update Total (with Owner's Costs) \$/W_{AC}	2015 IRP Total (with Owner's Costs) \$/W_{AC}
Utah/Single Axis Tracking	\$2.318	\$2.702
Oregon/Single Axis Tracking	\$2.429	\$2.829
Washington/Single Axis Tracking	\$2.476	n/a

The supply side resource costs for wind resources have also been updated. Market conditions and competition led to cost reductions for turbines and balance of plant costs on a \$/kW basis. PacifiCorp previously incorporated a combination of land lease and land ownership options for new wind generation projects, but determined that using both ownership structures made it more difficult to compare IRP cost assumptions to typical wind development projects. For the 2015 IRP Update, PacifiCorp structured the capital cost and fixed O&M to reflect wind projects based on leased land which reduced capital costs by removing land purchase costs and increased fixed O&M costs to cover annual lease payments. To provide greater definition of project costs, PacifiCorp created separate line items for each state to address sales tax impacts. For Utah and Oregon there are no state sales taxes whereas sales taxes of 2% are applied for Washington wind resources and 6% for Idaho and Wyoming wind resources. Table 4.2 shows the updated costs of wind resources.

Table 4.2 – Updated Cost of Wind Resources, 2014\$

Location	2015 IRP Update		2015 IRP	
	Capital Cost \$/W	Fixed O&M \$/kW-year	Capital Cost \$/W	Fixed O&M \$/kW-year
Washington	\$1.712	\$36.56	\$2.135	\$34.46
Oregon	\$1.672	\$36.56	\$2.135	\$34.46
Idaho	\$1.735	\$36.56	\$2.188	\$34.46
Utah	\$1.672	\$36.56	\$2.188	\$34.46
Wyoming	\$1.735	\$36.56	\$2.156	\$34.46

The 2015 IRP Update adds information for battery storage costs summarized in the table below. Data from the Department of Energy (DOE) Global Energy Storage Database was compiled to produce the information in this table. It shows how installed costs vary with nameplate duration. The results differ from the tables produced in the 2015 IRP based on the limited sizing duration data provided in the 2014 HDR storage study. Table 4.3 shows the updated costs of battery storage resources.

Table 4.3 – Updated Cost of Energy Storage, 2014\$

Average 1 MW Battery Cost Standardized at a 20 year life	Duration			
	1 hour	2 hours	4 hours	8 hours
Lithium Ion				
Installed Cost, \$/kWh energy storage	1,725	1,223	972	846
Installed Cost, \$/kW	1,725	2,446	3,887	6,770
Sodium Sulfur				
Installed Cost, \$/kWh energy storage	N/A	N/A	N/A	720
Installed Cost, \$/kW	N/A	N/A	N/A	5,763
Vanadium Redox				
Installed Cost, \$/kWh energy storage	2,028	1,525	1,274	1,149
Installed Cost, \$/kW	2,028	3,051	5,097	9,190

Due to extension in federal production tax credits and investment tax credits, the levelized cost of renewable resources are lower, not only due to updated capital costs and O&M costs, but also due to the application of tax credits that get passed through to customers. Table 4.4 shows updated costs of the renewable resources with and without applicable tax credits, assuming the projects are built as rate-based assets, considering timing of construction and in-service dates. First year real levelized costs for wind and solar resources are presented for 2018, assuming a 2018 wind project meets IRS guidance demonstrating the project began construction by January 1, 2017, and for the last year in which PTCs (wind) and ITCs (solar) are phased down. Wind and solar resources with online dates between 2018 and 2021/2023 were considered in the Company's analysis, but are now shown. Levelized costs for Pacific Northwest wind projects are shown at two different capacity factors, 29% and 35%, reflecting the range of performance anticipated from wind facilities in the region. The table also reports updated storage costs.

Table 4.4 – Updated Supply Side Resource Table, 2014\$

Supply Side Resource Options Mid-Calendar Year 2014 Dollars (\$)		Capital Cost (\$/kW)			Fixed Cost (\$/kW-Yr)				Total Fixed (\$/kW-Yr)
Resource Description	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	
2.0 MW turbine 29% CF WA_2018	\$1,712	7.339%	\$126.69	36.56	2.96%	1.08	0.00	37.65	\$164.34
2.0 MW turbine 35% CF WA_2018	\$1,712	7.339%	\$126.69	36.56	2.96%	1.08	0.00	37.65	\$164.34
2.0 MW turbine 29% CF OR_2018	\$1,672	7.339%	\$123.70	36.56	2.96%	1.08	0.00	37.65	\$161.35
2.0 MW turbine 35% CF OR_2018	\$1,672	7.339%	\$123.70	36.56	2.96%	1.08	0.00	37.65	\$161.35
2.0 MW turbine 31% CF ID_2018	\$1,735	7.339%	\$128.40	36.56	2.96%	1.08	0.00	37.65	\$166.05
2.0 MW turbine 31% CF UT_2018	\$1,672	7.339%	\$123.70	36.56	2.96%	1.08	0.00	37.65	\$161.35
2.0 MW turbine 43% CF WY_2018	\$1,735	7.339%	\$128.40	36.56	2.96%	1.08	0.00	37.65	\$166.05
2.0 MW turbine 29% CF WA_2021	\$1,712	7.339%	\$126.69	36.56	2.96%	1.08	0.00	37.65	\$164.34
2.0 MW turbine 35% CF WA_2021	\$1,712	7.339%	\$126.69	36.56	2.96%	1.08	0.00	37.65	\$164.34
2.0 MW turbine 29% CF OR_2021	\$1,672	7.339%	\$123.70	36.56	2.96%	1.08	0.00	37.65	\$161.35
2.0 MW turbine 35% CF OR_2021	\$1,672	7.339%	\$123.70	36.56	2.96%	1.08	0.00	37.65	\$161.35
2.0 MW turbine 31% CF ID_2021	\$1,735	7.339%	\$128.40	36.56	2.96%	1.08	0.00	37.65	\$166.05
2.0 MW turbine 31% CF UT_2021	\$1,672	7.339%	\$123.70	36.56	2.96%	1.08	0.00	37.65	\$161.35
2.0 MW turbine 43% CF WY_2021	\$1,735	7.339%	\$128.40	36.56	2.96%	1.08	0.00	37.65	\$166.05
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT_2018	\$2,318	8.029%	\$186.12	33.59	2.34%	0.79	0.00	34.38	\$220.50
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR_2018	\$2,439	8.029%	\$195.01	34.16	2.34%	0.80	0.00	34.96	\$229.97
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA_2018	\$2,476	8.029%	\$198.80	34.16	2.34%	0.80	0.00	34.96	\$233.76
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT_2023	\$2,318	8.029%	\$186.12	33.59	2.34%	0.79	0.00	34.38	\$220.50
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR_2023	\$2,439	8.029%	\$195.01	34.16	2.34%	0.80	0.00	34.96	\$229.97
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA_2023	\$2,476	8.029%	\$198.80	34.16	2.34%	0.80	0.00	34.96	\$233.76
Lithium Ion Battery (8 MWh/day)	\$6,770	10.428%	\$706.00	54.88	0.00%	0.00	0.00	54.88	\$760.88
Sodium-Sulfur Battery (8 MWh/day)	\$5,763	10.428%	\$600.95	41.52	0.00%	0.00	0.00	41.52	\$642.47
Vanadium RedOx Battery (8 MWh/day)	\$9,190	10.428%	\$958.37	95.00	0.00%	0.00	0.00	95.00	\$1,053.37

Table 4.4 – Updated Supply Side Resource Table, 2014\$, Continued*

Supply Side Resource Options Mid-Calendar Year 2014 Dollars (\$)	Convert to Mills				Variable Costs (mill./kWh)				Total Costs and Credits (Mill./kWh)			
	Capacity Factor	Total Fixed (Mill./kWh)	Storage Efficiency	Levelized Fuel		Capitalized Premium	O&M Capitalized	Integration Cost	Excess Demand	Total Resource Cost	PTC Tax Credit / ITC (\$/kWh)	Total Resource Cost With PTC / ITC Credits
				cents/kWh	Mill./kWh							
Resource Description												
2.0 MW turbine 29% CF WA_2018	29%	64.69	na	0	0.00	0.00	0.00	3.06	0.00	67.75	(19.45)	48.30
2.0 MW turbine 35% CF WA_2018	35%	53.60	na	0	0.00	0.00	0.00	3.06	0.00	56.66	(19.26)	37.40
2.0 MW turbine 29% CF OR_2018	29%	63.51	na	0	0.00	0.00	0.00	3.06	0.00	66.57	(19.42)	47.15
2.0 MW turbine 35% CF OR_2018	35%	52.62	na	0	0.00	0.00	0.00	3.06	0.00	55.68	(19.24)	36.44
2.0 MW turbine 31% CF ID_2018	31%	61.15	na	0	0.00	0.00	0.00	3.06	0.00	64.20	(19.39)	44.81
2.0 MW turbine 31% CF UT_2018	31%	59.42	na	0	0.00	0.00	0.00	3.06	0.00	62.47	(19.35)	43.12
2.0 MW turbine 43% CF WY_2018	43%	44.08	na	0	0.00	0.67	0.00	3.06	0.00	47.81	(19.10)	28.70
2.0 MW turbine 29% CF WA_2021	29%	64.69	na	0	0.00	0.00	0.00	3.06	0.00	67.75	(19.35)	60.40
2.0 MW turbine 35% CF WA_2021	35%	53.60	na	0	0.00	0.00	0.00	3.06	0.00	56.66	(19.35)	49.31
2.0 MW turbine 29% CF OR_2021	29%	63.51	na	0	0.00	0.00	0.00	3.06	0.00	66.57	(19.35)	59.22
2.0 MW turbine 35% CF OR_2021	35%	52.62	na	0	0.00	0.00	0.00	3.06	0.00	55.68	(19.35)	48.33
2.0 MW turbine 31% CF ID_2021	31%	61.15	na	0	0.00	0.00	0.00	3.06	0.00	64.20	(19.35)	56.86
2.0 MW turbine 31% CF UT_2021	31%	59.42	na	0	0.00	0.00	0.00	3.06	0.00	62.47	(19.35)	55.12
2.0 MW turbine 43% CF WY_2021	43%	44.08	na	0	0.00	0.67	0.00	3.06	0.00	47.81	(19.35)	40.46
PV Poly-Si Single Tracing 31.6% AC CF (1.34 MWdc MWhac) UT_2018	32%	79.65	na	0	0.00	0.00	0.00	0.76	0.00	80.42	(10.93)	69.49
PV Poly-Si Single Tracing 29.2% AC CF (1.34 MWdc MWhac) OR_2018	29%	89.91	na	0	0.00	0.00	0.00	0.76	0.00	90.67	(12.39)	78.28
PV Poly-Si Single Tracing 29.2% AC CF (1.34 MWdc MWhac) WA_2018	29%	91.39	na	0	0.00	0.00	0.00	0.76	0.00	92.15	(12.63)	79.52
PV Poly-Si Single Tracing 31.6% AC CF (1.34 MWdc MWhac) UT_2023	32%	79.65	na	0	0.00	0.00	0.00	0.76	0.00	80.42	(3.22)	77.19
PV Poly-Si Single Tracing 29.2% AC CF (1.34 MWdc MWhac) OR_2023	29%	89.91	na	0	0.00	0.00	0.00	0.76	0.00	90.67	(3.66)	87.01
PV Poly-Si Single Tracing 29.2% AC CF (1.34 MWdc MWhac) WA_2023	29%	91.39	na	0	0.00	0.00	0.00	0.76	0.00	92.15	(3.73)	88.42
Lithium Ion Battery (\$/MWh day)	33%	260.58	91%	474	33.83	0.00	0.00	0.00	0.00	294.41	0.00	294.41
Sodium-Sulfur Battery (\$/MWh day)	33%	220.02	75%	474	41.05	0.00	0.00	0.00	0.00	261.08	0.00	261.08
Vanadium Redox Battery (\$/MWh day)	33%	360.74	75%	474	41.05	0.00	0.00	0.00	0.00	401.80	0.00	401.80

*Total costs shown in mills/kWh represent the first year real levelized cost, which escalates annually the assumed annual rate of inflation net of assumed annual real cost declines that are applicable to solar resources.

CHAPTER 5 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used the System Optimizer (SO) capacity expansion optimization model to develop resource portfolios based on inputs and assumptions updated throughout its business planning process. Similarly, the SO model was used to develop resource portfolios for the 2015 IRP Update consistent with its most recent load and resource balance as described in Chapter 3. This chapter presents the 2015 IRP Update and Business Plan portfolios along with comparisons to the 2015 IRP preferred portfolio.

2015 IRP Update Resource Portfolio

The 2015 IRP Update focuses on changes that occurred after PacifiCorp filed its 2015 IRP and includes comparisons to the resource portfolio developed for the Business Plan. These involve updates to load forecasts, changes in existing resources and any additions to PacifiCorp's contracts with other entities.

Table 5.1 summarizes the annual capacity in the 2015 IRP Update relative to the 2015 IRP preferred portfolio for the 10-year period 2016 through 2025. Consistent with the change in PacifiCorp's load and resource balance, driven by the assumed retirement of Naughton Unit 3 at the end of 2017 and Cholla Unit 4 at the end of 2024, thermal resource capacity is lower in the 2015 IRP Update. The reduction in thermal generation is offset by increased front office transactions (FOTs) and demand side management (DSM) resources. With the assumed retirement of Cholla Unit 4 at the end of 2024, FOTs reach 1,440 MW in 2025, well beyond the near-term action plan window. The level of FOTs shown in 2025 is 670 MW higher than in the 2015 IRP, yet below the assumed 1,575 MW FOT limit. PacifiCorp has not updated its FOT limits for the 2015 IRP Update. PacifiCorp will review its FOT limits during the 2017 IRP public process. Table 5.2 summarizes the 2015 IRP Update load and resource balance, inclusive of incremental resources, for 2016-2025, and Table 5.3 displays the detailed 2015 IRP Update resource portfolio through 2034.

Class 2 DSM selections in the 2015 IRP Update were updated to reflect updated information on actual and projected acquisitions in the near-term and the value of Class 2 DSM resources to the system. Energy selections of Class 2 DSM for 2015 were updated to reflect preliminary year-end actual acquisitions in each state. For 2016 and 2017, Oregon and Washington projections were modified to reflect current Energy Trust of Oregon projections and the approved "Demand Side Management 2016-2017 Business Plan" filed with the Washington Utilities and Transportation Commission (WUTC).⁷ For Utah, 2017 projections were set at 2015 IRP levels to reflect an increase in funding from 3.62% to 4%, as approved by the Utah Public Service Commission in 2015. Beginning in 2018, the IRP model was optimized Class 2 DSM selections to provide current information on the need for, and value of, Class 2 DSM in the medium- and long-term.

⁷ Washington Utilities and Transportation Commission, Docket UE-152072, Order 01, December 17, 2015.

Table 5.1 – Comparison of 2015 IRP Update with 2015 IRP Preferred Portfolio (Megawatts)**2015 IRP Update**

Resource	Capacity (MW)											10- year Total
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2016-2025
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	143	128	138	146	158	142	149	155	161	162	135	1,476
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	39	39
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,062
Existing Unit Changes												
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	(667)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	685	1,031	886	960	1,403	1,345	1,120	1,215	1,126	1,155	1,227	

FOT in resource total are 10-year averages

2015 IRP Preferred Portfolio

Resource	Capacity (MW)											10- year Total
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2016-2025
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	133	139	146	146	153	135	137	144	146	149	123	1,419
DSM - Load Control	-	-	-	-	-	-	-	5	11	-	-	16
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	727	937	904	870	935	979	769	791	761	754	771	847
Existing Unit Changes												
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	(667)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	337	-	-	-	-	-	-	387	724
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	638	1,077	1,050	1,073	1,088	1,113	906	941	917	903	893	

FOT in resource total are 10-year averages

2015 IRP Update less 2015 IRP Preferred Portfolio

Resource	Capacity (MW)											10- year Total
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2016-2025
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	10	(11)	(8)	(0)	5	8	12	11	15	14	12	58
DSM - Load Control	-	-	-	-	-	-	-	(5)	(11)	-	39	23
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	37	(34)	(157)	224	311	224	202	269	205	239	670	215
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	(337)	-	-	-	-	-	-	(387)	(724)
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	47	(45)	(164)	(113)	315	232	214	275	209	252	333	

FOT in resource total are 10-year averages

Table 5.2 – 2015 IRP Update Capacity Load and Resource Balance (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	469	463	460	454	447	436	434	381	378
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	624	550	915	850	911	552	563	561	605	742
East Existing Resources	7,534	7,594	7,675	7,608	7,663	7,744	7,743	7,728	7,724	7,360
Front Office Transactions	0	0	0	109	64	0	0	0	0	315
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	40
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	0	0	0	109	64	0	0	0	0	356
East Total Resources	7,534	7,594	7,675	7,717	7,726	7,744	7,743	7,728	7,724	7,715
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class 2 DSM	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)
New Class 2 DSM	(62)	(131)	(209)	(297)	(376)	(461)	(551)	(646)	(740)	(817)
East obligation	6,645	6,698	6,770	6,807	6,815	6,831	6,830	6,816	6,813	6,806
Planning Reserves (13%)	889	896	905	910	911	913	913	911	911	910
East Reserves	889	896	905	910	911	913	913	911	911	910
East Obligation + Reserves	7,534	7,594	7,675	7,717	7,727	7,744	7,743	7,728	7,724	7,717
East Position	0	0	0	(0)	(0)	0	0	0	(0)	(1)
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	172	172	172	172	172	118	118	107	107
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	108	177	175	174	176	166	163	155	154	154
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(625)	(551)	(916)	(851)	(912)	(553)	(564)	(562)	(606)	(743)
West Existing Resources	2,596	2,721	2,366	2,311	2,309	2,490	2,394	2,492	2,456	2,307
Front Office Transactions	957	793	1,160	1,212	1,212	1,028	1,124	1,023	1,053	1,212
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	957	793	1,160	1,212	1,212	1,028	1,124	1,023	1,053	1,212
West Total Resources	3,553	3,514	3,526	3,523	3,521	3,518	3,517	3,515	3,509	3,519
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class 2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
New Class 2 DSM	(26)	(54)	(79)	(103)	(125)	(145)	(165)	(185)	(206)	(223)
West obligation	3,144	3,110	3,120	3,117	3,116	3,114	3,112	3,111	3,105	3,114
Planning Reserves (13%)	409	404	406	405	405	405	405	404	404	405
West Reserves	409	404	406	405	405	405	405	404	404	405
West Obligation + Reserves	3,553	3,514	3,525	3,523	3,521	3,518	3,517	3,515	3,509	3,519
West Position	0	(0)	0	0	0	(0)	0	(0)	(0)	(0)
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,087	11,107	11,201	11,239	11,247	11,262	11,260	11,243	11,232	11,234
Obligation	9,789	9,807	9,890	9,924	9,931	9,944	9,942	9,927	9,918	9,920
Reserves	1,298	1,300	1,311	1,315	1,316	1,318	1,318	1,316	1,315	1,315
Obligation + Reserves	11,087	11,107	11,201	11,239	11,247	11,262	11,260	11,243	11,232	11,235
System Position	0	(0)	0	(0)	(0)	0	0	0	(0)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 5.3 – 2015 IRP Update, Detailed Portfolio (Megawatts)

Resource	Existing Plant Retirements/Conversions	Capacity (MW)												Resource Totals 1/										
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034			
East	Hydén 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	(45)		
	Hydén 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	(33)		
	Itiner 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	(269)		
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	(450)		
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)		
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)		
	Globe 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)	
	DevelJohnston 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	(106)	
	DevelJohnston 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	(106)
	DevelJohnston 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	(220)
	DevelJohnston 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	(156)	
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	(201)	
	Naughton 3 (Coal Early Retirement/Conversions)	(50)	-	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)
	Expansion Resources																							
	CCGT - Dohins - F 2d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	-	-	-	-	-	635
	CCGT - Utah-N - J 1d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	423	-	423	
	CCGT - Utah-S - F 2d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	-	1,693	
	Total CCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	635	-	-	423	-	2.3	
	DSM, Class 1, IDCurtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	12.4	-	4.0	-	-	-	3.5	-	-	4.6	1.4	25.9	
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.0		
DSM, Class 1, UT-DLC-RIS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	67.7			
DSM, Class 1, UT-DLC-RIS	-	-	-	-	-	-	-	-	-	-	13.1	24.0	10.7	-	-	-	-	15.0	5.0	-	19.0			
DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	13.2	-	-	-	-	-	3.3	-	-	2.5	-			
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0	-			
DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-			
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	38.6	24.0	14.7	-	-	6.9	-	-	19.6	19.8	123.5			
DSM, Class 2, ID	5	3	3	5	5	4	4	5	5	5	5	5	5	4	5	5	3	3	4	3	44			
DSM, Class 2, UT	71	74	81	89	98	97	101	106	105	85	85	84	83	81	75	72	73	71	70	909	1,688			
DSM, Class 2, WY	6	7	7	11	14	12	13	15	15	16	13	13	14	14	14	14	14	15	15	116	257			
DSM, Class 2 Total	82	83	92	105	117	105	114	120	126	126	103	103	103	101	100	94	89	91	90	89	1,070	2,033		
FOT Monr Q3	-	-	-	-	103	60	-	-	-	-	297	297	300	49	80	300	2	126	300	300	16	111		
Expansion Resources																								
CCGT - OregonCal - J 1d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	454	-	-	-	454		
CCGT - WilliamVake - J 1d	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	477		
Total CCGT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	454	-	-	-	932		
DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.6	-	-	-	-	-	0.6	-	4.2		
DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	10.6	-	-	-	-	-	11.7	-	22.3		
DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	8.4	-	-	-	-	-	-	-	8.4		
DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.2	-	-	-	-	-	-	-	9.2		
DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.5	-	-	-	-	-	-	-	5.1		
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	36.4	-	-	-	-	-	-	-	49.3		
DSM, Class 2, CA	2	1	2	2	2	1	1	2	2	2	1	2	2	1	1	1	1	1	1	1	16	29		
DSM, Class 2, OR	49	36	37	31	29	27	25	25	23	24	22	22	22	21	21	20	19	19	19	18	305	508		
DSM, Class 2, WA	10	8	8	9	10	9	9	9	11	11	9	9	9	9	8	7	7	7	7	6	93	170		
DSM, Class 2 Total	61	45	47	42	41	37	35	35	36	36	32	32	32	30	30	29	27	27	27	25	415	707		
FOT COR Q3	-	28	-	219	268	268	95	185	90	118	268	268	268	253	268	230	173	268	268	127	190	190		
FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400		
FOT MidColumbia Q3 - 2	264	375	248	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	351	363		
FOT NOR Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100		
Total	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	(762)	-	(807)	(77)	-	-	(627)	-	-		
Existing Plant Retirements/Conversions																								
Annual Additions, Long Term Resources	143	128	138	146	158	142	149	155	161	162	173	159	186	1,244	1,330	764	571	118	560	147	147			
Annual Additions, Short Term Resources	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,440	1,443	1,177	1,223	1,443	1,107	1,174	1,443	1,443	1,443			
Total Annual Additions	907	1,031	886	1,240	1,403	1,345	1,120	1,215	1,126	1,155	1,614	1,600	1,629	2,421	1,353	2,207	1,678	292	2,003	1,590	1,590			

1/ Front office transaction amounts reflect one-year transaction periods, are not additive and are reported as a 10/20-year annual average.

Business Plan Resource Portfolio

The Business Plan resource portfolio was updated from 2015 IRP preferred portfolio to reflect changes in existing resource assumptions, as well as assumptions around DSM resources. The main change in existing resources adopted in the Business Plan was the assumed early retirement of Naughton Unit 3 at the end of 2017 and the assumed early retirement of Cholla Unit 4 at the end of 2024. Class 2 DSM selections in the 2015 IRP preferred portfolio were finalized in February 2015. In developing the business plan in the following months, certain Class 2 DSM acquisition levels for 2015-2025 were modified to reflect updated near-term commitments, delivery challenges in certain markets, and uncertainty around upcoming regulatory activity. No modifications were made for the period 2026-2034.

The reduction in existing thermal resources and DSM, as discussed above, are offset by changes in FOTs. Table 5.4 shows the capacity load and resource balance from the Business Plan, inclusive of incremental resources, over the period 2016-2025. Table 5.5 summarizes the annual capacity of incremental resources assumed in the Business Plan.

Table 5.4 – 2015 Fall Business Plan Capacity Load and Resource Balance (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	444	437	435	429	422	412	409	407	403
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	612	559	932	888	949	608	638	661	682	800
East Existing Resources	7,521	7,577	7,667	7,620	7,675	7,774	7,793	7,803	7,826	7,443
Front Office Transactions	0	0	0	105	68	0	0	0	0	309
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	0	0	0	105	68	0	0	0	0	309
East Total Resources	7,521	7,577	7,667	7,725	7,744	7,774	7,793	7,803	7,826	7,752
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class 2 DSM	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
New Class 2 DSM	(71)	(142)	(214)	(286)	(358)	(431)	(504)	(576)	(646)	(783)
East obligation	6,633	6,683	6,762	6,814	6,830	6,858	6,874	6,883	6,904	6,838
Planning Reserves (13%)	888	894	904	911	913	917	919	920	923	914
East Reserves	888	894	904	911	913	917	919	920	923	914
East Obligation + Reserves	7,521	7,577	7,667	7,725	7,744	7,775	7,792	7,803	7,826	7,752
East Position	0	(0)	(0)	(0)	(0)	(0)	0	0	(0)	(0)
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	173	173	173	173	173	118	118	108	108
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	112	190	202	200	202	190	186	179	178	178
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(613)	(560)	(933)	(889)	(950)	(609)	(639)	(662)	(684)	(802)
West Existing Resources	2,612	2,726	2,376	2,301	2,298	2,459	2,343	2,417	2,403	2,274
Front Office Transactions	936	781	1,140	1,212	1,212	1,047	1,155	1,068	1,076	1,212
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	5	17	17	17
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	936	781	1,140	1,212	1,212	1,047	1,161	1,085	1,092	1,228
West Total Resources	3,548	3,507	3,517	3,512	3,510	3,506	3,504	3,501	3,495	3,502
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class 2 DSM	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
New Class 2 DSM	(31)	(60)	(87)	(113)	(135)	(156)	(177)	(198)	(218)	(239)
West obligation	3,140	3,104	3,112	3,108	3,106	3,103	3,101	3,099	3,093	3,099
Planning Reserves (13%)	408	403	405	404	404	403	403	403	402	403
West Reserves	408	403	405	404	404	403	403	403	402	403
West Obligation + Reserves	3,548	3,507	3,517	3,512	3,510	3,506	3,504	3,502	3,495	3,502
West Position	0	(0)	0	(0)	0	0	0	(0)	(0)	0
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,069	11,084	11,183	11,237	11,253	11,281	11,297	11,305	11,321	11,254
Obligation	9,773	9,787	9,874	9,922	9,936	9,961	9,974	9,982	9,996	9,937
Reserves	1,296	1,298	1,309	1,315	1,317	1,320	1,322	1,323	1,325	1,317
Obligation + Reserves	11,069	11,085	11,183	11,238	11,253	11,281	11,296	11,305	11,321	11,254
System Position	0	(0)	0	(0)	(0)	0	0	0	(0)	(0)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 5.5 –Business Plan, Detailed Portfolio (Megawatts)

		Capacity (MW)											Resource Totals 1/ 10-year
Resource		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
East	Existing Plant Retirements/Conversions												
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Naughton 3 (Coal Early Retirement/Conversions)	(50)	-	-	(280)	-	-	-	-	-	-	-	(280)
	Expansion Resources												
	DSM, Class 2, ID	3	3	3	3	4	3	3	3	3	3	3	32
	DSM, Class 2, UT	61	61	63	63	63	63	64	63	63	61	65	629
	DSM, Class 2, WY	4	6	7	7	7	7	8	8	7	8	8	73
	DSM, Class 2 Total	67	70	73	73	74	73	75	75	73	72	76	734
	FOT Mona Q3	-	-	-	-	99	64	-	-	-	-	291	45
West	Expansion Resources												
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	10.6	-	-	10.6
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	5.0	-	-	-	5.0
	DSM, Class 1 Total	-	-	-	-	-	-	-	5.0	10.6	-	-	15.6
	DSM, Class 2, CA	1	1	2	2	2	1	1	1	1	1	1	14
	DSM, Class 2, OR	33	32	27	24	22	19	18	18	17	16	15	208
	DSM, Class 2, WA	8	8	8	8	8	6	7	7	8	7	6	73
	DSM, Class 2 Total	43	41	36	34	32	26	26	26	26	24	23	295
	FOT COB Q3	-	8	-	201	268	268	113	215	133	140	268	161
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	261	375	237	375	375	375	375	375	375	375	375	361
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100
	Existing Plant Retirements/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	
	Annual Additions, Long Term Resources	110	111	109	107	106	99	102	106	110	96	99	
	Annual Additions, Short Term Resources	761	883	737	1,076	1,242	1,207	988	1,090	1,008	1,015	1,434	
Total Annual Additions	871	994	846	1,183	1,348	1,306	1,090	1,196	1,117	1,111	1,533		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10-year annual average.

Renewable Portfolio Standard Compliance

Oregon

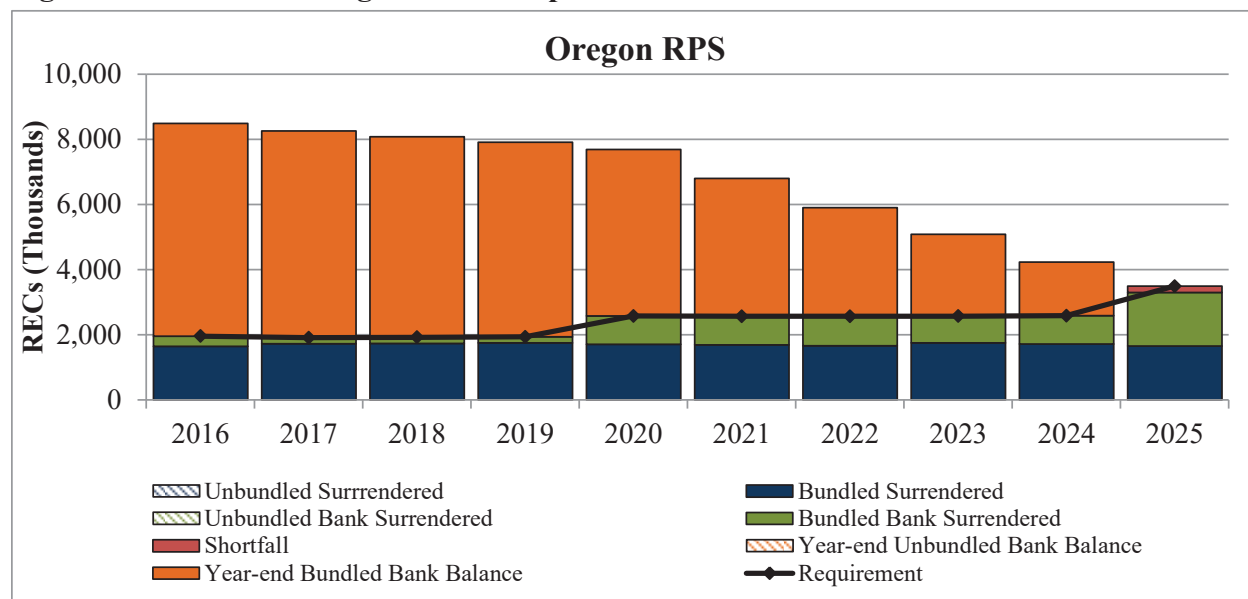
On March 8, 2016, Oregon Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition plan, was signed into law, which doubles the Oregon RPS target to 50% by 2040. Table 5.6 summarizes how the bill affects RPS targets for Oregon relative to those assumed in the 2015 IRP. In addition to revising RPS targets, SB 1547-B includes other provisions that influence how the company will plan to meet its RPS compliance requirements. One of these provisions introduces a five year banking limitation on renewable energy credits (RECs) issued after March 8, 2016. RECs issued on or before March 8, 2016 can be banked indefinitely. Another provision in SB 1547-B provides an early action incentive that allows for indefinite banking of RECs from new qualifying renewable resources that are issued over the first five years of the renewable resource's operation. New qualifying renewable resources include facilities that come online between March 8, 2016 and December 31, 2022. At the same time, SB 1547-B eliminates the requirement to surrender older vintage RECs for compliance first, prior to the surrender of newer vintage RECs.

Table 5.6 – Oregon RPS Targets

Year	2015 IRP	2015 IRP Update
2016	15%	15%
2020	20%	20%
2025	25%	27%
2030	25%	35%
2035	25%	45%
2040	25%	50%

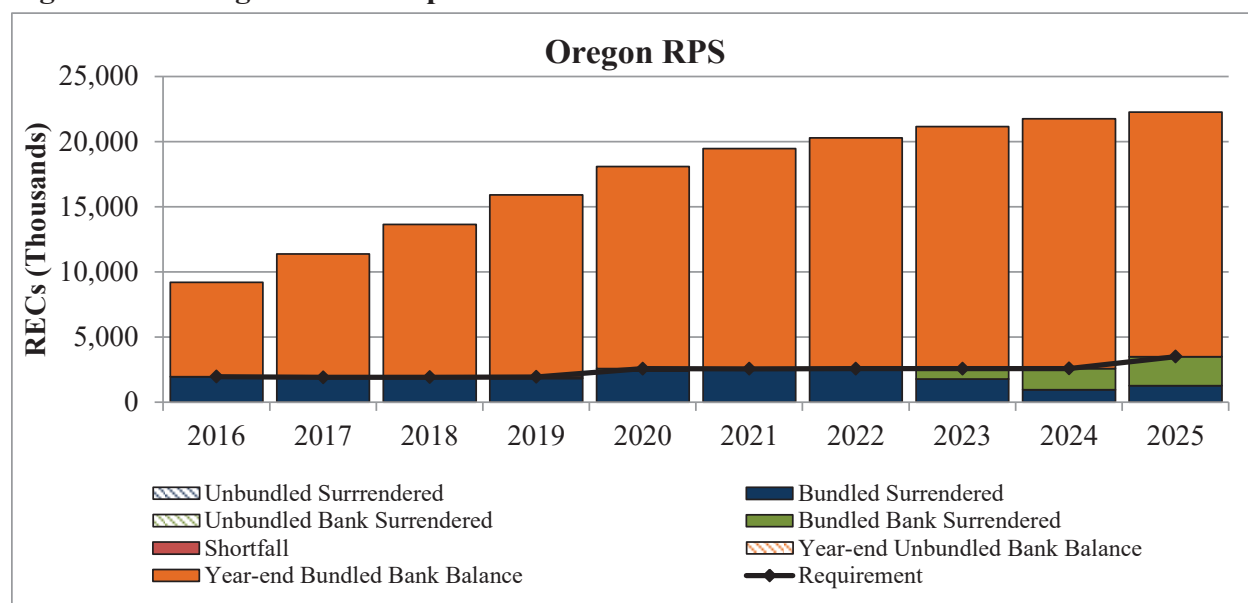
Figure 5.1 shows PacifiCorp's baseline RPS compliance position for Oregon for the front ten years of the planning horizon if no further action were taken. The baseline position indicates an initial shortfall, with the use of the existing bank, would occur in 2025.

Figure 5.1 – Baseline Oregon RPS Compliance Position



Considering the flexible provisions in the new law, updated RPS targets, updated REC banking provisions and the market potential for RECs, PacifiCorp can meet its Oregon RPS obligations through the 20-year IRP planning horizon through a number of flexible alternatives including the purchase of eligible RECs.⁸ Figure 5.2 shows PacifiCorp's RPS compliance forecast for Oregon, inclusive of REC purchase volumes that contribute to meeting RPS targets through the IRP planning horizon. Over the front ten years of the planning horizon, nearly 19 million RECs are needed to build the bank, which can be used to meet RPS requirements as the target rises over time. Over this same period, PacifiCorp estimates that there will be at least 23 million RECs generated from qualifying facility projects that have power purchase agreements with PacifiCorp in which the project developers hold title to the RECs. This volume is over and above eligible RECs from other facilities in the market with whom PacifiCorp is familiar through its industry leading Blue Sky program.

⁸ Under the Oregon RPS, RECs purchased from qualifying facility projects located in Oregon do not apply toward the 20% annual unbundled REC limit. RECs purchased from qualifying facilities in other states could be acquired as a bundled REC if the REC is purchased with the energy in the same contract.

Figure 5.2 – Oregon RPS Compliance Position with REC Purchases

REC purchases represent one avenue for achieving RPS compliance. PacifiCorp has also identified the potential for near-term, time-sensitive renewable resource acquisition opportunities that may reduce RPS compliance costs. The current planning environment, as fully described in Chapter 2, creates a potentially unique opportunity for the company to pursue low-cost renewable resources in the near-term as a way to reduce long-term RPS compliance costs. As discussed in Chapter 2, federal tax extender legislation passed in late 2015 retroactively and prospectively extended certain expired and expiring federal income tax deductions and credits over a multi-year phase out period. The most time-sensitive of these income tax credits is the federal production tax credit (PTC) for wind resources. To take advantage of the full PTC, currently set at 2.3 cents per kilowatt-hour, growing at inflation, for the first ten years of operation, a wind facility must commence construction by January 1, 2017. Under Internal Revenue Service (IRS) guidance, projects can demonstrate they have commenced construction by either starting work of a significant physical nature or by paying or incurring at least five percent of the total cost of the facility by January 1, 2017.

The PTC equates to over 3.7 cents per kilowatt-hour when grossed up by PacifiCorp's marginal tax rate. Consequently, the after-tax cost of a wind project that is eligible for 100% of the PTC is reduced by over \$37/MWh growing at inflation for the first ten years. For a 100 MW wind facility operating at a 29% capacity factor, this equates to over \$102 million over ten years—after-tax cost savings that are passed through to customers. If the up-front capital cost for this wind facility is \$180 million (about \$1,800/kW), then the PTCs received through the first ten years of operation cover 57% of the initial capital investment. If the project operates at a 35% capacity factor, the PTC savings increase to nearly \$124 million, representing about 69% of the initial capital investment. If a wind facility is unable to demonstrate it has commenced construction by January 1, 2017 but can commence construction by January 1, 2018, then the PTC is reduced by 20%. This one year delay would reduce PTC savings by between \$20 million (29% capacity factor) to \$25 million (35% capacity factor) for a 100 MW project.

In addition to the time-sensitive opportunity to take full advantage of PTC benefits, SB 1547-B also includes an opportunity to lower RPS compliance costs through the near-term acquisition of

renewable resources since RECs issued during the first five years of a new renewable facilities' operation can be banked indefinitely. RECs generated during this time period will allow PacifiCorp to build a bank of RECs that are not subject to a five year banking limit. Growing the bank now will allow the company to defer future RPS compliance needs, when cost savings from tax incentives will no longer be available.

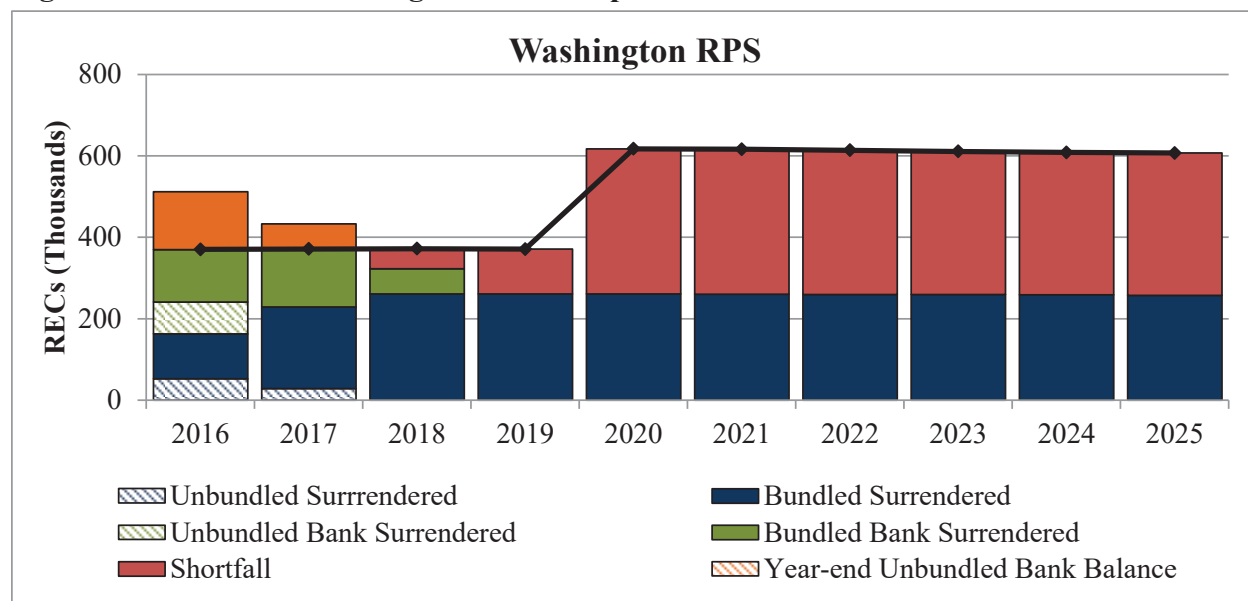
Near-term renewable resource procurement also provides value to customers because new renewable resources provide incremental energy and capacity that can also reduce system emissions. This additional energy and capacity will immediately offset fuel costs, purchased power and associated emissions. It will also offset the need for replacement resources as existing generating assets retire and reduce the Company's risk associated with the future greenhouse gas regulations. Procurement of renewable resources can further enable access to high quality renewable resource sites, which can provide future repowering and/or redevelopment value. With increased state RPS targets (i.e., Oregon and California targets now reach 50%) and the anticipated need to reduce greenhouse gas emissions through both state and federal policies such as the Clean Power Plan, demand for renewable resources is expected to grow and place upward pressure on future renewable resource costs, particularly if incremental transmission infrastructure is needed. Therefore, the acquisition of renewable resources now has the potential to optimally position the company and its Oregon customers in the face of increased and expanded carbon regulation.

To fully evaluate Oregon RPS compliance alternatives that consider potential near-term, time-sensitive resource procurement opportunities, PacifiCorp intends to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives. Resource proposals will be evaluated concurrent with REC proposals to comprehensively assess RPS compliance alternatives, considering both cost and risk metrics. Because proposals for new wind facilities must be able to demonstrate that they initiated construction by January 1, 2017 to take full advantage of PTC cost savings, PacifiCorp intends to issue this RFP in spring 2016 to complete the RFP evaluation, selection and contracting process by fall 2016. This schedule provides the best opportunity for customers to benefit from potentially cost effective wind and solar proposals that can take full advantage of the PTC and ITC.

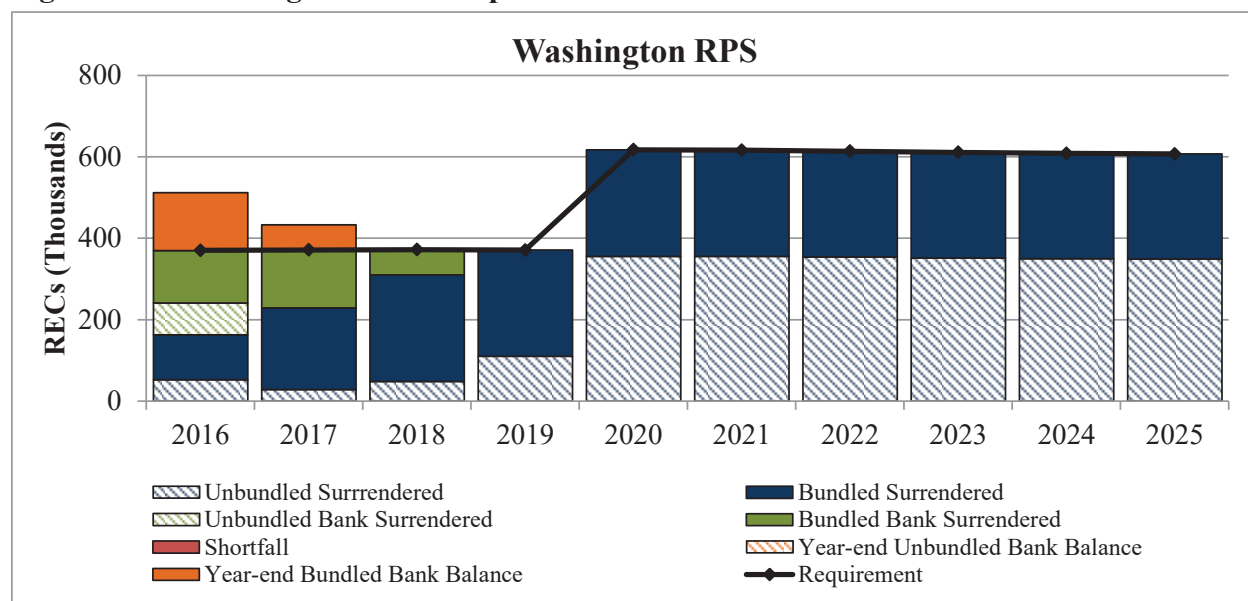
Notwithstanding the near-term renewable resource value incentives and opportunities, PacifiCorp will also consider longer term opportunities to take advantage of retiring coal facilities on its network that will free up transmission in renewable resource rich areas and provide access to low cost resources which today are constrained by lack of transmission.

Washington

Figure 5.3 shows PacifiCorp's baseline RPS compliance position for Washington for the front ten years of the planning horizon, prior to procuring incremental unbundled RECs. This baseline position incorporates PacifiCorp's most recent procurement of unbundled RECs for Washington's RPS. The baseline position indicates a potential shortfall in 2018 if no further action were taken.

Figure 5.3 – Baseline Washington RPS Compliance Position

Washington RPS rules do not impose restrictions on the use of unbundled RECs and effectively impose a one year life on all banked RECs. PacifiCorp can meet its Washington RPS targets with unbundled REC purchases through the IRP planning horizon. Figure 5.4 shows PacifiCorp's Washington RPS compliance position with unbundled REC purchase volumes required to achieve compliance. As requested by the Washington Utilities and Transportation Commission in its 2015 IRP acknowledgement letter, Washington RPS compliance is presented consistent with how Washington is currently allocated eligible renewable resources. Over the front ten years of the planning horizon, nearly 2.3 million additional unbundled RECs are needed to meet Washington RPS targets. As discussed above, PacifiCorp will consider whether near-term, time-sensitive resource procurement provides a low cost opportunity to displace or supplement unbundled REC purchases as an alternative approach to achieving compliance with the Washington RPS.

Figure 5.4 – Washington RPS Compliance Position with REC Purchases

California

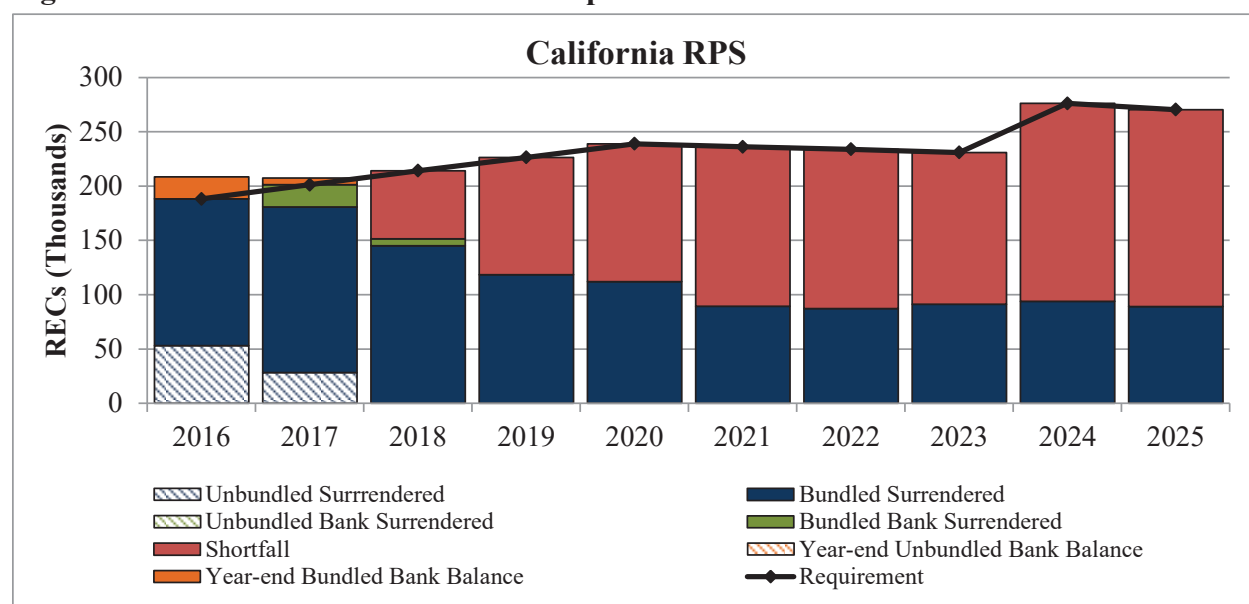
In October 2015, California Senate Bill No. 350 (SB 350) was signed into law, expanding the RPS target to 50% by 2030. Table 5.7 summarizes how the bill affects interim RPS targets for California relative to those assumed in the 2015 IRP.

Table 5.7 – California RPS Targets

Year	2015 IRP	2015 IRP Update
2016	25%	25%
2017	27%	27%
2018	29%	29%
2019	31%	31%
2020	33%	33%
2024	33%	40%
2027	33%	45%
2030	33%	50%

Figure 5.5 shows PacifiCorp’s baseline RPS compliance position for California for the front ten years of the planning horizon. This baseline position includes unbundled RECs that have been procured for California RPS compliance.⁹ The baseline position indicates a potential shortfall beginning 2018 if no further action were taken.

Figure 5.5 – Baseline California RPS Compliance Position

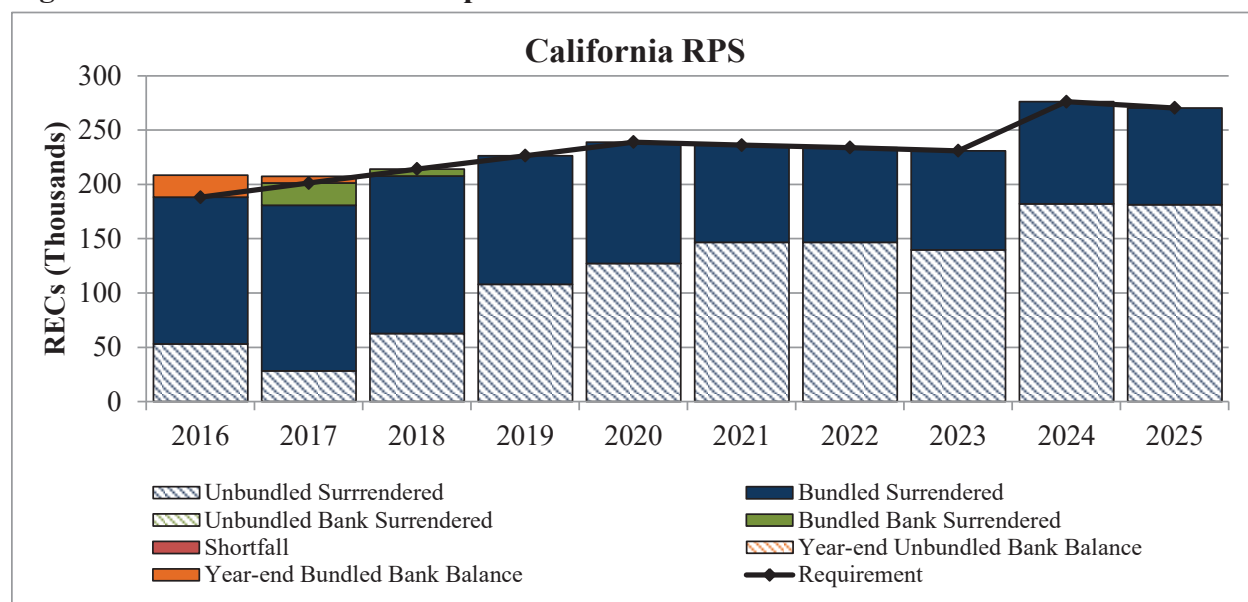


PacifiCorp is not restricted from using unbundled RECs to meet its RPS targets in California, and unbundled REC purchases can be used to achieve compliance through the IRP planning horizon. Figure 5.6 shows PacifiCorp’s California RPS compliance position with unbundled REC purchase volumes required to achieve compliance. Over the front ten years of the planning horizon, over one million additional unbundled RECs are needed to meet California RPS targets. As discussed above, PacifiCorp will consider whether near-term, time-sensitive resource

⁹ PacifiCorp selected a response to an unbundled REC RFP which meets the Company’s needs and pricing criteria. The contract is currently under review with the California Public Utilities Commission.

procurement provides a low cost opportunity to displace or supplement unbundled REC purchases as an alternative approach to achieving compliance with the California RPS.

Figure 5.6 – California RPS Compliance Position with REC Purchases



Utah

Utah Senate Bill 202, the Energy Resource and Carbon Emission Reduction Initiative, provides that beginning in 2025, 20% of adjusted retail sales of all Utah utilities be supplied by renewable energy, if cost effective. Retail electric sales are adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council area, and unbundled RECs can be used for up to 20% of the annual qualifying electricity target. Solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kilowatt-hour of generation. PacifiCorp has been building a bank of RECs from existing and contracted qualifying resources since 1995. This bank will be used to meet Utah's RPS goals well beyond the IRP planning horizon.

Carbon Dioxide Emissions

Figure 5.7 shows annual total CO₂ emissions of the resource portfolio and from coal-fueled generation facilities for both the 2015 IRP preferred portfolio and 2015 IRP Update resource portfolio. Emissions from the 2015 IRP Update resource portfolio are lower primarily due to reduced generation levels from fossil fired resources. Figure 5.8 shows the total generation and generation from coal-fueled facilities from the 2015 IRP and 2015 IRP Update. Figure 5.9 shows emissions from affected units under the FIP-based mass cap proposed by EPA for the Clean Power Plan.

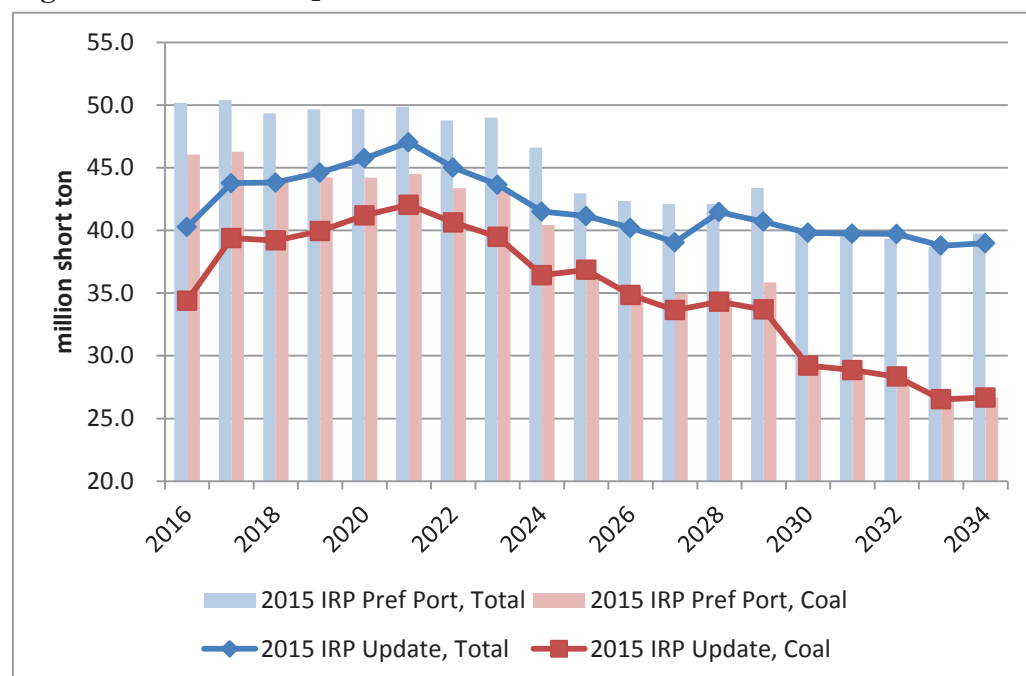
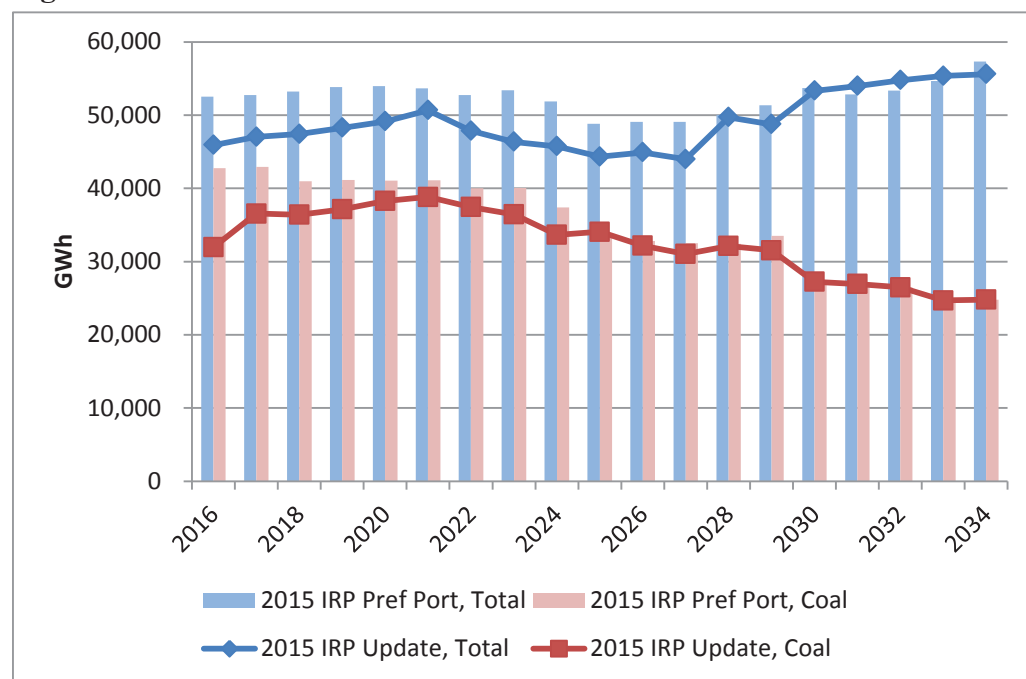
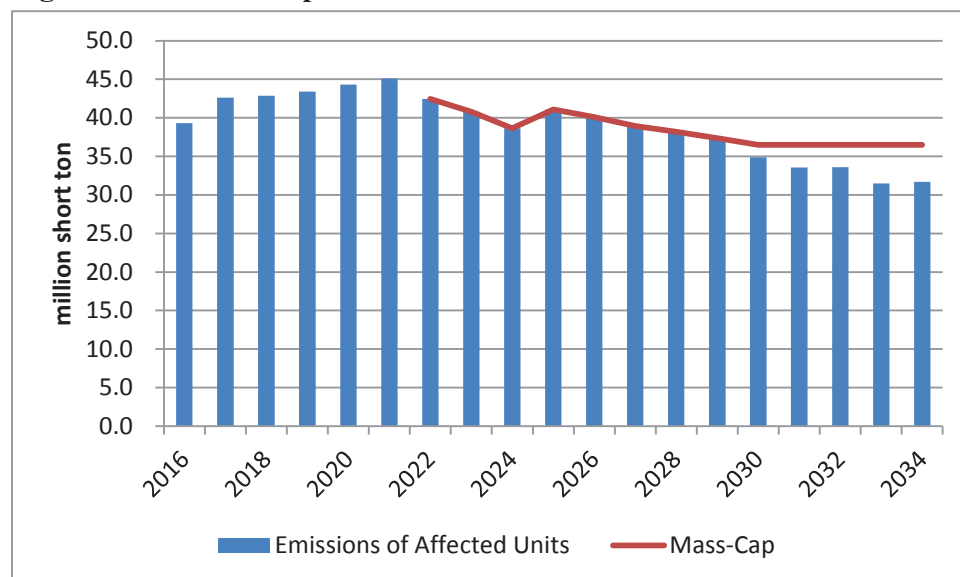
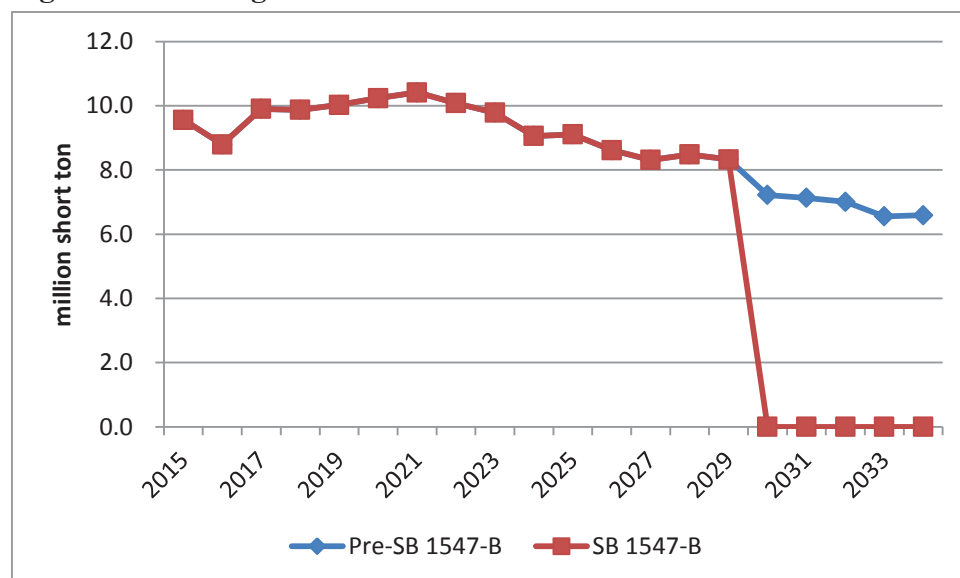
Figure 5.7 – Total CO₂ Emissions**Figure 5.8 – Total Thermal Generation**

Figure 5.9 – Mass-Cap and Emissions from Affected Units

Oregon SB 1547-B requires that coal-fired resources are eliminated from Oregon's allocation of electricity by January 1, 2030. Figure 5.10 shows the reduction in emissions from coal resources allocated to Oregon customers accounting for this provision of SB 1547-B.

Figure 5.10 – Oregon Share of CO₂ Emission from Coal-fueled Resources

Sensitivity Studies and Responses to Commission Requests

Clean Power Plan and Allocation of Renewable Energy Attributes

In its 2015 IRP acknowledgement letter, the WUTC encouraged the Company to use the 2015 IRP Update as an opportunity to begin modeling EPA's final CPP rule and to actively and constructively participate in Washington's process and any multi-state or regional efforts that emerge. The WUTC further requested PacifiCorp re-run Sensitivity Case S-15 in the 2015 IRP

Update, accounting for the final CPP rule, to determine whether lower cost compliance options that do not assume an early retirement of the Chehalis plant are available to meet its obligations without having to double allocate renewable energy.

PacifiCorp has and will continue to actively and constructively participate in the Washington Department of Ecology's CPP stakeholder process, which has included two utility stakeholder meetings so far. PacifiCorp is also engaging with state agencies on an informal basis and is participating in various regional efforts including efforts being led by the Center for New Energy Economy, WEST Associates, and the Western Interstate Energy Board.

Sensitivity Case S-15 from the 2015 IRP assumes state RPS-eligible RECs and CPP renewable attributes would need to be surrendered at the same time, forcing PacifiCorp to meet its share of emission rate targets outlined in the draft CPP rule with either situs-assigned renewable resources, or alternatively, by eliminating PacifiCorp's CPP compliance obligation in Washington by retiring the Chehalis plant. Given the low emission rate targets in EPA's draft rule for the state of Washington, PacifiCorp concluded that significant levels of situs-assigned renewable resources would be required to achieve compliance with draft emission rate targets proposed for the state of Washington, and determined that an early retirement of Chehalis would be lower cost when developing the resource portfolio for Sensitivity Case S-15.

When developing Sensitivity Case S-15 for the 2015 IRP, PacifiCorp determined an early retirement of Chehalis would be lower cost than adding situs-assigned renewable resources based on preliminary analysis performed during the public process that was presented to stakeholders at the January 29-30, 2015 public input meeting.¹⁰ This preliminary sensitivity analysis was produced for Sensitivity Case S-10, which developed standalone resource portfolios for the east and west balancing authority areas. In its preliminary modeling for this Sensitivity Case S-10, PacifiCorp developed one CPP compliance scenario assuming Chehalis retired early, eliminating PacifiCorp's CPP obligation in Washington, and another scenario assuming incremental renewable resources were added to meet then-current emission rate targets. This preliminary analysis showed that a renewable-based compliance solution would require over 1,100 MW of incremental renewable resources and that the present value revenue requirement (PVR) of system costs were \$515 million higher (over 77%) than the Chehalis early retirement alternative.

Since PacifiCorp performed these sensitivity analyses for the 2015 IRP, EPA issued its final CPP rule as summarized in Chapter 2. In its final rule, EPA significantly increased the emission rate targets for the state of Washington and provided states with a number of implementation options, including an alternative to adopt mass-based goals that EPA has determined are equivalent to the updated rate-based targets. Considering that the emission rate of the Chehalis plant falls below the final rate-based targets established for the state of Washington, PacifiCorp would not anticipate needing to eliminate its CPP compliance obligation by retiring Chehalis early or needing to acquire emission reduction credits (ERCs) to reduce its share of the Washington state emission rate targets should Washington adopt a rate-based plan. Moreover, should Washington adopt a mass-based plan, ERCs would not be used to achieve compliance, eliminating the concern of double-allocating renewable energy altogether.

¹⁰ The referenced analysis is summarized beginning on slide 78 of the presentation, which is available on PacifiCorp's website:

http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP_PIM06_2015-01-29-30.pdf

Considering that the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule, PacifiCorp has not performed comprehensive resource portfolio analysis of the CPP final rule in this 2015 IRP Update. PacifiCorp developed its updated resource portfolio assuming system mass cap emission rate targets consistent with EPA’s proposed mass-based FIP to limit CO₂ emissions from its existing affected generation facilities. PacifiCorp will evaluate CPP compliance scenarios, with input from its stakeholders, during the 2017 IRP public process.

Historical Cooling Degree Days

In its order regarding PacifiCorp’s 2013 IRP, the Public Service Commission of Utah (PSCU) directed PacifiCorp to perform a study on whether the available historical cooling degree day information, or some other alternative, is an appropriate predictor of future normal conditions. The request for the study was a result of a discussion on whether PacifiCorp should consider climate change implications when forecasting load. Changes in climate would ultimately be reflected by the data on historical weather and load, and the impact on the forecast of load would be guided by the historical relationship between weather on load. To respond to this order, PacifiCorp prepared a study to test the impacts of different historical weather patterns on the load forecast. There are no meaningful differences between using a five-year, ten-year, or 20-year normal weather pattern in the models. The results are presented on page nine of Appendix A to PacifiCorp’s 2015 IRP report.¹¹ PacifiCorp also prepared extreme weather scenarios to study the impacts of less likely weather patterns, which are presented on page 18 of Appendix A to PacifiCorp’s 2015 IRP report. The portfolio impact of different levels of load forecast is reflected by Sensitivity Cases S-01, S-02 and S-03 in PacifiCorp’s 2015 IRP.

Interaction of FERC Order 1000 and Energy Gateway

The PSCU also requested that PacifiCorp explain, as necessary, the interaction of requirements by the FERC Order 1000 and any Energy Gateway Project. PacifiCorp continues to participate in the Northern Tier Transmission Group that satisfies regional transmission planning requirements under the FERC’s Order No.1000 in addition to PacifiCorp’s local transmission planning requirements pursuant to Attachment K of its Open Access Transmission Tariff. Energy Gateway is also considered in the NTTG biennial transmission planning cycle efforts as well as at the Western Electricity Coordinating Council’s Transmission Expansion Policy and Planning Committee.

Accelerated Class 2 DSM

As recommended by the OPUC, PacifiCorp performed a sensitivity study on Class 2 DSM by replacing baseline DSM potential with accelerated DSM potential when developing an optimized resource portfolio. Table 5.8 shows the portfolio with accelerated DSM, the 2015 IRP Update portfolio with baseline DSM, and the differences between these two portfolios.

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http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

The sensitivity shows that when accelerated DSM potential is assumed, a slightly higher amount of Class 2 DSM resource is selected in the early years, while the total amount of Class 2 DSM selected over the 20-year study period is lower. The amount of DSM in 2015 through 2017 is the same between the two portfolios, because, as described earlier in this chapter, Class 2 DSM selections are fixed to reflect the most up to date planning for 2015 through 2017 and optimized beginning in 2018. The amount of Class 2 DSM in 2015 through 2017 exceeds the amount selected in the 2015 IRP, and thus, they were not modified in the accelerated sensitivity case. The portfolio with accelerated DSM also includes a larger CCCT in 2028 and delayed a CCCT in 2031. FOTs are generally less until 2031. For the 20-year study period, the portfolio added 41 MW less CCCT capacity, and added a total of 88 MW of utility solar on the east side of PacificCorp's system. The present value revenue requirement (PVR) of system costs from the portfolio with accelerated DSM is approximately \$45 million higher than the portfolio developed with baseline DSM assumptions.

Table 5.8 – Portfolio Comparison of Accelerated DSM Study and 2015 IRP Update (Megawatts)
Accelerated DSM portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total	
Expansion Options																						
Gas - CCT	-	-	-	-	-	-	-	-	-	-	-	-	-	1,314	-	635	-	-	635	-	2,584	
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
DSM - Energy Efficiency	143	128	138	149	164	149	153	155	157	155	128	128	126	107	110	103	101	101	101	96	2,590	
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	22	29	63	-	-	-	-	-	86	9	208	
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	1	3	-	-	-	-	-	-	-	84	88	
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Front Office Transactions	764	903	748	1,088	1,231	1,179	942	1,032	941	975	1,443	1,443	1,441	984	1,044	1,286	1,359	1,441	1,438	1,443	1,156	
Existing Unit Changes																						
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	-	-	-	(450)	-	(269)	-	(1,608)	
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	(1,554)	
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total	685	1,031	886	957	1,395	1,328	1,095	1,188	1,098	1,129	1,207	1,602	1,630	1,643	1,154	1,217	1,383	1,541	1,634	1,632		

2015 IRP Update

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total	
Expansion Options																						
Gas - CCT	-	-	-	-	-	-	-	-	-	-	-	-	-	1,112	-	635	454	-	423	-	2,625	
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
DSM - Energy Efficiency	143	128	138	146	158	142	149	155	161	162	135	136	135	131	130	122	117	118	117	114	2,740	
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	39	24	51	-	-	7	-	-	20	33	173	
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Front Office Transactions	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,440	1,443	1,177	1,223	1,443	1,107	1,174	1,443	1,443	1,164	
Existing Unit Changes																						
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	-	-	-	(450)	-	(269)	-	(1,608)	
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	(1,554)	
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total	685	1,031	886	960	1,403	1,345	1,120	1,215	1,126	1,155	1,227	1,600	1,629	1,659	1,353	1,400	1,600	1,292	1,376	1,590		

Portfolio Difference

Summary Portfolio Capacity by Resource Type and Year, Installed MW																							
Resource		Installed Capacity, MW																					
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total	
Expansion Options																							
	Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	202	-	-	-	(454)	-	212	-	(41)
	Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DSM - Energy Efficiency	-	-	-	3	7	6	3	(0)	(4)	(8)	(6)	(8)	(9)	(24)	(21)	(20)	(16)	(18)	(16)	(19)	(150)	
	DSM - Load Control	-	-	-	-	-	-	-	-	-	-	(17)	5	12	-	-	(7)	-	-	66	(24)	35	
	Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	1	3	-	-	-	-	-	-	-	84	88	
	Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Front Office Transactions	-	-	-	(6)	(15)	(24)	(28)	(28)	(25)	(18)	3	3	(2)	(194)	(179)	(157)	253	267	(4)	0	(8)	
Existing Unit Changes																							
	Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	Total	0	0	0	(3)	(8)	(17)	(25)	(28)	(29)	(26)	(19)	2	1	(16)	(199)	(184)	(218)	249	258	42	-	

CHAPTER 6 – ACTION PLAN STATUS UPDATE

This chapter provides an update to the action items listed in the Action Plan of PacificCorp's 2015 IRP. Some of the action items have been superseded or eliminated since they were identified in the 2015 IRP. The status for all action items is provided in Table 6.1 below.

Table 6.1 – 2015 IRP Action Plan Status Update

Action Item	Activity	Status
1a	<u>Renewable Portfolio Standard Compliance</u> - The Company will pursue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. - Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard targets through 2017. - Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2017. - With a projected bank balance extending out through 2027, defer issuance of RFPs seeking unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets until states begin to develop implementation plans under EPA’s draft 111(d) rule, providing clarity on whether an unbundled REC strategy is the least cost compliance alternative for Oregon customers.	For the Washington renewable portfolio standard, the Company did not issue a REC RFP in 2015. The Company determined that its current needs did not warrant issuance of a RFP. For the California renewable portfolio standard requirements, the Company issued a REC RFP on October 2, 2015 with bids due October 22, 2015. An offer meeting the Company’s needs and specific pricing criteria was selected and is currently under review with the California Public Utilities Commission. Action Item 1a has been revised in the 2015 IRP Update, as presented in the Executive Summary, to reflect changes in state RPS targets and banking provisions and changes in federal tax credits.
1b	<u>Renewable Energy Credit Optimization</u> On a quarterly basis, and through calendar year 2016, issue reverse RFPs to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.	The Company issued a reverse RFP in February 2015 and June 2015 to sell RECs. The Company will continue to issue reverse RFPs in 2016 to seek REC sale opportunities for RECs allocated to states that do not have a state RPS compliance need.
1c	<u>Oregon Solar Capacity Standard</u> Conclude negotiations with shortlisted bids from the 2013S Request for Proposals (RFP), seeking up to 7 MW_{AC} of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp’s obligation under Oregon’s 2020 solar capacity standard.	The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547-B. This action item was deleted from the updated action plan presented in the Executive Summary.

Action Item	Activity	Status
2a	<u>Front Office Transactions</u> – Acquire economic short-term firm market purchases for on-peak summer deliveries from 2015 through 2017 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.	For 2015, PacifiCorp acquired approximately 950 MW to 4,300 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2016, as of early February 2016, the Company has acquired approximately 550 MW to 650 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2017, as of early February 2016, the Company has not procured any short-term firm market purchases explicitly for delivery during the on-peak summer period.
3a	<u>Class 1 DSM</u> – Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.	On March 4, 2016, PacifiCorp filed with the Oregon Public Utilities Commission to implement an Irrigation Load Control pilot program. The proposed pilot program would begin in 2016 and target 3 MW of controlled load.

Action Item	Activity	Status															
3b	<u>Class 2 DSM</u> Acquire cost effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP. <table border="1"> <thead> <tr> <th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr> </thead> <tbody> <tr> <td>2015</td><td>551</td><td>133</td></tr> <tr> <td>2016</td><td>584</td><td>139</td></tr> <tr> <td>2017</td><td>616</td><td>146</td></tr> <tr> <td>2018</td><td>634</td><td>146</td></tr> </tbody> </table> *Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource.	Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)	2015	551	133	2016	584	139	2017	616	146	2018	634	146	Initial review indicates that in 2015, PacifiCorp acquired 589 GWh of Class 2 DSM, 7% above the Action Plan target. The Company is on track to achieve its 2016 Class 2 DSM target.
Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)															
2015	551	133															
2016	584	139															
2017	616	146															
2018	634	146															
4a	<u>Naughton Unit 3</u> - Issue an RFP to procure gas transportation and resume engineering, procurement, and construction (EPC) contract procurement activities for the Naughton Unit 3 natural gas conversion in the first quarter of 2016. - PacifiCorp may update its economic analysis of natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.	In July 2015 the competitive bid event was reopened using an Addendum 6 and all previous (2013) company responses to bid period requests for information. The “short-listed” bidders were asked to refresh all pricing and commercial terms to current market conditions. The only scope modifications for the 2015 refresh were that the bidders were to: (1) exclude updating the SCR option pricing; and (2) the pricing validity date must be extended to December 31, 2016. Refreshed proposals were received from the short-listed bidders on November 2, 2015. These refreshed proposals informed PacifiCorp's updated analysis of the Naughton Unit 3 gas conversion alternative, as summarized in Confidential Appendix B to this 2015 IRP Update. Action Item 4a has been															

Action Item	Activity	Status
		updated accordingly as presented in the updated action plan in the Executive Summary.
4b	<u>Dave Johnston Unit 3</u> - The portion of EPA’s final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals. - If following appeal, EPA’s final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacificCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. - If following appeal, EPA’s final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacificCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.	PacificCorp is still awaiting results of appeal of EPA’s final regional haze FIP.
4c	<u>Wyodak</u> - Continue to pursue the Company’s appeal of the portion of EPA’s final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. - If following appeal, EPA’s final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacificCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	PacificCorp is still awaiting results of appeal of EPA’s final regional haze FIP.
4d	<u>Cholla Unit 4</u> Continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a	In 2015, permit applications and studies required to amend the facility’s Title V permit and the Arizona regional haze SIP were submitted to the Arizona Department of Environmental Quality and EPA,

Action Item	Activity	Status
	coal-fueled resource by the end of April 2025.	respectively. The EPA acknowledged receipt of the final Arizona regional haze SIP amendment from Arizona Department of Environmental Quality on October 26, 2015. EPA is currently preparing for their review, public comment process, and final action.
5a	<u>Energy Gateway Permitting</u> - Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: - For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. - For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. - For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. - A final EIS for the Gateway South project, Segment F, is anticipated first quarter 2016 and the final Record of Decision second quarter 2016. - A draft supplemental EIS for the deferred portions of Segment E for the Gateway West project is anticipated first quarter 2016. A final Record of Decision is anticipated in December 2016. - PacifiCorp continues to support the Boardman to Hemingway project consistent with the project Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance of activities and plans associated with the permitting phase of the project.
5b	<u>Wallula to McNary 230 kilovolt Transmission Line</u> Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.	Updates on the construction are as follows - Received the Umatilla County Conditional Use Permit December 2015. - Continue permitting efforts with the Bureau of Land Management, the U.S. Army Corps of Engineers, U.S. Fish and Wildlife agencies, Bureau of Indian Affairs, and the Confederated Tribes of the Umatilla Indian Reservation. - Bonneville Power Administration continues work on the studies and the development of the plan of service

Action Item	Activity	Status
		required to interconnect at the McNary substation. – Right of way appraisal work is scheduled for first quarter 2016. – Note that all permitting documentation as required by each agency has been submitted and that various agencies are working through their required processes.

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APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 3 represents the data used for capacity expansion modeling, and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). Tables A.1 and A.2 report the October 2015 (2015 IRP Update) annual load and coincident peak load forecasts. These forecast data include reduction in loads for both distributed generation and new energy efficiency measures (Class 2 DSM), and have not been adjusted for line-losses.

Table A.1 – October 2015 (2015 IRP Update): Forecasted Annual Load Growth, 2016 through 2025 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	56,920,222	13,022,611	4,099,940	745,074	24,830,260	9,591,503	3,477,804	1,153,030
2017	55,580,892	12,715,915	4,085,272	737,702	24,908,433	9,685,196	3,448,374	
2018	55,896,683	12,822,029	4,079,018	730,863	25,049,965	9,763,711	3,451,096	
2019	56,207,036	12,849,252	4,069,749	722,665	25,284,842	9,827,527	3,453,001	
2020	56,314,053	12,819,960	4,063,519	716,384	25,457,899	9,803,611	3,452,680	
2021	56,205,931	12,769,059	4,039,095	707,205	25,487,966	9,752,466	3,450,140	
2022	56,233,170	12,773,767	4,025,178	700,233	25,577,211	9,702,548	3,454,232	
2023	56,243,085	12,799,681	4,007,953	690,117	25,652,375	9,633,596	3,459,363	
2024	56,424,298	12,867,245	4,003,015	679,539	25,792,573	9,613,965	3,467,962	
2025	56,360,934	12,865,292	3,979,977	663,862	25,846,991	9,538,532	3,466,281	
Average Annual Growth Rate for 2016-2025								
2016-2025	-0.11%	-0.13%	-0.33%	-1.27%	0.45%	-0.06%	-0.04%	

Table A.2 – October 2015 (2015 IRP Update): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	9,951	2,267	723	144	4,771	1,331	714	
2017	9,911	2,227	721	144	4,765	1,340	713	
2018	9,980	2,240	720	142	4,817	1,347	714	
2019	10,003	2,241	716	141	4,839	1,352	713	
2020	10,005	2,243	716	138	4,856	1,346	706	
2021	10,006	2,242	714	138	4,859	1,339	714	
2022	9,996	2,244	712	137	4,857	1,331	716	
2023	9,973	2,246	708	136	4,847	1,320	716	
2024	9,959	2,261	715	135	4,830	1,300	719	
2025	9,961	2,274	715	130	4,852	1,290	700	
Average Annual Growth Rate for 2016-2025								
2016-2025	0.01%	0.03%	-0.12%	-1.17%	0.19%	-0.34%	-0.22%	

Tables A.3 and A.4 report the September 2014 (2015 IRP) annual load and coincident peak load forecasts. These forecast data include reduction in loads for both distributed generation and new energy efficiency measures (Class 2 DSM), and have not been adjusted for line-losses.

Table A.3 – September 2014 (2015 IRP): Forecasted Annual Load Growth, 2016 through 2025 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	57,520,472	13,130,326	4,053,343	770,324	24,859,021	10,093,387	3,461,042	1,153,030
2017	56,674,813	13,134,849	4,048,309	767,939	25,090,125	10,164,886	3,468,704	
2018	57,004,095	13,146,512	4,053,605	767,434	25,294,074	10,260,988	3,481,482	
2019	57,346,137	13,185,105	4,057,536	766,591	25,568,374	10,271,982	3,496,549	
2020	57,741,106	13,214,731	4,060,617	764,114	25,830,740	10,359,862	3,511,043	
2021	57,818,735	13,189,208	4,040,875	758,757	25,994,725	10,316,336	3,518,834	
2022	58,154,197	13,224,659	4,036,682	756,518	26,245,188	10,359,347	3,531,804	
2023	58,505,705	13,278,459	4,040,509	755,385	26,541,576	10,341,950	3,547,826	
2024	59,070,023	13,358,920	4,057,429	756,514	26,910,407	10,417,356	3,569,396	
2025	59,291,219	13,347,506	4,052,651	753,447	27,180,526	10,376,693	3,580,395	
Average Annual Growth Rate for 2016-2025								
2016-2025	0.34%	0.18%	0.00%	-0.25%	1.00%	0.31%	0.38%	

Table A.4 – September 2014 (2015 IRP): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	9,949	2,265	722	148	4,734	1,385	696	
2017	9,985	2,269	721	148	4,756	1,393	698	
2018	10,044	2,268	725	147	4,800	1,403	700	
2019	10,082	2,272	722	147	4,836	1,404	701	
2020	10,139	2,281	724	145	4,883	1,412	695	
2021	10,189	2,286	723	145	4,921	1,407	706	
2022	10,243	2,294	723	146	4,960	1,411	710	
2023	10,295	2,301	724	146	5,005	1,408	712	
2024	10,357	2,304	725	146	5,054	1,415	714	
2025	10,406	2,316	729	143	5,121	1,410	686	
Average Annual Growth Rate for 2016-2025								
2016-2025	0.50%	0.25%	0.11%	-0.33%	0.88%	0.20%	-0.16%	

Tables A.5 and A.6 show the October 2015 (2015 IRP Update) forecast changes relative to the September 2014 (2015 IRP) load forecast for loads and coincident system peaks. These forecast data include reduction in loads for both distributed generation and new energy efficiency measures (Class 2 DSM), and have not been adjusted for line-losses.

Changes between these two forecasts are due to increases in Class 2 DSM and changes in economic conditions in the service territory that occurred between September 2014 and October 2015. While economic conditions continue to improve following the most recent recession, projected load growth in the residential and commercial customer classes is offset by forecasted increases in utility-sponsored energy efficiency programs. Weakness in commodities markets drove additional demand decreases in the Wyoming commercial and industrial and Utah industrial customer classes.

Table A.5 – Annual Load Growth Change: October 2015 (2015 IRP Update) Forecast less September 2014 (2015 IRP) Forecast (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	-600,250	-107,716	46,598	-25,250	-28,761	-501,884	16,762	
2017	-1,093,921	-418,934	36,963	-30,237	-181,692	-479,691	-20,330	
2018	-1,107,412	-324,483	25,414	-36,571	-244,109	-497,277	-30,386	
2019	-1,139,101	-335,854	12,213	-43,925	-283,533	-444,454	-43,548	
2020	-1,427,053	-394,770	2,902	-47,730	-372,841	-556,251	-58,362	
2021	-1,612,803	-420,149	-1,779	-51,551	-506,760	-563,870	-68,694	
2022	-1,921,028	-450,892	-11,504	-56,285	-667,977	-656,798	-77,571	
2023	-2,262,620	-478,778	-32,556	-65,268	-889,201	-708,354	-88,463	
2024	-2,645,725	-491,675	-54,415	-76,975	-1,117,834	-803,391	-101,434	
2025	-2,930,284	-482,215	-72,674	-89,585	-1,333,535	-838,161	-114,114	

Table A.6 – Annual Coincidental Peak Growth Change: October 2015 (2015 IRP Update) Forecast less September 2014 (2015 IRP) Forecast (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	1	2	2	-3	38	-54	18	
2017	-74	-42	0	-4	9	-53	15	
2018	-64	-29	-5	-5	17	-56	14	
2019	-79	-30	-6	-6	3	-52	12	
2020	-134	-39	-8	-7	-27	-65	11	
2021	-183	-44	-9	-8	-62	-68	8	
2022	-247	-50	-11	-9	-103	-80	6	
2023	-322	-55	-15	-10	-157	-88	4	
2024	-397	-43	-10	-11	-224	-115	5	
2025	-445	-43	-13	-14	-269	-120	14	

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-105:
PacifiCorp 2025 IRP



2025 Integrated Resource Plan

Volume I - March 31, 2025



This 2025 Integrated Resource Plan is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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CHAPTER 10 – ACTION PLAN

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CHAPTER 1 – EXECUTIVE SUMMARY

Maintaining customer focus

Our 2025 Integrated Resource Plan (IRP) is a roadmap for continual progress in safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp’s commitments to the diverse communities in which it operates.

Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.
- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

New Resources

- The following resources are added in the 2025 IRP:
 - o 3,782 megawatts of new wind resources
 - o 7,524 megawatts of storage resources, including four-hour, and 100-hour durations
 - o 5,912 megawatts of new solar resources, including utility-scale and small-scale
 - o 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

Customer Programs

- 5,255 megawatts of capacity saved through energy efficiency programs
- 769 megawatts of capacity saved through direct load control programs

Transmission

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front
- New transmission from the Walla Walla substation near Walla Walla, Washington to the Yakima substation near Yakima, Washington
- Various upgrades that increase transfer capability between the Summer Lake substation in Oregon and the Hemingway substation in Idaho

- New transmission, including a 110-mile line from Summer Lake to Burns, Oregon, and an 88-mile line from Summer Lake to the planned Full Circle substation in Central Oregon. These near-term upgrades connect with a later upgrade a new transmission line connecting Walla Walla to the Full Circle substation, expected in 2039.
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

Key Thermal Outcomes

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030 to comply with Wyoming’s low carbon portfolio standard
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Initiate the process of coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029

PacifiCorp’s Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are situs-allocated and deliverable to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.¹ Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements were represented:

- Utah, Idaho, Wyoming, and California (UIWC)²
 - Cost-effective resources
 - Includes WRAP compliance constraints for UIWC load
- Oregon
 - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
 - Includes WRAP compliance constraints for Oregon load
 - Includes small-scale renewable capacity requirement
- Washington
 - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
 - Includes WRAP compliance constraints for Washington load

Resources identified under each jurisdictional view are brought together into an “integrated” portfolio and assumed to be situs to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly their longer-range elements, can and do change over time.

PacifiCorp’s 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of this draft necessitated that coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting length and accelerating the timing of the coverage of all topics. Following the kick-off,

¹ Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

² While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

PacifiCorp hosted stakeholders in nine online public input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 1.1, PacifiCorp’s 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp’s system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp’s 2025 IRP Approach



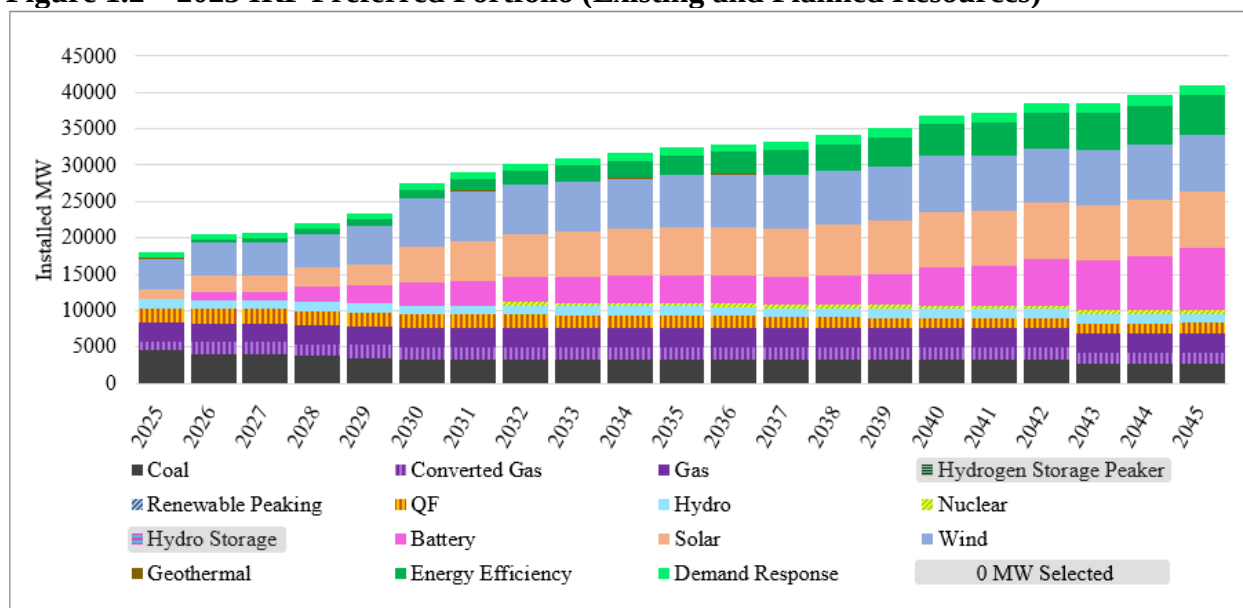
Preferred Portfolio Highlights

PacifiCorp’s selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp’s 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and renewable peaking resources facilitated by incremental transmission investments.

The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by the fall of 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912 MW of new solar.

Figure 1.2 – 2025 IRP Preferred Portfolio (Existing and Planned Resources)*



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The 2025 IRP preferred portfolio includes several transmission upgrades which increase transfer capability between southern Utah and the Wasatch Front and between Walla Walla and Yakima in Washington, as well as a series of upgrades that increase transfer capability between the Hemingway substation in Idaho, the Summer Lake Substation in southern Oregon, the planned Full Circle substation in Deschutes County, Oregon, and eventually connecting from Full Circle to Walla Walla in Washington. Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 1.1 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio. Currently, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 1.1 – Transmission Projects Included in the 2025 IRP Preferred Portfolio^{1,2}

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment (\$m)	Build (%)	From	To
2026	Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	Summer Lake	Hemingway
	Cluster 1/2/3: Walla Walla	0	0	393	328	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	628	64	100%	n/a	n/a
	Utah South - Wasatch Front: 138 kV reinforcement #2	200	200	200	12	100%	Utah South	Wasatch Front
2029	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 2 Area 19: Summer Lake to Central Oregon 500 kV	1,500	1,500	670	1,283	100%	Summer Lake	Central OR
	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	231	42	100%	n/a	n/a
2032	Cluster 1 Area 12: Southern Oregon	0	0	300	303	100%	n/a	n/a
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	518	372	100%	n/a	n/a
2039	Walla Walla - Central Oregon 500 kV	1,500	1,500	670	1,463	100%	Walla Walla	Central OR
Grand Total		4,250	4,250	5,404	4,169			

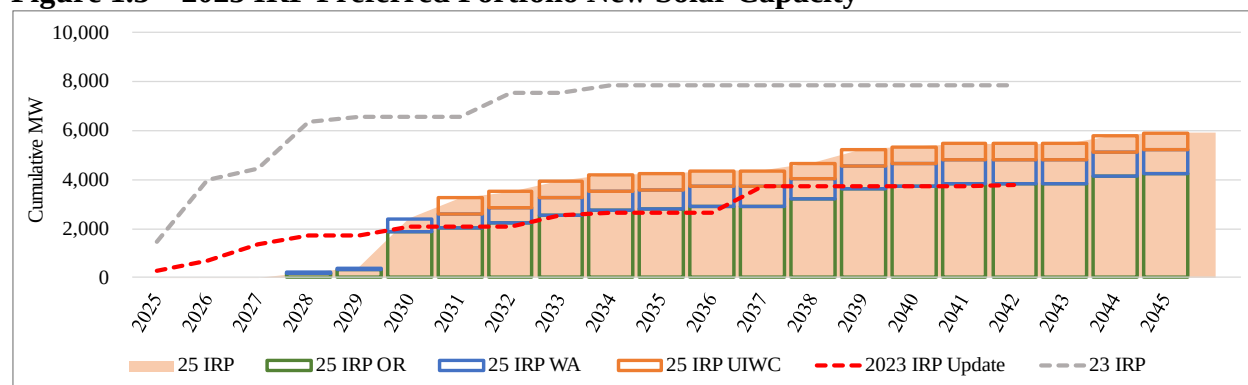
¹ Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

² Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

In Chapter 9 (Modeling and Portfolio Selection Results), a sensitivity analysis evaluates the impacts of significant new data center loads coming online in the 2027-2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

New Solar Resources

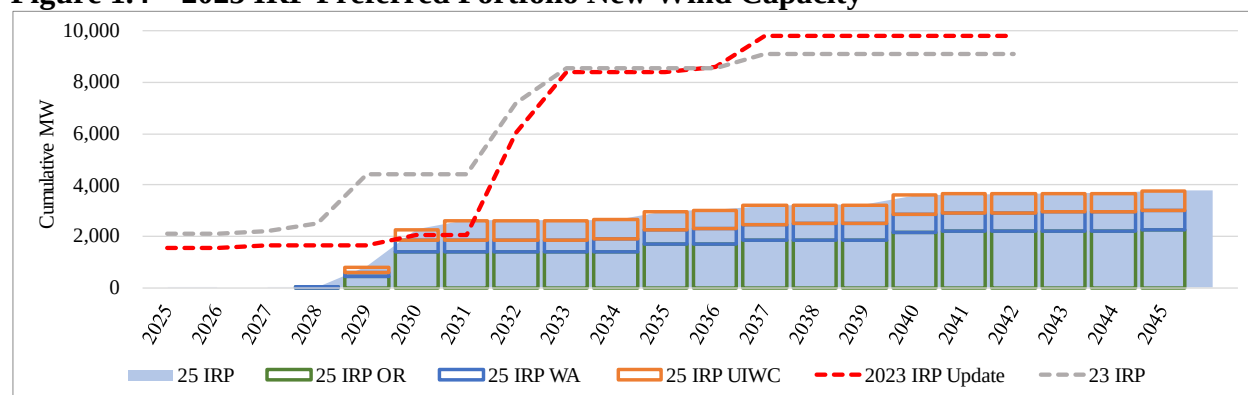
The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 1.3.

Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity

New Wind Resources

As shown in Figure 1.4, PacifiCorp’s 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

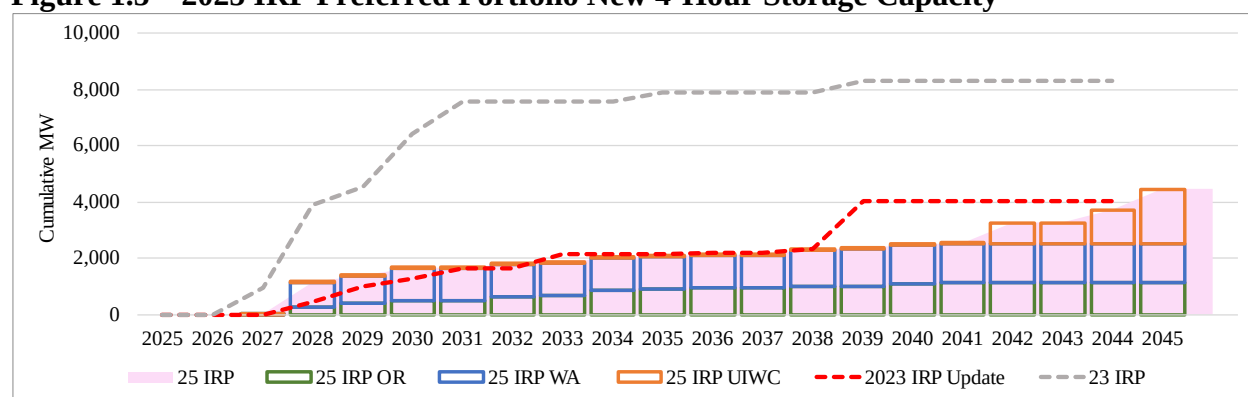
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

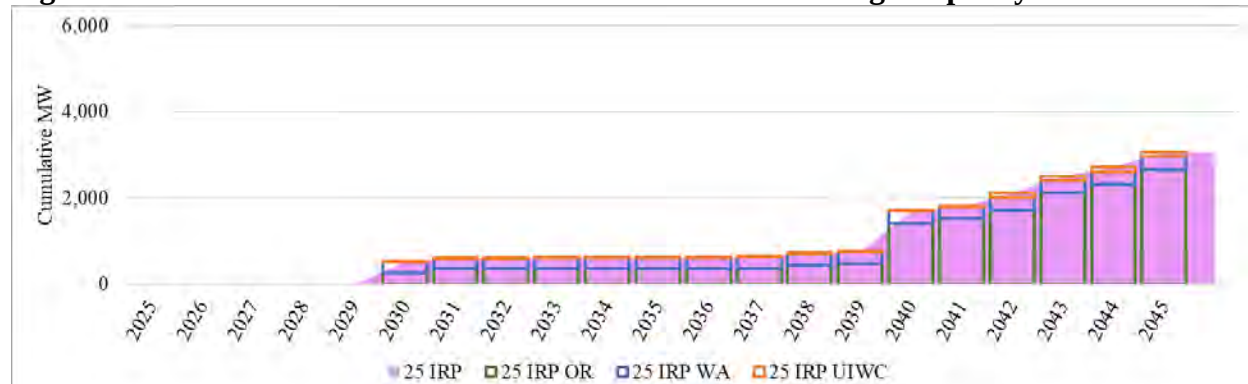
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of 100-hour iron air storage by the end of 2030, 616 MW by 2035 and 3,073 MW by 2045. Total storage selections, inclusive of both 4-hour and 100-hour resources, include a total of 7,524 MW of new storage.

Figure 1.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity^{1,2}



¹ The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.

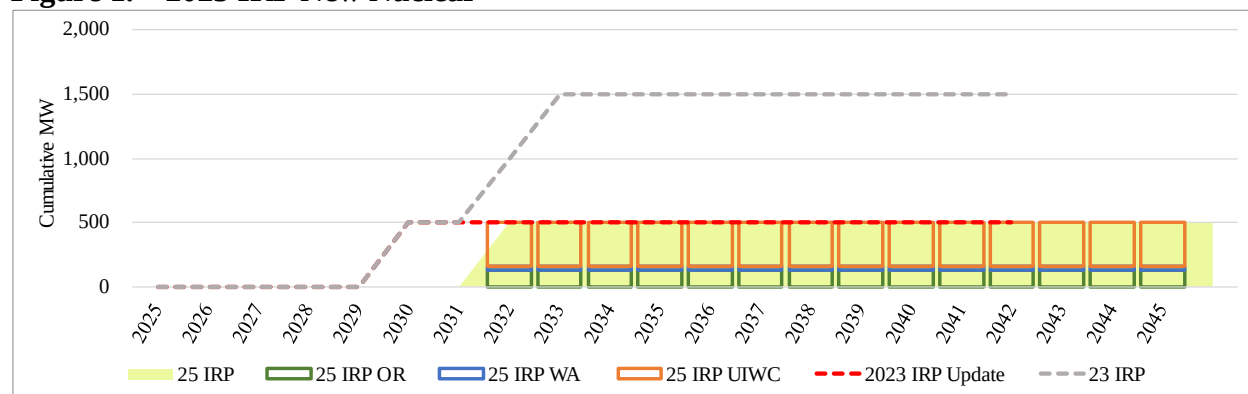
² The 2023 IRP and 2023 IRP Update totals shown in Figure 1.5 include a minimal amount of intermediate duration storage.

Figure 1.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity¹

¹The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

New Nuclear Resources

The 2025 IRP includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.7, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031.

Figure 1. – 2025 IRP New Nuclear¹

¹ While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

Demand-Side Management

PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP.

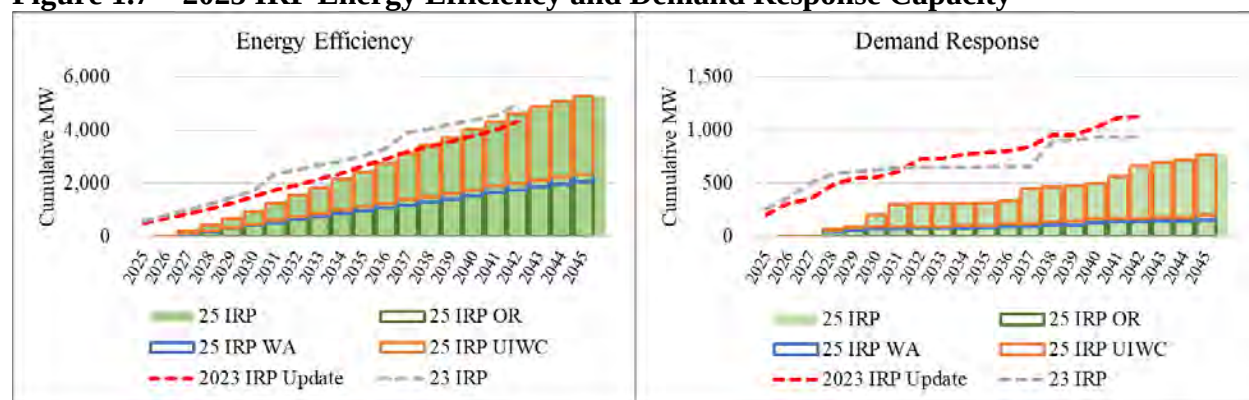
PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 12.3 percent

and forecasted coincident system peak is down 5.3 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.28 percent for load and 1.18 percent for peak. Changes to PacifiCorp's load forecast are driven by a shift in the 2025 IRP in which demand from new large customers is no longer included in the load forecast as those customers are expected to provide or pay for their necessary resources and transmission.

Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits. As shown in Figure 1.8, both energy efficiency and demand response show a lower trajectory in the latest forecast, however the trajectories continue to trend upward across the long-term planning horizon.

- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
 - 610 megawatts of energy efficiency from 2025 through 2028
 - 83 megawatts of demand response from 2025 through 2028

Figure 1.7 – 2025 IRP Energy Efficiency and Demand Response Capacity

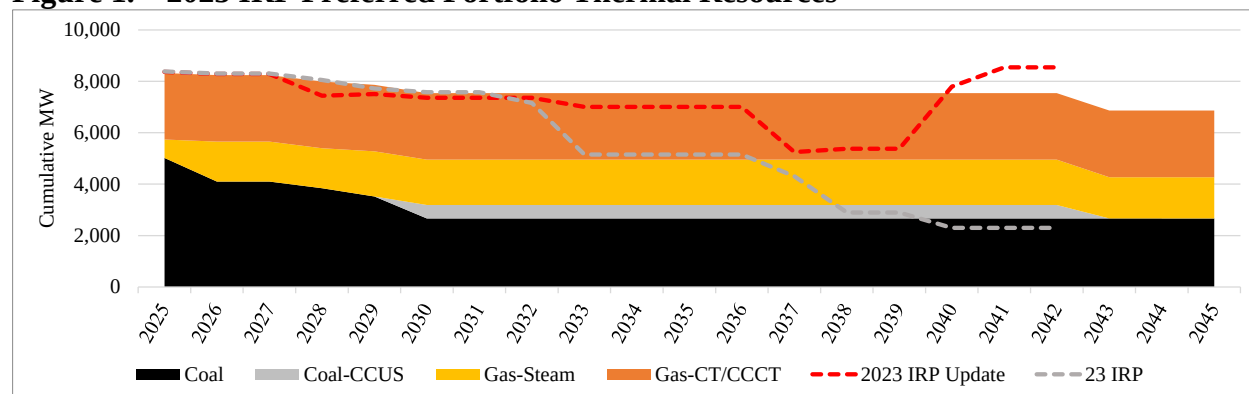


Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled the company to reduce fuel consumption and associated costs and emissions and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 1.9, the 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, exits PacifiCorp's share in 386

MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

Figure 1. – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP preferred portfolio is shown in Table 1.2. Also shown in Table 1.2 are the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

Table 1.2 – 2025 IRP Coal Resource Results Summary

Majority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	2032	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	2037 (Gas conversion 2024)
Jim Bridger 3 & 4	2042 (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	2042 (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039
Minority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	As Input		As Input
Colstrip 3	2025 (Transfer capacity to unit 4)		2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)		2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)		2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)		2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)		2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)		2027 (Assumed end of life)

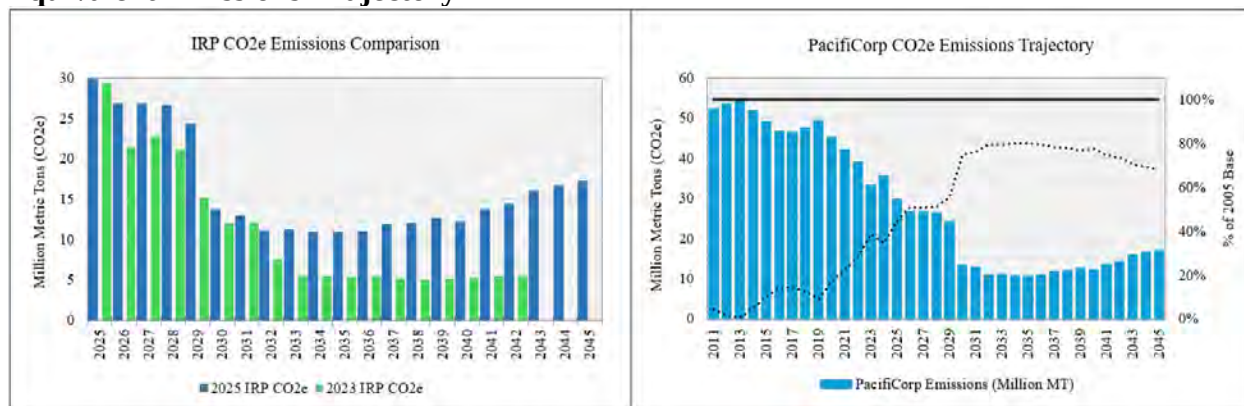
Carbon Dioxide Emissions

The 2025 IRP preferred portfolio demonstrates PacifiCorp's ongoing commitment to providing cost-effective clean energy solutions for its customers, continuing a trend of declining carbon dioxide (CO₂) and CO₂ equivalent (CO₂e) emissions over the next decade. Key drivers of this decline include PacifiCorp's participation in the Energy Imbalance Market (EIM), the ongoing transition to clean energy resources such as renewables, advanced nuclear, battery storage, and transmission, as well as compliance with Regional Haze regulations.

The chart on the left in Figure 1.10 compares projected annual CO₂e emissions between the 2025 IRP and 2023 IRP preferred portfolios. While the 2025 IRP emissions are projected to be slightly higher than those in the 2023 IRP, this difference stems from updates to modeling assumptions. The expected price-policy scenario in the 2025 IRP does not include a CO₂ price or the Ozone Transport Rule, both of which were included in the 2023 IRP. Increased emissions also result from higher unspecified market purchases, assigned a default emissions factor, although market-wide emissions are expected to decline with further renewable energy adoption. PacifiCorp is working with regulators to adjust this factor to reflect the evolving energy market landscape.

The chart on the right in Figure 1.10 presents historical emissions data, assigning emissions to unspecified market purchases, and indicates a long-term decline in system-wide CO₂e emissions compared to the company's baseline, with a slight increase toward the end of the planning horizon due to the factors discussed in more detail in Chapter 9.

Figure 1.8 – 2025 IRP Preferred Portfolio CO₂ Equivalent Emissions and PacifiCorp CO₂ Equivalent Emissions Trajectory¹



¹ PacifiCorp CO₂ equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO₂ equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO₂e/MWh) – emissions from sales are not removed.

Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 1.3 details specific 2025 IRP action items by resource category.

Table 1.3 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	<u>Colstrip Units 3 and 4:</u> PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	<u>Craig Unit 1:</u> PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	<u>Naughton Units 1 and 2:</u> PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	<u>Carbon Capture and Storage / Low Carbon Portfolio Standard:</u> PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming’s low carbon portfolio standard.
1e	<u>Regional Haze Compliance:</u> Following the resolution of first planning period regional haze compliance disputes, and the EPA’s determination of the states’ second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

1f	<u>Natrium™ Demonstration Project:</u> By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	<u>Ozone Transport Rule Compliance:</u> EPA finalized its approval of Wyoming’s cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. The Tenth Circuit granted a motion to stay EPA’s disapproval of Utah’s state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	<u>Natural Gas Emissions Compliance Strategies</u> The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon’s HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	<u>Federal Greenhouse Gas Emission Compliance:</u> EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	<u>Dave Johnston Units 1 and 2:</u> PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	<u>Customer Preference Request for Proposals:</u> PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	<u>2025 All-Source Request for Proposals:</u> PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.³ Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process. Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

³ Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

Action Item	3. Transmission Action Items
3a	<u>Local Reinforcement Projects</u> Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	<u>Gateway West Support</u> Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

Action Item	4. Demand-Side Management (DSM) Actions															
a	<u>Energy Efficiency & Demand Response Targets:</u> PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP. PacifiCorp will pursue cost-effective energy efficiency resources.															
	<table><tr><th>Year</th><th>First-Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr><tr><td>2025</td><td>595</td><td>92</td></tr><tr><td>2026</td><td>573</td><td>89</td></tr><tr><td>2027</td><td>597</td><td>209</td></tr><tr><td>2028</td><td>648</td><td>220</td></tr></table>	Year	First-Year Energy Efficiency (GWh)	Annual Capacity (MW)	2025	595	92	2026	573	89	2027	597	209	2028	648	220
	Year	First-Year Energy Efficiency (GWh)	Annual Capacity (MW)													
	2025	595	92													
	2026	573	89													
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	2028	648	220													
PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. ⁴ Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing. ⁵																
<table><tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr><tr><td>2025</td><td>18</td></tr><tr><td>2026</td><td>2</td></tr><tr><td>2027</td><td>0</td></tr><tr><td>2028</td><td>63</td></tr></table>	Year	Annual Incremental Capacity (MW)	2025	18	2026	2	2027	0	2028	63						
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⁴ A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

⁵ See Appendix D, Table D.3 for the split out between summer and winter capacity

Action Item	5. Market Purchases
5a	<u>Market Purchases:</u> PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: - Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. - Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. - Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	6. Renewable Energy Credit (REC) Actions
6a	<u>Renewable Portfolio Standards (RPS):</u> PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	<u>Renewable Energy Credit Sales:</u> Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

CHAPTER HIGHLIGHTS

- PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California.
- This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest.
- Regulatory staff, advocacy groups, and other interested parties influence the development of the IRP through a collaborative public input process.
- As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are made by PacifiCorp with respect to its obligations to customers, regulators, and shareholders.

INTRODUCTION

In recent integrated resource planning cycles, there has been increased focus on individual state jurisdictional outcomes aligned with both stakeholder and regulatory interest, and state legislation and rulemaking. To recognize and respect this trend, PacifiCorp's 2025 IRP enhances jurisdictional portfolio development and reporting leading to the integration of results into the preferred portfolio. Chapter 8 (Modeling and Portfolio Evaluation) describes the fundamental methodologies used to arrive at state-level initial portfolios and how they are subsequently integrated to form a single coherent plan.

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Chapter 9 (Modeling and Portfolio Selection Results), shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources (including iron-air technology with 100- hour storage duration), and advanced nuclear.¹

The 2025 IRP preferred portfolio is in addition to contracted resources, many of which are in Utah. The 100 MW Hornshadow I Solar and 200 MW Hornshadow Solar II facilities are set to come online in 2025, while two facilities combining solar and storage are set to come online in 2025 and 2026: Faraday with 525 MW solar and 150 MW storage and Green River with 400 MW solar and 400 MW storage. Finally, Oregon's Community Solar Program has ten small-scale solar facilities scheduled to come online in 2025 and 2026, totaling approximately 18 MW.

The 2025 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind, 5,492 MW of new solar and 7,668 MW of new storage resources.

New storage includes five battery facilities totaling 520 MW are projected to come online ahead of the peak summer season in 2026: Dominguez BESS (200 MW), Enterprise BESS (80 MW),

¹ See Chapter 7 (Resource Options)

Escalante BESS (80 MW), Granite Mountain BESS (80 MW) and Iron Springs BESS (80 MW). These signed battery storage contracts were committed since the filing of the 2023 IRP update.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission projects which are described in Volume I, Chapter 1 (Executive Summary), Chapter 4 (Transmission), and Chapter 9 (Modeling and Portfolio Selection Results).

Other significant analysis to support the 2025 IRP includes:

- An updated demand-side management resource conservation potential assessment
- A distributed generation study for PacifiCorp’s service territory
- A flexible reserve study
- An updated plant water consumption study
- An energy storage potential evaluation
- An assessment of grid enhancement technologies
- Historic weather years
- An updated load and resource balance

This chapter outlines the components of the 2025 IRP, summarizes the role of the IRP, and provides an overview of the public input process.

2025 Integrated Resource Plan Components

The basic components of PacifiCorp’s 2025 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities; Volume I, Chapter 3 (Planning Environment)
- Description of PacifiCorp’s transmission planning efforts and activities; Volume I, Chapter 4 (Transmission)
- Regional resource adequacy assessments, wildfire mitigation planning and the role of transmission in system reliability and incident recovery; Volume I, Chapter 5 (Reliability and Resiliency)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon; Volume I, Chapter 6 (Load and Resource Balance)
- Profile of resource options considered for addressing future capacity and energy needs; Volume I, Chapter 7 (Resource Options)
- Description of IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process; Chapter 8 (Modeling and Portfolio Evaluation)
- Presentation of IRP modeling results and selection of PacifiCorp’s preferred portfolio; Volume I, Chapter 9 (Modeling and Portfolio Selection Results)
- Presentation of PacifiCorp’s 2025 IRP action plan linking the company’s preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks; Volume I, Chapter 10 (Action Plan)

The IRP appendices, included as Volume II, contain the items listed below:

- Load Forecast (Volume II, Appendix A)
- Regulatory Compliance (Volume II, Appendix B)
- Public Input Process (Volume II, Appendix C)
- Demand-Side Management (Volume II, Appendix D)
- Grid Enhancement (Volume II, Appendix E)
- Flexible Reserve Study (Volume II, Appendix F)
- Plant Water Consumption Study (Volume II, Appendix G)
- Stochastics (Volume II, Appendix H)
- Capacity Expansion Results (Volume II, Appendix I)
- Capacity Contribution (Volume II, Appendix K)
- Distributed Generation Study (Volume II, Appendix L)
- Stakeholder Feedback Forms (Volume II, Appendix M)
- Washington Clean Energy Action Plan (Volume II, Appendix O)
- Oregon Clean Energy Update (Volume II, Appendix P)
- Renewable Portfolio Implementation Plan (Volume II, Appendix R)
- Acronyms (Volume II, Appendix Z)

PacifiCorp is also providing supporting workpapers for the 2025 IRP. These electronically provided materials support and provide additional details for the analysis described within the document. Supporting workpapers are generated for public, confidential, and highly confidential data to be provided as appropriate to each recipient. Confidential and highly confidential data access are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings. The “Highly Confidential” workpaper category, adopted in the prior 2023 IRP planning cycle, allows the company to provide the maximum amount of access to parties who are not participants in commercial developments or otherwise have direct conflicts of interest regarding commercially sensitive information.

The Role of PacifiCorp’s Integrated Resource Planning

PacifiCorp’s IRP establishes a proxy resource plan capable delivering adequate and reliable electricity supply at a reasonable cost and in a manner “consistent with the long-run public interest.”² In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp’s long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp’s preferred portfolio of generation, demand-side, and transmission resources.

² The Public Utility Commission of Oregon and Public Service Commission of Utah cite “long-run public interest” as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

Public Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized held nine public input meetings, spanning one or two days each, to facilitate information sharing, collaboration, and expectations for the 2025 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage is accessible using the following link:

www.pacifiCorp.com/energy/integrated-resource-plan.html

Messages relevant to PacifiCorp’s IRP can sent to the following email address:

irp@pacifiCorp.com

Additionally, a stakeholder feedback form provides opportunities for stakeholders to submit additional input and ask questions throughout the 2025 IRP public input process. The submitted forms, as well as PacifiCorp’s responses to these feedback forms are located on the PacifiCorp’s IRP website:

www.pacifiCorp.com/energy/integrated-resource-plan/comments.html

Summaries of stakeholder feedback forms received, and company responses were provided throughout the public input meeting series and are also available in Appendix M (Stakeholder Feedback Forms). In the 2025 IRP, links to stakeholder feedback forms are provided in footnotes to further tie together stakeholder feedback with the development of the filed IRP. Appendix C (Public Input Process) reports additional details regarding engagement for the 2025 IRP.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Federal and state tax credits continue to encourage the procurement of wind and solar resources, which will likely dominate U.S. capacity additions for the next decade. Flexible generation, transmission, new storage technologies, and market design changes will need to better integrate these resources into the grid.
- The federal Inflation Reduction Act (IRA) was enacted on August 16, 2022,, creating technology specific tax credits for projects placed in service after December 31, 2021, and technology neutral tax credits for projects placed in service after December 31, 2024. Eligible resources include any technology that generates electricity and does not emit greenhouse gases. The IRA is modeled in all 2025 IRP studies. As of December 2024, the future of some provisions of the IRA remains unknown under the new administration.
- 2024 saw significant new environmental regulation with potential impacts to PacifiCorp’s generation resources. These included Greenhouse Gas (GHG) emission standards for existing coal-fired and new gas-fired plants, Mercury and Air Toxics Standards (MATS) revisions, Effluent Limitations Guidelines revisions, Coal Combustion Residuals legacy rule, and the NEPA Phase 2 rule.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of retail electricity sales in Washington be 100% renewable and non-emitting by 2045. PacifiCorp filed its inaugural Clean Energy Implementation Plan (CEIP) in December 2021, and expects to file its second CEIP in October 2025, detailing the company’s action plan for the next four-year period.
- In 2021, Washington passed the Climate Commitment Act, which established a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp’s obligations under CETA, and utilities that are subject to CETA are allocated allowances commensurate with emissions associated with Washington retail load at no cost. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. The 2025 IRP includes modeling to support House Bill 2021 which will be expanded upon in PacifiCorp’s Oregon Clean Energy Plan submission to be filed within 180 days of the 2025 IRP.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary western energy imbalance market (WEIM) November 1, 2014, the first western energy market outside of California. Since inception, The WEIM’s footprint has grown significantly, generating \$3.4 billion in monetary benefits to customers of participating entities. (\$1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing

authority area. Building on the success of WEIM, in 2022 PacifiCorp, along with CAISO and other stakeholders, collaborated to develop a market design for an extended day ahead market (EDAM) that CAISO plans to launch in 2025.

Introduction

This chapter profiles the major external influences that affect PacifiCorp’s long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry include resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation, the role of emerging technologies, and the net costs of renewables and battery technologies also factor into the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a further significant issue in the power industry and facing PacifiCorp continues to be planning for eventual, but highly uncertain, climate change policies. This chapter provides discussion on climate change policies as well as a review of significant policy developments for currently regulated pollutants. This chapter also provides updates on the status of renewable portfolio standards and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp’s system operates in conjunction with a multifaceted market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by ensuring that resources with the lowest operating cost are serving demand throughout the region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to minimize costs and to keep its supply portfolio in balance with customers’ expectations. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp – or any other load serving entity – would need to construct or own an unnecessarily large margin of supplies that would go unused in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation can come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits and improved technology performance have continued to place wind and solar energy generators “in the money” in areas of high resource potential. As such, wind and solar will continue to play a dominant role in power supply options over the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, evolving storage technologies, and market design changes.

Regarding transmission, there are long-haul, renewable-driven transmission projects in advanced development in the U.S. WECC. These transmission lines ultimately connect areas of high renewable energy potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's 416-mile high-voltage 500-kilovolt (kV) Gateway South project and the 59-mile high-voltage 230-kV Gateway West Segment D.1 project, brought in-service in late 2024. These transmission projects will provide greater system-wide flexibility transferring energy from Wyoming to load centers located in Utah.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. As of 2022, nine states had implemented energy storage targets or mandates, with action being considered in at least one other.¹ In California, the Elkhorn Battery project became fully operational for Pacific Gas & Electric (PG&E) in April of 2022. The Moss Landing project in Monterey County includes 182.5 MW of Tesla Megapack energy storage.² Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Utah, Hawaii, Arizona, Nevada, California, and Texas.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets³. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barriers to the participation of electric storage resources in certain organized wholesale markets. PacifiCorp continues to evaluate the cost effectiveness of several energy storage systems, including pumped storage, stand-alone Li-ion batteries, flow batteries, iron-air storage and other long-duration storage, as well as energy storage co-located with generating resources.

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the Energy Imbalance Market (EIM). The EIM became operational November 1, 2014, and since that time has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho

¹ California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.

² In addition to Elkhorn, PG&E has contracts for more than 3,330 MW of battery storage being deployed statewide through 2024, more than 900 MW of which has been connected to California's electric grid. The Mercury News, March 8, 2023; [PG&E ushers in landmark Tesla battery energy storage system at Moss Landing \(mercurynews.com\)](https://www.mercurynews.com/2023/03/08/pg-e-ushers-in-landmark-tesla-battery-energy-storage-system-at-moss-landing/)

³162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission; Organizations and Independent System Operator* (Issued February 15, 2018)

Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico, Avista Utilities, Tucson Electric Power, Turlock Irrigation District, Tacoma Power, Bonneville Power Administration, Avangrid Renewables, El Paso Electric, and Western Area Power Administration join the EIM. Black Hills Power plans to join the EIM in 2026. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participating entities, PacifiCorp is also participating in the CAISO stakeholder process to establish an Extended Day-Ahead Market (EDAM), which is currently in the phase of implementation activities and expected to onboard participants in 2026.

As with all markets, electricity markets face a wide range of uncertainties. In February 2021, winter storm Uri caused an unprecedented 24.1% decline in marketed natural gas production in Texas, a drop of 186.7 billion cubic feet (Bcf) compared to the previous month. This decline contributed to the largest monthly decline in natural gas production on record in the Lower 48 states. This weather event caused widespread disruptions in energy supply and demand, including extended electric power blackouts in Texas.

The Western United States experienced an excessive heat event during the first week of September 2022. As a result, record temperatures were recorded on September 4th through September 7th, reaching as high as 114° F in Sacramento, California, 110° F in Burbank, California, and 107° F in Salt Lake City, Utah. With these record setting temperatures, the West saw a widespread surge in electricity demand and correspondingly tight supply conditions. Maintaining reliability across the region during this period was a testament to the benefits of energy markets, geographic diversity across the West, and conservation efforts during extreme heat events.

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability, and any number of data services are available that track the status of new resource additions⁴. In NERC's latest release, the WECC region was classified as "elevated risk", in which shortfalls may occur in extreme conditions.

The Western Resource Adequacy Program (WRAP)⁵ will also provide market participants insight into potential supply constraints and give participants some assurance that sufficient resources have been procured for the program to maintain a 1-in-10-year loss of load expectancy standard. In addition to binding load and resource showings for the upcoming season, the WRAP will conduct advisory two- and five-year resource adequacy assessments for the footprint that will allow participants to better plan for the future needs of their systems. The Forward Showing program will ensure participants procure sufficient resources to meet a footprint wide reliability standard, and the Ops Program will facilitate transfers between entities in a resource deficit and those with excess resources.

⁴ 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment

⁵ <https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program>

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Natural gas-fired generation and gas prices have been a critical determinant of western electricity prices, and this is expected to continue over the term of this plan’s decision horizon. While the share of natural gas in the resource western resource mix is expected to fall by the end of the horizon because of increasing renewable resource buildout, natural gas will remain on the margin in many hours, particularly critical hours when renewable resource output is limited. Another critical uncertainty that weighs heavily on the 2025 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp’s official forward price curve (OFPC) does not assume a federal carbon dioxide (CO₂) policy, but other price scenarios developed for the IRP consider impacts of potential future federal and state policies which drive additional costs and restrictions of emissions. However, PacifiCorp’s OFPC does include enforceable state climate programs that have been signed into law⁶.

Power Market Prices

Mild weather, strong production, and limited exports caused high storage levels in the fossil gas market, resulting in low gas prices throughout 2024. Low fuel prices coupled with mild demand led to an annually averaged 34% decrease in on-peak spot prices across the Non-CAISO WECC trading hubs in 2024, as seen in Table 3.1.

Table 3.1 - 2023 and 2024 Monthly Average On-Peak Spot Prices (\$/MWh)

Month	2023	2024	Difference	Percent
Jan	135.23	137.27	2.05	2%
Feb	84.41	41.95	-42.46	-50%
Mar	76.51	25.05	-51.46	-67%
Apr	79.53	18.57	-60.97	-77%
May	21.60	20.48	-1.13	-5%
Jun	38.87	31.13	-7.74	-20%
Jul	93.02	67.88	-25.13	-27%
Aug	88.59	48.50	-40.09	-45%
Sep	51.76	52.55	0.78	2%
Oct	78.57	46.24	-32.33	-41%
Nov	70.90	35.19	-35.71	-50%
Dec	52.12	47.50	-4.62	-9%
Annual	72.59	47.69	-24.90	-34%

*As of December 16, 2024

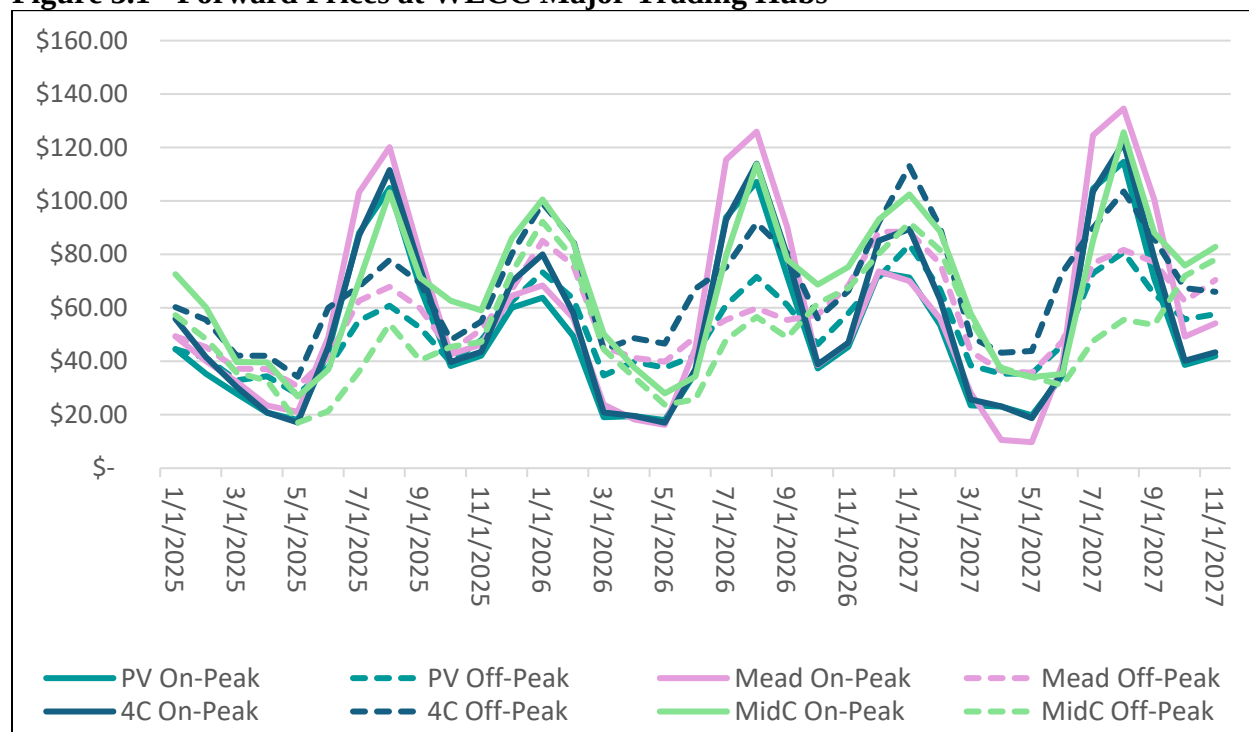
Source: SNL

Barring major geo-political disruptions or other sustained economic drivers, forecasted wholesale power prices are expected to increase slightly relative to 2024 peaks and will follow seasonal weather trends with higher prices over the summer months. Broker price spreads indicate August

⁶ California and Washington carbon allowance price forecasts are applied when appropriate. Washington allowance prices assumed the forecast published by Vivid Economics, commissioned by Washington Department of Ecology as part of its CCA Regulatory Impact Analysis for WAC 173-446, which was the best available information at the time of modeling. Available at <https://apps.ecology.wa.gov/publications/documents/2202047.pdf>.

2025 On-Peak power prices at Palo Verde, Mead, Four Corners, and Mid-Columbia are all trading around \$105-\$120 per MWh.

Figure 3.1 - Forward Prices at WECC Major Trading Hubs



Source: OTC, Siemens PTI

Table 3.2 reports the quarterly on-peak and off-peak price spread across the major WECC hubs, driving the peaks and valleys observed in Figure 3.1 above.

Table 3.2 - 2025-2027 Forward Price Spread (\$/MWh)

	Palo Verde		Mead		4 Corners		Mid-Columbia	
Date	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
1/1/2025	\$ 44.57	\$ 44.53	\$ 49.32	\$ 49.35	\$ 55.87	\$ 60.23	\$ 72.60	\$ 57.25
5/1/2025	\$ 18.04	\$ 27.62	\$ 21.12	\$ 30.62	\$ 17.05	\$ 34.20	\$ 26.81	\$ 17.02
8/1/2025	\$104.89	\$ 60.81	\$120.14	\$ 67.85	\$111.56	\$ 77.93	\$103.20	\$ 53.99
11/1/2025	\$ 42.14	\$ 47.94	\$ 46.28	\$ 51.86	\$ 43.55	\$ 54.89	\$ 59.08	\$ 47.28
1/1/2026	\$ 63.81	\$ 73.32	\$ 68.41	\$ 85.12	\$ 79.99	\$ 99.17	\$100.52	\$ 92.19
5/1/2026	\$ 17.98	\$ 37.62	\$ 16.18	\$ 39.84	\$ 17.00	\$ 46.59	\$ 27.99	\$ 23.71
8/1/2026	\$107.13	\$ 71.57	\$125.96	\$ 59.86	\$113.94	\$ 91.72	\$113.74	\$ 56.61
11/1/2026	\$ 45.38	\$ 57.92	\$ 46.83	\$ 68.32	\$ 46.89	\$ 66.32	\$ 75.27	\$ 67.37
1/1/2027	\$ 71.36	\$ 83.56	\$ 70.01	\$ 88.44	\$ 89.44	\$113.02	\$102.48	\$ 91.87
5/1/2027	\$ 19.80	\$ 35.40	\$ 9.73	\$ 35.70	\$ 18.71	\$ 43.83	\$ 34.07	\$ 34.10
8/1/2027	\$114.63	\$ 80.80	\$134.58	\$ 81.71	\$121.91	\$103.55	\$125.72	\$ 55.51
11/1/2027	\$ 41.95	\$ 57.62	\$ 54.19	\$ 70.41	\$ 43.35	\$ 65.97	\$ 82.83	\$ 78.10

Source: OTC

Power Market Dynamics

Non-CAISO WECC Generation and Capacity Mix

The generation mix in the non-CAISO WECC region reflects the influence of state RPS (renewable portfolio standard) and emissions policies. In 2023, natural gas resources provided about 31% of generated energy followed by hydro at 22%, coal at 18%, and wind at 12%. Natural gas and coal share is expected to decrease slightly, with non-hydro renewables expected to replace this energy throughout 2030.

Figure 3.2 - National RPS Targets

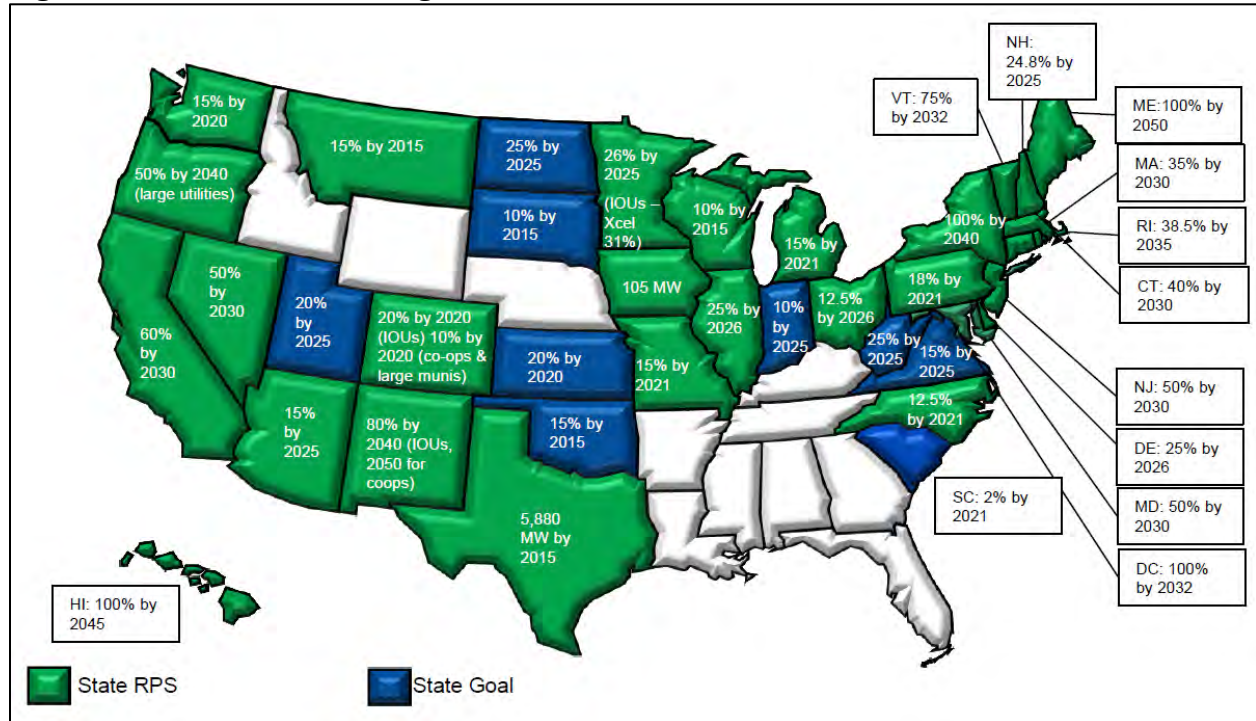
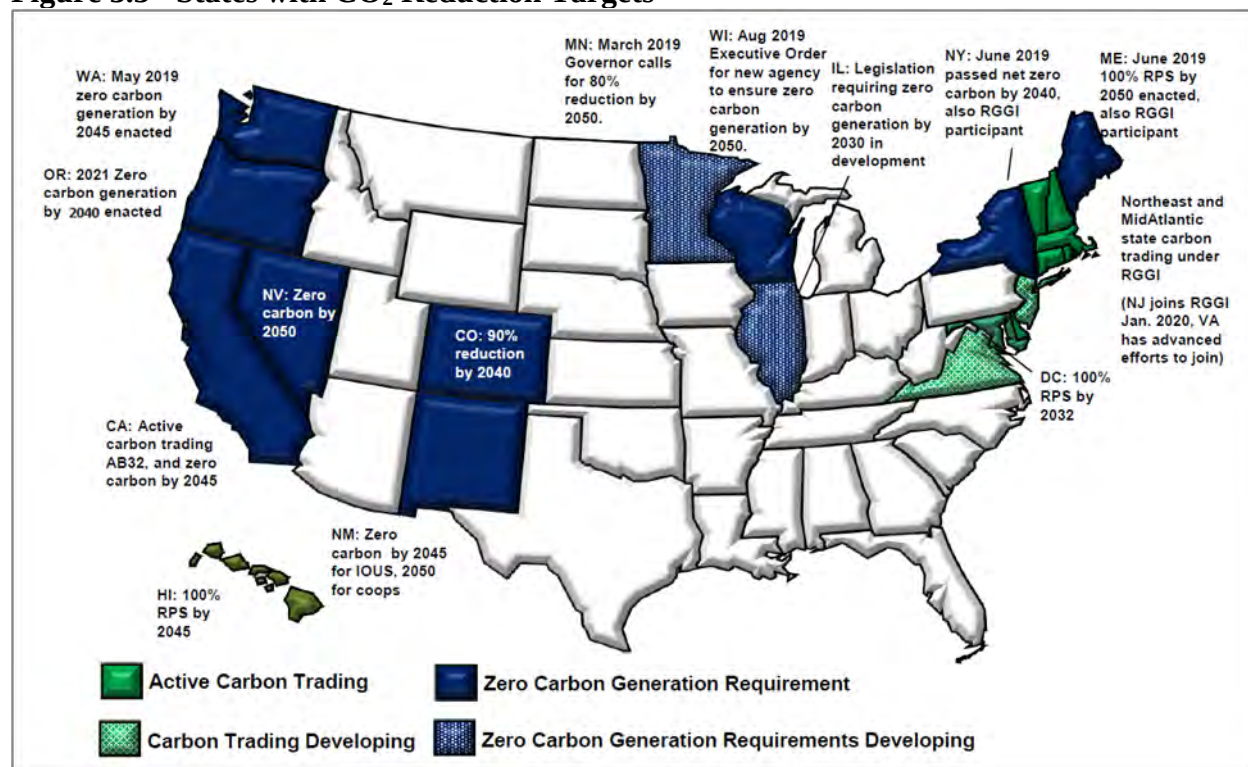
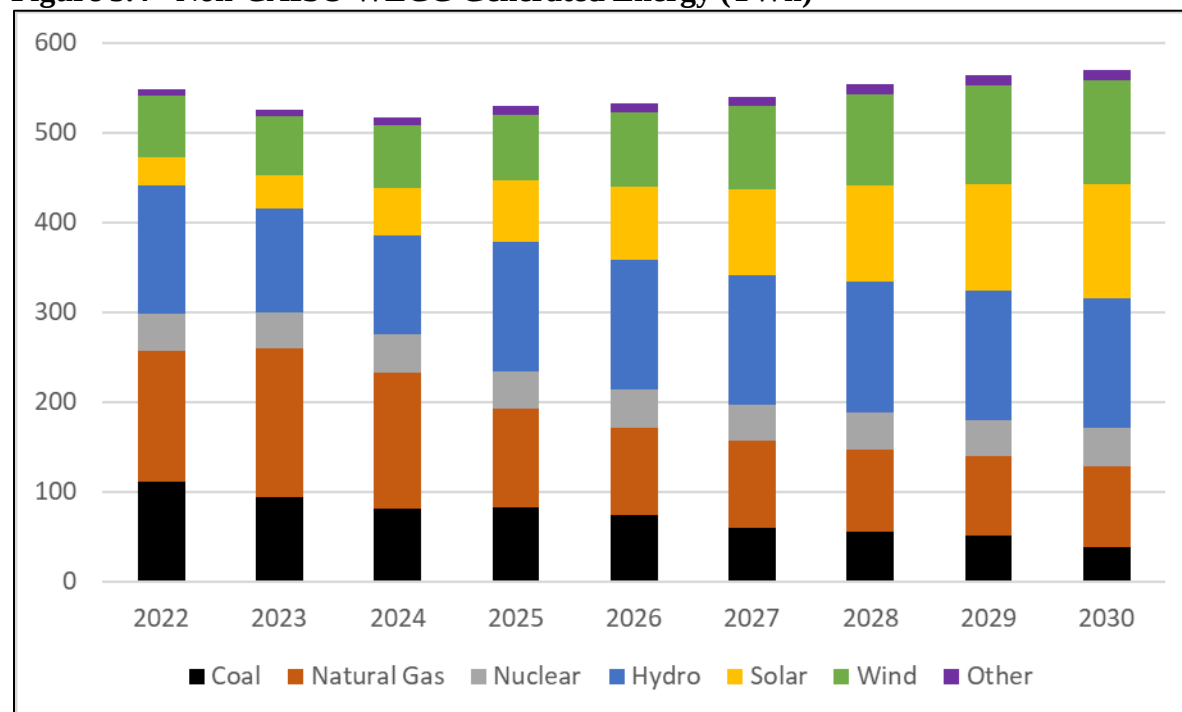


Figure 3.3 - States with CO₂ Reduction Targets

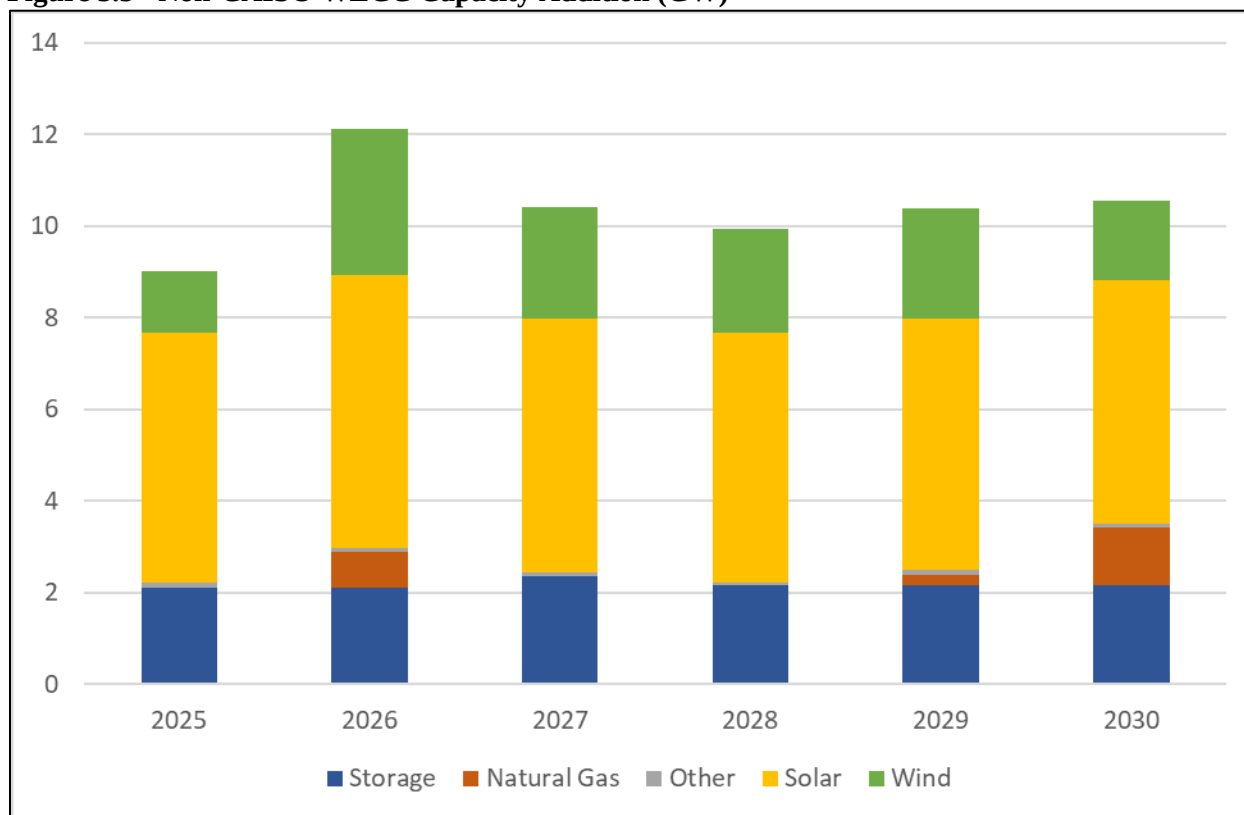
Source: Siemens PTI

Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)

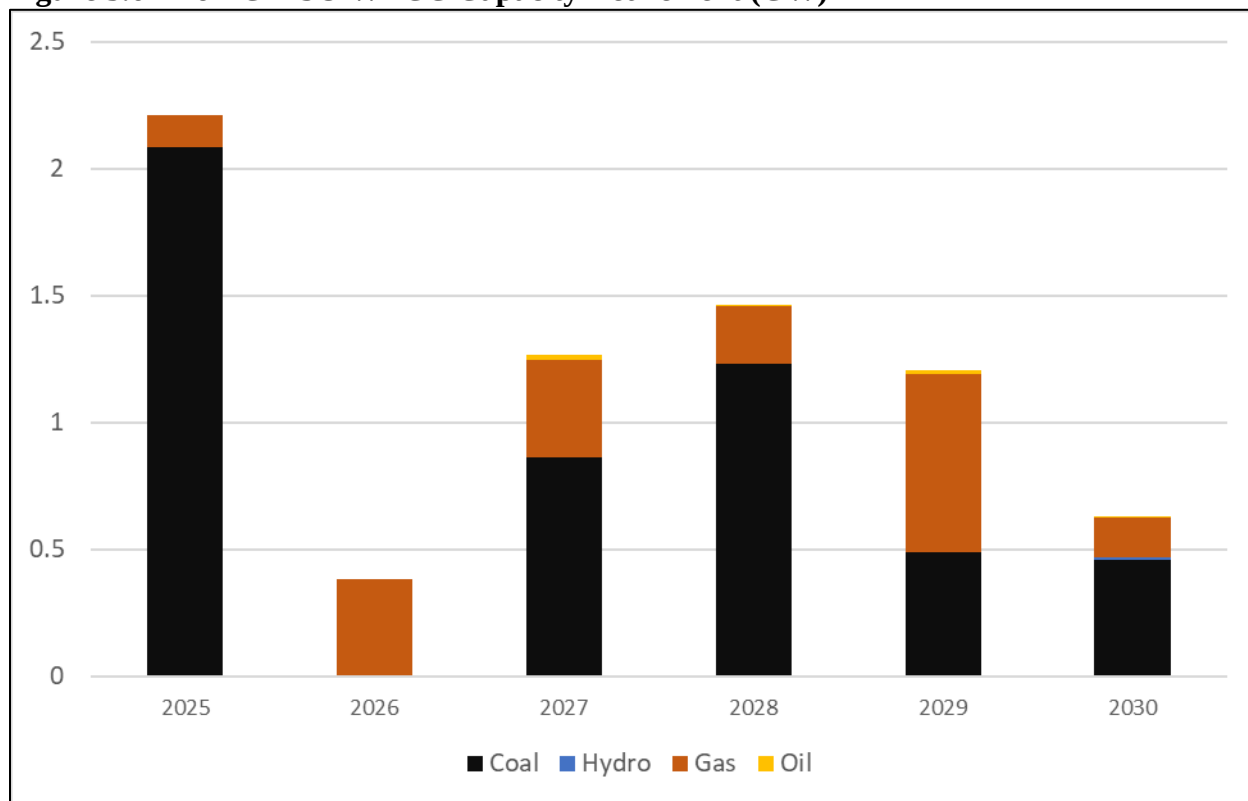
Source: IHS Markit, SNL, Siemens PTI

In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage capacity additions have also been significant, with 1.4 GW of storage capacity brought online in 2022 and 1.9 GW online through October 2024. Minimal fossil fuel capacity came online in 2023, and that trend may continue through 2030 if carbon reduction goals continue to drive renewable additions.

Figure 3.5 - Non-CAISO WECC Capacity Addition (GW)



Source: IHS Markit, SNL, Siemens PTI

Figure 3.6 - Non-CAISO WECC Capacity Retirement (GW)

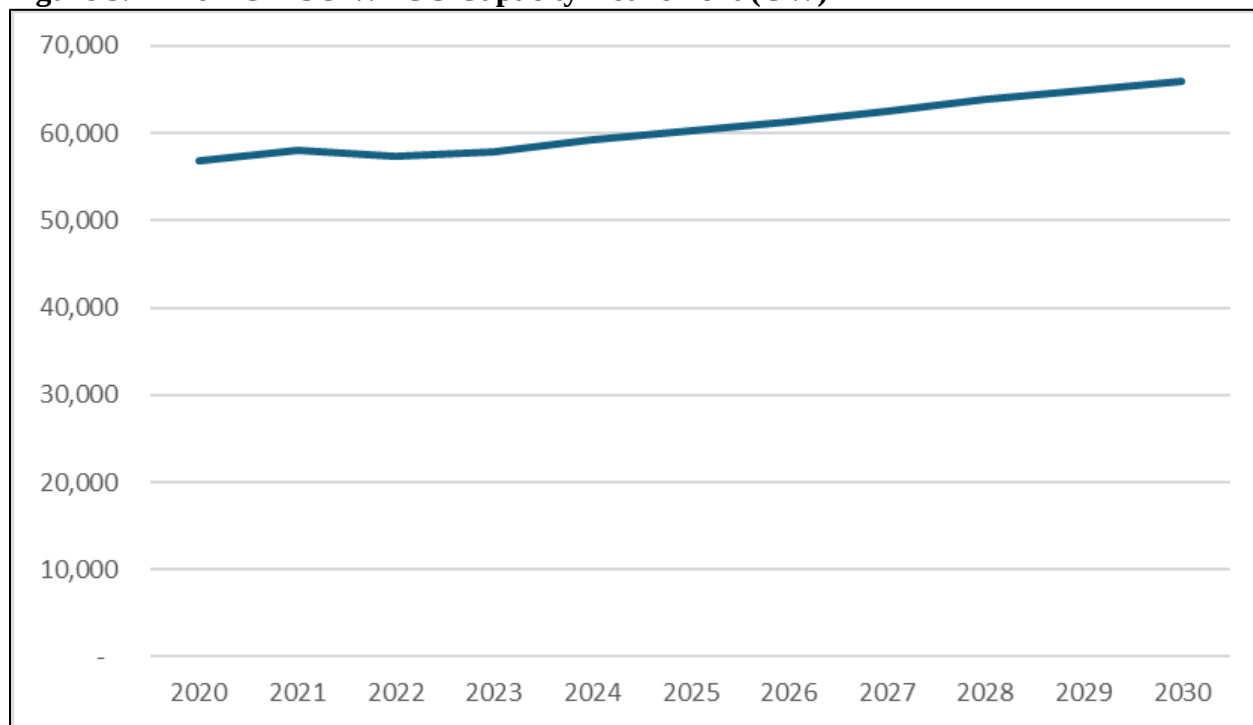
Source: IHS Markit, SNL, Siemens PTI

Emissions and Environment

Cool weather and low natural gas prices in 2023 led to decreased emissions and low demand for allowances. In addition, the finalization of the Good Neighbor Plan in March 2023 contributed to an 18% NO_x emission reduction within the ten implemented states. On April 25, 2024, the U.S. Environmental Protection Agency (EPA) unveiled its final rule to regulate greenhouse gas (GHG) emissions from power plants under Section 111 of the Clean Air Act. The updated rule mandates that coal-fired baseload units achieve 90% carbon capture and storage (CCS) by 2032. It also provides an option for plants scheduled for retirement by 2039 to co-fire up to 40% natural gas as a transitional measure to reduce emissions.

Non-CAISO WECC Demand Forecast

After years of relatively stagnant demand nationwide, recent additions of loads—such as data centers, manufacturing facilities, and electrification initiatives—have caused load forecast projections to surge. According to regional outlooks, the non-CAISO WECC region is anticipated to experience a compound annual growth rate (CAGR) of 1.8% from 2024 to 2030. Recent Integrated Resource Plans (IRPs) from utilities across the region, including Nevada Energy, Arizona Public Service, show higher-than-usual load growth expectations, largely due to significant new load additions expected to come online in the coming years.

Figure 3.7 - Non-CAISO WECC Capacity Retirement (GW)

Source: Siemens PTI

Forward Influence of the IRA

In August 2022, the US Congress Passed the Inflation Reduction Act (“IRA”). The notable near-term impacts of the IRA are to allow all non-carbon emitting resources and energy storage resources to select either production tax credits or investment tax credits. Production tax credits are expected to provide greater benefits for wind, solar, and many other generation technologies and may contribute to suppressed market prices during periods of renewable resource oversupply as generators may be willing to accept negative attempt to avoid losing production tax credits.

As of November 2024, the future of some provisions of the IRA remains uncertain under the new administration. While a repeal of the IRA is unlikely as that would require congressional approval, the Trump administration could slow the payment of grants and loans or rescind or modify regulations and guidance issued to date on how to implement provisions of the IRA. This action would make it difficult for companies and individuals to plan with certainty with respect to claiming tax credits for investments in new renewable and non-emitting technologies including EVs and offshore wind. A US policy movement away from federal climate initiatives could also enhance China’s global dominance in clean energy industries such as solar panels and EVs, while potential new import tariffs could hinder the deployment of energy generation and other technologies supported by the IRA.

Natural Gas Prices

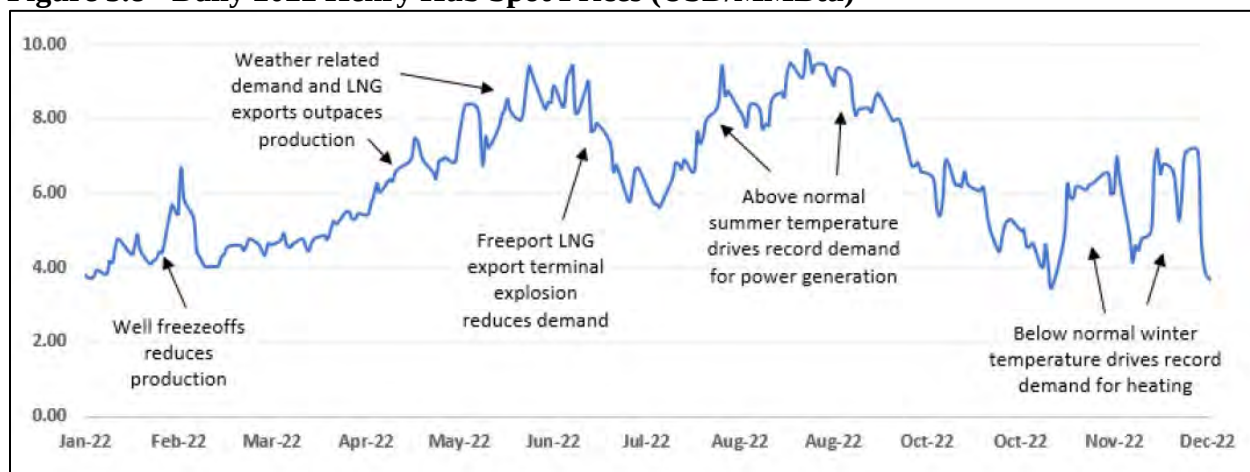
2022 Summary

In the first quarter of 2022, demand for natural gas surpassed production in the US due to well freeze-offs in January and February. High withdrawals of natural gas from storage during this time

caused prices to increase. Continued demand for U.S. liquefied natural gas (LNG) exports into Europe due to Russia's war on Ukraine, as well as increasing weather-driven demand, caused upward price pressure.

In the second quarter, starting in May, weather-related demand for natural gas for electric generation as well as uncertainty around storage injections led to an increase in natural gas prices. The Henry Hub spot prices, as you can see in Figure 3.8, rose to over \$9/MMBtu. However, in late June, the second largest LNG export terminal in the US, accounting for 17% of total LNG export capacity, suffered a tragic explosion which took it offline. As such prices fell to below \$6/MMBtu. For the first half of 2022, the U.S. was the largest exporter of LNG in the world, and over two-thirds of the cargoes headed to Europe.

Figure 3.8 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)



Source: S&P Global, Siemens PTI

The price of natural gas quickly rebounded in July and August, because of a heat wave in many parts of The U.S., which resulted in record high demand for power generation. The Western States of the U.S. were particularly affected by this not only due to higher demand for power but also from reduced supply of hydro resources due to continuing drought.

Despite these challenges, US Lower 48 supply surpassed pre-pandemic levels in the first half of 2022, led by gas production growth as higher prices spurred increased rig activity. Rig activity was more pronounced in low-cost basins such as Permian (Texas/New Mexico) and Haynesville (Louisiana) as they have better infrastructure to access demand areas.

Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d. Natural gas delivery in the US is complex due to the number of supply sources and pipelines that transport gas to various hubs around the country. As such prices at Henry Hub do impact prices in the West as the same source that supplies the gulf coast region can also supply the Western states.

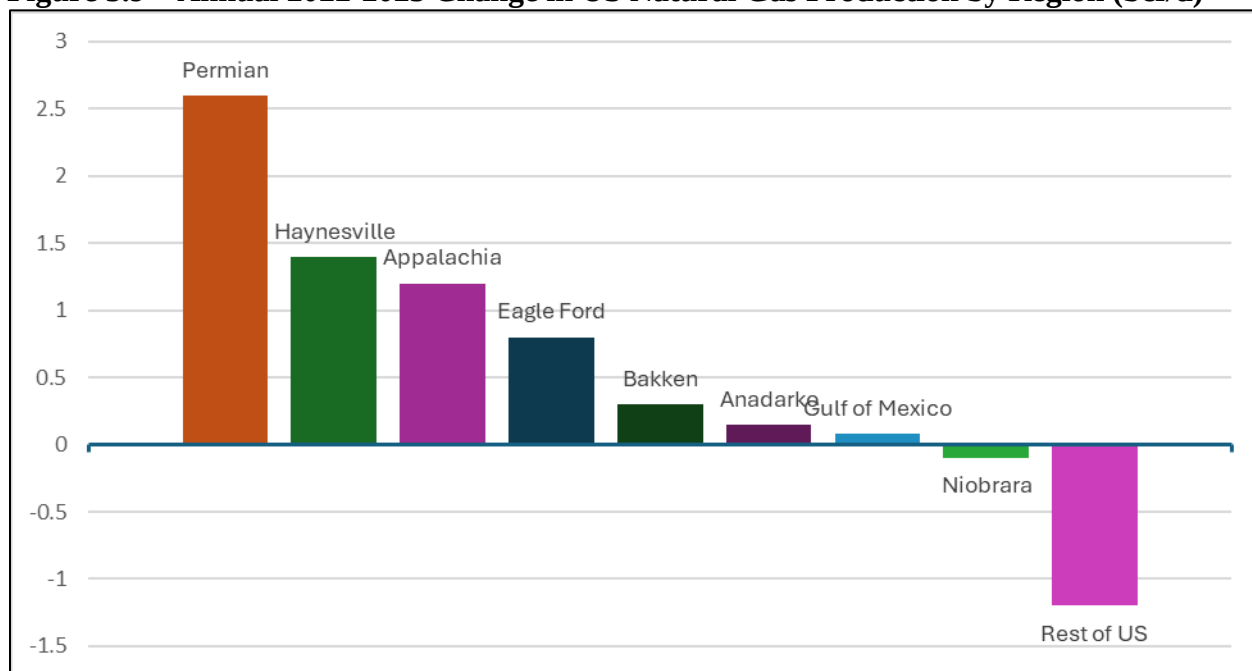
However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased

demand for natural gas. This higher demand, the constraint on pipelines, and reduce storage levels contributed to significantly higher prices that the west is currently experiencing.

2023 Summary

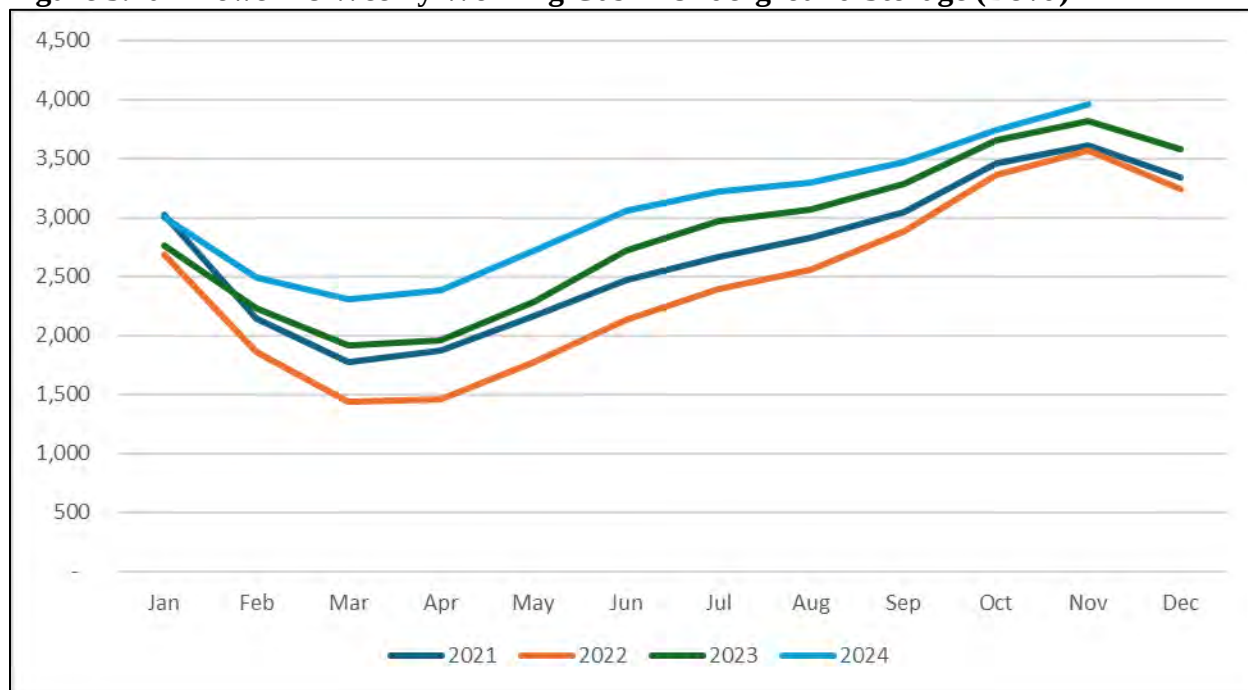
In 2023, U.S. natural gas prices saw a significant drop compared to the previous year, with the benchmark Henry Hub price averaging \$2.57 per million British thermal units (MMBtu), a steep 62% decline from 2022. This price decline was largely driven by record-high production levels, which reached an average of 104 billion cubic feet per day (Bcf/d), 4% higher than the previous year. This production increase was particularly notable in key regions like the Permian, Haynesville, and Appalachia, where technological advancements and strong oil prices supported higher outputs.

Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



Source: EIA, Siemens PTI

Weather played a critical role in shaping the market. Warmer-than-average winter temperatures in January and February significantly reduced demand for natural gas in residential and commercial heating, particularly in the Midwest and Northeast, where natural gas is a primary heating source for most households. These mild conditions led to the lowest winter consumption levels in seven years and kept storage inventories above the five-year average for much of the year, further pressuring prices downward.

Figure 3.10 – Lower 48 Weekly Working Gas in Underground Storage (Bcf/d)

Source: EIA, Siemens PTI

On the West Coast, natural gas prices were influenced by unique regional factors. Severe winter storms early in the year disrupted supply chains and increased demand for heating in California and surrounding areas, creating temporary price spikes in localized markets. However, as weather conditions stabilized and milder temperatures returned, these pressures eased, and West Coast prices aligned more closely with the broader national trend of declining natural gas costs.

While domestic demand for natural gas remained relatively flat overall, there were notable increases in liquefied natural gas (LNG) exports, which rose by 12%, and pipeline exports, which increased by 9%. These exports helped offset some of the impact of reduced residential and commercial consumption. Despite this, the overall supply-demand balance remained tilted toward oversupply, with storage levels high and production continuing at record rates.

Adding to the dynamics was the gradual recovery of the Freeport LNG facility, which had been offline due to an outage in 2022 and returned to full operation in 2023. While this increased export capacity, it did not significantly alter the broader market trajectory, as domestic production remained the dominant factor. Prices remained under \$3.00/MMBtu for most of the year, with May marking the lowest monthly average at \$2.19/MMBtu, illustrating how robust supply and subdued demand combined to create one of the least volatile years for natural gas in recent history.

2024 Summary

In 2024, U.S. natural gas prices remained relatively low, with the Henry Hub averaging under \$3.00 per MMBtu through November. Production levels, while slightly reduced compared to the previous year, remained robust at an average of 103.3 Bcf/d according to EIA. This marked the first annual production decline since 2020, driven by lower drilling activity because of subdued spot prices. Despite this, overall supply continued to outpace domestic demand, keeping inventories above the five-year average.

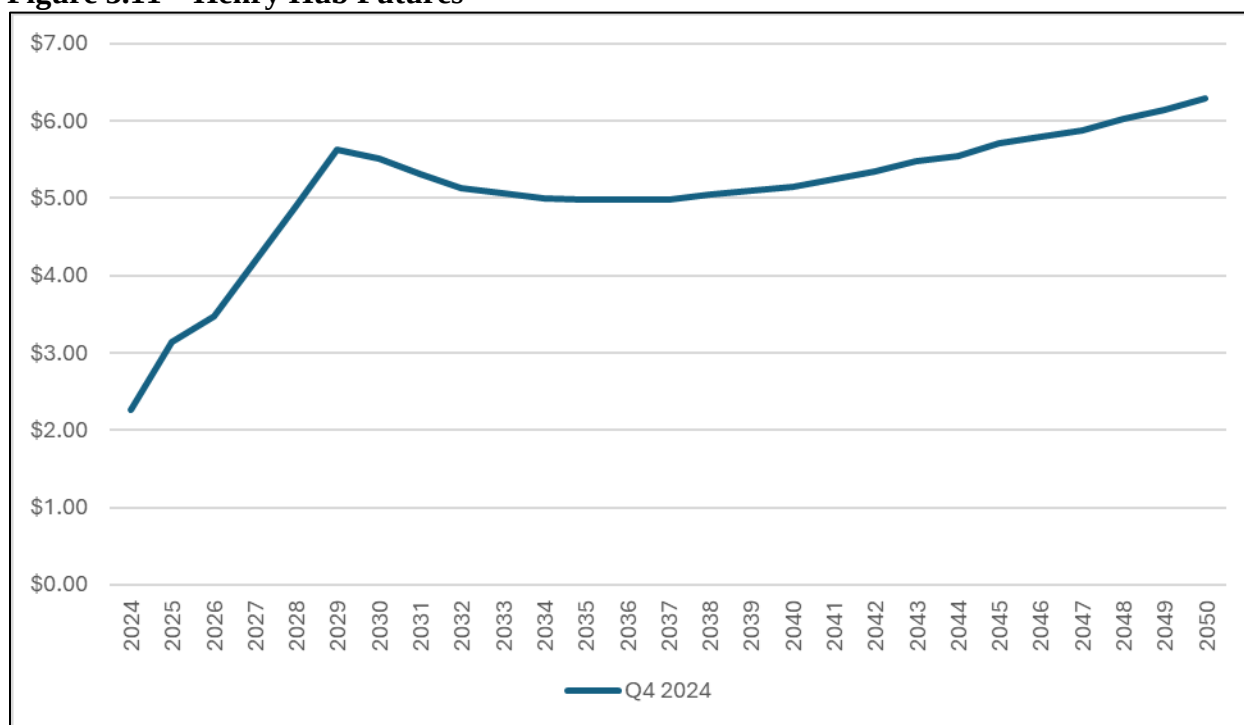
In the Permian Basin of western Texas and southeastern New Mexico, natural gas production, primarily as associated gas from oil wells, increased this year alongside rising oil production driven by oil prices, with expanding pipeline takeaway capacity, such as the Matterhorn pipeline, continuing to support higher production levels despite some volatility caused by periodic pipeline maintenance affecting Permian supply

On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts to diversify energy sources remained a priority. However, higher exports were offset by stable industrial demand and moderate consumption for power generation, resulting in a balanced domestic market. Regional pricing saw temporary variations, particularly in the West, where localized weather events, including early-season storms, increased heating demand briefly. Despite these regional factors, the national market reflected a stable supply-demand balance with minimal volatility. This relative stability was further supported by the continued high storage levels, maintaining downward pressure on prices throughout the year.

2025-2032 Forward View

As we consider the 2025 to 2030 timeframe, our fundamental forecast for natural gas spot prices at Henry Hub indicates a steady upward trend, with prices expected to average in the mid-\$4/MMBtu range in real terms by 2027. Total natural gas demand is projected to reach 122 Bcf/d by 2029, a 13% increase from 2023 levels, driven primarily by rising LNG exports and pipeline deliveries to Mexico. LNG exports are anticipated to double by 2027, as several terminals reach final investment decisions and expand capacity. Similarly, pipeline exports to Mexico are expected to grow significantly, fueled by increased demand for power generation and industrial use.

To meet this growing demand, U.S. natural gas production is expected to expand significantly, particularly from low-cost basins such as the Permian, Eagle Ford, and Haynesville. These regions are well-positioned to serve both domestic and export markets, benefiting from their proximity to demand centers and the development of new takeaway capacity through ongoing pipeline expansion projects. While the market may experience tightness through the middle of the decade due to accelerating LNG export growth, the combination of increased production and strategic infrastructure investments is expected to stabilize supply and support a balanced market by 2032.

Figure 3.11 – Henry Hub Futures

Source: Siemens PTI, GPCM

Conclusion

In summary, the natural gas market is poised for significant growth through the 2025–2030 timeframe, driven by surging export demand and supported by robust production from key basins and expanding infrastructure. While domestic demand shifts modestly, the market’s stability will hinge on the alignment of production growth with expanding export capacity. Despite periods of tightness mid-decade, strategic investments and rising supply will position the market for long-term equilibrium, with Henry Hub prices reflecting this balance.

PacifiCorp’s Multi-State Process

PacifiCorp is a multi-state utility that provides retail electric service to over 2 million customers across six states. The costs of providing this retail electric service to customers is recovered through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp’s integrated system, the collaborative multi-state process (MSP) has been used to develop an allocation methodology. This collaborative process has led to the development and adoption of PacifiCorp’s current inter-jurisdictional cost-allocation method.

The underlying principle of each of the historical inter-jurisdictional cost-allocation methods has been the use of PacifiCorp’s system as a single whole. Except for distribution, all states are served from a common portfolio of generation and transmission assets, which enables the company to leverage economies of scale and take advantage of load diversity to plan and operate in a way that results in cost savings for all customers. Recently, state energy policies across the states served by the company have challenged this principle. For example, requirements to remove coal-fired generation from rates in certain states will necessarily result in some states being allocated the

costs and benefits of coal-fired generation while other states are not. Similarly, diverging state policies related to implementation of the Public Utilities Regulatory Policy Act of 1978, retail choice, private generation, and incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol (2020 Protocol). Under the 2020 Protocol, five of PacifiCorp's six retail states would continue sharing all system resources, while Washington, which had previously only recognized resources in PacifiCorp's west Balancing Authority Area, would share in all system transmission and non-emitting resources. Signatories to the 2020 Protocol had been discussing the development of a future allocation methodology that would address all states' energy policy, while maintaining the benefits of PacifiCorp's system.

In 2024, PacifiCorp determined that a negotiated agreement was unlikely given the differences in state energy policies and data limitations for parties to compare alternatives. PacifiCorp will file a new allocation methodology for approval by all six state commissions in 2025 for implementation in 2026 and beyond. PacifiCorp's guiding principles in the development of the new allocation methodology will continue to be:

1. Provide a long-term, durable solution
2. Follow cost-causation principles
3. Minimize rate impacts at implementation
4. Allow for state autonomy for new resource portfolio selection
5. Maintain and optimize system-wide benefits and joint dispatch to the extent possible
6. Enable compliance with state policies
7. Ensure credit-supportive financial outcome
8. Provide the company with a reasonable opportunity to recover its costs

Environmental Regulation

The upcoming administration change featuring Republican control of the House, Senate, and presidency, sets the stage for significant shifts in federal energy policy that could influence PacifiCorp's portfolio selection process used in the development of future IRPs. PacifiCorp recognizes the potential for new legislative and regulatory priorities to impact the energy sector and resource planning. The company actively monitors federal legislative and regulatory developments and participates in rulemaking processes by submitting comments, engaging in hearings, and providing policy assessments to ensure alignment with evolving requirements.

Suggested upcoming legislative priorities under the new administration include changes to the Inflation Reduction Act and a reconciliation bill with energy as a focal point that could directly impact PacifiCorp's existing and potential generation portfolio.

Federal Policy Update

National Electric Vehicle Infrastructure Formula Program

\$5 billion FY 2022-2026

The U.S. Department of Transportation's (DOT) Federal Highway Administration (FHWA) NEVI Formula Program will provide funding to states to strategically deploy electric vehicle (EV) charging stations and to establish an interconnected network to facilitate data collection, access, and reliability. Funding is available for up to 80% of eligible project costs, including:

- The acquisition, installation, and network connection of EV charging stations to facilitate data collection, access, and reliability
- Proper operation and maintenance of EV charging stations
- Long-term EV charging station data sharing

On February 6, 2025, the FHWA released a letter suspending approval of state electric vehicle infrastructure deployment plans pending review of the policies underlying the implementation of the NEVI Formula Program. The FHWA aims to have updated draft NEVI Formula Guidance published for public comment in the spring. After the public comment period has closed, FHWA will publish updated final NEVI Formula Guidance that responds to the comments received.

Section 11401 Grants for Charging and Fueling Infrastructure

\$2.5 billion for FY 2022 – 2026

Competitive grant program to strategically deploy publicly accessible electric vehicle charging infrastructure and other alternative fueling infrastructure along designated alternative fuel corridors. At least 50 percent of this funding must be used for a community grant program where priority is given to projects that expand access to EV charging and alternative fueling infrastructure within rural areas, low- and moderate-income neighborhoods, and communities with a low ratio of private parking spaces. Opportunity to obtain funding through this grant closed on September 11, 2024.

New Credits and Considerations for Non-emitting Resources – Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation signed into law in August 2022 by President Biden. Substantive details of how the legislation will be implemented are still being fleshed out in the form of regulations and other guidance. The IRA contains newly structured technology-specific and technology-neutral tax credits for electric generating facilities and other clean energy incentives such as credits for Energy Storage Technology, Carbon Capture Use and Sequestration (CCUS), and hydrogen production. Furthermore, the IRA contains incentives that may affect demand, such as tax credits for electric vehicles.

Features of the IRA include:

- The bill directs \$437b in spending towards climate and healthcare investments with over \$300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment and production tax credits and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting

economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.

- **Key Energy Provisions:**
 - Extends wind, geothermal, and solar investment and production tax credits at full value through December 31, 2024. Solar projects are newly eligible to apply the production tax credit to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
 - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded.
 - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets.

In the 2025 IRP, resources in designated areas are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources)

New Credits and Considerations for Customer Resources—Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both EVs and FCEVs, and require a traction battery that has at least seven kilowatt-hours (kWh). An available tax credit under the CVC may be limited by the vehicle's MSRP and the buyer's modified adjusted gross income.

Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for \$3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a \$3,750 tax credit. Vehicles meeting both the critical mineral and the battery component requirements are eligible for a total tax credit of \$7,500.

The IRA also extends the federal Investment Tax Credit (ITC) for small scale solar systems through 2034 and expands the credit to include standalone energy storage systems as well. Since the passage of the IRA, the ITC has been extended beyond its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC is set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers.

The IRA funds multiple programs and tax incentives to improve the energy efficiency for residential and non-residential buildings and equipment. For non-residential buildings, the IRA provides tax deductions of \$0.50–5.00 per square foot (/sf) of floor area to owners of new and

improved energy-saving commercial buildings depending on the percentage of energy savings and whether the contractor pays prevailing wages. Even larger broad greenhouse gas emission reduction programs under the IRA could be used to reduce emissions from commercial buildings. The IRA also provides more than \$25 billion for programs and tax incentives to improve the energy efficiency of existing and new homes. In addition to program funding, the IRA enhances the 25C Energy Efficient Home Improvement Credit. This long-standing federal tax credit applies to home energy improvements such as insulation, windows, heat pumps, and furnaces. Starting in 2023, IRA increases the credit to 30% of cost, with an annual cap of \$1,200 along with smaller limits for most items, but it also allows up to \$2,000 for a heat pump (in 2022 the credit is under the old rules, with lower amounts and a lifetime cap of \$500).

New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d)

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in April 2024, EPA finalized new rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units (Clean Air Act Section 111(d) rule).

For new combustion turbines, the final rule establishes three subcategories based on operating intensity as measured by capacity factor.

1. Base load turbines (operating above 40% of maximum annual capacity factor) must initially meet a standard reflective of an efficient combined cycle design and achieve 90% carbon capture by January 1, 2032.
2. Intermediate load turbines (operating between 20% and 40% of capacity factor) must meet a standard reflective of an efficient simple cycle design.
3. Low load turbines (operating below 20% capacity factor) must meet a standard based on using low-emitting fuels.

For existing coal-fired electric generating units (EGUs), the final rule subcategorizes plants based on the units intended operational timeline.

1. Long-term units (operating beyond January 1, 2039) must meet emission limits based on 90% carbon capture and storage (CCS) by January 1, 2032.
2. Medium-term units (retiring by January 1, 2039) must meet limits by January 1, 2030, using 40% natural gas co-firing.
3. Near-term units (closing before January 1, 2032) have no emission reduction obligations.

For existing gas- or oil-fueled steam units, the final rule subcategories units based on capacity factor.

1. Base load units (annual capacity factor greater than or equal to 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,400 lb/MWh)
2. Intermediate load units (annual capacity factor between 8% and 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,600 lb/MWh)
3. Low load units (annual capacity factor less than 8%) must meet a standard based on using low-emitting fuels.

States are required to submit implementation plans within two years of the rule's publication. These plans must show meaningful engagement with stakeholders, including affected communities and reliability authorities. States also have flexibility to consider factors like Remaining Useful Life, allow for emissions trading and averaging, and provide one-year compliance extensions for delays beyond an operator's control.

The rule has been challenged by multiple parties and is currently awaiting a decision from the D.C. Circuit Court of Appeals.

Credit for Carbon Oxide Sequestration – Internal Revenue Service § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.⁷ Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from \$10/tonne to \$35/tonne for utilization and from \$20/tonne to \$50/tonne for storage.⁸ This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually (500,000 tonnes per year for an electric generating facility) and is available for 12 years from the date the carbon capture equipment is originally placed into service. The Consolidated Appropriations Act of 2021 extended the date construction must begin to receive the tax credits by two years, from January 1, 2024, to January 1, 2026.

The Inflation Reduction Act made considerable changes to the 45Q tax credit in 2022. The tax credit amount increased to \$60/tonne (use) and \$85/tonne (storage), the construction window was extended to January 1, 2033, the minimum capture thresholds were lowered (18,750 tonnes per year for electric generating facilities) and the Act now requires 75% of a generating units CO₂ production to be captured, among other requirements.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public, and establish the maximum allowable concentration allowed for each “criteria” pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NO_x), particulate matter (PM), and sulfur dioxide (SO₂). The primary standards are set at a level that protects public health with an adequate margin of safety. The secondary standards are set to protect the public welfare from adverse effects including those related to effects on soils, water, crops, vegetation, anthropogenic materials, among other impacts. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan (SIP) to bring that area into compliance, and that plan must be approved by

⁷ Before February 9, 2018, the tax credit was strictly for CO₂.

⁸ The tax credit reaches \$35/tonne and \$50/tonne in 2026.

EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

Ozone NAAQS

In October 2015, EPA issued a final rule modifying both the primary and secondary 8-hour ozone from 75 parts per billion (ppb) to 70 ppb. In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution to determine whether emissions from the state have a significant impact on neighboring states attaining or maintaining the ozone NAAQS. On April 6, 2022, EPA proposed its “Good Neighbor Rule” for the 2015 ozone NAAQS (the “Ozone Transport Rule” or “OTR”), which proposed a federal implementation plan (FIP) to eliminate interstate transport of ozone precursors from states that EPA identified as significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The proposed rule covered 26 states, including four western states included in the cross-state program for the first time – Wyoming, Utah, Nevada and California. Specifically, EPA proposed in that action to implement emissions reductions by requiring some sources within these states to participate in revised provisions of the Cross-State Air Pollution Rule (CSAPR). EPA applied the interstate transport framework developed in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules to propose to further limit NO_x emissions from electric generating unit (EGU) sources within the borders of 25 states during the ozone season and to limit ozone season NO_x emissions from non-EGU sources in 23 states to reduce interstate ozone transport.

On February 13, 2023, EPA finalized disapproval of interstate ozone transport SIP submissions for the 2015 8-hour ozone NAAQS for multiple states and issued a partial disapproval for two additional states. This included the SIP for Wyoming. In the same action, EPA deferred final action on its proposed disapproval for Wyoming. For both Utah and Wyoming, the agency determined that, among other failings, the states should have used a 1% threshold instead of the one ppb threshold despite EPA previously recognizing, in an August 2018 memorandum, that state may establish an alternative contribution threshold of 1 ppb. States, like Utah, for which EPA issued disapproval actions of their interstate ozone transport SIPs were required to comply with the interstate ozone transport FIP for the 2015 ozone standard upon finalization of that action on March 2023. Due to EPA’s delayed final action on Wyoming’s SIP submission, Wyoming was not required to comply with the final interstate ozone transport FIP for the 2015 8-hour ozone NAAQS.

Numerous states and industries, including PacifiCorp, challenged certain provisions of the ozone interstate transport SIP disapprovals and FIP for the 2015 ozone standard. The state of Utah and PacifiCorp filed petitions and motions for stay of EPA’s denial of the Utah SIP with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit), and the motion for stay was granted by the Tenth Circuit on July 27, 2023. The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the interstate transport FIP for the 2015 ozone NAAQS while the stay remains in place. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits. The EPA also issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been stayed.

The EPA finalized approval of Wyoming’s interstate ozone transport SIP on December 19, 2023. Given the approval of the Wyoming SIP, PacifiCorp facilities in Wyoming are not subject to the interstate ozone transport FIP. Given the court stay of EPA’s disapproval of Utah’s SIP, PacifiCorp

was not subject to the interstate ozone FIP requirements for the 2015 ozone NAAQS during the 2023 ozone season. The Utah ozone case was transferred to the D.C. Circuit on February 16, 2024, for adjudication on the merits, leaving the stay in place. Requirements for the 2024 ozone season and beyond will depend on the outcome of the litigation.

In addition to litigation over SIP disapprovals, numerous appeals of, and motions to stay, the interstate ozone FIP were filed in four different circuit courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the interstate ozone transport FIP for the 2015 ozone standard that was filed by several state and industry parties. The states of Ohio, Indiana and West Virginia filed a request for an emergency stay of the interstate ozone transport FIP with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement, and other industries affected by the rule, filed supportive requests for a stay on the same day. The U.S. Supreme Court granted a stay of the FIP on June 27, 2024. Accordingly, states are not required to comply with the ozone transport FIP pending the stay.

On December 9, 2024, EPA signed a final rule to reclassify the Northern Wasatch front, which includes Salt Lake County, from moderate to serious nonattainment for the 2015 Ozone NAAQS. PacifiCorp's Gadsby facility is in the Northern Wasatch Front area and was previously identified as a major source subject to Utah's moderate nonattainment area SIP for Ozone. In anticipation of EPA's decision, the Utah Department of Environmental Quality (DEQ) requested that PacifiCorp submit a reasonably available control technology (RACT) analysis to the Utah DEQ's Division of Air Quality. PacifiCorp submitted the RACT analysis on January 9, 2024, and followed the top down RACT analysis process for each nitrogen oxide and volatile organic carbon emission source at the at the Gadsby plant. Plant emissions from 2017 were utilized to prepare cost effectiveness analyses for add-on controls; these analyses demonstrated that no additional controls are cost effective at this time.

Particulate Matter NAAQS

On October 17, 2006, EPA revised the level of the 24-hour PM_{2.5} NAAQS from 65 micrograms per cubic (µg/m³) meter to 35 µg/m³. On May 10, 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo PM_{2.5} nonattainment areas from moderate to serious for the 2006 24-hour PM_{2.5} NAAQS. PacifiCorp's Lake Side and Gadsby facilities were subject to major source requirements due to their emissions of PM_{2.5}. On April 27, 2017, PacifiCorp submitted a Best Available Control Technology (BACT) determination for Lake Side and Gadsby to the Utah Division of Air Quality for review. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices for the Lake Side and Gadsby facilities in the SIP.

On November 17, 2020, EPA finalized redesignation of the Salt Lake City and Provo nonattainment areas to attainment for the 2006 24-hour PM_{2.5} NAAQS. On April 6, 2021, EPA reopened the comment period after adding supplemental information to the proposal. Redesignation to attainment would have no effect on current emissions and operating limits for the Lake Side and Gadsby facilities.

On March 6, 2024, EPA revised the primary annual PM_{2.5} NAAQS from 12.0 µg/m³ to 9.0 µg/m³. EPA has not yet designated areas as attainment, nonattainment, unclassifiable/attainment, or unclassifiable under this new standard.

Regional Haze

Clean Air Act (CAA) Section 169A includes a program for protecting visibility in the nation's mandatory Class I Federal areas, which include national parks and wilderness areas. The CAA directs EPA to promulgate regulations to assure reasonable progress toward meeting the goal of protecting visibility. In 1990, CAA section 169B was added to further address visibility impairment, specifically, impairment from regional haze. EPA promulgated the Regional Haze Rule in 1999, which requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado, and Montana). The states are required to update their regional haze rule plans generally every ten years, with second planning period revisions due in August of 2023. Litigation over the first planning period requirements for both Utah and Wyoming are mostly concluded.

On July 6, 2005, EPA published final amendments to its regional haze rule to require emission controls known as Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include PM, NO_x, SO₂, certain VOCs, and ammonia. The 2005 amendments included BART guidelines for states to use in determining which facilities must install controls and presumptive controls for certain sources subject to BART. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities.

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the regional haze program. EPA issued additional guidance on July 8, 2021, that discusses source selection, characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, consideration of visibility in making control determinations, and the consideration of five additional factors, among other topics.

Utah Regional Haze

In May 2011, the state of Utah submitted to EPA a regional haze SIP for the first planning period requiring the installation of SO₂, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, EPA approved the SO₂ portion of the Utah regional haze SIP and disapproved the NO_x and PM portions for Hunter Units 1 and 2 and Huntington Units 1 and 2. EPA's approval of the SO₂ SIP was appealed by environmental groups to the Tenth Circuit. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the SIP on the basis that the NO_x and PM BART determinations for the sources did not comply with the Regional Haze rules. PacifiCorp and the state's appeals were dismissed as was the appeal filed by environmental groups in the Tenth Circuit. In June 2015, Utah submitted a revised SIP to EPA for approval which included an alternative BART NO_x analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2 and crediting NO_x emission reductions from Hunter Units 1, 2, and 3 and Huntington Units 1 and 2. On July 5, 2016, EPA published a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a FIP. The FIP established NO_x emission limitations on Hunter Units 1 and 2 and Huntington Units 1 and 2 that are reflective of Selective Catalytic Reduction (SCR) and Low-NO_x Burners (LNB) and Separated Overfire Air (SOFA). On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative

and judicial review of EPA’s final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA’s FIP and hold the litigation in abeyance pending the rule’s reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP as well as the litigation were stayed pending EPA’s reconsideration, and EPA was required to file periodic status reports with the court.

Utah and PacifiCorp worked with EPA to develop a revised Utah regional haze SIP, based on new CAMx modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA that would require reporting of all deviations from compliance with the applicable requirements under BART and the BART Alternative, including the emission limits for Hunter and Huntington.

On January 22, 2020, EPA published its proposed approval of the Utah SIP revision and withdrawal of the FIP requirements that would have required emissions limitations for the Hunter and Huntington plants equivalent to SCR plus upgraded combustion controls (LNB/SOFA). EPA subsequently finalized approval of the SIP and withdrawal of the FIP as proposed on November 27, 2020. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp and EPA’s motion to dismiss the Utah regional haze petitions.

Environmental groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to EPA’s approval of Utah’s regional haze SIP for the first planning period. After holding the case in abeyance at EPA’s request, the Tenth Circuit lifted the abeyance and granted PacifiCorp and Hunter co-owners and Utah’s pending motions to intervene. On August 14, 2023, the Tenth Circuit determined EPA properly approved the Utah regional haze SIP for the first planning period and denied environmental groups’ petition.

On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp’s Huntington and Hunter plants. The analysis was requested by the state as part of its second planning period SIP development process. PacifiCorp’s analysis included a proposal to implement reasonable progress emission limits for NO_x and SO₂ at the Hunter and Huntington units to meet second planning period requirements.

The Utah Air Quality Division proposed, and the Utah Air Quality Board approved, final adoption of a SIP for the regional haze second planning period on July 6, 2022, and submitted the SIP to EPA on August 2, 2022. The SIP differs from PacifiCorp’s Reasonable Progress Analysis and requires updated mass-based NO_x limits. The SIP also concluded that existing SO₂ limits in Hunter and Huntington’s title V permits were necessary to make reasonable progress but required no further SO₂ emission limits for the plants.

On December 2, 2024, EPA finalized a final partial approval and partial disapproval for Utah’s regional haze state implementation plan for the second planning period without simultaneously

finalizing a federal implementation plan. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management (FLM) consultation components of the SIP. EPA’s disapproval of Utah’s long-term strategy is based, in part, on EPA’s rejection of Utah’s finding that installation of SCR or other physical NO_x pollution controls for Hunter and Huntington is not necessary to achieve reasonable progress. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously finalized FIP. PacifiCorp filed a petition for reconsideration on EPA’s disapproval action on January 30, 2025, and filed a petition for review in the Tenth Circuit the next day.

Wyoming Regional Haze

On January 30, 2014, EPA published a final rule partially approving and partially disapproving the Wyoming regional haze SIP for the first planning period and promulgating a FIP to address the deficiencies EPA found in the Wyoming SIP submission. As a result of the 2014 final rule and FIP, the following controls were required at PacifiCorp facilities for the regional haze first planning period:

- Naughton Units 1 and 2: LNB/OFA, with an emission limit of 0.28 lbs/MMBtu for each unit
- Naughton Unit 3 by December 31, 2014: SCR + LNB/SOFA, 0.07 lb/MMBtu (30-day rolling average).
- Jim Bridger Unit 3 by December 31, 2015: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 4 by December 31, 2016: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 2 by December 31, 2021: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NO_x emission limit of 0.26 lb/MMBtu by March 4, 2015
- Jim Bridger Unit 1 by December 31, 2022: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NO_x emission limit of 0.26 lb/MMBtu by March 3, 2015
- Dave Johnston Unit 3: Either a commitment to retire by 2027 and LNB/OFA, with an emission limit of 0.28 lbs/ MMBtu (30-day rolling average) or SCR + LNB/OFA, with an emission limit of 0.07 lbs/ MMBtu (30-day rolling average)
- Wyodak Unit 1: SCR+ LNB/SOFA, with an emission limit of 0.07 lb/ MMBtu (30-day rolling average)

Naughton – In its 2014 rule, EPA approved Wyoming’s determination that NO_x BART for Units 1 and 2 was LNB and OFA. While EPA approved Wyoming’s NO_x BART determination of SCR and LNB/OFA, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) for Naughton Unit 3, EPA stated that it would approve limitations that reflect the conversion of Unit 3 to natural gas once Wyoming submitted the requisite SIP revision. On November 28, 2017, Wyoming submitted to EPA a source-specific revision to its regional haze SIP for the first planning period for the Naughton Unit 3 conversion. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3’s conversion to natural gas, which allowed Unit 3 to operate on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA’s final rule approving Wyoming’s SIP revision for Naughton Unit 3’s gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA’s approval of LNB/OFA as NO_x BART for Units 1 and 2 in the Tenth Circuit. On August 15, 2023, the court determined EPA properly approved Wyoming’s Naughton determination and denied

environmental groups' petition.

Jim Bridger – In its 2014 rule, EPA approved Wyoming's determination that Jim Bridger Units 1 and 2 meet an emission limit of 0.07 lb/MMBtu (30-day rolling average) by 2022 and 2021, respectively. EPA also approved Wyoming's NOx BART determination that required Jim Bridger Units 1 and 2 to meet a NOx emission limit of 0.26 lb/MMBtu (30-day rolling average) by March 4, 2019. For Jim Bridger Units 3 and 4, EPA approved Wyoming's determination that the appropriate level of NOx control for Units 3 and 4 for purposes of reasonable progress is the SCR-based emission limit in the SIP of 0.07 lb/MMBtu, with compliance dates of December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. Accordingly, SCR was installed on Jim Bridger Units 3 and 4 by the dates required by the Wyoming SIP. On February 5, 2019, PacifiCorp submitted to Wyoming an air permit application for monthly average plant-wide NOx and SO₂ emission limits, in addition to an annual combined NOx and SO₂ limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. PacifiCorp proposed that the plantwide limits were more cost effective while leading to better modeled visibility than SCR installations on Units 1 and 2. Wyoming submitted a regional haze SIP revision to the EPA on May 14, 2020, that incorporated PacifiCorp's proposed emission limits in lieu of the requirement to install SCR on Jim Bridger Units 1 and 2. While EPA communicated that it would issue a proposed approval of Wyoming's Jim Bridger SIP, the proposal was not issued before the administration change in 2021.

When EPA failed to issue a determination by the statutory deadline in November 2021, the Governor of Wyoming issued a temporary emergency order on December 27, 2021, using authority granted by the Clean Air Act, suspending the existing SIP requirement for Jim Bridger Unit 2 to install SCR by December 31, 2021. The suspension was issued for four months due to the EPA's failure to act on the SIP revision submitted by Wyoming in 2020. EPA published a proposed disapproval of the Jim Bridger SIP revision on January 18, 2022. However, PacifiCorp negotiated a consent decree with Wyoming and an administrative consent order with EPA and the disapproval was not finalized. Under the Wyoming consent decree and EPA administrative consent order, PacifiCorp is required to comply with a compliance plan that allows continued operation of Jim Bridger Units 1 and 2 under the emission limits established by Wyoming in 2020 until they are converted to natural gas in 2024. The consent decree committed Wyoming to processing a SIP revision requiring the conversion and imposing post-conversion emission limits.

On December 30, 2022, Wyoming submitted to EPA for approval a revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming issued to PacifiCorp an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. PacifiCorp completed the conversion. On April 10, 2024, EPA proposed to approve Wyoming's December 2022 SIP revision for Jim Bridger Units 1 and 2. The SIP includes enforceable emissions and heat input limits at Jim Bridger Units 1 and 2, consistent with the conversion of those units to natural gas. EPA accepted comments on the proposed approval through May 10, 2024, but has not yet finalized the approval.

Dave Johnston – EPA's January 20, 2014, FIP action required either the installation of SCR on Dave Johnston Unit 3 or that the unit retire by the end of 2027. PacifiCorp opted not to install SCR. EPA approved Wyoming's NOx BART determination for Dave Johnston Unit 4 of an emission limit of 0.15 lb/MMBtu (30-day rolling average). EPA also approved Wyoming's NOx

reasonable progress determinations for Dave Johnston Units 1 and 2 that no controls were necessary.

Wyodak – EPA’s January 20, 2014, FIP action determined SCR + LNB/SOFA to be NO_x BACT. PacifiCorp and Wyoming petitioned EPA’s FIP that would require SCR at Wyodak in the Tenth Circuit. On September 9, 2014, the Tenth Circuit stayed the NO_x emission limits for Wyodak Unit 1 in the regional haze FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. EPA, Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. On January 4, 2021, EPA published the proposed settlement agreement in the Federal Register, requesting public comment. PacifiCorp submitted comments to EPA on March 5, 2021, in support of the Wyodak proposed settlement agreement. However, EPA did not proceed with final approval of the proposed settlement agreement but rather re-engaged with Wyoming and PacifiCorp in mediation through the Tenth Circuit. Litigation for the Wyodak case challenging EPA’s denial of the Wyoming SIP and finalization of a FIP recommenced when the mediation process was not successful. On August 15, 2023, the Tenth Circuit found EPA’s disapproval of Wyoming’s SIP for Wyodak unlawful and remanded the SIP to EPA for further review in accordance with the requirements of the Clean Air Act.

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp’s Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. Wyoming incorporated the four-factor analyses in its SIP for the regional haze second planning period. Wyoming determined that emission limits and planned unit retirements met the reasonable progress goals for Regional Haze. Wyoming submitted the state’s regional haze SIP for the second planning period to EPA on August 10, 2022.

On December 2, 2024, EPA finalized partial approval and partial disapproval of Wyoming’s regional haze SIP for the second planning period. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management consultation components of the state plan. EPA’s disapproval of Wyoming’s long-term strategy is based in part on the state’s decision to forego a full four-factor analysis for units at Jim Bridger, Naughton, Dave Johnston, and Wyodak. There are no new compliance obligations for PacifiCorp at this time, as the disapproval action did not include a simultaneously finalized FIP. On January 30, 2025, the state of Wyoming submitted an “open letter” to EPA stating its concerns about the agency’s disapproval of the regional haze second planning period plan for the state. On January 31, 2025, the state also filed a petition for review in the Tenth Circuit. PacifiCorp filed a petition for reconsideration with the agency on January 30, 2025, and petition for review in the Tenth Circuit the next day.

Colorado Regional Haze

Craig- The Colorado regional haze SIP for the first planning period established SO₂ BART emission limits on Craig Units 1 and 2 of 0.11 lb/MMBtu (30-day rolling average). Colorado incorporated NO_x emission limits of 0.28 lb/MMBtu (30-day rolling average) for Craig Unit 1 and 0.08 lb/MMBtu (30-day rolling average) for Craig Unit 2 in the SIP. Although the state determined that SNCR was reasonable for BART for both Units 1 and 2, Tri-State and Colorado agreed to a NO_x emission control plan for Unit 2 that reflected SCR and was therefore more stringent than the BART determination. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) at Craig Units 1 and 2, which could be met through the operation of the existing fabric filter baghouses.

Hayden- In its regional haze SIP for the first planning period, Colorado determined that the SO₂ BART emission limit for Hayden Unit 1 is 0.13 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.13 lb/MMBtu (30-day rolling average). These limits are met with the operation of the existing controls. For NO_x, Colorado determined that the NO_x BART emission limit for Hayden Unit 1 is 0.08 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.07 lb/MMBtu (30-day rolling average). These BART emission limits could be met through the installation and operation of SCR. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) for Hayden Unit 1 and Unit 2. These PM emission limits can be met through the operation of the current fabric filter baghouses.

EPA found Colorado's determinations for the Craig and Hayden units to be approvable and finalized approval of the Colorado regional haze SIP for the first planning period on December 31, 2012. Environmental groups appealed EPA's action in February 2013, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment, with a NO_x BART emission limit for Craig Unit 1 is 0.07 lb/MMBtu, calculated on a 30 boiler-operating-day rolling average at Craig Unit 1 by August 31, 2021, 2021.

On May 26, 2017, Colorado submitted a SIP amendment to EPA that reflected further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements. The revised SIP required Craig Unit 1 to meet an annual NO_x emission limit of 4,065 tons per year by December 31, 2019. The SIP revision also required the unit to either convert to natural gas by August 31, 2023, and if converting to natural gas, comply with a NO_x emission limit of 0.07 lb/MMBtu (30-day rolling average) beginning August 31, 2021, or shut down by December 31, 2025. EPA approved the SIP on July 5, 2018.

Colorado Regional Haze Second Planning Period – Colorado's regional haze SIP for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units 1 and 2 by 2028 and 2027, respectively. Colorado submitted its second planning period regional haze SIP to EPA on March 22, 2021. However, EPA has not yet acted on the Colorado regional haze SIP for the second planning period. The Colorado SIP is part of the deadline suit filed by environmental groups in the federal D.C. District Court.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that coal- and oil-fired facilities achieve emission standards for mercury, acid gas hazardous air pollutants (HAPs), non-mercury HAP metals, and organic HAPs. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, in response to a Supreme Court decision requiring consideration of costs, EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate coal- and oil-fired EGUs under the Clean Air Act.

On February 7, 2019, EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate HAPs, reversing the Agency's

prior determination. On May 22, 2020, EPA published a reconsideration of its 2016 supplemental finding. In the reconsideration action, EPA determined that it is not appropriate and necessary to regulate HAP emissions from coal- and oil-fired EGUs. The rule was effective May 22, 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting EPA's decision to rescind the appropriate and necessary finding. The court granted EPA's motion to hold the cases in abeyance while the agency reviewed the 2020 repeal. On March 6, 2023, EPA finalized a rule rescinding the 2020 revocation of the appropriate and necessary finding. The rule therefore reinstated the finding. Because PacifiCorp plants are in compliance with the MATS standards, the reinstatement of the finding has immediate impact on PacifiCorp's operations.

On April 25, 2024, EPA finalized revisions to the MATS rule following the agency's review of the 2020 Residual Risk and Technology Review. The final rule, effective July 8, 2024, tightens the standard for emissions of mercury from existing lignite-fired units by 70 percent and sets a more stringent standard for emissions of filterable particulate matter from existing coal-fired power plants. The rule also requires that continuous emissions monitoring be used to demonstrate compliance with the filterable PM standard.

Coal Combustion Residuals

On April 17, 2015, EPA finalized a rule to regulate the management and disposal of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The rule establishes minimum nationwide standards for new and existing CCR landfills and surface impoundments as well as all lateral expansions consistent of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, recordkeeping, notification, and internet posting requirements. In addition to other requirements, the rule requires existing unlined CCR surface impoundment that is contaminating groundwater to stop receiving CCR and either retrofit or close, except in limited circumstances. The rule also requires the closure of certain landfills and CCR impoundments. The first of these reports was posted to PacifiCorp's CCR compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCR. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCR and hence are not subject to the final rule.

On June 14, 2016, the United States Court of Appeals for the D.C. Circuit ordered the vacatur of the "early closure" provisions in the 2015 CCR rule which would have allowed inactive CCR surface impoundment units that had closed by a certain date to forgo groundwater monitoring or other requirements. In response to this decision, EPA published a direct final rule on August 5, 2016, to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under RCRA.

On July 30, 2018, in response to further legal challenge, EPA finalized a rule to establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by EPA. The rule also revised groundwater protection standards for certain constituents. In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, EPA extended the deadline by which facilities must

cease the placement of waste in CCR units closing for cause in certain instances. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule").

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") on August 28, 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which unlined surface impoundments that failed aquifer location restriction must initiate closure. In addition, the rule revised the alternative closure provisions to grant facilities additional time to develop alternative capacity to manage both CCR and/or non-CCR wastewater streams before they must stop receiving waste and initiate closure of their surface impoundments. Finally, the rule revised certain requirements related to the annual groundwater monitoring and corrective action report and the requirements for publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste and the newly constructed FGD Pond 3 was placed into service. EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative storage capacity demonstration request.

On November 12, 2020, EPA published the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process that allows facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. EPA proposed these options as part of a subsequent proposal on March 3, 2020. On February 20, 2020, EPA published a proposed rule to establish a federal CCR permit program in accordance with the requirements of the Water Infrastructure Improvements for the Nation (WIIN) Act. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 15, 2017, EPA published a request for comment on its proposed permitting guidance which describes EPA's interpretation of the WIIN Act provisions and how EPA will review states' CCR permit programs. The state of Utah adopted the federal final rule in September 2016 and issued the final permit for Huntington Power Plant CCR Landfill on March 21, 2023, and for Hunter Power Plant CCR Landfill on May 15, 2024. It is anticipated that Utah will submit an application to EPA for approval, but the timing of the submission remains uncertain. EPA rejected Wyoming's application due to concerns about the state's ability to meet federal standards for the safe management of coal ash.

On May 8, 2024, EPA finalized the legacy surface impoundments rule to (1) extend federal CCR regulatory requirements to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land (CCR management units or CCRMUs) and (2) allow for alternative closure provisions that allow a facility to complete the closure by removal in two stages. The final rule, which became effective on November 8, 2024, includes exemptions and establishes new categories

where regulation is deferred for applicable units, including CCRMU containing less than 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that were closed prior to the effective date of the new rule. Affected facilities must conduct a facility evaluation and report to determine the presence of CCRMUs and/or legacy surface impoundments. The first phase of such a report is due February 2026. Because the facility evaluation and report requirement will determine the magnitude of compliance obligations, PacifiCorp cannot assess the full impacts of the rule at this time.

On August 5, 2024, Utah, Wyoming and other Republican-led states filed a petition for review in the D.C. Circuit on EPA's May 2024 legacy rule, arguing that EPA acted arbitrarily and beyond its authority when enacting the new rule. On February 3, 2025, these same petitioners as well as power companies, utilities and trade groups filed their opening brief in a consolidated case contesting the rule in the D.C. Circuit.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act (Clean Water Act) establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to, and withdrawals from, waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact." In August 2014, EPA published a final rule, effective October 2014, under section 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule establishes requirements that apply to existing power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from Waters of the United States (WOTUS) and use at least 25 percent of the withdrawn water exclusively for cooling purposes. The rule includes standards to address impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility). The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from WOTUS for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers and withdraw more than two million, but less than 125 million, gallons of water per day.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards. Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous PARs.

Effluent Limit Guidelines

In November 2015, EPA published final effluent limitation guidelines and standards (ELG) for the steam electric power generating sector which, among other things, regulate the discharge of bottom

ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System (NPDES) permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018, and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with EPA. EPA granted the request for reconsideration and extended certain compliance dates for FGD wastewater and bottom ash transport water limits until November 1, 2020. On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing FGD wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on FGD wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet FGD wastewater requirements and includes additional subcategories to both wastewater categories.

On May 9, 2024, EPA finalized the Supplemental ELG and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule), which includes a new subcategory for EGUs permanently ceasing coal combustion by 2034. The 2024 ELG Rule also imposes a zero liquid discharge requirement at coal-based generating units for bottom ash transport water, flue gas desulfurization wastewater, and coal combustion residual leachate. The rule also eliminates 2020 ELG Rule's less stringent BAT requirements for two subcategories: high-flow facilities and low-utilization electric generating units (LUEGUs), except to the extent they apply to one new permanent cessation of coal combustion subcategory. The rule maintains, however, the 2020 ELG Rule subcategory for EGUs permanently ceasing the combustion of coal by 2028 and oil-fired and small (50 megawatts (MW) or less) EGUs established in the 2015 rule. The rule finalizes additional reporting and recordkeeping requirements and zero-discharge limitations applicable after EGUs cease coal combustion, as well as procedural requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

Most of the issues raised by the 2024 ELG Rule are already being addressed at PacifiCorp facilities through compliance with the CCR rule and will not impose significant additional requirements on the facilities. In October 2021, the Dave Johnston plant submitted a notice of planned participation in subcategorization for units ceasing coal combustion by December 31, 2028. Participation in the subcategory allows continued management of bottom ash transport water using impoundments and discharge of the waste stream. The plant requested that the option to transfer to the installation and operation of a bottom ash recycle system be included in the new NPDES permit.

Renewable Generation Regulatory Framework

Regulatory and permitting requirements for renewable energy projects are addressed at federal, state, and local levels. All wind projects in the United States must comply with federal regulations for wildlife impacts, aviation safety, clean water, communication systems, and Department of Defense impacts. Eagle Incidental Take Permits (EITPs), including associated surveys,

monitoring, and compensatory mitigation, are necessary for wind projects that may result in take of bald or golden eagles. State and county regulations often address localized topics such as road and traffic concerns, community economic impacts, viewshed requirements, sage-grouse stipulations, wind turbine location guidelines, and land use and zoning restrictions. Solar projects must comply with federal and state regulations that restrict disturbance of certain flora and fauna and are subject to local planning and zoning regulations for land use. Storm water pollution prevention plans for renewable projects are usually required on a state level to control sediment runoff during construction and all renewable projects must comply with the Clean Water Act rules which are controlled at the federal level. Renewable energy projects located on federally managed lands or that receive federal funding are subject to National Environmental Policy Act (NEPA) review, which may include cultural and biological resource surveys, assessment of potential impacts, public comment periods, and avoidance/minimization/mitigation efforts. Power lines associated with renewable energy projects, including collector lines at the project site and grid-connecting transmission lines, may also be subject to environmental regulations, review, stipulations, or permits.

The wind projects (TB Flats, Ekola Flats, and Cedar Springs) constructed as part of PacifiCorp's Energy Vision 2020 initiative, for example, were required to obtain permits from the State of Wyoming's Industrial Siting Division, which required extensive studies of the conditions of the site, coordination with state agencies in the development process, and forecast of impacts from the project. Renewable energy projects in the State of Wyoming that meet the Industrial Siting Division's size or capital thresholds must obtain approval before they can begin construction. Most wind project developers coordinate with federal and/or state authorities to evaluate and mitigate potential impacts to birds or other wildlife species, particularly eagles, migratory birds, and bats, during the wind turbine siting process to minimize wildlife impacts and potential operational risks. Greater sage-grouse are currently managed by the states, and renewable energy projects and associated transmission lines require state agency review; stipulations or mitigation requirements vary by state and project impacts. Because the generation capabilities of renewable energy projects are site specific and can vary greatly between different sites, understanding the specific permit requirements for each site is critical to developing a successful project.

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. CARB's 2022 Scoping Plan was

adopted laying out a path to achieve targets for carbon neutrality and reduce anthropogenic greenhouse gas emissions by 85 percent below 1990 levels no later than 2045, as directed by Assembly Bill 1279, passed in 2022.

CARB adopted the Advanced Clean Cars II Rule in August of 2022. The rulemaking establishes that by 2035 all new passenger cars, trucks and SUVs sold in California will be zero emissions. The Advanced Clean Cars II regulations take the state's already growing zero-emission vehicle market and robust motor vehicle emission control rules and augments them to meet more aggressive tailpipe emissions standards and ramp up to 100% zero-emission vehicles.

In 2002, California established a RPS requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded several times since its inception. In September 2018, Governor Brown signed into law Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045. The California Energy Commission, California Public Utilities Commission, and California Air Resources Board have not introduced rules on if and how electric utilities will demonstrate compliance with SB 100. Interim targets for the carbon-free target were subsequently adopted by SB 1020 in 2022.

Idaho

In 2007, Idaho released its State Energy Plan, focusing on developing of a broad range of power generation options, improving energy efficiency, diversifying the state's energy portfolio, and reducing dependency on fossil fuels. The plan outlined strategies for energy conservation, the development of renewable energy sources, and improvements to transmission infrastructure within the state, aiming to balance growth with environmental stewardship and promote both economic development and sustainable energy practices.

In 2012, Idaho updated its 2007 plan to address new energy challenges and opportunities, emphasizing five core objectives: 1) a secure and stable energy system for Idaho's citizens and businesses, 2) maintaining Idaho's low-cost energy supply, 3) protecting public health and conserving natural resources, 4) promoting economic growth, job creation, and rural economic development, and 5) ensuring Idaho's energy policy can adapt to changing circumstances.

In October of 2020, Governor Brad Little issued Executive Order 2020-17, continuing the role of the Office of Energy and Mineral Resources (OEMR) as the central coordinator for Idaho's energy policy. The OEMR manages energy production, conservation, and policy alignment, ensuring the state's energy resources remain stable and cost-effective.

Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to ten percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of

Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon’s regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of ten percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

In 2007, Oregon enacted Senate Bill (SB) 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon’s allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged as follows: 27 percent for 2025-2029, 35 percent for 2030-2034, 45 percent for 2035-2039, and 50 percent for 2040 and every subsequent year thereafter. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. HB 2021 also expanded the capacity standard for Small Scale Renewables from 8% to 10%. PacifiCorp filed its first Clean Energy Plan (CEP) on May 31, 2023, which included possible pathways towards compliance with HB 2021 emissions reduction goals, inclusive of the Small-Scale Renewable (SSR) targets and with emphasis on community-based actions. As also directed by HB 2021, PacifiCorp convened a Community Benefits and Impacts Advisory Group in the fall of 2022. An Oregon Tribal Nations Clean Energy-specific engagement series was started in March of 2023 after six months of direct outreach. The engagement series was formatted by informed feedback from outreach to Oregon Tribal Nations members with whom PacifiCorp had an existing relationship, and through new Tribal Nations relationship building.

In December 2022, Oregon Department of Environmental Quality adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. In Jan of 2022, HB 2165 passed requiring that all electricity companies (with $\geq 25,000$ retail customers) recover the cost of prudent infrastructure investments in transportation electrification. Furthermore, in November 2021, Oregon adopted California’s emission standards for HMDV via

the Advanced Clean Truck Rules 2021, paving the way for Oregon to adopt a target of 100% of new MHDV sales being ZEVs by 2050.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020 and every year thereafter. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In 2019, the Washington Legislature passed the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its retail electricity sales be supplied from renewable and non-emitting resources by 2045. PacifiCorp submitted its inaugural Clean Energy Implementation Plan (CEIP) on December 30, 2023, establishing a trajectory towards CETA compliance both for the current CEIP period, 2022 – 2025, and across the next two decades.

In 2021, Washington Legislature passed the Climate Commitment Act, which establishes a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances within the cap-and-trade program at no cost, for emissions associated with serving Washington retail load. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.

In December 2022, Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. Furthermore, in December 2021, Washington adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021. In 2022, Department of Ecology passed the Clean Fuel Standard law requires fuel suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034. There are several ways for fuel suppliers to achieve these reductions, including:

- Improving the efficiency of their fuel production processes
- Producing and/or blending low-carbon biofuels into the fuel they sell
- Purchasing credits generated by low-carbon fuel providers, including electric vehicle charging providers

Utah⁹

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

In April 2019, the Utah Legislature passed HB 411, Community Renewable Program, which allowed cities and municipalities in Utah to elect to participate on behalf of their residents. The Community Renewable Program is an opt-out program with the goal of being 100% net renewable by 2030. Customers within a participating community may opt out of the program and maintain existing rates. The legislation prohibits cost shifting to non-participating customers. By the end of 2019, 23 Utah communities passed a resolution as required by the legislation to participate in the program. Program design efforts are underway and ongoing.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, which enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of \$50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers. The Public Service Commission of Utah approved the Electric Vehicle Infrastructure Program on December 20, 2021, for implementation on January 1, 2022. The program construct will undergo regulatory review every three years through 2032.

In March 2024, the Utah Legislature passed SB 224, Energy Independence Amendments, that modifies the factors the Public Service Commission must consider when evaluating certain proposed energy resource decisions, establishes parameters for an affected electrical utility's recovery of costs associated with proven dispatchable generation resources located within the state, and encourages the commission to evaluate the purchase of excess proven dispatchable generation capacity.

In March 2024, the Utah Legislature passed HB 191, Electrical Energy Amendments, which requires the Public Service Commission to act in accordance with the state energy policy and make certain determinations before authorizing the early retirement of an electrical generation facility.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility;

⁹ Significant Utah legislative activity gathered interest in the 2025 IRP public input meeting series and stakeholder feedback. Regarding Utah SB-224, see Appendix M, stakeholder feedback form #13 (Emma Verhamme). Portfolio planning is currently not directly impacted by Utah SB-224, however variant and sensitivity studies may reflect this potential, such as the Low-Cost Renewables case and the No Coal 2032 case. Additional discussion of Utah activity is addressed in Appendix M, stakeholder feedback form #37 (Utah Citizens Advocating Renewable Energy).

requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 required the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement applies to generation allocated to Wyoming customers. HB 200 requires each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Wyoming Public Service Commission implemented new administrative rules Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. During the 2024 legislative session the Reliable and Dispatchable Low-Carbon Energy Standard statute was amended through SF 42, which extended the deadline for compliance with the Low-Carbon Energy Standards from July 1, 2030, to July 1, 2033.

In 2024, the Wyoming legislature passed SF 0023 Public Utilities-Energy Resource Procurement (SF 23) and SF 0024 Public Service Commission-Integrated Resource Plans (SF 24). SF 23 requires public utilities to conduct a solicitation process that is approved by the Wyoming Public Service Commission to acquire or construct a significant energy resource after July 1, 2024. A significant energy resource consists of 100 megawatts or more of new utility-owned generating capacity or utility-contracted generating capacity that has a dependable life or contract term of 10 or more years. SF 24 requires the Wyoming Public Service Commission to engage in long-range planning regarding public utility regulatory policy to facilitate the well-planned development and conservation of utility resources and requires the Commission to adopt rules providing a process for the review and acknowledgement of an action plan within an IRP.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO₂/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. Effective February 2025, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 876 lb GHG/MWh.

PacifiCorp purchased Chehalis in 2008 and this change in ownership is the act that triggered the applicability of the standard. Because the EPS was 1,100 lb GHG/MWh during the time of triggered applicability, that is the standard that Chehalis complies with. It isn't until Chehalis undergoes a change in ownership, upgrade, or new or renewed long-term financial commitment with anyone other than Bonneville Power Administration that applicability to the lowered standard would be triggered.

Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been generated, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.3, with additional discussion below.

Table 3.3 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted¹⁰ retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.¹¹ SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.¹² SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.4 below.

¹⁰ Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture storage and DSM.

¹¹ www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf

¹² leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

Table 3.4 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.75% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.25% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(46.67% * 2025 Retail Sales) + (49.33% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.67% * 2028 Retail Sales) + (57.33% * 2029 Retail Sales) + (60% * 2030 Retail Sales)

SB 2 (1X) established new “portfolio content categories” for RPS procurement, which delineated the type of renewable product that may be used for compliance and set minimum and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or

Have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.¹³

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.5.

¹³ A REC can be sold either “bundled” with the underlying energy or “unbundled” as a separate commodity from the energy itself into a separate REC trading market.

Table 3.5 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1 (2011-2013)	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2 (2014-2016)	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3 (2017-2020) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the CPUC confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC, and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources, or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites. Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

Oregon

In June of 2007, Oregon established a comprehensive renewable energy policy, including RPS, with the passage of SB 838, the Oregon Renewable Energy Act.¹⁴ Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,¹⁵ also referred to as Oregon’s Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon’s RPS requirements, which are set at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state’s investor-owned utilities must come from small-scale renewable projects under 20 megawatts.

¹⁴ www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf

¹⁵ olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state’s investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.¹⁶

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the “first-in, first-out” provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

PacifiCorp files an annual RPS compliance report by June 1 of every year. In addition, after the passage of Oregon House Bill 3161, effective January 1, 2024, ORS 469A.075 now aligns the filing of a renewable plan (formally called the Renewable Portfolio Implementation Plan or RPIP) with the filing of the IRP. Please see Appendix R for detailed information on PacifiCorp’s 2025

¹⁶ In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp’s share of the Oregon Solar Initiative was 8.7 megawatts.

RPS Renewable Plan, including annual targets, list of resources, applicable requirements, and assumptions and methodologies. These RPS compliance reports and plans are available on PacifiCorp's website.¹⁷

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are in Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative, later codified in Utah Code Title 54 Chapter 17.¹⁸ This law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024.

PacifiCorp filed its most recent progress report on December 29, 2023. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.0 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

¹⁷ www.pacificpower.net/ORrps

¹⁸ leg.utah.gov/~2008/bills/sbillenr/sb0202.pdf

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.¹⁹ The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. The only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs, or a combination of to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.²⁰

The WUTC adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

REC Management Practices

PacifiCorp provides the following summary of REC management practices in compliance with Order 20-186 in Oregon. The company intends to maximize the value of RECs for customers either through retirement for compliance purposes or monetization through sales. As a multi-state utility, PacifiCorp has Renewable Portfolio Standards in Washington, Oregon, and California, and a Renewable Portfolio Goal in 2025 in Utah. PacifiCorp generally retains and retires RECs allocated to Washington, Oregon, and California for compliance purposes, but requests flexibility to manage its RECs based on opportunities it sees in the market, which may include selling RECs at a favorable price and acquiring RECs at a lower price. The company maximizes the sale of RECs allocated to Utah, Idaho, and Wyoming and allocates the revenue from those sales to those states. One exception to REC sales is a special contract for one industrial customer where the customer foregoes REC sales revenue in exchange for a REC retirement to maintain renewable claims for corporate sustainability goals. An expansion of this program is currently under development to be offered under a new tariff in Utah, Idaho and Wyoming.

¹⁹ www.secstate.wa.gov/elections/initiatives/text/I937.pdf

²⁰ www.pacificpower.net/report

Clean Energy Standards

Washington

In 2019, Governor Jay Inslee signed into law Senate Bill 5116, the Clean Energy Transformation Act (CETA). Under the law, Washington utilities are required to be carbon neutral by January 1, 2030, and institute a planning target of 100 percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030, and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric sales over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

Oregon

As noted under State Policy Updates, above, in July 2021, Oregon Governor Kate Brown signed into law House Bill 2021, which set emissions reduction targets for utilities and electricity providers. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.

California

In 2018, California passed Senate Bill 100 – known as the “100 percent Clean Energy Act of 2018,” which sets a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources. The law also updates the state’s Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California’s electricity is renewable.

In 2022, California passed Senate Bill 1020, the Clean Energy, Jobs, and Affordability Act of 2022. This bill established interim targets to the previously established SB 100. It requires that eligible renewable energy resources and zero-carbon resources supply:

- 90% of all retail sales of electricity to California end-use customers by December 31, 2035
- 95% of all retail sales of electricity to California end-use customers by December 31, 2040
- 100% of all retail sales of electricity to California end-use customers by December 31, 2045
- 100% of electricity procured to serve all state agencies by December 31, 2030

In 2022, California passed Senate Bill 1158. This bill requires the State Energy Resources Conservation and Development Commission to adopt guidelines for the reporting and disclosure of electricity sources by the hour. The bill includes hourly power source reporting as a new set of reporting requirements at the Energy Commission and allows for the commission to modify those requirements for small entities with under 60,000 customers in California, like Pacific Power. In February 2025, the Commission adopted final rules that exempted multijurisdictional electric companies with 60,000 or fewer customers in California from compliance with the hourly reporting requirement.

Wyoming

In July 2020, House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards went into effect requiring the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The Wyoming Public Service Commission implemented rules for Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a final low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. The Company requested an extension and filed the final plan on March 29, 2024 that included a proposal to: conduct additional technical and economic analyses for an Allam Fetsvedt Cycle Project at either the Dave Johnston or Wyodak facilities by conducting a pre-FEED study in conjunction with SK and 8 Rivers; conduct additional technical and economic analyses by conducting a front-end engineering and design (FEED) study at the Jim Bridger facility; and no determination of a low-carbon portfolio standard at this time since CCUS continues to be evaluated for its technical and economic feasibility. The Commission approved the Company's final plan in public deliberations held on September 19, 2024. The statute also allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard.

Transportation Electrification

The electric transportation market continues to strengthen since 2022. Overall, light duty battery electric vehicle sales have grown since 2022 resulting in a market share of about 9% in the United States²¹. PacifiCorp states, especially west coast states continue to outpace the US market share percentage, California is number one, with Oregon and Washington close behind²². By 2030 EVs (LDV) are expected to reach 7.7 million or 46% of sales²³. EV sales still comprise a small portion of overall sales, however this will shift as medium-duty/heavy-duty (MD/HD) customers continue to expand. PacifiCorp also hosts major interstates and traffic corridors that will see continued electrification through policies discussed above. Furthermore, many businesses are moving to electrify their fleets from port authorities, transit agencies, etc. which will increase load over time.

This rapidly evolving market represents a potential driver of future load growth, and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation could improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

Current EV adoption numbers indicate that there is still an enormous opportunity for growth in the EV market. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light duty vehicles (LDVs) and medium-duty and heavy-duty vehicles (MD/HDVs). To inform a future vehicle adoption curve, the Company reviewed three national EV

²¹ [October 2024 auto sales volume to hold steady in the US | S&P Global](#)

²² [Electric vehicle market and policy developments in U.S. states, 2023 - International Council on Clean Transportation](#)

²³ [Electric Vehicle Sales and the Charging Infrastructure Required Through 2035](#)

forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves are quite different and can be adjusted to reflect state-specific parameters such as current market conditions, light duty truck saturation, and EV policies adopted in the state. PacifiCorp monitors vehicle adoption in each state on an annual basis and adjusts forecasts accordingly as new data is made available.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop commercial and residential charging programs, research new rate designs and implement time-of-use pricing programs and managed charging pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities.

In California, Pacific Power’s Electric Vehicle Infrastructure Rule 24 will pay for and coordinate the design and deployment of service extensions from our electrical distribution line facilities to the service delivery point for separately metered electric vehicle charging stations.²⁴ Pacific Power continues to provide programs funded by the Oregon Clean Fuels program as well as the recent HB 2165 legislation passed that created a transportation electrification benefits charge to support infrastructure development in the state of Oregon. As of November 2022, the Washington Utility and Transportation Commission approved Pacific Power’s Transportation Electrification Plan which sets out an estimated spend of \$3.5 million over the next five years to support TE in Washington state.

In Utah, PacifiCorp is implementing the \$50 million Electric Vehicle Infrastructure Program that has four core components: Company-owned public fast chargers, customer incentives, innovative projects, and outreach and education efforts. In June 2024, the first four locations with Company-owned public direct current fast chargers (DCFC) became operational. It is anticipated that there will be roughly 20 locations with an estimated 100 DCFC stations throughout Utah by the end of the program. As of the end of 2023, PacifiCorp had supported installation of over 4,800 EV ports throughout the territory.

Electric vehicle load is reflected in the Company’s load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts for electric vehicles.

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and the participation of numerous stakeholders including agencies, Native American tribes, non-governmental organizations, and local communities and governments.

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind and solar with carbon-free generation. In addition to operational flexibility, hydroelectric generation

²⁴ [California Electric Vehicle Infrastructure Line Extensions \(pacificpower.net\)](https://www.pacificpower.net)

does not have the emissions concerns of thermal generation. Hydroelectric projects can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

As of December 31, 2024, PacifiCorp has 15 FERC licensed hydroelectric projects. Each license may contain a single or multiple hydro developments (e.g., dams and powerhouses). PacifiCorp is currently seeking new licenses for the Cutler (30 MW) and Ashton (7.85 MW) hydroelectric projects. A new license for Cutler is expected in 2025, and a new license for Ashton in 2027. The next project to undergo the FERC relicensing process is the Bear River hydroelectric project (77 MW). That project's FERC license expires in 2033.

The FERC hydroelectric relicensing process can be extremely political and often controversial. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate those impacts. Tribal and interested party consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues, which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies could place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases, settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad involvement or that incorporate measures agreed upon through multi-party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2023, PacifiCorp had incurred approximately \$33 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on

PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler, Ashton and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing implementation and settlement costs relate to PacifiCorp's two largest hydroelectric projects: Lewis River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 7.

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting Tribal, agency and others' interests through creative solutions, is the best way to achieve environmental and social improvements while balancing customer costs and risks. PacifiCorp also has reached agreements to decommission projects where that has been the most cost-effective outcome for customers.

Rate Design

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No 20-035-04. The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has several rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage and is broken into separate charges for residential customers who live in single family and multi-family dwellings. All other remaining costs are recovered through volumetric-based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-

day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of December 2023, less than one percent of customers have opted to participate in the time-of-day rate option.

As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers an optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage,

Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. The power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the company the right to interrupt service to the participating customers when energy costs are higher.

Electricity Market Development Update

PacifiCorp and the CAISO launched the Western Energy Imbalance Market (WEIM) on November 1, 2014. The WEIM is a voluntary market and the first western energy market outside of California. NV Energy (NVE) began participating in December 2015, Arizona Public Service

(APS) and Puget Sound Energy (PSE) began participating in October 2016, and Portland General Electric (PGE) began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)¹ began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power (LADWP), Public Service Company of New Mexico (PNM), and Turlock Irrigation District (TID). Avista Utilities, Tucson Electric Power (TEP), Tacoma Power and Bonneville Power Administration (BPA) officially became a participant in the EIM in 2022. El Paso Electric (EPE), Western Area Power Administration Desert Southwest (WAPA DSW) and Avangrid (AVR) entered in April 2023. In 2026, Black Hills Montana and Berkshire Hathaway Energy Montana (BHE Montana) have planned entry into the WEIM.

The WEIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Texas, New Mexico, Utah, Washington, Wyoming, and British Columbia which make up almost eighty percent of the Western Energy Coordinating Council (WECC) load and will expand to include Montana in 2026. PacifiCorp continues to work with the CAISO, existing and prospective WEIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.12 – Western Energy Imbalance Market Expansion



The WEIM has produced approximately \$5.85B in monetary benefits since inception for participating utilities, quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every fifteen and five minutes within and across the WEIM footprint based on the most economical solution; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexible reserves in all WEIM balancing authority areas which reduces cost by aggregating load, wind, and solar variability and forecast errors of the WEIM footprint.

A significant contributor to WEIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations that exist in states with a price on carbon (i.e., California and Washington). Generally, transfer quantities are based on transmission and interchange rights between participating balancing authority areas.

After development and expansion of the WEIM in the west, a natural next question was – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of WEIM but short of a full regional transmission organization? PacifiCorp believes the answer is ‘yes’.

Over the duration of 2022, the CAISO held a robust stakeholder process to develop the market design of the Extended Day-Ahead Market (EDAM). With stakeholder feedback, the final EDAM proposal was released in early December 2022. On December 8th, PacifiCorp announced that it intends to join EDAM. The final EDAM design was approved by the CAISO Board of Governors and WEIM Governing Body in early February 2023 and received FERC approval on December 28, 2023. EDAM is scheduled to go live on May 1, 2026, and to date, PacifiCorp and Portland General Electric have signed their EDAM implementation agreements.

The Southwest Power Pool (SPP) has also been developing a day-ahead market offering, called Markets+. Markets+ introduces a potential risk to WEIM benefits through a shrinking WEIM footprint as stakeholders who want to participate in Markets+ would need to exit WEIM. In addition to a smaller WEIM footprint, day-ahead markets with different design elements and requirements for participation exacerbate the seams issue which already exist throughout the west. SPP and stakeholders filed their tariff with FERC on March 29, 2024, and received a deficiency letter on July 31, 2024, that SPP is currently working through to remedy FERC’s clarification and additional information request due at the end of November 2024. SPP does not believe the SPP Markets+ timeline will be impacted for their projected spring 2027 go-live target and stakeholders must be vigilant to ensure the markets work as cohesively as possible.

Recent Resource Procurement Activities

PacifiCorp’s past procurement efforts have resulted in a number of contracts for new resources that have recently come online or are projected to come online through 2026 as summarized in Table 3.6.²⁵ These resources are also included in the resource tables presented in Chapter 6.

²⁵ See Appendix M, stakeholder feedback form #59 (Renewable Northwest)

Table 3.6 – PacifiCorp’s Recent and Upcoming New Resource Additions

Resource	Type	Resource Capacity (MW)	Storage Capacity (MW)	Year contracted	Commercial operation	Source
Appaloosa Solar	Solar	200	n/a	2020	Jan 2024	Customer program: UT Sch 34
Rocket Solar	Solar	80	n/a	2020	Feb 2024	Customer program: UT Sch 34
Castle Solar	Solar	40	n/a	2020	Apr 2024	Customer program: UT Sch 32
Horseshoe Solar	Solar	75	n/a	2020	Apr 2024	Customer program: UT Sch 34
Elektron Solar	Solar	80	n/a	2020	Apr 2024	Customer program: UT Sch 34
Oregon Institute of Tech. BESS	Battery Storage	n/a	2	n/a (owned)	Mar 2025	OR HB 2193 (2015)
Rock River Wind	Wind	50	n/a	n/a (owned)	Sep 2024	Repowering of existing site
Cedar Creek Wind	Wind	151.8	n/a	2022	Mar 2024	2020 AS RFP
Anticline Wind	Wind	190	n/a	2022	Dec 2024	2020 AS RFP
Boswell Wind	Wind	100.5	n/a	2022	Dec 2024	2020 AS RFP
Cedar Springs Wind IV	Wind	320	n/a	2022	Jan 2025	2020 AS RFP
Rock Creek Wind I	Wind	350.4	n/a	n/a (owned)	Dec 2024	2020 AS RFP
Rock Creek Wind II	Wind	400	n/a	n/a (owned)	Sep 2025	2020 AS RFP
Green River Energy Center	Solar + Battery	400	400	2022	May 2026	2020 AS RFP: amended to increase storage capacity in 2023
Faraday Solar and Storage	Solar + Battery	525	150	2023	Sep 2025	Customer program: UT Sch 34
Hornshadow Solar	Solar	300	n/a	2023	Jun 2025	Customer program: OR Sch 272
Dominguez Grid	Battery Storage	n/a	200	2024	Jun 2026	Negotiated after 2022 AS RFP
Enterprise Storage	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Escalante BESS	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Granite Mountain BESS East	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Iron Springs BESS	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Oregon Comm. Solar (aggregate)	Solar	38.8	n/a	various	various	Oregon Community Solar Program
Total		3,301	1,072			

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.7 summarizes recent RFP activities.

Table 3.7 – PacifiCorp’s Requests for Proposal Activity

RFP	RFP Objective	Status	Issued	Completed
Renewable energy credits (Purchase)	Excess system RECs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing
2024 Utah Renewables Community RFP	Seeking resources consistent to the Community Clean Energy Act (Utah Code 54-17-901 to -909)	Ongoing	Expected November 2024	Expected October 2025

2022 All-Source RFP

On April 1, 2024, PacifiCorp published the company’s 2023 Integrated Resource Plan Update. The 2023 IRP Update preferred portfolio demonstrated that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is material customer benefit to scaling down and delaying resource acquisition until after 2030. As such, the 2022 All-Source Request for Proposals was terminated. PacifiCorp’s 2025 IRP will inform the next steps for incremental resource acquisition.

2024 Utah Renewables Community RFP

The 2024 Utah Renewable Communities’ Request for Proposals for renewable energy resources (2024 URC RFP) is administered by the Community Renewable Energy Agency (Agency) on behalf of customers that participate in the Community Clean Energy Program (Program). The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp’s transmission system. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

2025 All-Source RFP

PacifiCorp will seek to file the 2025 All Source RFP (“2025AS RFP”) based on results identified in the 2025 IRP preferred portfolio. Further updates on the status and schedule of the 2025AS RFP will be provided as they become available.

Recent Resource Procurement/DSM Procurement

In 2023, PacifiCorp issued a Request for Proposals to re-procure program delivery services for the Home Energy Savings and Wattsmart Business energy efficiency programs in Washington and California. As a result of the re-procurement, new contracts for Washington and California were signed in 2024. For Washington specifically, PacifiCorp followed its Competitive Procurement Framework,²⁶ including seeking Washington DSM Advisory Group input and posting a notice on the Company website prior to releasing the Request for Proposals. In 2024, PacifiCorp issued a Request for Proposals to re-procure program delivery services for Wattsmart Business in Utah, Idaho and Wyoming, and contracting is underway.

In 2024, PacifiCorp also issued an RFP for energy efficiency implementation services for a commercial new construction program in its Utah service area. The procurement and subsequent contracting steps are still underway.

²⁶ 2022-2023 Biennial Conservation Plan, Appendix 6 (Docket UE-201830)

The current Competitive Procurement Framework for Washington Conservation and Efficiency Resources is available in Appendix 6 to the 2024-2025 Biennial Conservation Plan (Docket UE-230904).

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp’s planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp’s transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2025 IRP preferred portfolio includes the following notable transmission upgrades:¹
 - A series of upgrades to increase transfer capability between southern Utah and the Wasatch Front, projected to come online between 2026 and 2036.
 - New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington, projected to come online in 2031.
 - 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon, projected to come online in 2032.
 - New transmission including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon, projected to come online in 2036.
 - A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2), projected to come online in 2036.
- Further, the 2025 IRP preferred portfolio includes near-term transmission upgrades across PacifiCorp’s transmission system including investment in infrastructure in Oregon, Utah, and Washington that will facilitate continued and long-term growth in new resources needed to serve PacifiCorp’s customers.

Introduction

PacifiCorp’s bulk transmission network is a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

¹ Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP base modeling:

- The Energy Gateway South transmission line - a new 416-mile, high-voltage 500 –kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in Q4-2024.
- The Energy Gateway West Subsegment D1 project - a new high-voltage 230-kilovolt transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in Q4-2024.

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, considering scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a carbon free energy future.
4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Resiliency to protect against system and market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process. PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve the growing energy needs of our customers.

This chapter provides:

- An overview of PacifiCorp's regulatory requirements including recent updates to PacifiCorp's generation interconnection procedures.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which

supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service and generation interconnection requests, as factors to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on this data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.² A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

For point-to-point transmission service, the OATT requires PacifiCorp to grant service on existing transmission infrastructure using existing capacity or to build transmission system infrastructure as required to provide the service. The required action is determined with each point-to-point transmission service request through FERC-approved study processes that identify the transmission need.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC reliability coordinator. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to always meet aggregate electrical demand for customers. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

² For example, PacifiCorp's application to begin the Environmental Impact Statement process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management in 2007. A partial Record of Decision (ROD) was received in late April 2013, and a supplemental ROD was received in January 2017.

Generation Interconnection Study Methodology Changes

In 2022 PacifiCorp filed a request with FERC to modify its large generator interconnection procedure to allow PacifiCorp to study new standalone storage resources as not discharging during high generation of other resources in the region. The request was approved by FERC in March 2022 and the new assumptions were implemented into generation interconnection studies starting with Cluster 2. The new operating assumptions have allowed PacifiCorp to use more realistic study assumptions for storage resources which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources.

In 2023 FERC released Order 2023 which required modifications of all transmission provider's including PacifiCorp's, generator interconnection procedures. Several notable changes were included in Order 2023. First, FERC required all transmission providers to move to a first ready, first serve cluster study process which PacifiCorp had already transitioned to in 2020. Second, FERC required all transmission providers to use a distribution factor analysis to assign cost responsibility to specific interconnection customer requests driving the need for network upgrades. This change to PacifiCorp's procedures will allow for projects sited in locations that have smaller impacts on the transmission system, avoiding cost responsibility for upgrades in the region that its project does not cause. Other aspects of the Order 2023 include requiring 100 percent of site control for proposed generating facilities with the initial application and substantial withdrawal penalties at the facilities study stage both of which should disincentivize speculative projects. PacifiCorp will implement a transition process in which existing interconnection requests that have not yet proceeded far enough in the study process will have the opportunity to be studied in a transition cluster study or be withdrawn. PacifiCorp's next application window for new generation interconnection requests will open in 2026.

Aeolus to Mona/Clover (Gateway South – Segment F)

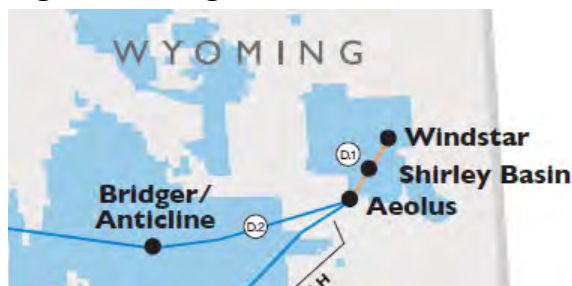
The Energy Gateway South transmission line is a new 416-mile, high-voltage 500-kV transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line is currently under construction and scheduled to come online by the end of 2024.

Windstar-Populus (Gateway West – Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

- D1—Recently placed in service, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming.
- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020.
- D3—A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho.

Figure 4.1 - Segment D



Populus-Hemingway (Gateway West - Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects specifically transmission segment between Midpoint-to-Hemingway portion of Segment E.

Figure 4.2 - Segment E



The Gateway West Segment E project would enable PacifiCorp to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The record of decision (ROD) and right-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management (BLM) to review progress.

Boardman-Hemingway (Segment H)

Boardman-to-Hemingway (B2H) is an approximately 290-mile high-voltage 500-kV transmission line capable of coming online in 2027. PacifiCorp is continuing to coordinate with regional transmission providers and retail customers to evaluate options for this project.

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities and other pre-construction activities agreed to in the updated agreement.

Idaho Power's 2023 IRP identified the B2H as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2027 or beyond.

The BLM released its record of decision ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the

B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018, for lands administered by the USFS based on the analysis in the final environmental impact statement. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019, in support of construction of a portion of the B2H project on 7.1-miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

On September 27, 2022, Oregon’s Energy Facility Siting Council approved the Oregon site certificate completing Oregon’s permit actions that provide for the construction of the project across private lands in Oregon. Following this action an appeal was made to the Oregon Supreme court challenging the approval. On March 8, 2023, the court affirmed the site certificate which finalized the site certificate.

In January of 2022 Idaho Power, BPA and PacifiCorp agreed in a non-binding term sheet to negotiate Bonneville’s exit of the project with Idaho Power acquiring Bonneville’s share responsibility of the project. This will provide Idaho Power with a 45 percent share of the project and retain PacifiCorp’s 55 percent share. Additional terms under negotiations include changes in transmission service between PacifiCorp and BPA, between BPA and Idaho Power, as well as the purchase and sale of certain assets between Idaho Power and PacifiCorp. The Boardman to Hemingway amended Permit Funding Agreement removing Bonneville and updating the agreement to capture additional pre-construction tasks was executed on March 23, 2023. The Joint Purchase and Sale agreement between Idaho Power and PacifiCorp provides Idaho Power with certain assets allowing service to BPA customers in southeast Idaho via the B2H line, and capacity from the Four Corners substation in New Mexico to the Populus substation in southern Idaho. Associated with the term sheet is the Hemingway project construction agreement, construction agreements for upgrades that provide PacifiCorp additional capacity across Idaho Power’s transmission system and a construction agreement that provides PacifiCorp additional capacity to serve central Oregon loads. These agreements were all executed on March 23, 2023.

Idaho Power has applied for Certificates of Public Convenience and Necessity (CPCN) in Oregon and Idaho. Issuance of both certificates were received in June of 2023. PacifiCorp received a CPCN in Idaho in June 2023 and in Wyoming in August 2023.

The current project schedule includes projected completion in 2027.

At this time, PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Spanish Fork – Mercer 345-kV line

The 2025 preferred portfolio includes the construction of a new, approximately 50-mile, 345-kV transmission line between Spanish Fork Substation and Mercer substation in Utah, with an identified in-service date of 2036, based on projected interconnection requirements. Load-service and reliability requirements may bring this date forward, as could accelerated generator

interconnection demand. PacifiCorp has begun the permitting process for this new transmission line and is currently targeting an in-service date of 2027 for the line.

Other Transmission System Improvements

The 2025 IRP preferred portfolio also includes near-term transmission upgrades across its transmission system. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources and increased reliability for its customers.

Energy Gateway Transmission Expansion Plan

Introduction

Given the long-lead time required to successfully site, permit, and construct major new transmission lines, these projects need to be planned well in advance. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements and other state-specific policy goals. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy

groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

- **Rocky Mountain Area Transmission Study**

Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:

- Bridger system expansion is like Gateway West.
- Southeast Idaho to southwest Utah expansion akin to Gateway Central, Segment B, Segment C and Sigurd to Red Butte (in service 2015).
- Improved east-west connectivity like Energy Gateway Segment H alternatives.

“The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices.”

- **Western Governors’ Association Transmission Task Force Report**

Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high conventional resource scenarios. Again, for PacifiCorp’s system, the transmission expansion that supported these scenarios closely resembled Energy Gateway’s configuration.

“The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location.”

- **NorthernGrid Regional Transmission Plan Reports**

In the 2020-2021 NorthernGrid Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study: the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

“After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced... then, NTTG’s Technical Committee determined additional facilities would be needed to meet the reliability criteria....”

The NorthernGrid 2022-2023 Regional Transmission Plan identified the regional combination consisting of Gateway West (Segment D.3 and Segment E) and B2H as the most efficient and cost-effective set of projects for the NorthernGrid 10-year planning horizon. Gateway South was considered as an in-service project in all cases, including the selected regional combination.

- **WECC/Reliability Assessment Committee (RAC) Annual Reports and Western Interconnection Transmission Path Utilization Studies**

These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments were included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

“Path 19 [Bridger] is the most heavily loaded WECC path in the study.... Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area.”

Energy Gateway Configuration

To address constraints identified on PacifiCorp’s transmission system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle of reliability that spans Utah, Idaho and Wyoming with paths extending into Oregon and Washington. This plan contemplates geographically diverse resource locations based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway’s initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp’s OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp’s Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NorthernGrid regional planning organization and WECC’s Reliability Assessment Committee and was formally a member of Northern Tier Transmission Group (NTTG) regional planning organization.

These groups continually evaluate PacifiCorp’s transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp’s OASIS site for information and materials related to these public processes.³

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to

³ <http://www.oatioasis.com/ppw/index.html>

establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

While the core tenets for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (for example, maximized use of energy corridors, reduced environmental impacts and improved economies of scale), PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received more than 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, PacifiCorp entered memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway (B2H) project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing

authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500 kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

In 2012, PacifiCorp determined that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the B2H Permitting Agreement with Idaho Power Company and BPA that provides for PacifiCorp's participation through the permitting phase of the project. The B2H project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the B2H project, and PacifiCorp continues to support these activities under the conditions of the B2H Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. PacifiCorp further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that was terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed and placed in service the Mona-to-Oquirrh project. In November 2013, the BLM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd-to-Red Butte project was completed and placed in service.

In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

In January 2017, the BLM issued its ROD and right-of-way grant, previously deferred as part of the November 2013 partial ROD, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

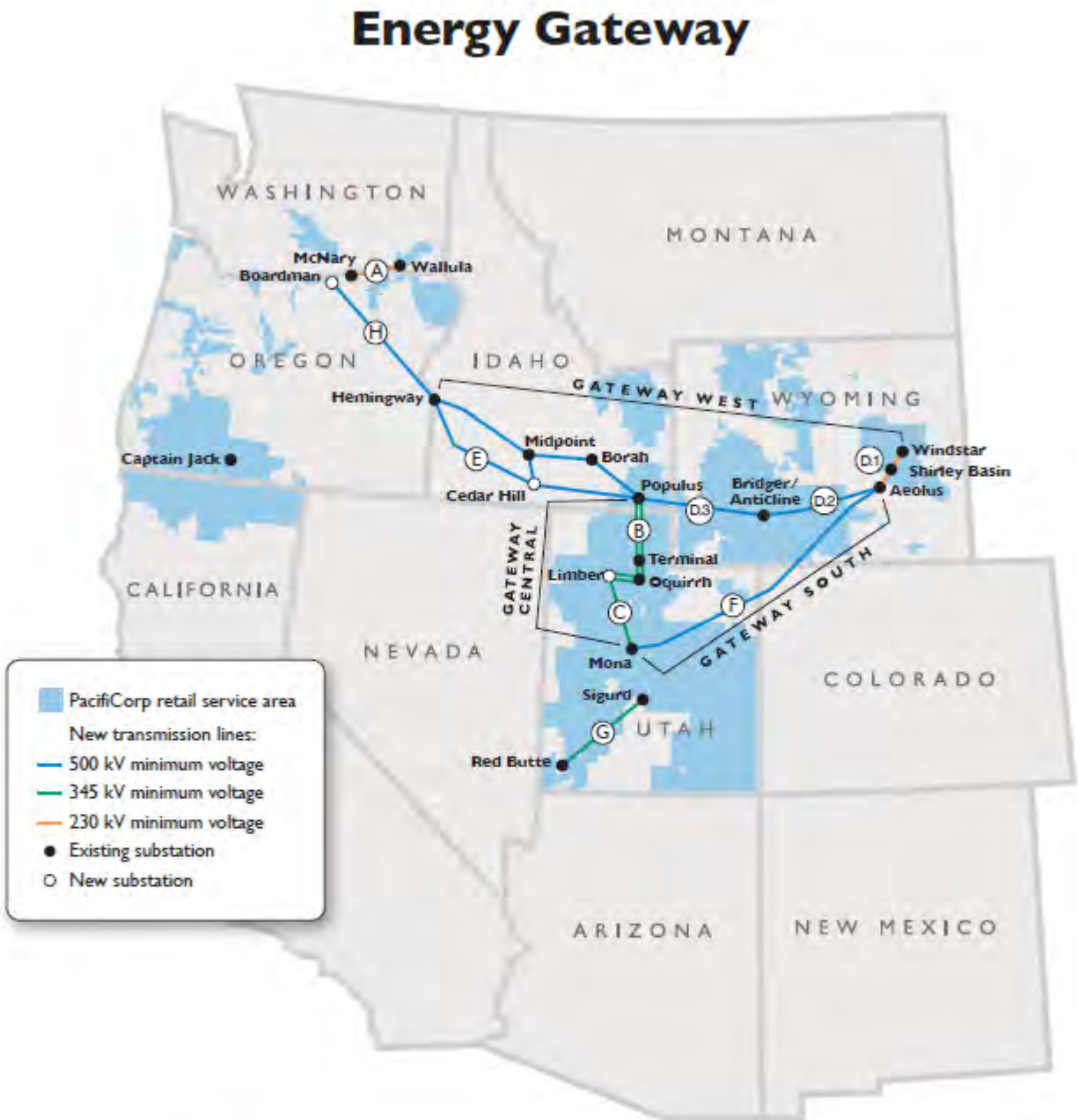
In October 2020, Segment D2 of Gateway West, from Aeolus to Jim Bridger was placed into service which included a new 500 kV substation at Aeolus, and a new 345 kV substation at Anticline.

In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 230 kV line between Shirley Basin and Dave Johnston substations is under construction with an expected completion date of both lines in December 2024.

Gateway Segment F, referred to as Gateway South, a 416-mile 500 kV line from Aeolus substation in Wyoming to Mona/Clover substation in central Utah is under construction with an expected completion date of December 2024.

Other Gateway segments, including Gateway West Segment D3 from Bridger substation in Wyoming to Populus substation in Idaho and Gateway West Segment E from Populus to Hemingway, in Idaho, are in pre-construction activities to address requirements as defined in their permitting Record of Decision and right-of-way grants issued by the BLM.

PacifiCorp will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs, its compliance with mandatory reliability standards, and the stipulations in its project permits.

Figure 4.3 – Energy Gateway Transmission Expansion Plan

This map is for general reference only and reflects current plans.

It may not reflect the final routes, construction sequence or exact line configuration.

PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	- Status: completed - Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	- Status: completed - Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	- Status: completed - Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	- Status: right-of-way acquisition underway - Scheduled in-service: 2024
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	- Status: permitting underway - Scheduled in-service: December 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	- Status: completed - Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	- Status: permitting underway - Scheduled in-service: 2034 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	- Status: permitting underway - Scheduled in service: 2036 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	- Status: permitting underway - Scheduled in-service: December 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	- Status: completed - Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	- Status: pre-construction activities in progress - Scheduled in-service: 2027

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, PacifiCorp has instituted more than 130 grid operating procedures and 20 remedial action schemes (RAS) to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market (EIM) since November 2014. As of April 2023, 22 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system can identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

To secure further benefits from market-based resource dispatch, PacifiCorp announced in December 2022 that it expects to participate in the Extended Day-Ahead Market (EDAM) being

developed by the California Independent System Operator (CAISO).⁴ While the EIM makes full use of resource flexibility within the hour and will continue to do so, the EDAM will provide economic, reliability, and environmental benefits by optimizing the pool of resources that are made available to EIM in light of forecasted requirements for the entire market footprint over the following several days, well beyond the end of the current hour. This includes coordination of generator starts and shutdowns and the charging and discharging of energy storage resources.

Transmission System Improvements Placed In-Service Since the 2023 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area

- Installs a 345 kV, 200-MVAr switched shunt reactor at Mona substation:
 - Project driver was to address the high voltage conditions experienced during steady state operations under light load and light transfer conditions.
 - Benefits include more effective high voltage control and safe and more reliable power for the Utah area by reducing lines taken out of service and preservation of substation equipment life, particularly circuit breakers which are exposed to frequent switching, reduced probability of mis operation and increased maintenance costs.

2. Northern Utah/Southeast Idaho Area

- Constructed a new 345 kV yard adjacent to the existing Bridgerland 138 kV substation. Looped in the existing Populus – Terminal 345 kV line into Bridgerland and Ben Lomond substations:
 - Project driver was to resolve System Operating Limit on Path C.
 - Benefits include the ability to maintain the WECC Path C rating to 1600 MW southbound and 1250 MW northbound.

3. Salt Lake City Utah area

- Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line:
 - Project driver was to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
 - Benefits included mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability.

4. Southern Utah area

- Reconductor 2.57-miles of the St. George-Purgatory Flat 138 kV transmission line:
 - Project driver was to increase the thermal rating of the line which loaded to 95 percent of its continuous summer thermal rating summer 2022.
 - Benefits included the increases of the transmission line summer continuous rating by 63 MVA.

⁴ <http://www.caiso.com/Documents/EDAM-Fact-Sheet.pdf>

PacifiCorp West (PACW) Control Area

1. Klamath Falls Oregon Area

- Constructed a second 230 kV transmission line from Snow Goose to Klamath Falls substation:
 - Project driver was to resolve NERC Standard TPL-001-5 Category P6 (N-1-1) for a double contingencies on the 230-kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
 - Benefits included reinforcing 230 kV system between in Klamath Falls area to cover TPL-001-5 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.

2. Prineville Oregon Area

- Construct a second 115 kV line between Houston Lake and Ponderosa substations:
 - Project driver was to eliminate potential N-1 overloads of the Prineville 115 kV system associated with increased load, changing generation mix, and grid flow conditions in the area.
 - Benefits included the elimination of a NERC Standard TPL-001-5 Category P1 contingency event for a fault on the 115 kV line between Baldwin Road and Ponderosa substation or a fault on the 115 kV line between Houston Lake and Stearns Butte.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Utah Area

- Upgrade the 345-138 kV 167-MVA transformer at Camp Williams substation to a 345-138 kV 700-MVA transformer:
 - Project driver is to correct NERC Standard TPL-001-5 Category P6 deficiencies during peak summer loading conditions for the N-1-1 event of losing both Spanish Fork substation 345-138 kV transformers that would cause thermal overloads to the Camp Williams 345-138 kV transformer and the Clover – Nebo 138 kV line.
 - Benefits include mitigating the NERC Standard TPL-001-5 Category P6 deficiencies. Provides additional 345 kV source to northern Utah Valley and Jordan Valley as well as increase system reliability.
- Install a second 345-138 kV 700 MVA transformer at Oquirrh substation:
 - Project driver is to correct N-1 contingency overload issues in the South Jordan area.

- Benefits include increasing capacity on the 138 kV network serving the Salt Lake Valley.
 - Construct a new 345 kV line between Spanish Fork and Mercer 345 kV substations:
 - Project driver is to eliminate the need for the Lakeside II Remedial Action Scheme (RAS) and prevent generation shedding during contingencies. Once flows across the Wasatch Front South boundary exceed 5,562 MW, the Lakeside RAS is no longer effective and cannot be modified to accommodate more flow.
 - Benefits include the increase of path limit to 6,300 MW and allow 1,000 MW additional generation to be interconnected in southern Utah.
2. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers:
- Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming:
 - Project driver was to correct NERC Standard TPL-001-5 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 12 substations to be addressed as required per R2.8.
 - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-5 Requirement R2.3 deficiencies and as required per R2.8.
3. Salt Lake City, Utah Area:
- Convert North Salt Lake Substation to 138-kV:
 - Project driver is to correct N-1 contingency overload issues in the North Salt Lake area.
 - Converting to 138 kV at North Salt Lake substation increases the capacity in the area while mitigating the contingency overloads, reduces the burden on the 46 kV system, and brings better reliability to the customers in the area.
 - Loop the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard:
 - Project Driver is to eliminate identified overloading of the 90th South – Midvalley 345 kV #1 line under heavy transfer conditions across the Wasatch Front South boundary.
 - Benefits include increasing the transfer capability across the Wasatch Front South boundary by 45-MW, improving operating flexibility, and allowing additional transfers from Clover/Mona as well as from southern Utah to the Wasatch Front.
 - Construct a new 230-46 kV substation near Eden, Utah:
 - Project driver is to provide a transmission loop to the area to facilitate a line rebuild through Ogden Canyon.
 - Benefits include improved future reliability and area capacity.
4. Southeast Idaho Area:
- Install a 25 MVAR shunt capacitor bank at the Franklin 138 kV substation:
 - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) contingency events for the loss of the Treasureton – Franklin 138 kV line.

- o Benefits include resolving the NERC Standard TPL-001-5 Category P1 voltage issues.

PacifiCorp West (PACW) Control Area

1. Eastern Oregon Area

- Replace the entire Burns 500 kV reactive station, including the series capacitor bank, bypass breakers, shunt reactors, and all switches and circuit switchers:
 - o Project driver is to replace obsolete and degrading assets to prevent equipment failure which would result in a substantial financial impact and limiting Jim Bridger and Wyoming wind generation for an extended time.
 - o Benefits include replacement of obsolete equipment with modern SCADA-operable equipment (reducing operational labor), reduces the risk of failure, and improves recovery time.

2. Portland Oregon Area

- Reconfigure and convert the existing Bonneville Power Administration's (BPA) St. Johns – Columbia and PacifiCorp's (PAC) Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina to 115 kV:
 - o Project driver is to correct NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies for load loss of up to 62-MW in the urban northeast Portland core area and Category P6 (N-1-1) deficiencies for voltage issues on the 57 kV system.
 - o Benefits include resolution of NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies, elimination of the 57 kV system voltage in the North Portland and creates a third 115 kV path between the St. Johns/Rivergate and the Knott/Albina area.

3. Roseburg Oregon Area

- Convert the 69 kV transmission Lines 30 and 65 to 115 kV, along with four distribution substations and construct a new 115 kV tie from Roberts Creek to the converted Green substation:
 - o Project driver is to resolve multiple capacity limitations in the area; notably the Roberts Creek 115-69 kV transformer, the Winchester 115-69 kV transformer, Line 66 between Dixonville and Sutherlin and Line 65 between Dixonville and Southgate. 12 system problems were identified as being affected by these limitations.
 - o Benefits include improvement of operability of the system to increase reliability during outages and maintenance and gives the system enough excess capacity to accommodate 20 years of growth at a 1.3 percent per year rate.
- Replace the existing 230-115 kV transformer at Dixonville substation with a new 280 MVA transformer:
 - o Project driver is to resolve excess voltage on the 115 kV bus. The current transformer steady state voltage sits at 10.4 percent above nominal in the North Umpqua Hydroelectric System and is nearly 8.7 percent above nominal at Dixonville substation.
 - o Benefit includes bringing the 115 kV bus voltage at Dixonville to operate within an acceptable range and avoids excessive voltage throughout the Roseburg and North

Umpqua areas extending the life of the transformers as well as all the downstream equipment.

4. Medford Oregon Area

- Construct a 230-kV transmission line between Lone Pine and Whetstone substations:
 - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) and P6 (N-1-1) outage combinations including loss of the two Meridian-Lone Pine 230-kV lines (N-1), N-1-1 loss of the Meridian-Whetstone and Dixonville-Grants Pass 230-kV lines, or N-1-1 loss of Sams Valley 500-230 kV source and either the Meridian-Whetstone 230-kV line or Dixonville-Grants Pass 230-kV line.
 - Benefits include resolving the NERC Standard TPL-001-5 Category P1 and P6 issues as well as preventing reverse flow across the Medford 115 kV system to support the 230 kV system and allows operating the Medford 115 kV system radial.
- Construct one new 500-230 kV substation called Sams Valley:
 - Project driver is to correct NERC Standard TPL-001-5 deficiencies for the loss of a single 230 kV line and for N-1-1 and N-2 outages to 230 kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported through subsequent NERC TPL Assessments, and to provide a second 500 kV source to address load growth in the Southern Oregon region.
 - Benefits include adding a second source of 500 kV capacity, adding a new 230-kV line, improving reliability of the 230 kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-5 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. In conditions of increased demand and resource variability, higher summer temperatures reduce excess energy supply, in turn tightening supply from the market.
- PacifiCorp’s wildfire mitigation plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2025 IRP preferred portfolio includes the Energy Gateway South (GWS) and Energy Gateway West segment D.1, which are currently operational. The preferred portfolio also includes future transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of low-cost resource options and relieves stress on current assets.

Introduction

Serving reliably (i.e., keeping the lights on for customers), as well as planning for a resilient system (i.e., operating through and recovering from a major disruption) is a primary focus for PacifiCorp. With the increasing retirement of thermal baseload resources, the incorporation of increasing numbers of intermittent renewable resources, and the impacts of climate change, planning for a reliable and resilient energy future is more crucial, and more complex, than ever. PacifiCorp continues to build on a strong history of serving its customers safely, reliably, and affordably.

The focus on reliability and resiliency spans across several areas of the company: PacifiCorp’s resource planning and energy supply teams work closely with regional partners and ensure that there is sufficient supply to serve customers, while transmission and distribution teams work to mitigate the destructive impact of wildfire risk throughout the west to ensure that PacifiCorp can deliver power safely to customers now and in the future.

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2025 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information.

In December 2024 the Western Electricity Coordinating Council (WECC) published the Western Assessment of Resource Adequacy (WARA), which serves as an interconnection-wide assessment of resource adequacy as discussed below. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

WECC Western Assessment of Resource Adequacy Report

The WECC WARA was published in December 2024 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years.¹ The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. A key driver of the results is the forecasted growth in load across the west, which is projected to increase by over 20.4% in the next ten years (on an energy basis), more than double the 9.6% growth forecast from the 2022 WARA. PacifiCorp’s loads are located in the NW-Northwest and NW-Central regions evaluated as part of the WARA. Peak demand in the NW-Northwest region is forecasted to grow by 13.5% in the next ten years, while the NW-Central region is forecasted to grow by 8.5% over the same time. While significant, these are both lower than the growth of the Western Interconnection as whole, where growth is projected at 17.2%, driven by increases in California and the Desert Southwest.

Resource plans have identified a vast quantity of resources to meet this demand, 172 GW of new generation resources, which is more than double the generation capacity added in the last ten years. Plans include 68 GW of solar capacity additions in the next ten years, while will nearly triple the 35 GW in operation in 2023, plus 40 GW of wind capacity additions in the next ten years, relative to 37 GW in operation in 2023. Similarly, battery storage is projected to grow by 37 GW. The WARA highlights concerns that planned resources will not be brought online in a timely manner and includes four scenarios evaluating various levels of resource build out.

In the “All Additions” scenario, which includes all planned resources, the WARA identifies risks in the NW-Northwest region, primarily in the winter, and primarily in 2029 and later. Risks increase and appear in other regions if lower levels of planned resources are achieved, as summarized in Table 5.1.

Table 5.1 – WARA Demand-at-Risk Summary²

Region	55% Resource Additions Scenario											
	Month 1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	Medium	Medium	Low	-	-	-
NW-Northwest	High	High	Medium	Low	-	-	Low	Medium	Medium	High	High	High
NW-Northeast	-	Low	-	-	-	-	Low	Medium	-	-	-	-
NW-Central	-	-	-	-	-	Low	Medium	Medium	Medium	-	-	-

Region	85% Resource Additions Scenario											
	Month 1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	-	-	-	-	-	-
NW-Northwest	Medium	Medium	-	-	-	-	-	Low	-	Medium	Low	Medium
NW-Northeast	-	Low	-	-	-	-	-	Low	-	-	-	-
NW-Central	-	-	-	-	-	Low	Low	Low	Medium	-	-	-

Risk reflects the count of hours in each month that exceed a one-day-in-ten-years threshold by 2034.

High >50 hours

Medium 10-49 hours

Low <10 hours

¹ WECC. Western Assessment of Resource Adequacy 2024. Available online: <https://feature.wecc.org/wara/> (accessed 12/18/2024)

² WECC. WARA 2024 Demand-at-Risk Hours by Subregion. Available online at: <https://www.wecc.org/wecc-document/17071> (Accessed 12/18/2024)

The NW-Northwest and NW-Central regions which include PacifiCorp's load both have hours at risk. In the NW-Northwest region, significant risk exists in both the summer and winter seasons. While PacifiCorp has significant transfer capability into the NW-Northwest and proportionately lower dependence on hydropower than the NW-Northwest region as a whole, regional capacity limitations would result in less margin for error. In the NW-Central region, risks are somewhat lower, and concentrated in the summer, but still indicate that incremental resources are necessary to serve growing loads. The results shown assume import capability between sub-regions – in the absence of imports, risks are high in the NW-Northwest and NW-Central regions even if all planned new resources are built.

The WARA characterizes four risks that impact planned resource additions: supply chain disruptions, interconnection queue, siting delays, and increased costs. Some of the impacts are reduced because of PacifiCorp's particular circumstances. PacifiCorp's relatively large portfolio and geographic footprint create a wider range of opportunities than are available to many other utilities, increasing the likelihood that some new projects will be able to proceed. This is bolstered by PacifiCorp's implementation of a cluster study interconnection process in 2020, which has enabled large numbers of interconnection requests to be processed more quickly than was possible in the past, increasing the likelihood that projects will be available in desired timeframes. After cost-effective projects are identified, PacifiCorp's relatively large demand allows it to contract with multiple developers for multiple sites, reducing the impact if any single developer or site falls through or is delayed. That said, substantial risks remain for any resource additions.

The WARA also characterizes risks associated with other factors: resource variability, transmission considerations, energy policy, and extreme weather. The limitations of wind, solar, and energy-limited resources like energy storage are different from those of baseload or dispatchable resources, and those limitations become more restrictive as the share of these resources increases. Given the expected tripling of solar capacity and doubling of wind capacity, variability is expected to increase significantly. The variability and operational requirements of that future resource mix is not fully characterized and could be impacted further by extreme weather events. The other risk factors cover a range of planning and policy considerations, and the process through which resource and transmission build outs are implemented. Utility planning and procurement takes time, and the build out of resources and transmission is reliant upon a range of state and federal processes and requirements.

NERC Long-Term Reliability Assessment (LTRA)

Resources

As part of the regional reliability assessment to support the 2025 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2024.³ The NERC LTRA organizes prospective resources into three broad capacity supply categories in its 10-year WECC region reliability assessment:

- Tier 1: resources under construction, or with signed contracts.
- Tier 2: resources with completed interconnection studies.
- Tier 3: resources in an interconnection queue that do not meet the Tier 2 requirement.

Planning Reserve Margin

The LTRA defines “planning reserve margin” as the difference between resources and demand, divided by demand, expressed as a percentile.

Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- High Risk: shortfalls may occur at normal peak conditions.
- Elevated Risk: shortfalls may occur in extreme conditions.
- Normal Risk: low likelihood of electricity supply shortfall.

WECC Subregions

Table 5.2 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

Table 5.2 – WECC Subregion Descriptions

Designation	Subregion	Country	Peak
NW	The rest of WECC, beyond the exceptions listed below	United States	Summer
SW	Primarily Arizona and New Mexico	United States	Summer
CA/MX	California / Mexico	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table 5.3 presents the WECC LTRA assessments for the three WECC subregions that include the United States. Anticipated Reserve Margin is based on existing resources, firm transfers, and Tier 1 additions, less confirmed retirements. Prospective Reserve Margin adds existing resources without firm transmission, or with other potential limitations, likely transfers, and Tier 2 capacity additions, less unconfirmed retirements. Values that fall below the reference margin level (i.e. planning target) are highlighted.

³ NERC. 2024 Long-Term Reliability Assessment. December 2024. Available online at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed 12/18/2024)

Table 5.3 – NERC LTRA for Selected WECC Subregions

	WECC-NW									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%

	WECC-SW									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%

	WECC-CA/MX									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%

As shown, the WECC-NW subregion that includes PacifiCorp’s load meets the reference margin with anticipated resources through 2030, and with prospective resources through the ten-year horizon. The WECC-SW subregion also meets the reference margin with anticipated resources through 2030 but only has sufficient prospective resources through 2031. The WECC-CA/MX region meets the reference margin with anticipated resources through 2033, and with prospective resources through the ten-year horizon. While this presents a relatively favorable view of supply and demand, the LTRA definition of Tier 1 resources includes everything with an interconnection agreement and/or power purchase agreement. Not all such resources will ultimately be brought online in a timely manner. The factors identified the WECC WARA (supply chain disruptions, interconnection queue, siting delays, and increased costs) can all derail projects that are otherwise feasible.

Pacific Northwest Power Supply Adequacy Assessment

The Northwest Power and Conservation Council released its 2029 Adequacy Assessment in August 2024.⁴ Starting in 2011, an annual loss-of-load-probability of up to five percent was deemed adequate. Starting with the 2023 assessment a multi-metric framework of shortfall frequency, duration, and magnitude was used. These metrics include:

- **Loss of load events (LOLEV):** limits the expected frequency of shortfall events to protect against frequent use of emergency measures.
- **Duration Value at Risk:** limits shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
- **Peak Value at Risk:** limits maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
- **Energy Value at Risk:** limits total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

An adequate system must meet all these metrics. The 2029 Adequacy Assessment is based on the 2021 Northwest Power Plan, discussed below, with updates for expected changes through 2029, including load growth, resource development, and transmission. Based on updated results for adequacy in year 2029, the 2029 Adequacy Assessment concludes that power supply would be

⁴ Northwest Power and Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029. August 2024. Available online at: <https://www.nwccouncil.org/fs/18853/2024-4.pdf> (accessed 12/18/2024)

adequate under reference conditions. This conclusion is in part based on coal plants changing to natural gas, rather than retiring (including Jim Bridger 1 and 2, which were converted in 2024). The 2029 Adequacy Assessment identifies two scenarios that could lead to reliability shortfalls. First, if energy efficiency savings only meet the low end of the targeted quantity, shortfall risks increase in the winter. Second, higher data center loads in the absence of commensurate resource supply could lead to reliability shortfalls in both the winter and the summer. An additional potential risk is related to the Boardman-to-Hemingway project which the 2029 Adequacy Assessment assumes is operational by 2029, increasing transfer capability between Idaho and the Pacific Northwest, as this upgrade is not part of PacifiCorp’s 2025 IRP preferred portfolio. The metric results from the 2029 Adequacy Assessment are provided in Table 5.4, with shortfalls highlighted in orange.

Table 5.4 – Northwest Power and Conservation Council 2029 Adequacy Assessment

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.35	1.294
Frequency	Summer LOLEV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9600 MWh	0	4,196	196,324

Western Resource Adequacy Program (WRAP)

The WRAP is a regional reliability planning and compliance program, intended to help facilitate region-wide resource adequacy, and initiated on behalf of the utilities that are part of the Western Power Pool (formerly the Northwest Power Pool). WRAP allows for coordination and visibility of resource needs and supply among the participants, taking advantage of the diversity and sharing from pooling resources.

WRAP begins with regional analysis, as the program sets regional reliability metrics for upcoming seasons, including planning reserve margins that are applied to loads and qualifying capacity contributions that apply to resources. With those values in hand, utilities must secure resources and, seven months prior to the start of a winter or summer season, must submit a forward showing demonstrating they have resources and transmission to cover their load and planning reserve margin requirements. Time is provided to cover shortfalls before the season begins. Within the season, an operational component allows those participants with a day-ahead resource shortfall to call upon the program and receive incremental resources from participants who have a surplus.

WRAP is based on two seasons: summer (June through September) and winter (November through March). Planning reserve margins vary by month, and by region, as WRAP covers two regions: the Pacific Northwest (primarily Oregon and Washington and British Columbia, with parts of northern Idaho and Montana) and the Desert Southwest, including the remainder of Idaho, Utah, Wyoming, Colorado, Nevada, and Arizona. Similarly, monthly qualifying capacity contributions are calculated for each resource, and capture technology type, regional variations, and resource-specific performance. For example, wind and solar contributions incorporate a resource’s output

during capacity critical hours (the highest load hours after netting out wind, solar, and run of river hydro generation).

As of September 2024, the Western Power Pool Board of Directors has approved updates to the WRAP tariff along with seven business practice manuals detailing of the program will operate. WRAP is currently operational with non-binding requirements and has plans in place to enable fully binding operations in Summer 2027 for participants that provide notice of their intent by January 2026. All participants will be binding for Winter 2027-2028 (i.e. starting November 2027). If a WRAP Participant chooses to exit the program, a two-year exit period applies. Current WRAP Participants have until October 31st, 2025, to exit the program without being subject to a financially binding season.

PacifiCorp is currently participating in WRAP and is working with the Western Power Pool to address outstanding issues, including the interaction between WRAP and the CAISO's Enhanced Day-Ahead Market (EDAM) and complexity from PacifiCorp's footprint spanning both WRAP regions. While issues remain, PacifiCorp's 2025 IRP includes modeling to capture WRAP compliance requirements starting in 2028 and continuing through the study horizon. While proxy resource selections within the 2025 IRP can only begin on January 1st of each year, actual resource procurement could be targeted to the November 2027 start date to the extent necessary, or short-term products could be used to address unmet requirements, if any.

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp previous IRP modeling has included front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions. However, market transactions that are not based on a specified source do not provide qualifying capacity for WRAP compliance. While other short-term products exist, such as slices of hydropower projects on the Mid-Columbia or tolling agreements for merchant-owned natural gas plants, there are relatively few such opportunities and there may be significant competition for such products given rising demand and stricter resource adequacy requirements under WRAP. With that in mind, for the 2025 IRP, PacifiCorp is not including short-term market products as options for WRAP compliance.

WRAP compliance does not guarantee reliability, in particular a monthly qualifying capacity contribution value does not ensure resources will be available to meet hourly requirements such as the hourly balancing test in the EDAM. At the same time, PacifiCorp recognizes that increasing coordination of spot market transactions through EIM, EDAM, and WRAP is likely to provide significant economic benefits. To balance the limitations of market transactions for capacity and reliability requirements and the benefits of market transactions for regional dispatch, the 2025 IRP does not allow market purchases in certain key periods, but otherwise allows market purchases up to transmission limits. During the summer WRAP season (June through September), market purchases are not allowed from 4:00 p.m. to 12:00 a.m. on PacifiCorp's top five load days in each month. Similarly, in the winter WRAP season (November through March), market purchases are

not allowed from 4:00 a.m. to 8:00 a.m. as well as 4:00 p.m. to 12:00 a.m., again on PacifiCorp's top five load days in each month. For the 2025 IRP, PacifiCorp is also differentiating market prices within each month, to reflect historical patterns on the days used to derive the chaotic normal load forecast and reflecting the same weather conditions used to develop wind and solar generation profiles. In general, market prices are higher when load is high and wind and solar output is relatively low, though market prices reflect region-wide conditions of PacifiCorp's supply and demand is only a part. Market prices in EIM and EDAM will reflect the balance of supply-and-demand, and surplus supply from PacifiCorp is likely to result in lower market clearing prices. While this effect is not captured in PacifiCorp's hourly market price forecast, market sales for the 2025 IRP have been capped at historical average levels, since large surpluses would impact pricing.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, the company will continue to refine its assessments of market depth and liquidity for transactions to quantify the risk associated with the level of market reliance. Additional description is provided in Volume I, Chapter 7 (Resource Options); also, see the sensitivities discussion in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has accounted for climate change within the 2025 IRP to assess the ways in which climate change may impact planning assumptions.

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2004 through 2023. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively. These temperature changes lead to higher summer peaks and lower winter peaks, with increasing impacts across the study horizon. See Appendix A for additional detail regarding how climate change is incorporated into the load forecast.

Weather-Related Impacts to Variable Generation

New for the 2025 IRP, all wind and solar generation profiles are based on historical weather conditions on the same historical day underlying the load forecast. This captures the relationship between load, wind, and solar that happened in recent history. Each month of the Company's chaotic normal load forecast reflects the range of weather conditions experienced in the most typical month from 2013-2022, while stochastic analysis for the 2025 IRP will reflect the range of weather conditions experienced in every year from 2006-2023. The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios. For the 2025 IRP, PacifiCorp is not projecting specific climate impacts on wind and solar generation but notes that recent history

may be more representative of future conditions than earlier conditions. As a result, reliability and system cost risks identified using inputs derived from recent historical years may be of greater concern as an indicator of future risk.

Wildfire Impacts

Increased wildfire frequency associated with climate change is expected to have a range of impacts to intermittent generation sources, including wind, solar, and hydro resources.

Wind generation sites in PacifiCorp's system are most likely to be subjected to fast moving range fires. Impacts at wind generation sites from range fires are likely to be limited and short in duration, as turbines and collector substations are surrounded by gravel surfaces that are fire resistant. Sensitive turbine equipment is located far above the ground away from damaging heat sources. Impacts to transmission lines and aboveground collector lines from range fires at wind generation sites is also anticipated to be minor due to the limited fuels available to cause ignition to wooden poles. Outage durations are likely to be short when operations staff is required to evacuate a site in advance of a fire and to curtail generation as a precautionary measure.

Climate change also poses fire risks at solar generation sites, which are also likely to manifest as range fires given solar projects are typically sited away from substantial tree stands that could block solar panels. Impacts could be significant depending on the amount of vegetation at a site, as generating equipment is close to the ground close to potential fuel sources. If a range fire creates sufficient heat to impact equipment, resumption of generation will be dependent on the ability to obtain and install necessary replacement equipment.

Fire impacts at hydro generation sites will be driven primarily by impacts to transmission lines. Hydro generation sites are typically in heavily forested terrain and serviced by only one or two transmission lines. An intense forest fire can damage miles of transmission lines that can take weeks to months to restore to service. If a fire threatens a hydro generation site, the site will be proactively evacuated with generation units typically taken offline and the facility put into spill to avoid potential instream flow impacts that could occur with an unplanned unit shutdown resulting from impacts to local transmission lines. Generation units would be restarted as soon as possible when conditions permit safe re-entry to provide generation locally until transmission service, if interrupted, is restored. Fire damage to dams, water conveyance structures, and generating plants is expected to be minimal. Damage to local distribution lines and communication infrastructure upon which hydro generation sources rely is also possible, which could impact generation restoration timelines.

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Like wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to

modify runoff patterns impacting hydro generation but is not expected to impact dam safety at PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

Changes to wind patterns and wind speeds, and changes in extreme high and low air temperatures have the potential to impact wind and solar generation. Extreme high temperatures can raise ground temperatures, which has the potential to impact collector system capacities at wind and solar projects and reduce collector system carrying capacity, limiting output, similar to high temperature impacts to high voltage transmission lines. However, these impacts are not anticipated to be significant on wind energy resources given peak output is typically observed outside of summer months. Increasing air temperatures result in lower air densities, which could negatively impact wind energy output even if wind speeds are unchanged. Lower wind speeds in the summer relative to historic experience because of extreme high temperatures is also possible. Wind turbines in PacifiCorp's fleet generally are protected from extreme low temperatures given the conditions in which they currently operate, and low temperature protection features are installed in PacifiCorp turbines where weather conditions warrant their inclusion.

There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.

Impacts on Wind and Solar Energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.⁵ Some broad impacts anticipated from climate change are noted below:⁶

Wind Energy

- Changes to wind speed: could impact energy assessments.
- Changes in temperature: with increased temperatures the air density could reduce energy outputs.
- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand.

⁵ Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.

⁶ Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

- Rising sea levels: could damage offshore wind farm infrastructure.

Solar Energy

- Changes in mean temperatures: increased global temperatures could reduce cell efficiency.
- Changes in solar irradiation, dirt, snow, precipitation: increase in these variables could reduce energy output.

Integration of energy storage with wind and solar projects is a way to help make use of generated energy more efficiently.

Wildfire Risk Mitigation

PacifiCorp's Wildfire Mitigation Plans (WMPs) are designed to meet regulatory requirements while delivering safe and reliable power. These plans focus on enhancing situational awareness, implementing robust operational practices, and hardening the power system to mitigate wildfire risks while balancing customer and community impacts.⁷

PacifiCorp Wildfire Mitigation Plan Regulatory Compliance

PacifiCorp meets regulatory requirements through the submittal of Wildfire Mitigation Plans (WMPs) with the specific regulatory alignments for each state stated below:

1. **California:** The WMP complies with California Senate Bill 901 and the California Public Utilities Commission (CPUC) provisions under Section 8386.
2. **Idaho:** The WMP was submitted in accordance with Idaho Public Utilities Commission Order No. 36045.
3. **Utah:** The WMP adheres to Utah Administrative Code R746-315-2, effective June 1, 2023, and complies with Subsection 54-24-201.
4. **Oregon:** The WMP meets the requirements set forth in Oregon Administrative Rule 860-300-0040.
5. **Washington:** The WMP was submitted on October 31, 2024, and compliance with statutory requirements was confirmed by the Washington Utilities and Transportation Commission as complying with the Revised Code of Washington (RCW) 80.28.440.

Although Wyoming does not have regulatory requirements for a wildfire mitigation plan, PacifiCorp has proactively filed one in conjunction with the general rate case.

Core Principles

All WMPs are publicly accessible via the [PacifiCorp Wildfire Mitigation Plan website \(linked here\)](#). These plans detail the investments and strategies for constructing, maintaining, and operating electrical lines and equipment for wildfire mitigation projects and programs. While there

⁷ Wildfire mitigation and impacts were discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).

are state-specific requirements, the core strategy across all six states remains consistent, guided by the following principles:

- **Situational Awareness and Operational Readiness:** Implementing systems that enhance situational awareness, and operational readiness is crucial for mitigating fire risks and their impacts.
- **Operational Practices:** Minimizing the impact of fault events through rapid isolation using advanced equipment and trained personnel.
- **System Hardening:** Reducing the frequency of ignition events by engineering more resilient systems that experience fewer faults.

Balancing Mitigation and Community Impact

PacifiCorp is committed to balancing wildfire risk mitigation with the needs of customers and communities. Adjustments to power system operations, such as modifying protective device settings and testing protocols, are carefully considered to reduce wildfire risks. These measures are applied selectively to avoid unnecessary disruptions to the power supply.

The wildfire mitigation program approach includes deploying advanced technologies like fault indicators and assessing outages to inform short-term mitigation projects. These efforts are designed to enhance safety while maintaining reliable service.

PacifiCorp's Wildfire Mitigation Plans (WMPs) reflect the Company's dedication to balancing costs, benefits, operational impacts, and risk mitigation with the goal to provide safe, reliable, and affordable electric service, prioritizing the well-being of customers and communities.

Transmission-Based Reliability

PacifiCorp is required to meet mandatory FERC, NERC, and WECC reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC Reliability Coordinator for PacifiCorp. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

With the increasing number of variable resources added to the grid throughout the west, PacifiCorp's ability to meet federal reliability directives depends increasingly on an interconnected transmission system across the western states and on the ability to move electricity throughout the six states served by the company. PacifiCorp's planning process ensures that the company is developing a portfolio that balances sufficient supply to serve all PacifiCorp customers with sufficient resources and transmission to ensure that electricity can be moved from generation sources to the communities served.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, PacifiCorp's transmission capacity provides benefits to customers by increasing reliability and allowing additional generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generating resources for reserve capacity to comply with mandatory reliability standards.

Federal Reliability Standards

The Energy Policy Act of 2005 included expanded reliability-related elements of the federal regulatory structure and directed the FERC to institute mandatory reliability standards that all users of the bulk electric system (BES) must follow.

FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States under a variety of operating conditions. These standards are a federal requirement and are subject to oversight and enforcement by the WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other reliability initiatives or investigations.

The transmission planning standards (TPL Standards), found within the NERC transmission reliability standards, specify transmission system planning performance requirements to develop a BES that will operate reliably over a broad spectrum of system conditions. They also require study of a wide range of probable contingencies in short-term (1-2 years), medium term (5 years) and long-term (10-20 years) scenarios to ensure system reliability. Together with regional planning criteria, such as those established by the NERC/WECC, and utility-specific planning criteria, the TPL Standards define the minimum transmission system requirements to safely and reliably serve customers.

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 as detailed in Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produce a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers. In 2024, FERC issued Order 1920 which will further expand regional planning processes, including a requirement for a long-term (20 year) regional plan. PacifiCorp is working with NorthernGrid members to draft tariff revisions to outline the expanded process in preparation for the FERC required compliance filing in August 2025.

Power Flow Analyses and Planning for Generator Retirements

PacifiCorp transmission planning has performed various coal unit retirement assessments analyzing potential impacts to the transmission system. These studies are performed outside of the IRP process under PacifiCorp's OATT processes which includes either 1) a customer request to perform a consulting study; or 2) a customer request to un-designate a network resource which then triggers a system impact and facilities study if the study determines that mitigations are required due to retirement.

Past studies have found that several factors are critical in determining transmission system impacts and necessary mitigation, if any. These factors include: 1) location of the unit(s) to be retired, 2) the number of units being retired, 3) the size of the units being retired, 4) year of retirement, and 5) location, size, and type of replacement resources, if any. Based on the location, number of units, and size of the retired unit/s, studies can identify if the retirement results in either thermal or voltage issues on the transmission system. A retirement of a coal unit may result in voltage issues due to lack of reactive support that was previously provided by the retired unit/s. A retirement may also result in thermal overload of the transmission system due to changes in the flows post unit retirement. As such, until official notification to PacifiCorp transmission of coal unit designation/retirement is received, all such coal retirement analysis is considered preliminary.

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- New for the 2025 IRP, PacifiCorp is calculating its capacity position based on Western Resource Adequacy Program (WRAP) compliance requirements, with binding operations under the program expected to begin by 2028. WRAP participants with projected resource shortfalls on a day-ahead basis will be able to purchase from WRAP participants with excess supply.
- Every resource has a qualifying capacity contribution (QCC) for each month of the summer (June-September) and winter (November-March) seasons. These values are calculated by WRAP based on resource-specific historical performance and are based on the loads and resource mix of the regional participants. These values are updated by WRAP ahead of each compliance season.
- Seven months prior to the start of each season, WRAP participants must make a forward showing, demonstrating that the QCC for their resources is sufficient to meet their peak load plus a monthly planning reserve margin determined by WRAP.
- While WRAP is projected to enhance reliability by providing priority access to supply from other participants, the monthly QCC values do not ensure a utility will be reliable or have sufficient resources to meet its requirements from hour to hour, so hourly analysis of the load and resource balance is also necessary.
- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements.
- The company's load obligation is calculated based on projected load less distributed generation, energy efficiency savings, and demand response, including interruptible load.
- A distributed generation study prepared by DNV produced estimates on distributed generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2025 IRP load and resource balance reflects base case distributed generation penetration levels as a reduction in load.
- Relative to WRAP compliance requirements, PacifiCorp's system is capacity deficient (before adding proxy resources other than energy efficiency, and without considering short-term capacity procurement, i.e. market purchases) in the summer beginning in 2026, and the winter peaks throughout the planning horizon.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. PacifiCorp's 2025 IRP reflects renewable resource generation profiles based on the same patterns of historical weather conditions used to develop its load forecasts, both on a normalized basis and for stochastic analysis. While adjustments to account for climate change are included in the base forecast, customer demand may be further influenced by climate change directly as well as indirectly through electrification, with uncertain impacts on future demand. These resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp’s assessment of its load and resource balance. PacifiCorp’s long-term load forecasts (both energy and coincident peak load) for each state and the system are summarized in Appendix A (Load Forecast). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp’s existing resources. Finally, load and resource balances for capacity are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, assumed coal unit retirements and incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The 2025 IRP relies on PacifiCorp’s May 2024 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency. The system summer peak load grows at a compound annual growth rate (CAGR) of 1.67 percent over the period 2025 through 2044.

Table 6.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System	11,318	11,270	11,425	11,553	11,690	11,844	12,104	12,193	12,363	12,575
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
System	12,819	13,134	13,404	13,693	13,978	14,279	14,581	15,008	15,237	15,518

Existing Resources

Thermal Plants

Table 6.2 lists PacifiCorp’s existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The “End of Coal-fired Operation” reflects the year a resource must retire or converts to natural gas (if option is available) as reflected in modeling inputs.

Table 6.2 – Coal-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)	End of Coal-fired Operation
Colstrip 3	10	Montana	74	2025 (Transfer capacity to unit 4)
Colstrip 4	10*	Montana	74	2029 (PacifiCorp exit)
Craig 1	19	Colorado	82	2025 (Assumed end of life)
Craig 2	19	Colorado	79	2028 (Assumed end of life)
Dave Johnston 1	100	Wyoming	99	2028 (Gas conversion option)
Dave Johnston 2	100	Wyoming	106	2028 (Gas conversion option)
Dave Johnston 3	100	Wyoming	220	2027 (Retire: Clean air compliance)
Dave Johnston 4	100	Wyoming	330	
Hayden 1	24	Colorado	44	2028 (Assumed end of life)
Hayden 2	13	Colorado	33	2027 (Assumed end of life)
Hunter 1	94	Utah	418	
Hunter 2	60	Utah	269	
Hunter 3	100	Utah	471	
Huntington 1	100	Utah	459	
Huntington 2	100	Utah	450	
Jim Bridger 3	67	Wyoming	349	
Jim Bridger 4	67	Wyoming	351	
Naughton 1	100	Wyoming	156	2025 (Gas conversion option)
Naughton 2	100	Wyoming	201	2025 (Gas conversion option)
Wyodak	80	Wyoming	268	
TOTAL – Coal			4,533	

*PacifiCorp’s share of Colstrip 4 is projected to include its current ownership of Colstrip 3 starting in 2026.

Table 6.3 – Natural Gas-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)
Chehalis	100	Washington	500
Currant Creek	100	Utah	540
Gadsby 1	100	Utah	64
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	105
Gadsby 4	100	Utah	40
Gadsby 5	100	Utah	40
Gadsby 6	100	Utah	40
Hermiston	100	Oregon	237
Jim Bridger 1	67	Wyoming	354
Jim Bridger 2	67	Wyoming	359
Lake Side	100	Utah	580
Lake Side 2	100	Utah	677
Naughton 3	100	Wyoming	247
TOTAL – Natural Gas			3,852

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 5,154 MW of wind resources. Table 6.4 shows existing (or under construction) wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Goodnoe Hills East	WA	94
Leaning Juniper	WA	101
Marengo I	WA	156
Marengo II	WA	78
Cedar Springs 2	WY	199
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
High Plains	WY	99
McFadden Ridge 1	WY	29
Pryor Mountain	WY	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats 1-2	WY	500
Foote Creek II-IV	WY	43
Rock Creek I	WY	190
Rock Creek II	WY	400
Rock River	WY	50
TOTAL – Owned Wind		2,937

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements	State	PPA or QF	Capacity (MW)
Wolverine Creek	ID	PPA	65
Chopin-Schumann	WA	QF	8
Cedar Springs I	WY	PPA	199
Cedar Springs III	WY	PPA	133
Three Buttes Power	WY	PPA	99
Top of the World	WY	PPA	200
Meadow Creek Project Five Pine	ID	QF	40
Meadow Creek Project North Point	ID	QF	80
Latigo	UT	QF	60
Mountain Wind I	UT	QF	61
Mountain Wind II	UT	QF	80
Power County Park North	UT	QF	23
Power County Park South	UT	QF	23
Spanish Fork Park 2	UT	QF	19

Tooele 1 and 2	UT	QF	3
Big Top	WA	QF	2
Butter Creek Power	WA	QF	5
Chopin	WA	QF	10
Four Corners	WA	QF	8
Four Mile Canyon	WA	QF	10
Orchard 1	WA	QF	10
Orchard 2	WA	QF	10
Orchard 3	WA	QF	10
Orchard 4	WA	QF	10
Oregon Trail	WA	QF	10
Pacific Canyon	WA	QF	8
Sand Ranch	WA	QF	10
Three Mile Canyon	WA	QF	8
Wagon Trail	WA	QF	3
Ward Butte	WA	QF	7
BLM Rawlins	WY	QF	0.1
Pioneer Park I	WY	QF	80
Cedar Creek	ID	PPA	152
Anticline	WY	PPA	101
Boswell	WY	PPA	320
Cedar Springs IV	WY	PPA	350
TOTAL – Purchased Wind			2217

Solar

PacifiCorp has a total of 97 solar projects under contract representing 3,615 MW of nameplate capacity. Of these, two recently signed solar resources also include a total of 550 MW of battery storage. Table 6.6 list solar power purchase agreements, and through Table 6.7 through Table 6.9 list solar qualifying facilities for each relevant state.

Table 6.6 – Solar Power Purchase Agreements

Power Purchase Agreements			
Resource	State	Solar Capacity (MW)	Storage Capacity (MW)
Black Cap	OR	2	-
Millican	OR	60	-
Old Mill	OR	5	-
Oregon Solar Incentive Project	OR	9	-
Prineville	OR	40	-
Appaloosa Solar IA	UT	120	-
Appaloosa Solar IB	UT	80	-
Castle Solar (Retail 1)	UT	20	-
Castle Solar (Retail 2)	UT	20	-
Cove Mountain	UT	58	-
Cove Mountain II	UT	122	-
Elektron Solar 20Yr	UT	10	-
Elektron Solar 25Yr	UT	70	-
Faraday	UT	525	150
Graphite	UT	80	-
Green River	UT	400	400
Hornshadow Solar I	UT	100	-
Hornshadow Solar II	UT	200	-
Horseshoe	UT	75	-
Hunter	UT	100	-
Milford	UT	99	-
Pavant III	UT	20	-
Rocket	UT	80	-
Sigurd	UT	80	-
TOTAL – Power Purchase Agreements		2375	550

Table 6.7 – Solar Qualifying Facilities, Oregon

Oregon Qualifying Facilities		
Resource	Solar Capacity (MW)	Storage Capacity (MW)
7 Mile Solar	1	-
Adams	10	-
Antelope Creek Solar	2	-
Bear Creek	10	-
Black Cap II	8	-
Blackwell Creek Solar*	1	-
Bly	8	-
Buckaroo Solar 1*	3	-
Buckaroo Solar 2*	3	-
Canyonville Solar 1*	1	-
Canyonville Solar 2*	2	-
Chapman Creek Solar*	3	-
Cherry Creek Solar*	0.4	-
Chiloquin Solar	10	-
Elbe	10	-
Goodling Community Solar*	1	-
Green Solar*	3	-
Hay Creek Solar*	0.6	-
Klamath Falls Solar 1	0.8	-
Klamath Falls Solar 2	3	-
Linkville Solar*	3	-
Merrill	10	-
Norwest Energy 2 (Neff)	10	-
Norwest Energy 4 (Bonanza)	6	-
Norwest Energy 7 (Eagle Point)	10	-
Norwest Energy 9 Pendleton	6	-
OR Solar 2, LLC (Agate Bay)	10	-
OR Solar 3, LLC (Turkey Hill)	10	-
OR Solar 6, LLC (Lakeview)	10	-
OR Solar 8, LLC (Dairy)	10	-
Orchard Knob Solar	2	-
OSLH Collier	10	-
Pilot Rock Solar 1*	3	-
Pilot Rock Solar 2*	3	-
Pine Grove Solar	1	-
Round Lake Solar	1	-
Skysol	55	-
Solorize Rogue*	0.1	-
Sunset Ridge Solar	2	-
Tumbleweed	10	-
Tutuilla Solar*	2	-
Wallowa County*	0.4	-
Whisky Creek Solar*	0.2	-
Wocus Marsh Solar*	0.9	-
Wood River Solar*	0.4	-
Woodline Solar	8	-
TOTAL – Oregon Solar QF Resources	264	0

*New project added in 2025 IRP

Table 6.8 – Solar Qualifying Facilities, Utah

Utah Qualifying Facilities		
Resource	Solar Capacity (MW)	Storage Capacity (MW)
Beryl	3	-
Buckhorn	3	-
Cedar Valley	3	-
Enterprise	80	-
Escalante I	80	-
Escalante II	80	-
Escalante III	80	-
Ewauna	1	-
Ewauna II	3	-
Granite Mountain - East	80	-
Granite Mountain - West	50	-
Granite Peak	3	-
Greenville	2	-
Iron Springs	80	-
Laho	3	-
Milford 2	3	-
Milford Flat	3	-
Pavant	50	-
Pavant II	50	-
Quichapa I	3	-
Quichapa II	3	-
Quichapa III	3	-
Red Hill	80	-
South Milford	3	-
SunE1	3	-
SunE2	3	-
SunE3	3	-
Three Peaks	80	-
TOTAL – Utah Solar QF Resources	838	0

Table 6.9 – Solar Qualifying Facilities, Wyoming

Wyoming Qualifying Facilities		
Resource	Solar Capacity (MW)	Storage Capacity (MW)
Sage I	20	-
Sage II	20	-
Sage III	18	-
Sweetwater	80	-
TOTAL – Wyoming Solar QF Resources	138	0

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW,

was completed at the end of 2007. The Oregon Institute of Technology has a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp also has a power purchase agreement with the 20 MW Soda Lake geothermal project located in Nevada, which became operational in November 2019.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 12 projects totaling approximately 80 MW of nameplate capacity.

Distributed Generation Resources

Table 6.10 provides a breakdown of distributed generation capacity and customer counts from data collected as of March 31, 2024. In addition to resources, PacifiCorp's customers also have over 60 MW of battery storage capacity. For forecasted growth in distributed generation and storage, please refer to Appendix L (Distributed Generation Study).

Table 6.10 – Distributed generation Customers and Capacity

Fuel	Solar	Wind	Gas ¹	Hydro	Mixed ²
Nameplate (kW)	772,160	847	784	965	1,233
Capacity (percentage of total)	99.51%	0.11%	0.10%	0.12%	0.16%
Number of customers	86,449	192	3	21	63
Customer (percentage of total)	99.68%	0.22%	0.00%	0.02%	0.07%

¹ Gas includes: biofuel, waste gas, and fuel cells

² Mixed includes projects with multiple technologies, one project is solar and biogas, and the others are solar and wind

Energy Storage

In addition to the battery storage contracted with solar resources listed in Table 6.6 PacifiCorp has existing or committed battery storage projects totaling approximately 523 MW of nameplate capacity, as shown in Table 6.11.

Table 6.11 – Storage Resources

Power Purchase Agreements / Exchanges	State	Technology	Capacity (MW)
Dominguez Storage*	UT	Battery	200
Enterprise*	UT	Battery	80
Escalante*	UT	Battery	80
Granite Mountain*	UT	Battery	80
Iron Springs*	UT	Battery	80
Panguitch	UT	Battery	1
Oregon Institute of Technology (OIT)	OR	Battery	2
TOTAL – Purchased Battery			523

*New project added in 2025 IRP

Hydroelectric Generation

PacifiCorp owns or purchases over 1,200 MW of hydroelectric generation capacity. In addition to being non-emitting generation sources hydro resources provide various operational benefits that

can include flexible generation, spinning reserves, and voltage control. PacifiCorp-owned hydroelectric plants are in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity available from hydroelectric plants is dependent upon several factors, including the water content of snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control.

Table 6.12 – PacifiCorp Hydroelectric Generation Facilities

Plant	River System	State	Capacity (MW)
East - Owned			
Cutler	Bear	UT	29
Grace	Bear	UT	33
Oneida	Bear	UT	27.9
Soda	Bear	UT	14
Small East ^{1/}	Other	UT	20.5
West - Owned			
Bend	Other	OR	1
Big Fork	Other	MT	4.6
Swift 1 ^{2/}	Lewis	WA	263.6
Yale	Lewis	WA	163.6
Merwin	Lewis	WA	151
Clearwater 1	N. Umpqua	OR	17.9
Clearwater 2	N. Umpqua	OR	31
Fish Creek	N. Umpqua	OR	10.4
Lemolo 1	N. Umpqua	OR	32
Lemolo 2	N. Umpqua	OR	38.5
Slide Creek	N. Umpqua	OR	18
Soda Springs	N. Umpqua	OR	11.6
Toketee	N. Umpqua	OR	45
Eagle Point	Rogue	OR	2.8
Prospect 1	Rogue	OR	4.6
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7.7
Prospect 4	Rogue	OR	0.9
Fall Creek	Other	OR	2
Wallowa Falls	Other	OR	1.1
		Total Owned	968
Qualifying Facilities (QF)			
QF	Various	CA	9.4
QF	Various	ID	22.7
QF	Various	OR	40
QF	Various	UT	2.2
QF	Various	WA	2.9
Mid-Columbia	Columbia	WA	170
		Total QF	247
Total Hydroelectric			1215

^{1/} Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Veyo, Sand Cove, Viva Naughton, and Gunlock.

^{2/} Cowlitz County PUD owns Swift No. 2 and is operated in coordination with other Lewis River projects by PacifiCorp.

Demand-Side Management/Distributed Generation

For resource planning purposes, PacifiCorp classifies demand-side management (DSM) resources into four categories, or “classes.” These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

- **Demand Response—Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Modeling includes program drop-out rate and event non-performance rate assumptions to account for program parameters. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program. These are considered Class 1 DSM resources.
- **Energy Efficiency—Resources from non-dispatchable, firm energy and capacity product offerings/programs:** Energy efficiency programs are energy and related capacity savings which are achieved through facilitation of technological advancements in equipment, appliances, structures, or repeatable and predictable voluntary actions on a customer’s part to manage the energy use at their business or home. These programs generally provide financial incentives or services to customers to improve the efficiency of existing or new residential or commercial buildings through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) increasing building efficiency, such as improved insulation levels or windows; or (3) behavioral modifications, such as strategic energy management efforts at businesses. The savings are considered firm over the life of the improvement or customer action. These are considered Class 2 DSM resources.
- **Price Response and Load Shifting—Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided. These are considered Class 3 DSM resources.

- Education and Information—Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment, and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Like price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs. These are considered Class 4 DSM resources.

PacifiCorp has been operating successful DSM programs since the late 1970s. Over time, PacifiCorp's DSM acquisition has grown in investment levels, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 6.13 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.13 is shown as having zero MW.¹ Similarly, demand response resources available to the preferred portfolio, are characterized as incremental to Table 6.13. For a summary of current DSM program offerings in each state, refer to Appendix D (Demand-Side Management Resources).

¹ The historical effects of previous energy efficiency savings are captured in the load forecast before the modeling for new energy efficiency.

Table 6.13 – Existing DSM Resource Summary

Program	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2025-2045 Period
Demand Response	Residential/small commercial air conditioner load control	135 MW summer ^{1/}	Yes.
	Irrigation load management	200 MW summer	Yes.
	Interruptible contracts	136 MW summer	Yes.
	Wattsmart® Batteries	32 MW summer	Yes.
	Wattsmart® Business	45 MW summer	Yes.
Energy Efficiency	PacifiCorp and Energy Trust of Oregon programs	0 MW	No. Energy efficiency programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
Price Response and Load Shifting	Time-based pricing	Energy and capacity impacts are not available/measured.	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured.	No. Historical savings from customer response to pricing structure is reflected in load forecast.
Education and Information	Energy education	Energy and capacity impacts are not available/measured.	No. Historical savings from customer participation are reflected in the load forecast.

^{1/} A/C load control is based on long duration event characterization which assumes 50% cycling of ACs. A faster event (<1 hr) is characterized as 270 MW within the model.

Distributed Generation Forecast

For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)² penetration with new market, policy, and incentive developments.^{3,4} The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, photovoltaic solar coupled with battery storage, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

² In the 2023 IRP, this study was referred to as the “Private Generation” assessment.

³ See Appendix L (Distributed Generation Study).

⁴ PacifiCorp’s and DNV’s decisions in the development of the DG study were topics of discussion in the 2025 IRP public input meeting series and stakeholder feedback.

See Appendix M, stakeholder feedback form #6 (Renewable Northwest).

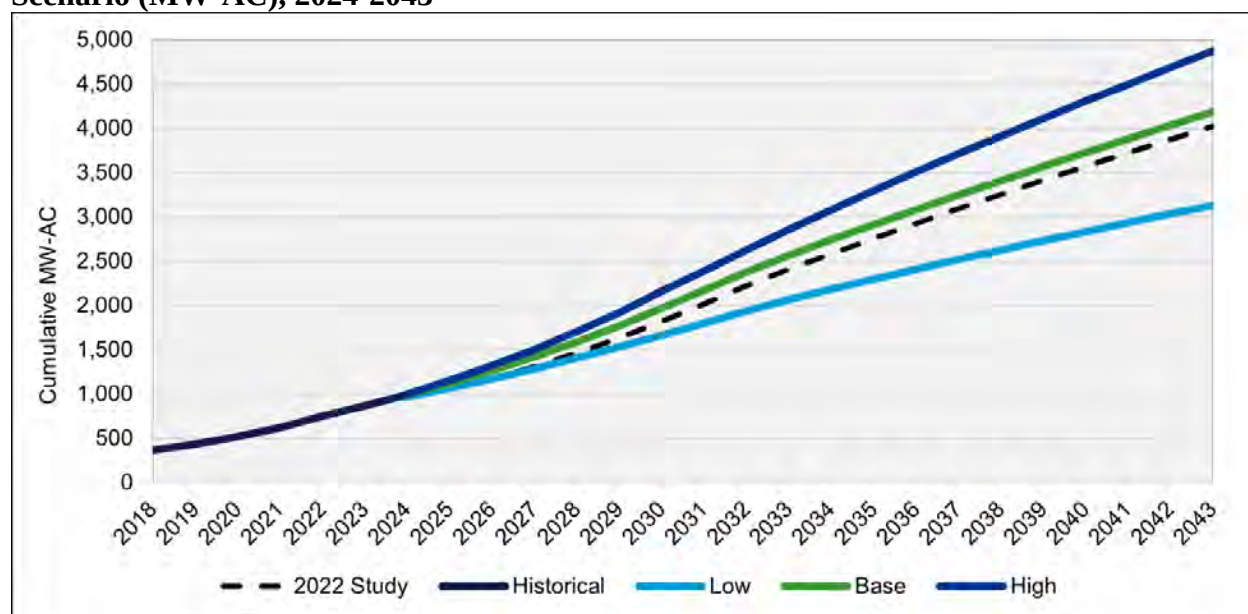
See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon).

See Appendix M, stakeholder feedback form #26 (Vote Solar).

DNV estimates approximately 4.18 gigawatts (GW) of DG capacity will be installed in PacifiCorp’s service area by 2043 in the base case scenario. As shown in Figure 6.1, the low and high scenarios project a cumulative installed capacity of 3.12 GW and 4.87 GW by 2043, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Inflation Reduction Act of 2022 (IRA) extends tax credits for distributed generation that creates favorable economics for adoption and is incorporated into each case. The DNV study identifies expected levels of customer-sited DG, which is applied as a reduction to PacifiCorp’s forecasted load for IRP modeling purposes and informs customer cited demand response battery potential for the conservation potential assessment (CPA).

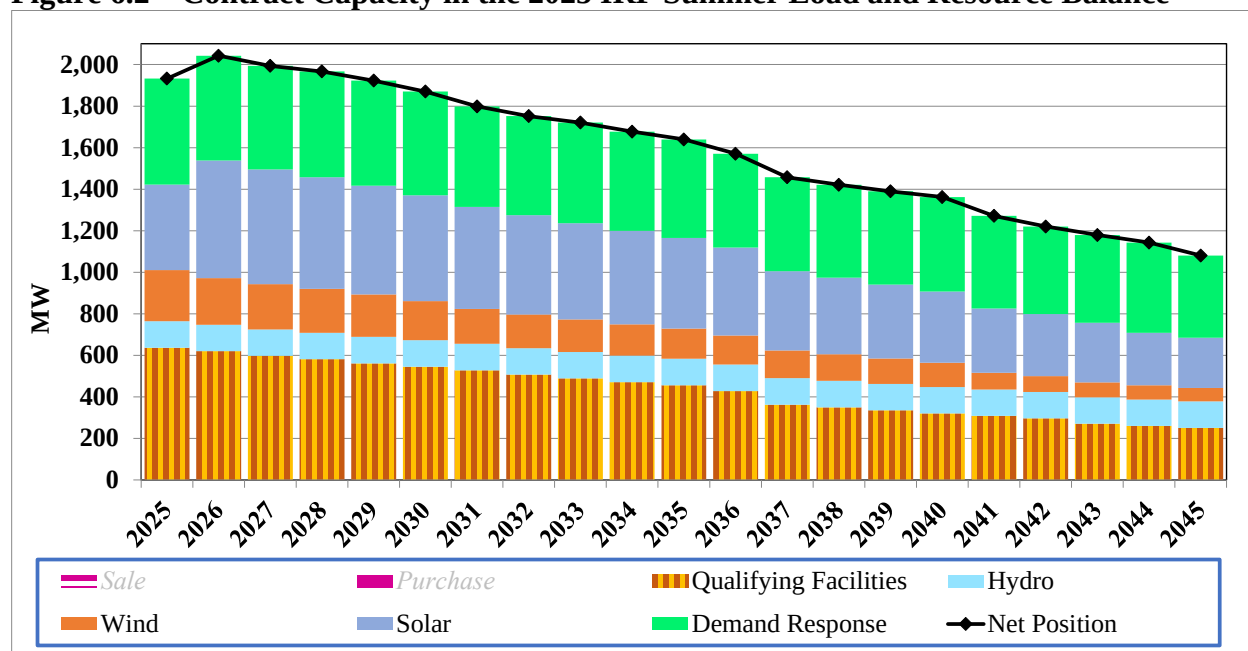
See Appendix L for the full DNV Distributed Generation report.

Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



Power-Purchase Agreements

PacifiCorp also meets capacity and energy requirements through long-term firm contracts. Figure 6.2 presents the contract capacity in place for 2025 through 2045. As shown, major capacity reductions in solar purchases, wind purchases, and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts and demand response are extended through the end of the IRP study period. After their current contract terms, QF contracts are extended at a reduced level that reflects the historical renewal rate of 75%. All contracts are shown at their peak capacity contribution levels.

Figure 6.2 – Contract Capacity in the 2025 IRP Summer Load and Resource Balance

Capacity Load and Resource Balance

Capacity Balance Overview

The purpose of the load and resource balance is to compare annual obligations to the annual capability of PacifiCorp's existing resources after retirements and future energy efficiency savings from the 2025 IRP preferred portfolio, and without new generating resource additions.

The capacity balance compares generating capability to load obligations across both summer and winter. For the 2025 IRP, the load and resource balance use values from the Western Resource Adequacy Program (WRAP). WRAP calculates project-specific qualifying capacity contribution values for all existing and contracted resources, and those values are used where data is available. WRAP also provides the average contribution for wind, solar, energy storage and run of river hydro in different geographic areas, and these estimates are used for proxy resources in the 2025 IRP. WRAP will update the capacity contributions for resources ahead of each season, reflecting the current resource mix of the WRAP footprint through time. WRAP has also provided projections for future years and different resource penetration levels – as the penetration of wind, solar, and storage increases, contributions are expected to decline. Significant uncertainty remains, due to resource mix and timing, along with indirect factors like climate impacts on load and hydro. To better reflect future WRAP compliance requirements, PacifiCorp used the projections provided by WRAP to estimate contributions in 2045 based on the regional resource mix developed as part of the forward price curve used in the 2025 IRP. Because PacifiCorp is a relatively small portion of the regional resource mix, the calculation is static and does not vary with PacifiCorp's specific portfolio selections. WRAP contributions fall linearly from the current values for 2025 to the projected values for 2045. Additional detail is provided in Appendix K (Capacity Contribution).

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly distributed generation projections to determine the net

system coincident peak load for each of the first ten years (2025-2034) of the planning horizon. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are included as part of the existing resources. The annual resource deficit or surplus is then computed by multiplying the obligation by the planning reserve margin (14.4% for the 2025 IRP, reflecting the WRAP value for the month of July) and then subtracting the result from existing resources. This view is presented both without and with uncommitted Market purchases.

The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

The main component categories consist of the following: resources, obligation, reserves, position, and available market purchases.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—coal, gas, hydroelectric, wind, solar, other renewables, storage, QFs, demand response, and purchases. Categories in the obligation section include load, distributed generation, and energy efficiency from the preferred portfolio.

Demand Response

Existing demand response program capacity is categorized as a resource. Under WRAP, demand response must be designated as either a load reduction, where any impacts are captured in peak loads, or as a resource, based on its availability and duration during peak conditions. For the 2025 IRP, demand response is used for operating reserves and dispatched within the PLEXOS model based on economic need and is not targeted to reduce summer-time peak loads which often occur during solar generation hours when net demand is lower. As a result, treatment as a resource provides a larger capacity benefit currently. PacifiCorp expects to continue evaluating this as the WRAP gets underway, as some demand response programs may be suitable for peak load reduction. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts with large load customers for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less distributed generation and energy efficiency from the preferred portfolio. The following are descriptions of each of these components:

Load Net of Distributed generation

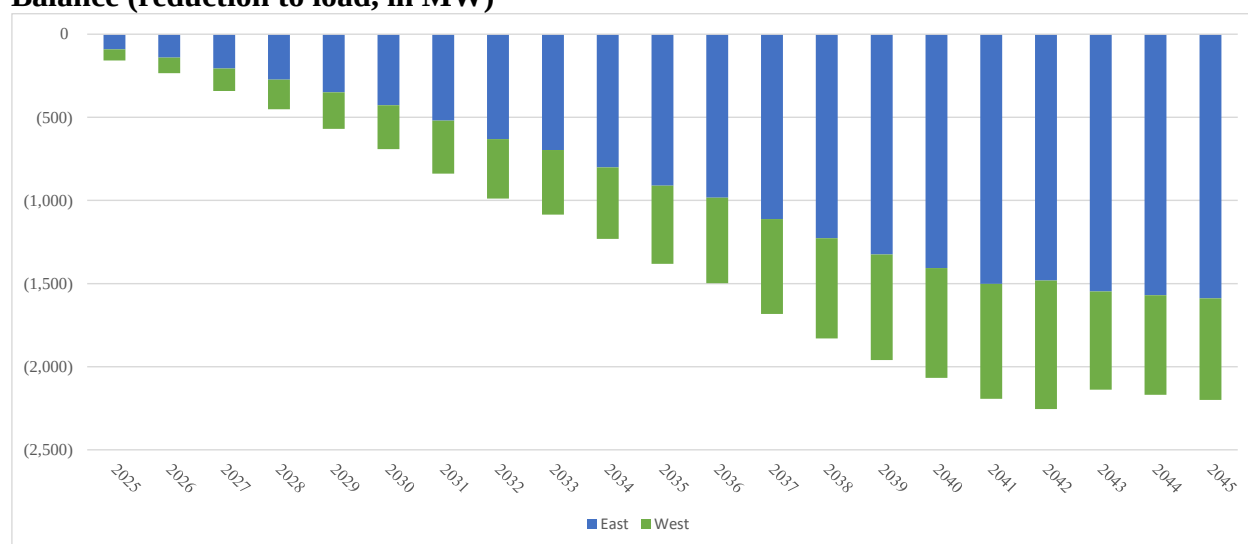
The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system

coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp’s coincident system summer and winter peaks.

Energy Efficiency

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2024 energy efficiency that is not incorporated in the forecast. The 2024 energy efficiency forecast has been added to the energy efficiency line along with the energy efficiency selected in the 2025 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2025 IRP preferred portfolio.

Figure 6.3 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load, in MW)



Planning Reserve Margin

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

Position

The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

$$\text{Existing Resources} = \text{Coal} + \text{Gas} + \text{Hydro} + \text{Renewable} + \text{Storage} + \text{Firm Purchases} + \text{Qualifying Facilities} + \text{Demand Response}$$

The peak load, distributed generation, energy efficiency (from the preferred portfolio) are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

$$\text{Obligation} = \text{Load} - \text{Distributed generation} - \text{Energy Efficiency}$$

The level of reserves to be added to the obligation is then calculated. This is accomplished by taking the net system obligation calculated above multiplied by the 14.4 percent PRM for July and 16.8 percent PRM for December adopted from WRAP for the 2025 IRP. The formula for this calculation is:

$$\text{Planning Reserves} = \text{Obligation} \times \text{PRM}$$

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, including available Market purchases, as shown in the following formula:

$$\text{Capacity Position} = (\text{Existing Resources} + \text{Available Market purchases}) - (\text{Obligation} + \text{Planning Reserves})$$

Capacity Balance Results

Table 6.14 and Table 6.15 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 14.4 percent in the summer and 16.8 percent in the winter to calculate the planning reserve amount.⁵ Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis up to the limits of the transfer capability between the two areas. Also note that QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewable, or other line items.

⁵ PacifiCorp acknowledged errors in its 2023 IRP load and resource balance, which have been addressed in the 2025 IRP. See Appendix M, stakeholder feedback form #12 (Utah Association of Energy Users).

Table 6.14 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

East										
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,960	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,294	3,469	3,469	3,469	3,469	3,469	3,469
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	587	613	596	578	561	534	503	487	470	453
Solar	342	499	487	475	463	452	440	428	416	404
Other Renewable	46	45	44	42	41	40	39	37	36	35
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	405	394	383	372	361	351	340	328	314	301
Demand Response	451	446	440	452	450	443	429	423	431	425
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(274)	(1,440)	(1,361)	(1,096)	(902)	(631)	(476)	(421)	(380)	(277)
East Existing Resources	8,578	8,433	8,452	8,479	8,504	8,540	8,611	8,603	8,592	8,632
Load	7,746	7,655	7,781	7,919	8,068	8,234	8,447	8,609	8,528	8,700
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(321)	(354)
Energy Efficiency	(91)	(141)	(206)	(274)	(349)	(428)	(520)	(631)	(696)	(801)
East Total obligation	7,498	7,372	7,388	7,412	7,433	7,465	7,527	7,520	7,511	7,545
Planning Reserve Margin (14.4%)	1,080	1,062	1,064	1,067	1,070	1,075	1,084	1,083	1,082	1,087
East Obligation + Reserves	8,578	8,433	8,452	8,479	8,504	8,540	8,611	8,603	8,592	8,632
East Position	0	0	0	0	0	0	0	0	0	0
Available Market Purchases	500	500	500	0	0	0	0	0	0	0
West										
Coal	133	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	74	72	70	67	65	63	61	59	57	54
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	232	226	215	209	200	194	187	179	174	170
Demand Response	60	59	58	57	57	56	55	54	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	274	1,440	1,361	1,096	902	631	476	421	380	277
West Existing Resources	2,271	3,426	3,330	3,054	2,846	2,431	2,260	2,192	2,141	2,028
Load	3,778	3,812	3,905	3,967	4,032	4,103	4,239	4,255	4,288	4,376
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(132)	(148)
Energy Efficiency	(67)	(94)	(135)	(178)	(220)	(263)	(318)	(359)	(389)	(431)
West Total obligation	3,662	3,664	3,695	3,690	3,688	3,688	3,738	3,684	3,767	3,798
Planning Reserve Margin (14.4%)	527	528	532	531	531	531	538	530	542	547
West Obligation + Reserves	4,189	4,192	4,227	4,222	4,219	4,219	4,277	4,214	4,309	4,345
West Position	(1,918)	(766)	(898)	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)
Available Market Purchases	2,603	2,603	2,603	0	0	0	0	0	0	0
System										
Total Resources	10,849	11,859	11,782	11,533	11,349	10,971	10,871	10,795	10,734	10,660
Obligation	11,160	11,036	11,084	11,102	11,121	11,153	11,265	11,203	11,278	11,343
Planning Reserves (14.4%)	1,607	1,589	1,596	1,599	1,601	1,606	1,622	1,613	1,624	1,633
Obligation + Reserves	12,767	12,625	12,680	12,701	12,723	12,759	12,887	12,817	12,902	12,977
System Position	(1,918)	(766)	(898)	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)
Available Market Purchases	3,103	3,103	3,103	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	1,918	766	898	0	0	0	0	0	0	0
Net Surplus/(Deficit)	0	0	0	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)

Table 6.14 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

East											
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,432	2,432	2,432
Gas	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,322	3,322	3,322
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	437	421	404	387	371	355	308	293	278	263	249
Solar	392	381	340	329	319	308	297	286	276	243	233
Other Renewable	33	32	31	12	11	10	10	9	9	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	291	269	221	212	203	192	184	176	169	162	155
Demand Response	422	401	402	398	400	406	398	375	376	389	351
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(161)	0	0	0	0	0	0	0	0	0	0
East Existing Resources	8,690	8,763	8,643	8,569	8,519	8,472	8,383	8,310	7,622	7,564	7,472
Load	8,893	9,150	9,349	9,567	9,774	9,993	10,214	10,478	10,693	10,891	11,097
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(911)	(983)	(1,112)	(1,227)	(1,325)	(1,407)	(1,501)	(1,482)	(1,547)	(1,570)	(1,588)
East Total obligation	7,596	7,752	7,792	7,865	7,946	8,057	8,156	8,413	8,536	8,686	8,848
Planning Reserve Margin (14.4%)	1,094	1,116	1,122	1,133	1,144	1,160	1,174	1,211	1,229	1,251	1,274
East Obligation + Reserves	8,690	8,869	8,914	8,998	9,090	9,217	9,330	9,624	9,766	9,937	10,123
East Position	0	(105)	(271)	(429)	(571)	(745)	(947)	(1,314)	(2,144)	(2,373)	(2,650)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	52	50	48	46	44	41	39	37	35	33	31
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	142	138	132	128	124	120	101	97	95
Demand Response	52	51	51	50	49	48	48	47	46	45	44
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	161	0	0	0	0	0	0	0	0	0	0
West Existing Resources	1,902	1,731	1,708	1,700	1,689	1,681	1,651	1,644	1,621	1,613	1,608
Load	4,475	4,577	4,692	4,807	4,927	5,049	5,173	5,376	5,430	5,553	5,680
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
New Energy Efficiency	(471)	(515)	(571)	(603)	(634)	(661)	(691)	(774)	(591)	(599)	(612)
West Total obligation	3,841	3,885	3,929	3,998	4,073	4,154	4,233	4,340	4,562	4,663	4,764
Planning Reserve Margin (14.4%)	553	559	566	576	586	598	609	625	657	671	686
West Obligation + Reserves	4,394	4,444	4,495	4,574	4,659	4,752	4,842	4,965	5,219	5,334	5,450
West Position	(2,492)	(2,713)	(2,787)	(2,874)	(2,970)	(3,072)	(3,191)	(3,321)	(3,598)	(3,721)	(3,842)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,592	10,494	10,351	10,269	10,209	10,152	10,034	9,954	9,243	9,178	9,080
Obligation	11,438	11,637	11,721	11,863	12,019	12,211	12,388	12,753	13,099	13,349	13,612
Planning Reserves (14.4%)	1,647	1,676	1,688	1,708	1,731	1,758	1,784	1,836	1,886	1,922	1,960
Obligation + Reserves	13,085	13,313	13,409	13,572	13,750	13,969	14,172	14,589	14,985	15,272	15,573
System Position	(2,492)	(2,818)	(3,058)	(3,303)	(3,541)	(3,817)	(4,138)	(4,635)	(5,742)	(6,094)	(6,493)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(2,492)	(2,818)	(3,058)	(3,303)	(3,541)	(3,817)	(4,138)	(4,635)	(5,742)	(6,094)	(6,493)

Table 6.15 – Winter Peak System Capacity Loads and Resources without Resource Additions

East										
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,734	3,734	3,499	3,185	3,015	3,015	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	1,837	1,957	1,892	1,829	1,766	1,657	1,523	1,463	1,404	1,346
Solar	38	104	101	98	95	92	89	85	82	79
Other Renewable	41	39	38	37	35	34	33	32	30	29
Storage	1	621	606	591	576	561	546	531	516	500
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	176	171	166	161	156	149	140	124
Demand Response	119	118	118	128	129	128	121	120	128	127
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,585)	(1,353)	(1,118)
East Existing Resources	7,804	8,523	8,433	8,120	7,911	7,608	7,442	7,369	7,522	7,662
Load	5,898	5,911	6,036	6,164	6,278	6,408	6,569	6,706	6,899	7,084
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(75)	(118)	(157)	(197)	(239)	(283)	(331)	(388)	(450)	(513)
East Total obligation	5,821	5,790	5,876	5,963	6,033	6,119	6,231	6,309	6,440	6,560
Planning Reserve Margin (16.8%)	978	973	987	1,002	1,014	1,028	1,047	1,060	1,082	1,102
East Obligation + Reserves	6,799	6,763	6,863	6,964	7,047	7,147	7,278	7,369	7,522	7,662
East Position	1,005	1,760	1,570	1,156	864	461	164	0	0	0
Available Market Purchases	500	500	500	0	0	0	0	0	0	0
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	62	59	57	55	53	51	49	47	45
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	2	2	2	2	2	2	2	2	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	70	69	62	61	58	57	57	56	56	56
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,585	1,353	1,118
West Existing Resources	3,345	3,342	3,333	3,330	3,325	3,174	3,171	3,153	2,919	2,679
Load	3,511	3,571	3,640	3,701	3,741	3,805	3,904	3,981	4,068	4,160
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(52)	(65)	(118)	(173)	(229)	(286)	(345)	(401)	(457)	(511)
West Total obligation	3,459	3,506	3,521	3,527	3,511	3,517	3,558	3,578	3,609	3,647
Planning Reserve Margin (16.8%)	581	589	591	593	590	591	598	601	606	613
West Obligation + Reserves	4,041	4,095	4,112	4,120	4,101	4,108	4,156	4,180	4,215	4,259
West Position	(696)	(753)	(780)	(790)	(776)	(934)	(985)	(1,027)	(1,297)	(1,581)
Available Market Purchases	2,603	2,603	2,603	0	0	0	0	0	0	0
System										
Total Resources	11,149	11,865	11,766	11,450	11,235	10,783	10,613	10,522	10,441	10,341
Obligation	9,281	9,296	9,397	9,490	9,544	9,636	9,789	9,888	10,049	10,207
Planning Reserves (16.8%)	1,336	1,339	1,353	1,367	1,374	1,388	1,410	1,424	1,447	1,470
Obligation + Reserves	10,617	10,635	10,750	10,857	10,918	11,024	11,199	11,312	11,497	11,677
System Position	532	1,230	1,016	594	317	(241)	(586)	(789)	(1,056)	(1,336)
Available Market Purchases	3,103	3,103	3,103	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	532	1,230	1,016	594	317	(241)	(586)	(789)	(1,056)	(1,336)

Table 6.15 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East											
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	2,503	2,503	2,503
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,378	3,378	3,378
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,285	1,226	1,168	1,107	1,049	990	850	797	744	689	636
Solar	76	73	70	67	64	61	58	55	52	42	39
Other Renewable	28	26	25	9	8	8	7	7	6	6	0
Storage	485	470	455	440	425	410	395	379	365	350	334
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	120	112	99	94	90	86	82	78	75	71	67
Demand Response	128	117	121	121	125	132	129	117	121	132	109
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(919)	(674)	(414)	(137)	0	0	0	0	0	0	0
East Existing Resources	7,778	7,925	8,097	8,275	8,336	8,262	8,096	8,008	7,276	7,204	7,101
Load	7,248	7,421	7,645	7,863	8,087	8,287	8,466	8,705	8,909	9,134	9,224
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(579)	(624)	(700)	(766)	(826)	(886)	(954)	(973)	(1,022)	(1,049)	(1,077)
East Total obligation	6,659	6,786	6,932	7,084	7,248	7,387	7,498	7,717	7,872	8,070	8,131
Planning Reserve Margin (16.8%)	959	977	998	1,020	1,044	1,064	1,080	1,111	1,134	1,162	1,171
East Obligation + Reserves	7,618	7,763	7,931	8,105	8,292	8,451	8,578	8,828	9,005	9,232	9,302
East Position	160	163	166	170	44	(189)	(482)	(820)	(1,729)	(2,028)	(2,201)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	42	40	38	36	34	32	30	28	25	23	21
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	54	53	53	51	51	50	50	50	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	919	674	414	137	0	0	0	0	0	0	0
West Existing Resources	2,478	2,229	1,967	1,687	1,546	1,544	1,541	1,539	1,536	1,534	1,531
Load	4,232	4,334	4,471	4,605	4,720	4,832	4,959	5,143	5,253	5,374	5,365
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(568)	(624)	(668)	(714)	(760)	(819)	(858)	(900)	(786)	(803)	(826)
West Total obligation	3,662	3,707	3,800	3,888	3,957	4,010	4,097	4,239	4,463	4,567	4,535
Planning Reserve Margin (16.8%)	615	623	638	653	665	674	688	712	750	767	762
West Obligation + Reserves	4,277	4,330	4,438	4,541	4,622	4,684	4,786	4,952	5,212	5,334	5,297
West Position	(1,799)	(2,100)	(2,471)	(2,854)	(3,075)	(3,140)	(3,245)	(3,413)	(3,676)	(3,801)	(3,766)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,255	10,155	10,064	9,962	9,882	9,806	9,637	9,547	8,812	8,737	8,632
Obligation	10,321	10,493	10,732	10,973	11,205	11,398	11,596	11,957	12,334	12,637	12,666
Planning Reserves (16.8%)	1,486	1,511	1,545	1,580	1,614	1,641	1,670	1,722	1,776	1,820	1,824
Obligation + Reserves	11,807	12,003	12,278	12,553	12,819	13,039	13,265	13,678	14,110	14,456	14,490
System Position	(1,552)	(1,849)	(2,214)	(2,591)	(2,937)	(3,233)	(3,628)	(4,132)	(5,298)	(5,719)	(5,858)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(1,552)	(1,849)	(2,214)	(2,591)	(2,937)	(3,233)	(3,628)	(4,132)	(5,298)	(5,719)	(5,858)

Figure 6.4 through Figure 6.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available Market purchases, which can be used

to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 7 (Resource Options).

Figure 6.4 – Summer System Capacity Position Trend

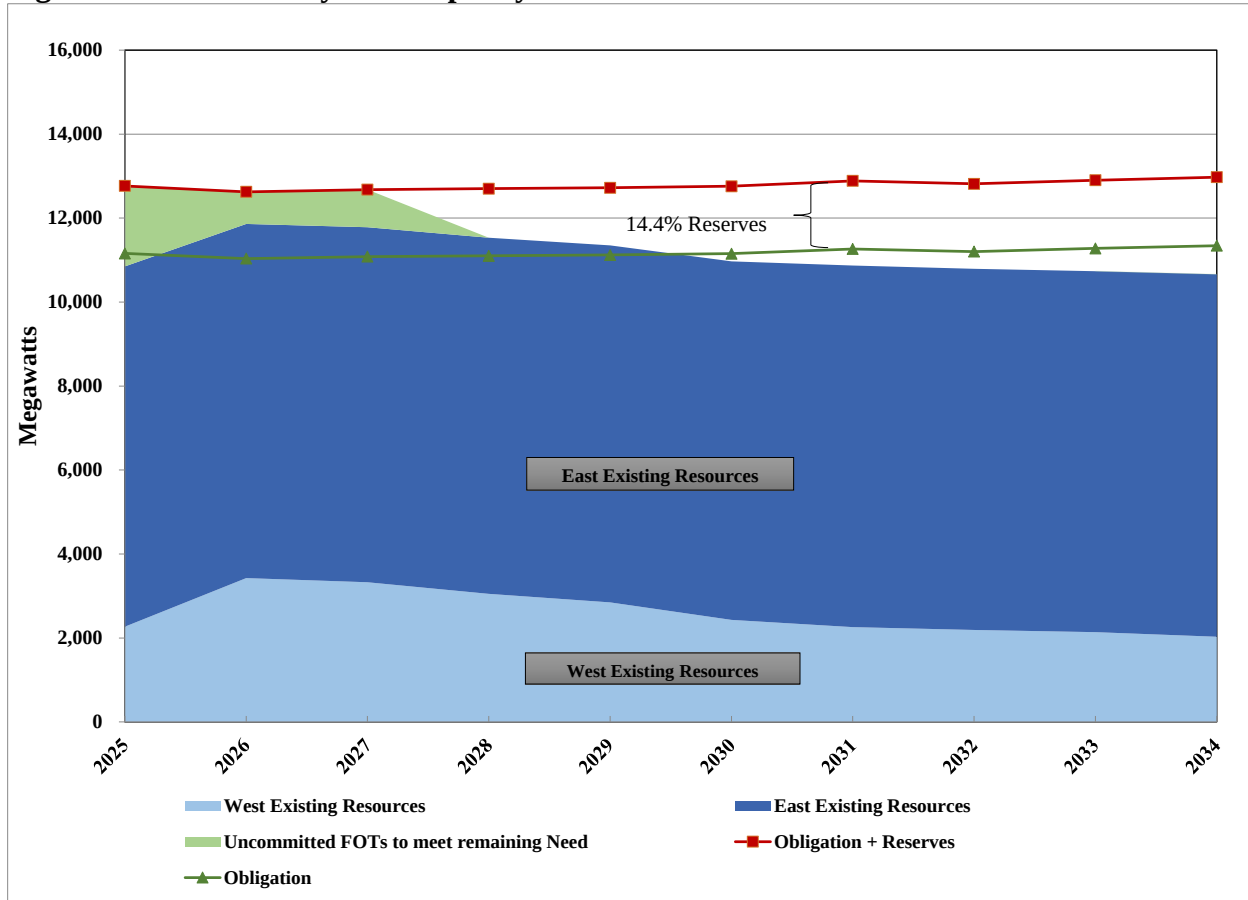


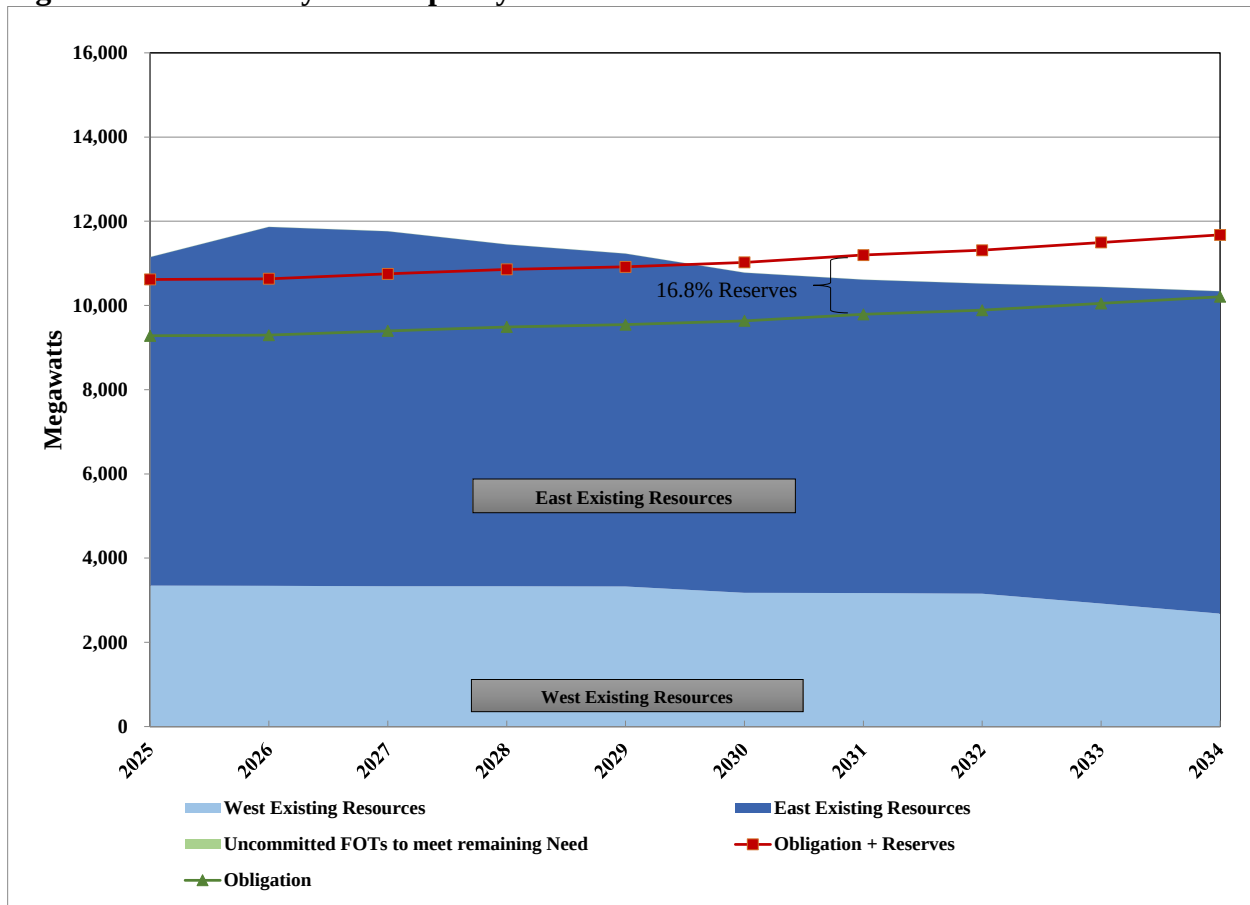
Figure 6.5 – Winter System Capacity Position Trend

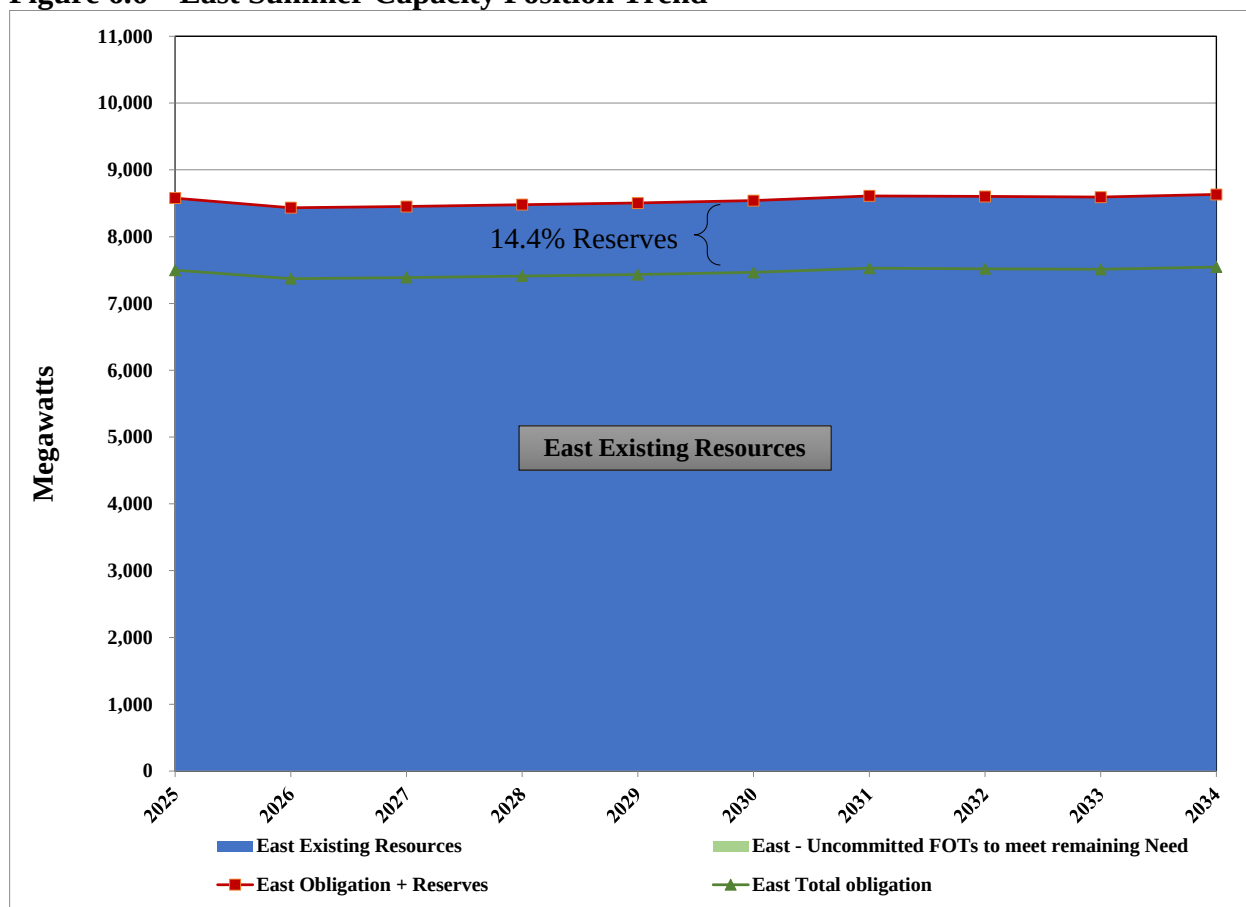
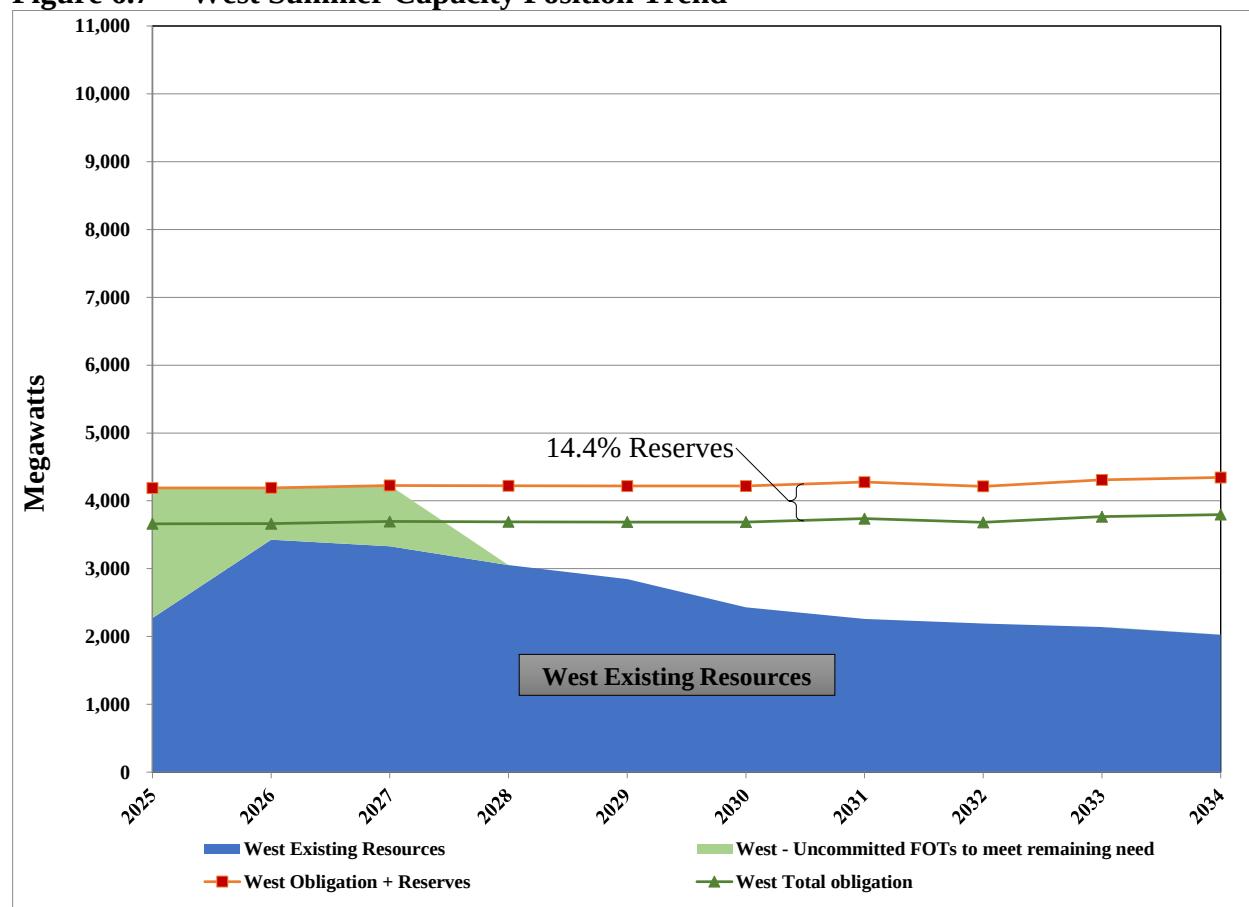
Figure 6.6 – East Summer Capacity Position Trend

Figure 6.7 – West Summer Capacity Position Trend

CHAPTER 7 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp’s resource attributes and costs for future generation resource options reflect updated information, based on assumptions from the National Renewable Energy Laboratory’s 2024 Annual Technology Baseline to the extent data was available.¹
- In addition to utility-scale resources (generally 200 megawatts (MW) or more), the 2025 IRP includes small-scale (20 MW) wind, solar, and biodiesel peaking options. These small-scale resource options are assumed to be sited in relative proximity to load, such that they do not require significant transmission system upgrades.
- Renewable resource generation profiles have been updated and expanded to include more proxy resource locations as well as distinct profiles for utility-scale and small-scale wind resources, rather than one generation profile per state as in the 2023 IRP. This update extends to online and contracted resources, as well as proxy resource options, and includes expanded historical data for use with stochastic analysis.
- Options for utility-scale lithium-ion batteries (20 MW and 200 MW options), gravity energy storage systems, pumped hydro energy storage (PHES), thermal energy storage, one-hundred-hour iron-air storage, and adiabatic compressed air energy storage are included in this IRP. In a change from prior IRPs, hydrogen peaking resources are also treated as storage resources (rather than using pipelines and a market price for hydrogen). Hydrogen is electrolyzed using excess generation output and stored in either high-pressure tanks or underground caverns.
- PLEXOS endogenously models transmission upgrades, allowing for increases to transfer limits and resource interconnection. Where applicable, upgrades are restricted until all pre-requisites are in place.
- PacifiCorp continues to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, demand-side management (DSM) programs, transmission resources and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the various technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

¹ <https://atb.nrel.gov/electricity/2024/index>

Supply-Side Resources

The list of supply-side resource options reflects the expected realities evidenced through external studies, internally generated studies, permitting, regulatory requirements, and stakeholder input. The process began with the list of major generating resources from the 2023 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)² was used as much as possible to maintain consistency. Some of the terminology used in this chapter is from the ATB. A glossary of some of the terminology is provided below in Table 7.12 and a list of acronyms is provided in Table 7.13.

The supply-side resource options include the following technologies grouped by energy source. More information about each technology is provided in the “Resource Option Descriptions” section of this chapter. The terminology here matches that used in the supply-side resource table, although some may have been shortened per the acronym list in Table 7.13.

- Natural Gas
 - Internal Combustion Engines.
 - SCCT, Aero, & F-Frame.
 - CCCT, 1x1, & 2x1.
 - Adjustments for 95% Carbon Capture.
 - Adjustments for Brownfield Construction.
 - Adjustments for advanced technology innovation scenario (“Innovations far from market-ready today are successful and become widespread in the market. New technology architectures could look different from those observed today. Public and private R&D investment increases. For biopower technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages.”³)
- Hydrogen
 - Adjustments for 100% Hydrogen burning capability.
 - Adjustments for Hydrogen Storage.
 - Electrolyzer.
- Coal, Carbon Capture Retrofits at existing plants
- Energy Storage
 - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW all with 4-hour duration):
 - Adjustments for double duration (i.e., 8-hour duration).
 - Adjustments for co-location with other generating resources.
 - Adjustments for advanced technology innovation scenario.
 - Gravity Batteries.
 - Adiabatic Compressed Air Energy Storage (ACAES).
 - 100-Hour Iron Air Batteries.
 - PHES (single and double reservoirs).
 - Pumped Thermal.
- Solar

² <https://atb.nrel.gov/electricity/2024/definitions#scenarios>

³ <https://atb.nrel.gov/electricity/2024/definitions#scenarios>

- Adjustments for advanced technology innovation scenario.
- Wind (various on-shore wind classes and off-shore class 12, as appropriate for PacifiCorp’s service area)
 - Adjustments for advanced technology innovation scenario.
- Nuclear⁴
 - Small Modular Reactor.
 - Adjustments for adding thermal energy storage.
 - Large Light Water Reactor.
 - Adjustments for advanced technology innovation scenario (in addition to the earlier definition: “for nuclear technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages.”)
- Geothermal (near field enhanced geothermal system, binary)
 - Adjustments for advanced technology innovation scenario.

Derivation of Resource Attributes

Once a basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table, which is used to develop inputs for IRP modeling:

- Annual Technology Baseline (ATB) prepared by the National Renewable Energy Laboratory (NREL).⁵
- U.S. Energy Information Administration (EIA) “Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies” (“EIA Report,” both the 2024⁶ and 2020⁷ editions) prepared by Sargent and Lundy.
- Original equipment manufacturers capital and operation and maintenance estimates.
- Developer cost and performance estimates.
- Publicly available cost and performance estimates.
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes.
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.
- Additional references are provided in the Resource Option Descriptions section of this chapter.

⁴ Nuclear technology is intentionally limited to years outside the 2-4 year action plan window. Nuclear resource assumptions were discussed in the 2025 IRP public input meeting series and stakeholder feedback, See Appendix M, stakeholder feedback form #1 (Peter Gross).

See Appendix M, stakeholder feedback form #41 (Nathan Strain).

⁵ <https://atb.nrel.gov/electricity/2024/index>.

⁶ *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration’s *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

⁷ *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration’s *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf.

Most of the supply-side resource options rely on the ATB and EIA reports. Some resources contained in the supply-side resource table are not listed in the ATB, but were developed through other reports, conversations with industry experts, developers, and original equipment manufacturers (OEM's). The 2024 ATB with its numerous references and the 2024 EIA Report was used for:

- Natural Gas
 - SCCT (Aero).
 - CCCT (1x1 & 2x1).
 - Adjustments for 95% Carbon Capture.
 - Adjustments for advanced technology innovation scenario.
- Energy Storage
 - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW, 4-hour duration).
 - Adjustments for double duration.
 - Adjustments for co-location.
 - Adjustments for advanced technology innovation scenario.
 - PHES (single and double reservoirs).
- Solar
 - Adjustments for advanced technology innovation scenario.
- Wind
 - Adjustments for advanced technology innovation scenario.
- Nuclear
 - Small Modular Reactor.
 - Large Light Water Reactor.
 - Adjustments for advanced technology innovation scenario.
- Geothermal (near field enhanced geothermal system, binary)
 - Adjustments for advanced technology innovation scenario.

The 2020 EIA Report provided the Internal Combustion Engines (ICE) data because no ICE option was included in the 2024 EIA report. The ICE option was included to address Oregon requirements for small-scale resources under 20 MW. Although the ICE option consists of 4 x 5.6 MW engines at ISO conditions, it is assumed that the engines, if not derated due to altitude or other factors, can be curtailed to meet the 20 MW threshold.

The brownfield cost adjustment was developed based on prior IRP estimates.

Hydrogen capable resource data is based on the following:⁸

- Adjustments for 100% hydrogen burning capability are based on conversations with OEMs and industry experts and the report “Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems.”⁹ A 15% cost adder for new gas turbines indicated by Table 3 in the report was corroborated by OEMs and other industry experts.

⁸ The option of hydrogen as an alternative fuel, including electrolyzer cost and performance, was discussed in the course of the 2025 IRP public input meeting series. For specific recommendations and PacifiCorp's response, see Appendix M, stakeholder feedback form #23 (NP Energy, LLC)

⁹ Simon Oberg, Mikael Odenberger, Filip Johnsson “Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems,” Division of Energy Technology, Chalmers University of Technology, 412 96, Gothenburg, Sweden, <https://www.sciencedirect.com/science/article/pii/S0360319921039768>

- Adjustments for hydrogen storage are based on information in the U.S. Department of Energy (DOE) reports: “Pathways to Commercial Liftoff: Clean Hydrogen”¹⁰ (Clean Hydrogen Liftoff report), “2022 Grid Energy Storage Technology Cost and Performance Assessment,”¹¹ and the Hydrogen and Fuel Cell Technologies Office’s “Multi-Year Program Plan.”¹²
- Electrolyzer costs are based on the DOE report “Hydrogen Production Cost from PEM Electrolysis – 2019,”¹³ and the NREL report “Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers.”

Data for “Carbon Capture Retrofits at existing coal plants” is based on adjustments made to incorporate capital and operational costs of emission control technologies (SCR and FGD) needed to scrub flue gas prior to the carbon capture technology, and adjustments made to account for economies of scale.

Gravity Batteries costs were escalated from the 2023 IRP.

Adiabatic Compressed Air Energy Storage (ACAES) were originally escalated from the 2023 IRP which used data provided by Renewable Energy Storage Company (RESC) but later updated based on input from Hydrostor.

100-Hour Iron Air Battery data is based on information provided by Form Energy.¹⁴

Pumped Thermal energy storage is based on integrated thermal storage for nuclear, but with a resistive heater for energy storage.

Data for “Adjustments for adding thermal energy storage to nuclear plants” represents thermal energy storage and only stores energy from the heat of the reactor, not from a resistive heater.

The following costs were excluded from the cost estimates provided by the referenced sources, but were added by the Company as appropriate, using confidential data specific to the Company’s business practices:¹⁵

- Allowance for Funds Used During Construction (AFUDC).
- Capital Surcharge.
- Escalation.
- Property taxes.

Interconnection costs and sales tax are included in the PLEXOS modeling depending on the locational node in which each technology is being considered.

¹⁰ <https://liftoff.energy.gov/>

¹¹ <https://www.energy.gov/sites/default/files/2022-09/2022%20Grid%20Energy%20Storage%20Technology%20Cost%20and%20Performance%20Assessment.pdf>

¹² <https://www.energy.gov/sites/default/files/2024-05/hfto-mypp-2024.pdf>

¹³

https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master

¹⁴ See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).

¹⁵ Additional cost considerations were the subject of discussion and feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #24 (NP Energy, LLC).

Wind and Solar Generation Profiles

For the 2025 IRP, PacifiCorp has updated the wind and solar generation profiles for both existing resources and proxy resource options. PacifiCorp provided the location and expected generation levels for existing and contracted resources to a consultant, Hendrickson Renewables, and received back an hourly generation profile for 2006-2023 that reflects expected performance under historical weather conditions.

For existing resources, results were tuned to recent historical actual generation levels, while resources that are not yet operating were tuned to forecasted output. For wind, hourly generation is based on hourly wind speeds and air density from the ERA5 reanalysis dataset, with scaling and adjustments to represent project-specific power curves and expected output.¹⁶ For solar, hourly solar irradiance and weather data was extracted from a Vaisala satellite irradiance dataset¹⁷ and configured in a PV_{syst} model¹⁸ that was tuned to correspond to actual or forecasted output.

For proxy resources, PacifiCorp identified locations across its system, and Hendrickson Renewables determined the expected output of the equipment represented in NREL's ATB, which was used to develop cost inputs. In the 2023 IRP, PacifiCorp used one wind and solar profile for each of its five largest state jurisdictions (excluding California). For the 2025 IRP, wind and solar profiles have been developed which correspond to thirteen different transmission areas spread across PacifiCorp's system. To account for technological differences that impact generation output, generation profiles were also developed for five small-scale wind profiles for the west side of the system, along with an off-shore wind profile for the potential lease area near Brookings.¹⁹

For many years, PacifiCorp has used a chaotic normal load forecast to account for the range of load conditions experienced. For each month of the year, the chaotic normal load forecast is derived from the most representative historical month from recent history (currently 2013-2022). The pattern of load in each of the selected months from history is reflected in every year of the forecast, with adjustments to account for the rotation of calendar days and weekdays from year to year, as well as for forecasted changes in load over time. As a result, every day of PacifiCorp's load forecast is tied to a specific day in history. For the 2025 IRP, the normalized wind and solar output modeled in PLEXOS is drawn from the same historical day as the load forecast. The result is a generation profile specific to each of the years of the IRP forecast (2025-2045) that inherently represents the correlation between renewable generation and load. The expanded historical generation data set developed for the 2025 IRP also enables stochastic analysis that captures the relationship between renewable generation and load in each of the historical years (2006-2023).

Sodium Demonstration Project

PacifiCorp's 2025 IRP includes the Sodium® advanced nuclear demonstration project: an 840 megawatt thermal pool-type sodium fast reactor that contains a compact and simple safety envelope and a molten salt energy storage system which enables the plant to vary its supply of energy to the grid, up to 500 megawatts electric net, providing both firm and flexible emissions-free energy. The reactor operates near atmospheric pressure, circulating sodium through its core

¹⁶ European Centre for Medium-Range Weather Forecasts. <https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5>

¹⁷ Vaisala. <https://www.vaisala.com/>

¹⁸ PV_{syst}. <https://www.pvsyst.com/>

¹⁹ Bureau of Ocean Energy Management. <https://www.boem.gov/renewable-energy/state-activities/Oregon>

with pumps. The design includes reliable inherent and passive safety features including near atmospheric operating pressures, always-on passive air cooling and inherent reactivity feedback.

At this time, the specific cost and performance assumptions for the Natrium® advanced nuclear demonstration project are confidential and are not summarized in the supply-side resource table. TerraPower and PacifiCorp remain committed to bringing the Natrium technology to market to enhance the company's ability to serve its customers, meet growing demand and ensure a reliable and resilient energy future. PacifiCorp is also committed to protecting customers from first-of-a-kind (FOAK) technology risk and FOAK program and construction costs. The Company is implementing an innovative commercial energy acquisition structure that allows Natrium benefits to flow to customers while ensuring those customers are not burdened with FOAK technology cost and risk. This commercial structure is in the final stages of development and the details are confidential at this time.

The Natrium advanced nuclear demonstration project has been named Kemmerer Power Station Unit 1 (KU1) which is planned to be built near the Naughton Power Plant. KU1 is currently in the design and licensing phase. TerraPower submitted the Construction Permit Application to the US Nuclear Regulatory Commission (US NRC) in March 2024. The US NRC has published their review schedule and anticipates the Preliminary Safety Analysis Report and Environmental Report to be approved by August 2026, and the Construction Permit Application to be approved by December 2026. This approval will allow the beginning of construction of the Nuclear Island. An Operating License is also required. TerraPower anticipates the Operating License Application to be submitted in September 2027 and achieving commercial operations the fall of 2031.

On June 10, 2024, TerraPower broke ground for the Natrium reactor demonstration project with construction of the sodium test and fill facility commencing first. On January 14, 2025, the State of Wyoming Industrial Siting Council (ISC) approved TerraPower's permit for construction and operational activities on the Natrium plant that are not under jurisdiction of the US NRC. This approval allows for the construction of non-nuclear facilities, including the energy island portion of the Natrium plant that houses the molten salt energy storage tanks and turbines.

Resource Options and Attributes

Table 7.2 through Table 7.11 report characteristics, attributes and costs for resource options considered in the 2025 IRP. Unlike previous IRP's the supply-side resource table does not list multiple versions of the same technology for various altitudes. Instead, the location adjustments from Appendix A and B of the 2024 EIA²⁰ report are applied in PLEXOS. Total resource cost attributes for supply-side resource options are based on estimates of the first-year, real-levelized

²⁰ https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

costs for resources, stated in June 2024 dollars.^{21,22} Table 7.1 provides a listing of these ten tables for convenience.

Table 7.1 – Supply-Side Resource Option Tables

	Characteristics and Costs	Operating Characteristics and Environmental Data
Thermal	Table 7.2	Table 7.4
Non-Thermal and Storage	Table 7.3	Table 7.5
	Additional Attributes and Fixed O&M	Variable O&M, Total Cost and Credits
Thermal	Table 7.6	Table 7.9
Non-Thermal	Table 7.7	Table 7.10
Storage	Table 7.8	Table 7.11

A Glossary of Terms and a Glossary of Acronyms from the supply-side resource table is summarized in Table 7.12 and Table 7.13.

²¹ Supply-side resource attributes were discussed throughout the 2025 public input meeting series and generated stakeholder feedback forms inquiries. 2028 was determined to be the appropriate earliest commercial online year for most proxy resource options. However, PacifiCorp does not preclude the possibility of achieving specific (non-proxy) projects on an earlier timeline outside of the IRP.

See Appendix M, stakeholder feedback form #7 (Renewable Northwest).

See Appendix M, stakeholder feedback form #36 (Sierra Club).

²² The supply-side resource table was made publicly available during the 2025 IRP public input meeting series and discussed extensively as it developed. <https://www.pacifiCorp.com/energy/integrated-resource-plan/support.html>

Table 7.2 – 2025 Thermal Supply-Side Resources, Characteristics and Costs (2024\$)

Fuel	Resource Description	Characteristics						Costs						
		Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital (\$/kW)	Var O&M (\$/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M (\$/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost (\$/kW)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	0	20	2025	2.5	2027	30	\$2,131	\$6.93	74%	91%	\$42.82	3%	\$14.59
Natural Gas	SCCT Aero, with SCR	0	50	2025	3.5	2028	40	\$2,613	\$7.40	87%	98%	\$12.42	3%	\$32.46
Natural Gas	SCCT Aero x4, with SCR	0	211	2025	3.5	2028	40	\$1,789	\$5.92	87%	98%	\$9.93	3%	\$32.46
Natural Gas	SCCT Frame "F" x1, with SCR	0	233	2025	5.0	2030	40	\$1,387	\$7.75	100%	99%	\$27.92	3%	\$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	0	649	2025	5.0	2030	40	\$1,839	\$2.70	0%	100%	\$42.44	0%	\$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	0	1,227	2025	5.0	2030	40	\$1,553	\$2.28	0%	100%	\$35.18	0%	\$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	0	565	2025	5.0	2030	+40	\$3,429	\$5.32	0%	100%	\$77.07	0%	\$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	0	1,085	2025	5.0	2030	+40	\$2,846	\$4.83	0%	100%	\$62.99	0%	\$65.08
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	0	20	2025	2.5	2027	30	\$1,918	\$6.24	74%	91%	\$42.82	3%	\$14.59
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	0	50	2025	3.5	2028	40	\$2,352	\$6.66	87%	98%	\$12.42	3%	\$32.46
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	0	211	2025	3.5	2028	40	\$1,610	\$5.33	87%	98%	\$9.93	3%	\$32.46
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	0	233	2025	5.0	2030	40	\$1,248	\$6.98	100%	99%	\$27.92	3%	\$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	0	649	2025	5.0	2030	40	\$1,655	\$2.43	0%	100%	\$42.44	0%	\$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	0	1,227	2025	5.0	2030	40	\$1,398	\$2.05	0%	100%	\$35.18	0%	\$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	0	565	2025	5.0	2030	40	\$3,086	\$4.78	0%	100%	\$77.07	0%	\$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	0	1,085	2025	5.0	2030	40	\$2,561	\$4.34	0%	100%	\$62.99	0%	\$65.08
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100% Hydrogen burning capability	0	233	2025	5.0	2030	40	\$1,595	\$8.91	100%	99%	\$27.92	3%	\$13.95
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100% Hydrogen burning capability	0	649	2025	5.0	2030	40	\$2,115	\$3.11	0%	100%	\$42.44	0%	\$13.89
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100% Hydrogen burning capability	0	1,227	2025	5.0	2030	40	\$1,786	\$2.62	0%	100%	\$35.18	0%	\$13.67
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	233	2025	5.0	2030	40	\$2,586	\$8.18	100%	99%	\$35.12	3%	\$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	649	2025	5.0	2030	40	\$3,038	\$3.13	0%	100%	\$49.64	0%	\$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	1,227	2025	5.0	2030	40	\$2,752	\$2.70	0%	100%	\$42.38	0%	\$26.89
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	233	2025	5.0	2030	40	\$2,098	\$8.32	100%	99%	\$40.78	3%	\$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	649	2025	5.0	2030	40	\$2,550	\$3.27	0%	100%	\$55.30	0%	\$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	1,227	2025	5.0	2030	40	\$2,264	\$2.85	0%	100%	\$48.04	0%	\$26.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	0	649	2025	5.0	2030	+40	\$1,832	\$2.68	0%	100%	\$41.33	0%	\$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	0	1,227	2025	5.0	2030	+40	\$1,518	\$2.23	0%	100%	\$34.07	0%	\$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	0	565	2025	5.0	2030	+40	\$3,261	\$5.03	0%	100%	\$72.60	0%	\$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	0	1,085	2025	5.0	2030	+40	\$2,637	\$4.49	0%	100%	\$57.74	0%	\$65.08
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	0	-119	2025	5.0	2030	40	\$561	\$23.91	+0%	0.00	\$10.28	100%	\$32.46
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	5,541	-85	2027	5.0	2032	30	\$3,501	\$11.40	0%	0%	\$277.68	0%	\$53.20
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	6,429	-297	2027	5.0	2032	30	\$2,951	\$9.73	0%	0%	\$235.36	0%	\$53.20
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	6,933	-233	2027	5.0	2032	30	\$2,951	\$9.63	0%	0%	\$242.12	0%	\$53.20
Coal	CCS Jan Bridger 3&4 (costs on post retrofit basis)	7,513	-174	2025	5.0	2030	30	\$2,598	\$10.57	0%	0%	\$254.91	0%	\$53.20
Coal	CCS Wyodak (costs on post retrofit basis)	4,448	-69	2027	5.0	2032	30	\$3,504	\$11.69	0%	0%	\$309.51	0%	\$53.20
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	N/A	600	2030	5.0	2035	60	\$9,662	\$9.74	0%	0%	\$97.42	0%	\$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	N/A	600	2030	4.0	2034	60	\$6,368	\$8.74	0%	0%	\$84.53	0%	\$12.00
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	5.0	2035	60	\$10,628	\$10.72	0%	0%	\$107.16	0%	\$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	4.0	2034	60	\$7,005	\$9.61	0%	0%	\$92.98	0%	\$12.00
Nuclear	Large Light Water Reactor, Moderate Technology Case	N/A	2,000	2030	7.0	2037	60	\$7,563	\$9.38	0%	0%	\$125.36	0%	\$10.00
Nuclear	Large Light Water Reactor, Advanced Technology Case	N/A	2,000	2030	5.0	2035	60	\$6,265	\$7.88	0%	0%	\$90.26	0%	\$9.00
Geothermal	Near Field Enhanced Geothermal System (NF-EGS) Binary	N/A	707	2025	3.0	2028	30	\$7,593	included in FOM	0%	0%	\$194.00	6%	\$125.09
Geothermal	Near Field Enhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	707	2025	3.0	2028	30	\$5,949	included in FOM	0%	0%	\$173.90	6%	\$125.09

Table 7.3 – 2025 Non-Thermal Supply-Side Resources, Characteristics and Costs (2024\$)²³

Fuel	Resource Description	Characteristics						Costs						
		Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital (\$/kW)	Var O&M (\$/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M (\$/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost (\$/kW)
Storage ¹	Li-Ion, 4-hour, 20 MW	N/A	20	2025	1.0	2026	20	\$1,748	Included in FOM	0%	0%	\$45.05	0%	\$29.94
Storage ¹	Li-Ion, 4-hour, 200 MW	N/A	200	2025	2.0	2027	20	\$1,498	Included in FOM	0%	0%	\$38.77	0%	\$25.66
Storage ¹	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	N/A	200	2025	2.0	2027	20	\$2,557	Included in FOM	0%	0%	\$69.78	0%	\$46.19
Storage ¹	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	20	\$1,459	Included in FOM	0%	0%	\$36.92	0%	\$25.66
Storage	Gravity Battery, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	50	\$2,021	Included in FOM	0%	0%	\$50.51	0%	\$0.19
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	N/A	1,000	2025	3.0	2028	50	\$3,006	Included in FOM	0%	0%	\$90.92	0%	\$0.35
Storage	Adiabatic CAES, 500 MW, 4000 MWh	N/A	500	2025	3.0	2028	50	\$3,754	\$2.60	50%	0%	\$19.20	42%	\$49.31
Storage	100-hour Iron Air	N/A	200	2028	2.0	2030	20	\$2,730	Included in FOM	0%	0%	\$21.04	19%	\$171.06
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	N/A	400	2025	5.0	2030	100	\$2,984	\$0.58	0%	0%	\$20.20	45%	\$149.21
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	N/A	400	2025	5.0	2030	100	\$4,159	\$0.58	0%	0%	\$20.20	45%	\$207.95
Storage	Pumped Hydro, One New Reservoir, 4-hour	N/A	400	2025	5.0	2030	100	\$2,883	\$0.58	0%	0%	\$20.20	45%	\$144.16
Storage	Pumped Hydro, One New Reservoir, 10-hour	N/A	400	2025	5.0	2030	100	\$3,537	\$0.58	0%	0%	\$20.20	45%	\$176.87
Storage	Pumped Thermal Energy Storage, 10-hour	N/A	100	2026	5.0	2031	60	\$6,174	\$0.70	0%	0%	\$2.00	0%	\$60.00
Storage	Pumped Thermal Energy Storage, 24-hour	N/A	50	2026	5.0	2031	60	\$11,525	\$0.70	0%	0%	\$1.00	0%	\$60.00
Solar	PV, 20 MW, Class 1-10	by location	20	2025	3.0	2028	25	\$1,965	included in FOM	0%	0%	\$18.16	12%	\$39.29
Solar	PV, 200 MW, Class 1-10	by location	200	2025	3.0	2028	25	\$1,217	included in FOM	0%	0%	\$20.52	12%	\$24.33
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	20	2025	3.0	2028	25	\$1,832	included in FOM	0%	0%	\$17.24	12%	\$37.33
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	200	2025	3.0	2028	25	\$1,135	included in FOM	0%	0%	\$19.47	12%	\$23.11
Wind	Wind Class 1-10, 20 MW	by location	20	2025	3.0	2028	30	\$2,555	included in FOM	0%	0%	\$38.79	35%	\$63.57
Wind	Wind Class 1-6, 200 MW	by location	200	2025	5.0	2030	30	\$1,421	included in FOM	0%	0%	\$31.65	35%	\$63.57
Wind	Wind Class 7, 200 MW	by location	200	2025	5.0	2030	30	\$1,492	included in FOM	0%	0%	\$31.65	35%	\$63.57
Wind	Offshore, Wind Class 12	0	200	2027	5.0	2032	30	\$8,341	included in FOM	0%	0%	\$69.26	35%	\$169.16
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	by location	20	2025	3	2028	30	\$2,434	included in FOM	0%	0%	\$34.87	35%	\$60.58
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	\$1,354	included in FOM	0%	0%	\$28.45	35%	\$60.58
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	\$1,422	included in FOM	0%	0%	\$28.45	35%	\$60.58
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	0	200	2027	5	2032	30	\$6,011	included in FOM	0%	0%	\$63.21	35%	\$121.92

¹ Assumed co-located²³ See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users)

Table 7.4 – 2025 Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024\$)

Fuel	Resource Description	Operating Characteristics				Environmental Data				
		Average Full Load Heat Rate (HHV Btu/KWh)	Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO ₂ (lbs/MMBtu)	NO _x (lbs/MMBtu)	Hg (lbs/TBTu)	CO ₂ (lbs/MMBtu)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02000	0.000	117
Natural Gas	SCCT Aero, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Aero x4, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02131	0.000	117
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	9,717	35.12%	2.70%	3.90%	28.4	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	6,040	56.49%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	6,122	55.74%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	N/A	79.13%	1.50%	1.5%	45.7	0.00000	0.00000	0.000	0
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	14,795	23.06%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	14,011	24.35%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	13,662	24.98%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	14,483	23.56%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Wyodak (costs on post retrofit basis)	16,653	20.49%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Moderate Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Advanced Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Geothermal	Near Field Enhanced Geothermal System (NF-EGS) Binary	N/A	N/A	10%	10%	510.0	n/a	n/a	n/a	n/a
Geothermal	Near Field Enhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	N/A	10.00%	10.00%	510.0	n/a	n/a	n/a	n/a

Table 7.5 – 2025 Non-Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024\$)

Fuel	Resource Description	Operating Characteristics				Environmental Data				
		Average Full Load Heat Rate (HHV Btu/KWh)	Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Storage ¹	Li-Ion, 4-hour, 20 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage ¹	Li-Ion, 4-hour, 200 MW	n/a	85%	1%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage ¹	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	n/a	85.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage ¹	Li-Ion, 4-hour, 1000 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW	n/a	83%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	n/a	83.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Adiabatic CAES, 500 MW, 4000 MWh	n/a	63%	1.1%	1.1%	n/a	0.00000	0.00000	0.000	0
Storage	100-hour Iron Air	n/a	43%	1.0%	included in CF	0.0	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 10-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 24-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Solar	PV, 20 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a

¹ Assumed co-located

Table 7.6 – 2025 IRP Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024\$)

Resource Description	Additional Attributes							Fixed O&M						Total Fixed Cost Converted (\$/MWh)
	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment (\$/kW-Yr)	Capacity Factor	O&M (\$/kW-Yr)	Capitalized Premium	O&M Capitalized (\$/kW-Yr)	Gas Transport (\$/kW-Yr)	Total Fixed O&M (\$/kW-Yr)	Total Fixed Cost (\$/kW-Yr)	
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	Yes	0	\$ 2,130.94	\$ 14.59	6.890%	\$147.83	92.50%	\$42.82	2.62%	\$1.12	\$0.00	\$43.94	\$191.77	\$23.67
SCCT Aero, with SCR	No	0	\$ 2,612.80	\$ 32.46	6.101%	\$161.39	33.00%	\$12.42	2.62%	\$0.32	\$0.00	\$12.74	\$174.13	\$60.24
SCCT Aero x4, with SCR	No	0	\$ 1,789.35	\$ 32.46	6.104%	\$111.20	33.00%	\$9.93	2.62%	\$0.26	\$0.00	\$10.19	\$121.40	\$41.99
SCCT Frame "F" x1, with SCR	Yes	0	\$ 1,386.92	\$ 12.13	6.100%	\$85.34	33.00%	\$27.92	2.62%	\$0.73	\$0.00	\$28.65	\$114.00	\$39.43
Goshen	Yes	2,814	\$ 1,400.79	\$ 12.13	6.100%	\$86.19	33.00%	\$27.92	2.62%	\$0.73	\$96.20	\$124.85	\$211.04	\$73.00
Wasatch Front	Yes	4,225	\$ 1,373.05	\$ 12.13	6.100%	\$84.50	33.00%	\$27.92	2.62%	\$0.73	\$14.72	\$43.38	\$127.87	\$44.23
Wyoming East	Yes	6,130	\$ 1,373.05	\$ 12.13	6.100%	\$84.50	33.00%	\$27.92	2.62%	\$0.73	\$25.80	\$54.45	\$138.95	\$48.07
CCCT Dry "H", 1X1, DF, with SCR	Yes	0	\$ 1,839.00	\$ 12.08	6.233%	\$115.58	78.00%	\$42.44	2.62%	\$1.11	\$0.00	\$43.55	\$158.93	\$23.26
Goshen	Yes	2,814	\$ 1,857.39	\$ 12.08	6.233%	\$116.52	78.00%	\$42.44	2.62%	\$1.11	\$60.34	\$103.89	\$220.41	\$32.26
Wasatch Front	Yes	4,225	\$ 1,820.61	\$ 12.08	6.233%	\$114.23	78.00%	\$42.44	2.62%	\$1.11	\$9.25	\$52.81	\$167.04	\$24.45
Wyoming East	Yes	6,130	\$ 1,820.61	\$ 12.08	6.233%	\$114.23	78.00%	\$42.44	2.62%	\$1.11	\$16.33	\$59.88	\$174.11	\$25.48
CCCT Dry "H", 2X1, DF, with SCR	Yes	0	\$ 1,451.26	\$ 11.89	6.234%	\$97.47	78.00%	\$35.18	2.62%	\$0.92	\$0.00	\$36.10	\$133.67	\$19.56
Goshen	Yes	2,814	\$ 1,568.79	\$ 11.89	6.234%	\$98.54	78.00%	\$35.18	2.62%	\$0.92	\$61.16	\$97.26	\$195.80	\$28.66
Wasatch Front	Yes	4,225	\$ 1,537.73	\$ 11.89	6.234%	\$96.60	78.00%	\$35.18	2.62%	\$0.92	\$9.38	\$45.48	\$142.08	\$20.79
Wyoming East	Yes	6,130	\$ 1,537.73	\$ 11.89	6.234%	\$96.60	78.00%	\$35.18	2.62%	\$0.92	\$16.55	\$52.65	\$149.26	\$21.84
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	No	0	\$ 3,429.38	\$ 65.28	6.239%	\$218.03	78.00%	\$77.07	5.54%	\$4.27	\$0.00	\$81.34	\$299.37	\$43.81
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	No	0	\$ 2,846.02	\$ 65.08	6.241%	\$181.68	78.00%	\$62.99	5.54%	\$3.49	\$0.00	\$66.48	\$248.16	\$36.32
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	No	0	\$ 1,917.85	\$ 14.59	6.891%	\$133.16	33.00%	\$42.82	2.62%	\$1.12	\$0.00	\$43.94	\$177.10	\$61.26
SCCT Aero, with SCR + Δ for CT Brownfield construction	No	0	\$ 2,351.52	\$ 32.46	6.102%	\$145.47	33.00%	\$12.42	2.62%	\$0.32	\$0.00	\$12.74	\$158.21	\$54.73
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	No	0	\$ 1,610.42	\$ 32.46	6.105%	\$100.30	33.00%	\$9.93	2.62%	\$0.26	\$0.00	\$10.19	\$110.49	\$38.22
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	Yes	0	\$ 1,248.23	\$ 12.13	6.100%	\$76.88	33.00%	\$27.92	2.62%	\$0.73	\$0.00	\$28.65	\$105.53	\$36.51
Goshen-Brownfield	No	2,814	\$ 1,260.71	\$ 12.13	6.100%	\$77.64	33.00%	\$27.92	2.62%	\$0.73	\$96.20	\$124.85	\$202.50	\$70.05
Wasatch Front-Brownfield	Yes	4,225	\$ 1,235.75	\$ 12.13	6.100%	\$76.12	33.00%	\$27.92	2.62%	\$0.73	\$14.72	\$43.38	\$119.50	\$41.34
Wyoming East-Brownfield	Yes	6,130	\$ 1,235.75	\$ 12.13	6.100%	\$76.12	33.00%	\$27.92	2.62%	\$0.73	\$25.80	\$54.45	\$130.57	\$45.17
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	\$ 1,455.10	\$ 12.08	6.234%	\$103.93	78.00%	\$42.44	2.62%	\$1.11	\$0.00	\$43.45	\$147.48	\$21.58
Goshen-Brownfield	No	2,814	\$ 1,671.65	\$ 12.08	6.234%	\$104.96	78.00%	\$42.44	2.62%	\$1.11	\$60.34	\$103.89	\$208.85	\$30.57
Wasatch Front-Brownfield	Yes	4,225	\$ 1,638.55	\$ 12.08	6.234%	\$102.90	78.00%	\$42.44	2.62%	\$1.11	\$9.25	\$52.81	\$155.71	\$22.79
Wyoming East-Brownfield	Yes	6,130	\$ 1,638.55	\$ 12.08	6.234%	\$102.90	78.00%	\$42.44	2.62%	\$1.11	\$16.33	\$59.88	\$162.78	\$23.82
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	\$ 1,397.93	\$ 11.89	6.234%	\$87.89	78.00%	\$35.18	2.62%	\$0.92	\$0.00	\$36.10	\$123.99	\$18.15
Goshen-Brownfield	No	2,814	\$ 1,411.91	\$ 11.89	6.234%	\$88.76	78.00%	\$35.18	2.62%	\$0.92	\$61.16	\$97.26	\$186.02	\$27.22
Wasatch Front-Brownfield	Yes	4,225	\$ 1,383.95	\$ 11.89	6.234%	\$87.02	78.00%	\$35.18	2.62%	\$0.92	\$9.38	\$45.48	\$132.50	\$19.39
Wyoming East-Brownfield	Yes	6,130	\$ 1,383.95	\$ 11.89	6.234%	\$87.02	78.00%	\$35.18	2.62%	\$0.92	\$16.55	\$52.65	\$139.67	\$20.44
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	No	0	\$ 3,086.44	\$ 65.28	6.240%	\$196.67	78.00%	\$77.07	5.54%	\$4.27	\$0.00	\$81.34	\$278.00	\$40.69
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	No	0	\$ 2,561.42	\$ 65.08	6.242%	\$163.95	78.00%	\$62.99	5.54%	\$3.49	\$0.00	\$66.48	\$230.43	\$33.72
SCCT Frame "F" x1, with SCR + Δ for 100% hydrogen burning capability	No	0	\$ 1,594.96	\$ 13.95	5.605%	\$90.18	33.00%	\$27.92	2.62%	\$0.73	\$0.00	\$28.65	\$118.83	\$41.11
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100% hydrogen burning capability	No	0	\$ 2,114.85	\$ 13.89	5.604%	\$119.29	78.00%	\$42.44	2.62%	\$1.11	\$0.00	\$43.55	\$162.85	\$23.83
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100% hydrogen burning capability	No	0	\$ 1,786.25	\$ 13.67	5.604%	\$100.87	78.00%	\$35.18	2.62%	\$0.92	\$0.00	\$36.10	\$136.97	\$20.05
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	\$ 2,585.91	\$ 27.13	9.271%	\$242.26	33.00%	\$35.12	2.62%	\$0.92	\$0.00	\$36.04	\$278.30	\$96.27
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	\$ 2,038.01	\$ 27.08	9.254%	\$203.64	78.00%	\$49.64	2.62%	\$1.30	\$0.00	\$50.94	\$334.59	\$48.97
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	\$ 2,752.27	\$ 26.89	9.263%	\$257.43	78.00%	\$42.38	2.62%	\$1.11	\$0.00	\$43.49	\$300.93	\$44.04
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	\$ 2,097.84	\$ 27.13	9.255%	\$196.67	33.00%	\$40.78	2.62%	\$1.07	\$0.00	\$41.85	\$338.51	\$82.51
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	\$ 2,549.91	\$ 27.08	9.245%	\$238.24	78.00%	\$55.30	2.62%	\$1.45	\$0.00	\$56.75	\$294.99	\$43.17
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	\$ 2,264.18	\$ 26.89	9.250%	\$211.92	78.00%	\$48.04	2.62%	\$1.26	\$0.00	\$49.30	\$261.22	\$38.23
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	No	0	\$ 1,831.63	\$ 12.08	6.233%	\$114.92	78.00%	\$41.33	2.62%	\$1.08	\$0.00	\$42.41	\$157.33	\$23.02
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	No	0	\$ 1,517.84	\$ 11.89	6.234%	\$95.36	78.00%	\$34.07	2.62%	\$0.89	\$0.00	\$34.96	\$130.32	\$19.07
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	No	0	\$ 3,260.88	\$ 65.28	6.233%	\$207.32	78.00%	\$72.60	5.54%	\$4.02	\$0.00	\$76.62	\$283.94	\$41.56
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	No	0	\$ 2,637.12	\$ 65.08	6.234%	\$168.46	78.00%	\$57.74	5.54%	\$3.20	\$0.00	\$60.94	\$229.40	\$33.57
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	Yes	0	\$ 2,858.50	\$ 44.94	4.170%	\$121.07	98.00%	\$60.95	0.00%	\$0.00	\$0.00	\$60.95	\$182.03	\$21.20
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	No	0	\$ 560.99	\$ 32.46	4.170%	\$24.75	97.00%	\$10.28	0.00%	\$0.00	\$0.00	\$10.28	\$35.03	\$4.12
Δ CCS Dave Johnston 4 (costs on post retrofit basis)	No	5,541	\$ 3,500.78	\$ 53.20	6.447%	\$229.12	85.00%	\$277.68	5.54%	\$15.38	\$0.00	\$293.06	\$522.19	\$70.13
Δ CCS Hunter 1-3 (costs on post retrofit basis)	No	6,420	\$ 2,951.20	\$ 53.20	6.451%	\$193.81	85.00%	\$235.36	5.54%	\$13.04	\$0.00	\$248.39	\$442.21	\$59.39
Δ CCS Huntington 1&2 (costs on post retrofit basis)	No	6,933	\$ 2,951.40	\$ 53.20	6.451%	\$193.81	85.00%	\$242.12	5.54%	\$13.41	\$0.00	\$255.53	\$449.36	\$60.35
Δ CCS Jim Bridger 3&4 (costs on post retrofit basis)	Yes	7,513	\$ 2,598.38	\$ 53.20	6.454%	\$171.13	85.00%	\$254.91	5.54%	\$14.12	\$0.00	\$269.03	\$440.16	\$59.11
Δ CCS Wyoak (costs on post retrofit basis)	No	4,448	\$ 3,504.25	\$ 53.20	6.447%	\$229.35	85.00%	\$309.51	5.54%	\$17.15	\$0.00	\$326.65	\$556.00	\$74.67
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	Yes	N/A	\$ 9,662.09	\$ 17.00	5.042%	\$488.02	93.00%	\$97.42	9.42%	\$9.18	\$0.00	\$106.60	\$594.62	\$72.99
Goshen	Yes	2,814	\$ 9,855.33	\$ 17.00	5.042%	\$497.76	93.00%	\$97.42	9.42%	\$9.18	\$0.00	\$106.60	\$604.36	\$74.18
Wasatch Front	Yes	4,225	\$ 9,855.33	\$ 17.00	5.042%	\$497.76	93.00%	\$97.42	9.42%	\$9.18	\$0.00	\$106.60	\$604.36	\$74.18
Wyoming East	Yes	6,130	\$ 9,565.47	\$ 17.00	5.042%	\$483.15	93.00%	\$97.42	9.42%	\$9.18	\$0.00	\$106.60	\$589.75	\$72.39
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	No	N/A	\$ 6,368.23	\$ 12.00	5.042%	\$321.69	93.00%	\$84.53	9.42%	\$7.97	\$0.00	\$92.49	\$414.18	\$50.84
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	No	N/A	\$10,628.30	\$ 17.00	5.042%	\$536.74	93.00%	\$107.16	9.42%	\$10.10	\$0.00	\$117.26	\$654.00	\$80.28
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	No	N/A	\$ 7,005.05	\$ 12.00	5.042%	\$355.80	93.00%	\$92.98	9.42%	\$8.76	\$0.00	\$101.74	\$455.54	\$55.92
Large Light Water Reactor, Moderate Technology Case	No	N/A	\$ 7,562.87	\$ 10.00	5.042%	\$381.82	93.00%	\$125.36	9.42%	\$11.81	\$0.00	\$137.17	\$518.99	\$63.71
Large Light Water Reactor, Advanced Technology Case	No	N/A	\$ 6,265.25	\$ 9.00	5.042%	\$316.35	93.00%	\$90.26	9.42%	\$8.51	\$0.00	\$98.76	\$415.11	\$50.95
Near Field Enhanced Geothermal System (NF-EGS) Binary	Yes	N/A	\$ 7,591.06	\$ 125.09	6.262%	\$483.31	80.00%	\$194.00	0.87%	\$1.69	\$0.00	\$195.69	\$679.00	\$96.69
Southern OR	Yes	497	\$ 8,883.88	\$ 125.09	6.262%	\$564.14	80.00%	\$194.00	0.87%	\$1.69	\$0.00	\$195.69	\$759.83	\$108.42
Wasatch Front	Yes	4,225	\$ 7,591.06	\$ 125.09	6.262%	\$483.31	80.00%	\$194.00	0.87%	\$1.69	\$0.00	\$195.69	\$679.00	\$96.69

* Δ for CCS installation on existing coal units is for CCS costs and operating characteristics only, not the operation of the existing coal resource.

Table 7.7 – 2025 IRP Non-Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024\$)

Resource Description	Additional Attributes							Fixed O&M				Total Fixed Cost (\$/kW-Yr)	Total Fixed Cost Converted (\$/MWh)
	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment (\$/kW-Yr)	Capacity Factor	O&M (\$/kW-Yr)	Capitalized Premium	O&M Capitalized (\$/kW-Yr)	Total Fixed O&M (\$/kW-Yr)		
PV, 20 MW, Class 1-10	Yes	by location	\$ 1,964.64	\$ 39.29	6.861%	\$137.49	27.33%	\$18.16	1.37%	\$0.25	\$18.41	\$155.90	\$65.11
Portland North Coast	Yes	19	\$ 2,082.51	\$ 39.29	6.861%	\$145.58	24.49%	\$18.16	1.37%	\$0.25	\$18.41	\$163.99	\$76.45
Southern OR	Yes	497	\$ 2,180.75	\$ 39.29	6.861%	\$152.32	29.29%	\$18.16	1.37%	\$0.25	\$18.41	\$170.73	\$66.54
Walla Walla	Yes	2,353	\$ 2,003.93	\$ 39.29	6.861%	\$140.19	25.96%	\$18.16	1.37%	\$0.25	\$18.41	\$158.60	\$69.74
Goshen	Yes	2,814	\$ 1,984.28	\$ 39.29	6.861%	\$138.84	27.79%	\$18.16	1.37%	\$0.25	\$18.41	\$157.25	\$64.59
Wasatch Front	Yes	4,225	\$ 1,964.64	\$ 39.29	6.861%	\$137.49	29.00%	\$18.16	1.37%	\$0.25	\$18.41	\$155.90	\$61.38
Wyoming East	Yes	6,130	\$ 1,964.64	\$ 39.29	6.861%	\$137.49	27.47%	\$18.16	1.37%	\$0.25	\$18.41	\$155.90	\$64.79
PV, 200 MW, Class 1-10	Yes	by location	\$ 1,216.55	\$ 24.33	6.861%	\$85.14	27.33%	\$20.52	1.37%	\$0.28	\$20.80	\$105.93	\$44.24
Portland North Coast	Yes	19	\$ 1,289.55	\$ 24.33	6.861%	\$90.15	24.49%	\$20.52	1.37%	\$0.28	\$20.80	\$110.94	\$51.72
Southern OR	Yes	497	\$ 1,350.37	\$ 24.33	6.861%	\$94.32	29.29%	\$20.52	1.37%	\$0.28	\$20.80	\$115.12	\$44.87
Walla Walla	Yes	2,353	\$ 1,240.88	\$ 24.33	6.861%	\$86.81	25.96%	\$20.52	1.37%	\$0.28	\$20.80	\$107.60	\$47.32
Goshen	Yes	2,814	\$ 1,228.72	\$ 24.33	6.861%	\$85.97	27.79%	\$20.52	1.37%	\$0.28	\$20.80	\$106.77	\$43.86
Wasatch Front	Yes	4,225	\$ 1,216.55	\$ 24.33	6.861%	\$85.14	29.00%	\$20.52	1.37%	\$0.28	\$20.80	\$105.93	\$41.71
Wyoming East	Yes	6,130	\$ 1,216.55	\$ 24.33	6.861%	\$85.14	27.47%	\$20.52	1.37%	\$0.28	\$20.80	\$105.93	\$44.02
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	\$ 1,832.22	\$ 37.33	6.862%	\$128.29	27.33%	\$17.24	1.37%	\$0.24	\$17.48	\$145.76	\$60.88
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	\$ 1,134.56	\$ 23.11	6.862%	\$79.44	27.33%	\$19.47	1.37%	\$0.27	\$19.74	\$99.18	\$41.42
Wind Class 1-10, 20 MW	Yes	by location	\$ 2,554.58	\$ 63.57	6.292%	\$164.73	29.07%	\$38.79	4.39%	\$1.70	\$40.49	\$205.22	\$80.60
Portland North Coast	Yes	19	\$ 2,835.59	\$ 63.57	6.292%	\$182.42	24.91%	\$38.79	4.39%	\$1.70	\$40.49	\$222.90	\$102.14
Southern OR	Yes	497	\$ 3,014.41	\$ 63.57	6.292%	\$193.67	25.18%	\$38.79	4.39%	\$1.70	\$40.49	\$234.15	\$106.14
Walla Walla	Yes	2,353	\$ 2,656.77	\$ 63.57	6.292%	\$171.16	23.13%	\$38.79	4.39%	\$1.70	\$40.49	\$211.65	\$104.46
Goshen	Yes	2,814	\$ 2,605.68	\$ 63.57	6.292%	\$167.95	34.26%	\$38.79	4.39%	\$1.70	\$40.49	\$208.44	\$69.45
Wasatch Front	Yes	4,225	\$ 2,580.13	\$ 63.57	6.292%	\$166.34	33.69%	\$38.79	4.39%	\$1.70	\$40.49	\$206.83	\$70.08
Wyoming East	Yes	6,130	\$ 2,503.49	\$ 63.57	6.292%	\$161.52	33.22%	\$38.79	4.39%	\$1.70	\$40.49	\$202.01	\$69.41
Wind Class 1-6, 200 MW	Yes	by location	\$ 1,421.10	\$ 63.57	6.316%	\$93.77	34.37%	\$31.65	4.39%	\$1.39	\$33.04	\$126.81	\$42.12
Portland North Coast	Yes	19	\$ 1,577.43	\$ 63.57	6.316%	\$103.65	37.62%	\$31.65	4.39%	\$1.39	\$33.04	\$136.68	\$41.47
Southern OR	Yes	497	\$ 1,676.90	\$ 63.57	6.316%	\$109.93	34.06%	\$31.65	4.39%	\$1.39	\$33.04	\$142.97	\$45.92
Walla Walla	Yes	2,353	\$ 1,477.95	\$ 63.57	6.316%	\$97.36	32.59%	\$31.65	4.39%	\$1.39	\$33.04	\$130.40	\$45.68
Goshen	Yes	2,814	\$ 1,449.53	\$ 63.57	6.316%	\$95.57	30.28%	\$31.65	4.39%	\$1.39	\$33.04	\$128.61	\$48.49
Wasatch Front	Yes	4,225	\$ 1,435.32	\$ 63.57	6.316%	\$94.67	30.42%	\$31.65	4.39%	\$1.39	\$33.04	\$127.71	\$47.93
Wyoming East	Yes	6,130	\$ 1,392.68	\$ 63.57	6.316%	\$91.98	41.25%	\$31.65	4.39%	\$1.39	\$33.04	\$125.02	\$34.60
Wind Class 7, 200 MW	No	by location	\$ 1,491.78	\$ 63.57	6.313%	\$98.19	34.37%	\$31.65	4.39%	\$1.39	\$33.04	\$131.23	\$43.59
Offshore, Wind Class 12	Yes	0	\$ 8,340.57	\$ 169.16	5.202%	\$442.68	31.54%	\$69.26	4.39%	\$3.04	\$72.30	\$514.98	\$186.38
Southern OR	Yes	497	\$ 9,841.87	\$ 169.16	5.202%	\$520.77	48.94%	\$69.26	4.39%	\$3.04	\$72.30	\$593.07	\$138.33
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	No	by location	\$ 2,434.26	\$ 60.58	6.292%	\$156.98	29.07%	\$34.87	4.39%	\$1.53	\$36.40	\$193.37	\$75.95
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	\$ 1,354.17	\$ 60.58	6.316%	\$89.36	34.37%	\$28.45	4.39%	\$1.25	\$29.70	\$119.06	\$39.54
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	\$ 1,421.51	\$ 60.58	6.313%	\$93.56	34.37%	\$28.45	4.39%	\$1.25	\$29.70	\$123.27	\$40.94
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	No	0	\$ 6,011.05	\$ 121.92	4.841%	\$296.90	84.43%	\$63.21	4.39%	\$2.78	\$65.99	\$362.89	\$49.06

Table 7.8 – 2025 IRP Storage Supply-Side Resources, Additional Attributes and Fixed O&M (2024\$)

Resource Description	Additional Attributes								Fixed O&M				Total Fixed Cost (\$/kW-Yr)	Total Fixed Cost Converted (\$/MWh)
	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment (\$/kW-Yr)	Capacity Factor	Storage Efficiency	O&M (\$/kW-Yr)	Capitalized Premium	O&M Capitalized (\$/kW-Yr)	Total Fixed O&M (\$/kW-Yr)		
Li-Ion, 4-hour, 20 MW ¹	No	N/A	\$ 1,747.61	\$ 29.94	5.354%	\$95.17	16.67%	85%	\$45.05	0.00%	\$ -	\$45.05	\$140.22	\$96.04
Li-Ion, 4-hour, 200 MW ¹	Yes	N/A	\$ 1,497.89	\$ 25.66	5.354%	\$81.57	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$120.34	\$82.42
Portland North Coast	Yes	19	\$ 1,587.77	\$ 25.66	5.354%	\$86.38	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$125.15	\$85.72
Southern OR	Yes	497	\$ 1,617.73	\$ 25.66	5.354%	\$87.99	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$126.75	\$86.82
Walla Walla	Yes	2,353	\$ 1,542.83	\$ 25.66	5.354%	\$83.98	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$122.74	\$84.07
Goshen	Yes	2,814	\$ 1,527.85	\$ 25.66	5.354%	\$83.18	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$121.94	\$83.52
Wasatch Front	Yes	4,225	\$ 1,542.83	\$ 25.66	4.452%	\$69.83	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$108.60	\$74.38
Wyoming East	Yes	6,130	\$ 1,482.92	\$ 25.66	4.452%	\$67.16	16.67%	85%	\$38.77	0.00%	\$0.00	\$38.77	\$105.93	\$72.55
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW ¹	Yes	N/A	\$ 2,556.57	\$ 46.19	5.355%	\$139.38	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$209.16	\$71.63
Portland North Coast	Yes	19	\$ 2,709.97	\$ 46.19	5.355%	\$147.59	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$217.37	\$74.44
Southern OR	Yes	497	\$ 2,761.10	\$ 46.19	5.355%	\$150.33	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$220.11	\$75.38
Walla Walla	Yes	2,353	\$ 2,633.27	\$ 46.19	5.355%	\$143.48	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$213.27	\$73.04
Goshen	Yes	2,814	\$ 2,607.71	\$ 46.19	5.355%	\$142.12	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$211.90	\$72.57
Wasatch Front	Yes	4,225	\$ 2,633.27	\$ 46.19	4.453%	\$119.32	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$189.10	\$64.76
Wyoming East	Yes	6,130	\$ 2,531.01	\$ 46.19	4.453%	\$114.76	33.33%	85%	\$69.78	0.00%	\$0.00	\$69.78	\$184.54	\$63.20
Li-Ion, 4-hour, 1000 MW ¹	No	N/A	\$ 1,459.50	\$ 25.66	5.356%	\$79.55	16.67%	85%	\$36.92	0.00%	\$0.00	\$36.92	\$116.47	\$79.77
Gravity Battery, 4-hour, 1000 MW ¹	Yes	N/A	\$ 2,020.99	\$ 0.19	2.916%	\$58.94	16.67%	83%	\$50.51	0.00%	\$0.00	\$50.51	\$109.45	\$74.97
Wasatch Front	Yes	4,225	\$ 2,081.62	\$ 0.19	2.916%	\$60.71	16.67%	83%	\$50.51	0.00%	\$0.00	\$50.51	\$111.22	\$76.18
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW ¹	No	N/A	\$ 3,006.34	\$ 0.35	2.916%	\$87.68	33.33%	83%	\$90.92	5.48%	\$4.98	\$95.90	\$183.58	\$62.87
Adiabatic CAES, 500 MW, 4000 MWh	No	N/A	\$ 3,754.00	\$ 49.31	4.288%	\$163.09	33.33%	63%	\$19.20	0.00%	\$0.00	\$19.20	\$182.29	\$62.43
100-hour Iron Air	Yes	N/A	\$ 2,729.67	\$ 171.06	4.581%	\$132.88	30.07%	43%	\$21.04	2.62%	\$0.55	\$21.59	\$154.47	\$58.64
Portland North Coast	Yes	19	\$ 2,893.45	\$ 171.06	5.484%	\$168.06	30.07%	43%	\$21.04	2.62%	\$0.55	\$21.59	\$189.65	\$72.00
Wasatch Front	Yes	4,225	\$ 2,811.56	\$ 171.06	4.581%	\$136.63	30.07%	43%	\$21.04	2.62%	\$0.55	\$21.59	\$158.22	\$60.07
Pumped Hydro, Two New Reservoirs, 4-hour	No	N/A	\$ 2,984.23	\$ 149.21	3.121%	\$97.79	16.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$118.52	\$81.18
Pumped Hydro, Two New Reservoirs, 10-hour	Yes	N/A	\$ 4,158.90	\$ 207.95	3.121%	\$136.29	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$157.02	\$43.02
Portland North Coast	Yes	19	\$ 4,408.44	\$ 207.95	3.121%	\$144.08	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$164.81	\$45.15
Southern OR	Yes	497	\$ 4,491.61	\$ 207.95	3.121%	\$146.67	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$167.40	\$45.86
Goshen	Yes	2,814	\$ 4,242.08	\$ 207.95	3.121%	\$138.89	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$159.61	\$43.73
Wasatch Front	Yes	4,225	\$ 4,283.67	\$ 207.95	2.582%	\$115.97	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$136.70	\$37.45
Wyoming East	Yes	6,130	\$ 4,117.31	\$ 207.95	2.582%	\$111.68	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$132.41	\$36.28
Pumped Hydro, One New Reservoir, 4-hour	No	N/A	\$ 2,883.24	\$ 144.16	3.121%	\$94.49	16.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$115.21	\$78.91
Pumped Hydro, One New Reservoir, 10-hour	No	N/A	\$ 3,537.41	\$ 176.87	3.121%	\$115.92	41.67%	80%	\$20.20	2.62%	\$0.53	\$20.73	\$136.65	\$37.44
Pumped Thermal Energy Storage, 10-hour	No	N/A	\$ 6,173.76	\$ 60.00	3.361%	\$209.52	35.48%	55%	\$2.00	2.62%	\$0.05	\$2.05	\$211.57	\$68.06
Pumped Thermal Energy Storage, 24-hour	No	N/A	\$ 11,525.17	\$ 60.00	3.362%	\$389.49	35.48%	55%	\$1.00	1.37%	\$0.01	\$1.01	\$390.51	\$125.63

¹Assumed co-located

Table 7.9 – 2025 IRP Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024\$)

Resource Description	Variable O&M				Total Resource Cost (\$/MWh)	Credits		
	Levelized Fuel (\$/MWh)	O&M (\$/MWh)	Capitalized Premium	O&M Capitalized (\$/MWh)		Tax Credits (\$/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits (\$/MWh)	Total Fixed Cost with Tax Credit (\$/kW-yr)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	\$ 357.85	\$6.93	14.39%	\$1.00	\$389.44	-	\$389.44	\$191.77
SCCT Aero, with SCR	\$ 53.04	\$7.40	14.39%	\$1.07	\$121.75	-	\$121.75	\$174.13
SCCT Aero x4, with SCR	\$ 53.04	\$5.92	14.39%	\$0.85	\$101.81	-	\$101.81	\$121.40
SCCT Frame "F" x1, with SCR	\$ 54.56	\$7.75	14.39%	\$1.12	\$102.86	-	\$102.86	\$114.00
Goshen	\$ 55.25	\$7.75	14.39%	\$1.12	\$137.12	-	\$137.12	\$211.04
Wasatch Front	\$ 55.27	\$7.75	14.39%	\$1.12	\$108.37	-	\$108.37	\$127.87
Wyoming East	\$ 47.47	\$7.75	14.39%	\$1.12	\$104.40	-	\$104.40	\$138.95
CCCT Dry "H", 1X1, DF, with SCR	\$ 33.91	\$2.70	14.39%	\$0.39	\$60.26	-	\$60.26	\$158.93
Goshen	\$ 34.65	\$2.70	14.39%	\$0.39	\$70.00	-	\$70.00	\$220.41
Wasatch Front	\$ 34.74	\$2.70	14.39%	\$0.39	\$62.27	-	\$62.27	\$167.04
Wyoming East	\$ 30.05	\$2.70	14.39%	\$0.39	\$58.62	-	\$58.62	\$174.11
CCCT Dry "H", 2X1, DF, with SCR	\$ 34.37	\$2.28	14.39%	\$0.33	\$56.54	-	\$56.54	\$133.67
Goshen	\$ 35.12	\$2.28	14.39%	\$0.33	\$66.39	-	\$66.39	\$195.80
Wasatch Front	\$ 35.21	\$2.28	14.39%	\$0.33	\$58.61	-	\$58.61	\$142.08
Wyoming East	\$ 30.45	\$2.28	14.39%	\$0.33	\$54.90	-	\$54.90	\$149.26
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	\$ 37.86	\$5.32	11.52%	\$0.61	\$87.60	-	\$87.60	\$299.37
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	\$ 38.42	\$4.83	11.52%	\$0.56	\$80.12	-	\$80.12	\$248.16
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	\$ 46.57	\$6.24	14.39%	\$0.90	\$114.97	-	\$114.97	\$177.10
SCCT Aero, with SCR + Δ for CT Brownfield construction	\$ 53.04	\$6.66	14.39%	\$0.96	\$115.39	-	\$115.39	\$158.21
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	\$ 53.04	\$5.33	14.39%	\$0.77	\$97.36	-	\$97.36	\$110.49
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	\$ 54.56	\$6.98	14.39%	\$1.00	\$99.05	-	\$99.05	\$105.53
Goshen-Brownfield	\$ 54.23	\$6.98	14.39%	\$1.00	\$132.26	-	\$132.26	\$202.50
Wasatch Front-Brownfield	\$ 54.29	\$6.98	14.39%	\$1.00	\$103.60	-	\$103.60	\$119.50
Wyoming East-Brownfield	\$ 53.90	\$6.98	14.39%	\$1.00	\$107.05	-	\$107.05	\$130.57
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	\$ 33.91	\$2.43	14.39%	\$0.35	\$58.28	-	\$58.28	\$147.48
Goshen-Brownfield	\$ 34.01	\$2.43	14.39%	\$0.35	\$67.36	-	\$67.36	\$208.85
Wasatch Front-Brownfield	\$ 34.12	\$2.43	14.39%	\$0.35	\$59.69	-	\$59.69	\$155.71
Wyoming East-Brownfield	\$ 34.12	\$2.43	14.39%	\$0.35	\$60.72	-	\$60.72	\$162.78
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	\$ 34.37	\$2.05	14.39%	\$0.30	\$54.87	-	\$54.87	\$123.99
Goshen-Brownfield	\$ 34.48	\$2.05	14.39%	\$0.30	\$64.05	-	\$64.05	\$186.02
Wasatch Front-Brownfield	\$ 34.58	\$2.05	14.39%	\$0.30	\$56.32	-	\$56.32	\$132.50
Wyoming East-Brownfield	\$ 34.58	\$2.05	14.39%	\$0.30	\$57.37	-	\$57.37	\$139.67
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	\$ 37.86	\$4.78	11.52%	\$0.55	\$83.88	-	\$83.88	\$278.00
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	\$ 38.42	\$4.34	11.52%	\$0.50	\$76.99	-	\$76.99	\$230.43
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	\$ 54.56	\$8.91	14.39%	\$1.28	\$105.86	-	\$105.86	\$118.83
SCCT "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	\$ 33.91	\$3.11	14.39%	\$0.45	\$61.30	-	\$61.30	\$162.85
SCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	\$ 34.37	\$2.62	14.39%	\$0.38	\$57.42	-	\$57.42	\$136.97
SCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	\$ 34.37	\$2.70	14.39%	\$0.39	\$81.51	-	\$81.51	\$300.93
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	\$ 54.56	\$8.18	14.39%	\$1.18	\$160.18	-	\$160.18	\$278.30
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	\$ 33.91	\$3.13	14.39%	\$0.45	\$86.46	-	\$86.46	\$334.59
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	\$ 34.37	\$2.70	14.39%	\$0.39	\$81.51	-	\$81.51	\$300.93
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	\$ 54.56	\$8.32	14.39%	\$1.20	\$146.59	-	\$146.59	\$238.51
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	\$ 33.91	\$3.27	14.39%	\$0.47	\$80.83	-	\$80.83	\$294.99
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	\$ 34.37	\$2.85	14.39%	\$0.41	\$75.86	-	\$75.86	\$261.22
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	\$ 33.91	\$2.68	14.39%	\$0.39	\$60.00	-	\$60.00	\$157.33
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	\$ 34.37	\$2.23	14.39%	\$0.32	\$56.00	-	\$56.00	\$130.32
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	\$ 37.86	\$5.03	11.52%	\$0.58	\$85.02	-	\$85.02	\$283.94
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	\$ 38.42	\$4.49	11.52%	\$0.52	\$77.00	-	\$77.00	\$229.40
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	\$ -	\$0.00	0.00%	\$0.00	\$21.20	\$ (4.85)	\$21.20	\$182.03
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	\$ -	\$23.91	0.00%	\$0.00	\$28.03	\$ (0.96)	\$28.03	\$35.03
CCS Dave Johnston 4 (costs on post retrofit basis)	\$ -	\$11.40	11.52%	\$1.31	\$82.84	\$ (160.13)	\$ (77.29)	\$ (487.20)
CCS Hunter 1-3 (costs on post retrofit basis)	\$ -	\$9.73	11.52%	\$1.12	\$70.24	\$ (160.13)	\$ (89.89)	\$ (565.96)
CCS Huntington 1&2 (costs on post retrofit basis)	\$ -	\$9.63	11.52%	\$1.11	\$71.09	\$ (160.13)	\$ (89.04)	\$ (562.82)
CCS Jim Bridger 3&4 (costs on post retrofit basis)	\$ -	\$10.57	11.52%	\$1.22	\$70.90	\$ (160.13)	\$ (89.23)	\$ (554.00)
CCS Wyodak (costs on post retrofit basis)	\$ -	\$11.69	11.52%	\$1.35	\$87.70	\$ (160.13)	\$ (72.43)	\$ (459.16)
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	\$ -	\$9.74	0.00%	\$0.00	\$82.73	\$ (20.29)	\$62.44	\$448.80
Goshen	\$ -	\$9.74	0.00%	\$0.00	\$83.93	\$ (20.29)	\$63.64	\$458.27
Wasatch Front	\$ -	\$9.74	0.00%	\$0.00	\$83.93	\$ (22.29)	\$61.64	\$443.88
Wyoming East	\$ -	\$9.74	0.00%	\$0.00	\$82.13	\$ (22.29)	\$59.85	\$429.73
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	\$ -	\$8.74	0.00%	\$0.00	\$59.58	\$ (22.29)	\$37.29	\$259.26
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	\$ -	\$10.72	0.00%	\$0.00	\$90.99	\$ (20.29)	\$70.71	\$508.18
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	\$ -	\$9.61	0.00%	\$0.00	\$65.53	\$ (22.29)	\$43.24	\$300.62
Large Light Water Reactor, Moderate Technology Case	\$ -	\$9.38	0.00%	\$0.00	\$73.09	\$ (20.29)	\$52.80	\$374.94
Large Light Water Reactor, Advanced Technology Case	\$ -	\$7.88	0.00%	\$0.00	\$58.83	\$ (22.29)	\$36.55	\$257.87
Near Field Enhanced Geothermal System (NF-EGS) Binary	\$ -	\$0.00	0.00%	\$0.00	\$96.89	\$ (23.46)	\$73.43	\$514.59
Southern OR	\$ -	\$0.00	0.00%	\$0.00	\$108.42	\$ (23.46)	\$84.96	\$595.43
Wasatch Front	\$ -	\$0.00	0.00%	\$0.00	\$96.89	\$ (25.77)	\$71.12	\$498.40

* Δ for CCS installation on existing coal units is for CCS costs and operating characteristics only, not the operation of the existing coal resource.

Table 7.10 – 2025 IRP Non-Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024\$)

Resource Description	Total Resource Cost (\$/MWh)	Credits		
		Tax Credits (\$/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits (\$/MWh)	Total Fixed Cost with Tax Credit (\$/kW-yr)
PV, 20 MW, Class 1-10	\$65.11	\$ (25.15)	\$39.96	\$95.69
Portland North Coast	\$76.45	\$ (25.15)	\$51.30	\$110.04
Southern OR	\$66.54	\$ (25.15)	\$41.39	\$106.20
Walla Walla	\$69.74	\$ (25.15)	\$44.59	\$101.40
Goshen	\$64.59	\$ (25.15)	\$39.44	\$96.03
Wasatch Front	\$61.38	\$ (27.63)	\$33.75	\$85.73
Wyoming East	\$64.79	\$ (27.63)	\$37.16	\$89.42
PV, 200 MW, Class 1-10	\$44.24	\$ (25.15)	\$19.09	\$45.72
Portland North Coast	\$51.72	\$ (25.15)	\$26.57	\$56.99
Southern OR	\$44.87	\$ (25.15)	\$19.72	\$50.59
Walla Walla	\$47.32	\$ (25.15)	\$22.17	\$50.41
Goshen	\$43.86	\$ (25.15)	\$18.71	\$45.54
Wasatch Front	\$41.71	\$ (27.63)	\$14.08	\$35.76
Wyoming East	\$44.02	\$ (27.63)	\$16.40	\$39.46
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	\$60.88	\$ (27.63)	\$33.25	\$79.62
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	\$41.42	\$ (27.63)	\$13.80	\$33.03
Wind Class 1-10, 20 MW	\$80.60	\$ (23.46)	\$57.14	\$145.49
Portland North Coast	\$102.14	\$ (23.46)	\$78.68	\$171.70
Southern OR	\$106.14	\$ (23.46)	\$82.68	\$182.40
Walla Walla	\$104.46	\$ (23.46)	\$81.00	\$164.12
Goshen	\$69.45	\$ (23.46)	\$45.99	\$138.03
Wasatch Front	\$70.08	\$ (25.77)	\$44.31	\$130.77
Wyoming East	\$69.41	\$ (25.77)	\$43.64	\$127.01
Wind Class 1-6, 200 MW	\$42.12	\$ (23.46)	\$18.66	\$56.18
Portland North Coast	\$41.47	\$ (23.46)	\$18.01	\$59.36
Southern OR	\$47.92	\$ (23.46)	\$24.46	\$72.97
Walla Walla	\$45.68	\$ (23.46)	\$22.22	\$63.43
Goshen	\$48.49	\$ (23.46)	\$25.03	\$66.38
Wasatch Front	\$47.93	\$ (25.77)	\$22.16	\$59.04
Wyoming East	\$34.60	\$ (25.77)	\$8.83	\$31.90
Wind Class 7, 200 MW	\$43.59	\$ (23.46)	\$20.13	\$60.59
Offshore, Wind Class 12	\$186.38	\$ (32.72)	\$186.38	\$514.98
Southern OR	\$138.33	\$ (24.88)	\$138.33	\$593.07
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	\$75.95	\$ (25.77)	\$50.18	\$127.76
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	\$39.54	\$ (25.77)	\$13.77	\$41.47
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	\$40.94	\$ (25.77)	\$15.17	\$45.68
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	\$49.06	\$ (11.74)	\$49.06	\$362.89

Table 7.11 – 2025 IRP Storage Supply-Side Resources, Variable O&M, Total Cost and Credits (2024\$)

Resource Description	Variable O&M	Credits	
	O&M (\$/MWh)	Tax Credits (\$/MWh) (ITC already applied)	Total Fixed Cost with Tax Credit (\$/kW-yr)
Ion, 4-hour, 20 MW ¹	\$0.00	\$ (32.40)	\$140.22
Ion, 4-hour, 200 MW ¹	\$0.00	\$ (27.77)	\$120.34
Portland North Coast	\$0.00	\$ (29.44)	\$125.15
Southern OR	\$0.00	\$ (29.99)	\$126.75
Walla Walla	\$0.00	\$ (28.61)	\$122.74
Goshen	\$0.00	\$ (28.33)	\$121.94
Wasatch Front	\$0.00	\$ (38.14)	\$108.60
Wyoming East	\$0.00	\$ (36.66)	\$105.93
Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW ¹	\$0.00	\$ (23.69)	\$209.16
Portland North Coast	\$0.00	\$ (25.11)	\$217.37
Southern OR	\$0.00	\$ (25.59)	\$220.11
Walla Walla	\$0.00	\$ (24.40)	\$213.27
Goshen	\$0.00	\$ (24.17)	\$211.90
Wasatch Front	\$0.00	\$ (32.54)	\$189.10
Wyoming East	\$0.00	\$ (31.27)	\$184.54
Ion, 4-hour, 1000 MW ¹	\$0.00	\$ (27.05)	\$116.47
Gravity Battery, 4-hour, 1000 MW	\$0.00	\$ (33.10)	\$109.45
Wasatch Front	\$0.00	\$ (34.09)	\$111.22
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	\$0.00	\$ (24.62)	\$183.58
Adiabatic CAES, 500 MW, 4000 MWh	\$2.60	\$ (27.92)	\$182.29
100-hour Iron Air	\$0.00	\$ (37.40)	\$154.47
Portland North Coast	\$0.00	\$ (29.72)	\$189.65
Wasatch Front	\$0.00	\$ (38.52)	\$158.22
Pumped Hydro, Two New Reservoirs, 4-hour	\$0.58	\$ (33.01)	\$118.52
Pumped Hydro, Two New Reservoirs, 10-hour	\$0.58	\$ (18.40)	\$157.02
Portland North Coast	\$0.58	\$ (19.51)	\$164.81
Southern OR	\$0.58	\$ (19.87)	\$167.40
Goshen	\$0.58	\$ (18.77)	\$159.61
Wasatch Front	\$0.58	\$ (25.28)	\$136.70
Wyoming East	\$0.58	\$ (24.30)	\$132.41
Pumped Hydro, One New Reservoir, 4-hour	\$0.58	\$ (31.89)	\$115.21
Pumped Hydro, One New Reservoir, 10-hour	\$0.58	\$ (15.65)	\$136.65
Pumped Thermal Energy Storage, 10-hour	\$0.70	\$ (34.12)	\$211.57
Pumped Thermal Energy Storage, 24-hour	\$0.70	\$ (63.70)	\$390.51

¹Assumed co-located

Table 7.12 - Glossary of Terms Used in the Supply-Side Resource Tables

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Resource Availability Year	The earliest year the Company would sign a contract for a Resource being studied in this IRP. If available prior to the development of this database, this defaults to IRP year.
Total Implementation Time	Number of years necessary to implement all phases of resource development and construction after signing a contract to build the Resource: permitting (e.g., air, land, water, and wildlife), maintenance contracts, owner's engineering, construction, testing, and grid interconnection.
Commercial Operation Year	Year when the Resource is available for generation and dispatch. It is based on the Resource Availability Year plus the Total Implementation Time.
Design Life (years)	Average number of years the resource is expected to be "used and useful."
Base Capital (\$/kW)	Total capital expenditure in dollars per kilowatt (\$/kW) for the development and construction of a Resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit, and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, and owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes, and escalation during construction, if applicable).
Var O&M (\$/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance, and fired hour fees in dollars per megawatt hour (\$/MWh).
Fixed O&M (\$/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, and training.
Demolition Cost (\$/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt (\$/kW).
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
Efficiency	Typical operational round-trip efficiency of energy storage of alternating current (AC) energy delivered to the grid divided by AC energy stored from the grid.

Term	Description
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given Resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given Resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a Resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO ₂ (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO ₂) emissions in pounds of sulfur dioxide per million Btu of heat input.
NO _x (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NO _x) (expressed as NO ₂) in pounds of NO _x per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO ₂ (lbs/MMBtu)	Pounds of carbon dioxide (CO ₂) emitted per million Btu of heat input.

Table 7.13 - Glossary of Acronyms Used in Chapter 7

Acronyms	Description
ACAES	Adiabatic Compressed Air Energy storage
AFSL	Average Feet (Above) Sea Level
ATB	Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CF	Capacity Factor
CSP	Concentrated Solar Power
CT	Combustion Turbine
DF	Duct Firing
DOE	United States Department of Energy
EIA	Energy Information Agency
FGD	Flue Gas Desulfurization
GAIN	Gateway for Accelerated Innovation in Nuclear
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine (reciprocating engine)
IGCC	Integrated Gasification Combined Cycle
ISO	International Standards Organization (Temperature = 59 degrees Fahrenheit (°F) / 15 degrees Celsius (°C), Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
LFP	Lithium Iron Phosphate (sub-chemistry of lithium-ion)
MW	Megawatt
NCM	Nickel Cobalt Manganese (sub-chemistry of lithium-ion)
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
OSTI	Office of Scientific and Technical Information

OSW	Offshore Wind
PCCC	Post Combustion CO2 Capture
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PC CCUS	Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
RTE	Round Trip Efficiency (typical operational AC to AC energy storage efficiency)
SCCT	Simple Cycle Combustion Turbine
SCR	Selective catalytic reduction
STG	Steam turbine generator

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.2 through Table 7.11. For all technology that is included in the 2024 NREL ATB, the ATB costs were used. For incremental items, a percentage difference between the technology with and without the incremental resource was used. Where data is available for an advanced technology innovation scenario²⁴, there is a resource row for that scenario.

Internal Combustion Engine x4, renewable biofuel, with SCR & fuel tank – This is a reciprocating internal combustion engine (RICE) power plant based on four large-scale engines, that are assumed to burn a liquid renewable biofuel like biodiesel or renewable diesel. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW.”²⁵ It is presented in the IRP as a 20 MW resource to meet Oregon’s regulatory requirements for distributed generation resources, under the assumption that it could be derated to meet the requirements. The 24-hour fuel tank was added to the 2020 EIA Report’s resource based on available market information on in-ground fuel tanks.²⁶

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4 – This is “four of aeroderivative dual-fuel CTs in a simple-cycle configuration, with a nominal output of approximately 54 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is approximately 211 MW. Each CT’s inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also

²⁴ <https://atb.nrel.gov/electricity/2024/definitions#scenarios>

²⁵ *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration’s *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf

²⁶ See Appendix M, stakeholder feedback form #59 (Renewable Northwest).

equipped with burners designed to reduce the CT's emission of NO_x. Included are SCR units for further reduction of NO_x emissions and CO catalysts for further reduction of CO emissions.”²⁷

Natural Gas, SCCT Frame "F" x 1, with SCR – This is “one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of NO_x.”²⁸ Although the 2020 EIA Report does not include an SCR for this resource, to be on par with the other IRP resources, the approximate cost of an SCR was added based on the cost difference on a percentage basis from previous IRP's.

Natural Gas, CCCT "H", 1x1, DF, with SCR – This is “one Model HL dual-fuel CT in a 1x1x1 single-shaft CC configuration. The CT generates approximately 453 MW gross, and the STG generates 192 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 627 MW.”²⁹

Natural Gas, CCCT "H", 2x1, DF, with SCR – This is “a pair of Model H, dual-fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine). Each CT generates approximately 436 MW gross; the STG generates approximately 393 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1227 MW.”³⁰

Natural Gas, Δ for adding 95% CCS – This option reflects incremental changes for a greenfield “power plant w/ commercially available solvent-based post combustion CO₂ capture (PCCC) designed for 95% capture.”³¹ The 95% option was chosen because that is the most economic option available in the NREL ATB that meets the EPA 111 regulations.

Natural Gas, Δ for CT Brownfield construction – This option reflects incremental changes for construction of a resource at an existing powerplant site with the same technology.

Hydrogen, Δ for 100% Hydrogen burning capability – This option reflects incremental changes for a CT to burn a mixture of fuel up to 100% hydrogen.

Hydrogen, Δ for Hydrogen storage, cavern, 80 bar, 1 week – This option reflects incremental changes for storing hydrogen underground in a solution-mined geologic salt dome. Hydrogen gas

²⁷ *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

²⁸ *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf

²⁹ *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

³⁰ Ibid 17

³¹ 2024 ATB Excel Workbook, available at <https://atb.nrel.gov/electricity/2024/data>.

is compressed and stored at ambient temperature in at elevated pressure (70-190 bar). Salt domes only exist in a limited number of locations (~2000 salt caverns in North America with an average capacity of 10^5 - 10^6 m³). There are at least two salt domes under development within PacificCorp's area of operation. This assumes a "600 tons per day (TPD) pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume."³² In addition to the Pathways to Commercial Liftoff: Clean Hydrogen (Clean Hydrogen Liftoff Report), the Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan³³ was used for cost and technical data.

Hydrogen, Δ for Hydrogen storage, tanks, 500 bar, 24-hour – This option reflects incremental changes for storing hydrogen in tanks constructed above ground. "H₂ gas is compressed at ambient temperature to 300 – 700 bar. Storage capacity is limited due to the low volumetric density of H₂ at room temperature. Assumes 950 kg stored at 500 bar with 1 cycle per week."³⁴

Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day – Also known as polymer electrolyte membrane, including balance of plant (BOP) costs, the "electrolyzer design is intended to represent the current state-of-the-art (2022) stacks with respect to catalyst loadings (3 milligrams per square centimeter [mg/cm²] total platinum group metal [PGM] loading) and material specifications."³⁵ Data from the DOE Hydrogen and Fuel Cells Program Record³⁶ was also used in the development of this resource.

Coal, CCS– These are retrofits of an existing conventional coal-fired boiler and steam-turbine generator resources with amine based post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCS would remove 95 percent of the carbon dioxide and would provide reductions in other emissions.³⁷

Storage, Lithium Ion Battery – This is lithium-ion batteries rated at 20 and 200 MW capacities with 4-hour duration. The 20 MW option uses the ATB's "Commercial Battery" data, while the 200 MW option uses the ATB's "Utility-Scale" data.

³² Pathways to Commercial Liftoff: Clean Hydrogen, U.S. Department of Energy, Office of Technology Transitions: Hannah Murdoch; Office of Clean Energy Demonstrations: Jason Munster; Hydrogen & Fuel Cell Technologies Office: Sunita Satyapal, Neha Rustagi; Argonne National Laboratory: Amgad Elgowainy; National Renewable Energy Laboratory: Michael Penev, <https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf>

³³ Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan, Dr. Sunita Satyapal, U.S. Department of Energy, <https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office-multi-year-program-plan>

³⁴ *ibid* 20

³⁵ Badgett, Alex, Joe Brauch, Amogh Thatte, Rachel Rubin, Christopher Skangos, Xiaohua Wang, Rajesh Ahluwalia, Bryan Pivovar, and Mark Ruth. 2024. *Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87625. <https://www.nrel.gov/docs/fy24osti/87625.pdf>.

³⁶ David Peterson, James Vickers, Dan DeSantis, *Hydrogen Production Cost From PEM Electrolysis – 2019*, February 3, 2020, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master

³⁷ Carbon capture costs and parameters were the subject of discussion and feedback during the 2025 IRP public input meeting series.

See Appendix M, stakeholder feedback form #25 (NP Energy, LLC).

See Appendix M, stakeholder feedback form #44 (Sierra Club).

Storage, Δ double duration – This option reflects incremental changes for doubling the duration of a battery energy storage resource, modifiers on this row must be applied to the data in the appropriate resource row. Appropriate resources are limited to those utilizing lithium-ion energy storage, including lithium-ion energy storage collocated with other resources.

Storage, Δ for Co-Located Energy Storage – This option reflects incremental changes for lithium-ion energy storage collocated with another resource, modifiers on this row must be applied to the appropriate energy storage data.

Storage, Gravity Battery, 4-hour, 1000 MW – This is an estimate for any technology that uses the potential energy differential of a large mass but excludes pumped hydro. Pumped hydro is a well-established technology and because of this there is more accurate data available for pumped hydro. Examples include dense weights lifted vertically, heavy rail cars moved up and down a steep track, or a piston displacing a fluid vertically. Costs were escalated from the 2023 IRP.

Storage, Adiabatic CAES – Compressed air energy storage (CAES) system consists of an air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. Only the system sizes of 500 MW are included because that size was the lowest cost per kWh in the 2023 IRP. The air storage reservoir is an engineered tank. “Adiabatic” conserves heat during storage and discharge and means the system does not burn natural gas to generate power.

Storage, Pumped Hydro, Two New Reservoirs – Also known as closed-loop pumped hydro, this technology pumps and releases water between a higher and a lower reservoir. It is modeled as a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 1 data.

Storage, Pumped Hydro, One New Reservoirs – Also known as an open-loop system, this technology pumps and releases water between a higher reservoir and a lower natural water body, usually a river. It is modeled as a nominal 400 MW PHES system using both natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 5 data.

Storage, 100-hour Iron Air – This is a low capital cost battery option with the trade off a low round trip efficiency. “While discharging, the battery breathes in oxygen from the air and converts iron metal to rust. While charging, the application of an electrical current converts the rust back to iron and the battery breathes out oxygen.”³⁸

Storage, Pumped Thermal Energy Storage – This is a system using a storage tank of high temperature fluid to store energy. A resistive heater converts electric energy to heat energy in the

³⁸ <https://formenergy.com/technology/battery-technology/>

fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator.

Solar, PV, Class 1 - 10 – This is ATB PV Class 1 through 10 (20 MW or 200 MW) solar photovoltaic resources using crystalline silica solar panels in a single axis tracking system. The 20 MW option uses the ATB’s “Commercial” data, while the 200 MW option uses the ATB’s “Utility-Scale” data. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-10, 20 MW – This is ATB “Distributed Wind, Large Turbine Technology Class.” It is a wind resource of 1,500 kW turbines with 107-meter rotor diameter and 80-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-6, and 7200 MW – This is ATB Land-Based Wind technology configuration T1. It is a wind resource of 34 x 6 MW turbines with 170-meter rotor diameter and 115-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 7, 200 MW – This is the same as wind classes 1- 6, but different wind conditions and cost data.

Wind, Offshore, Wind Class 12 – This is ATB “Floating Offshore Wind.” It is a wind resource of 12 MW turbines with 216-meter rotor diameter and 137-meter hub height. Wind Class 12 represents the wind conditions off the coast of northern California and southern Oregon. The ATB lists a net capacity factor of 47% for Offshore Wind Class 12.

Nuclear, Small Modular Reactor or Advanced Reactor – This is a conceptual technology that could be a small modular reactor or small advanced reactor. “Modular” refers to a reactor that can be built off site and easily transported to the installation location, however scale of economy requires multiple modular reactors to share support facilities at a single powerplant site. Data is from the ATB and relies heavily on a DOE Office of Scientific and Technical Information, Gateway for Accelerated Innovation in Nuclear report³⁹ (“OSTI GAIN Report”).

Nuclear, Δ for nuclear integrated thermal storage, 5 hours - This option reflects incremental changes for a system using a storage tank of high temperature fluid. To store energy, heat from a nuclear reactor is transferred in a heat exchanger to the storage fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator. This method eliminates the resistive heater losses in the stand-alone thermal storage, and therefore has a much higher RTE.

Nuclear, Large Light Water Reactor – This is a modern dual unit reactor similar to most of the existing utility reactors in the United States. Data is from the ATB and relies heavily on the OSTI GAIN Report.

³⁹ Abdalla Abou-Jaoude, Levi M Larsen, Nahuel Guaita, Ishita Trivedi, Frederick Joseck, and Christopher Lohse, Idaho National Laboratory; Edward Hoffman and Nicolas Stauff. Argonne National Laboratory; Koroush Shirvan, Massachusetts Institute of Technology; Adam Stein, Breakthrough Institute; Gateway for Accelerated Innovation in Nuclear (GAIN); *Meta-Analysis of Advanced Nuclear Reactor Cost Estimations*, July 2024, https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_107010.pdf

Geothermal, Near Field Enhanced Geothermal System (NF-EGS) Binary – This is the ATB geothermal plant utilizing a 175°C thermal resource with 1.5 km wells and production well flow rates of 60 kg/s.⁴⁰

Locational Modifiers and Selected Cost Forecasts

Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options in the supply-side resource table. For any resource option without a technology specific cost forecast, escalation is assumed to be level. These locational modifiers and cost forecasts are applied in PLEXOS. Cost forecast histories for selected resource types are shown in the following sections.

PV Cost Forecast History

Figure 7.1 shows a history of capital cost forecasts used in the supply-side resource table for PV resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost estimates for solar resources are based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is essentially the same as the trend line of the 2021 IRP.

⁴⁰ Geothermal modeling was the subject of stakeholder feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See Appendix M, stakeholder feedback form #41 (Nathan Strain).

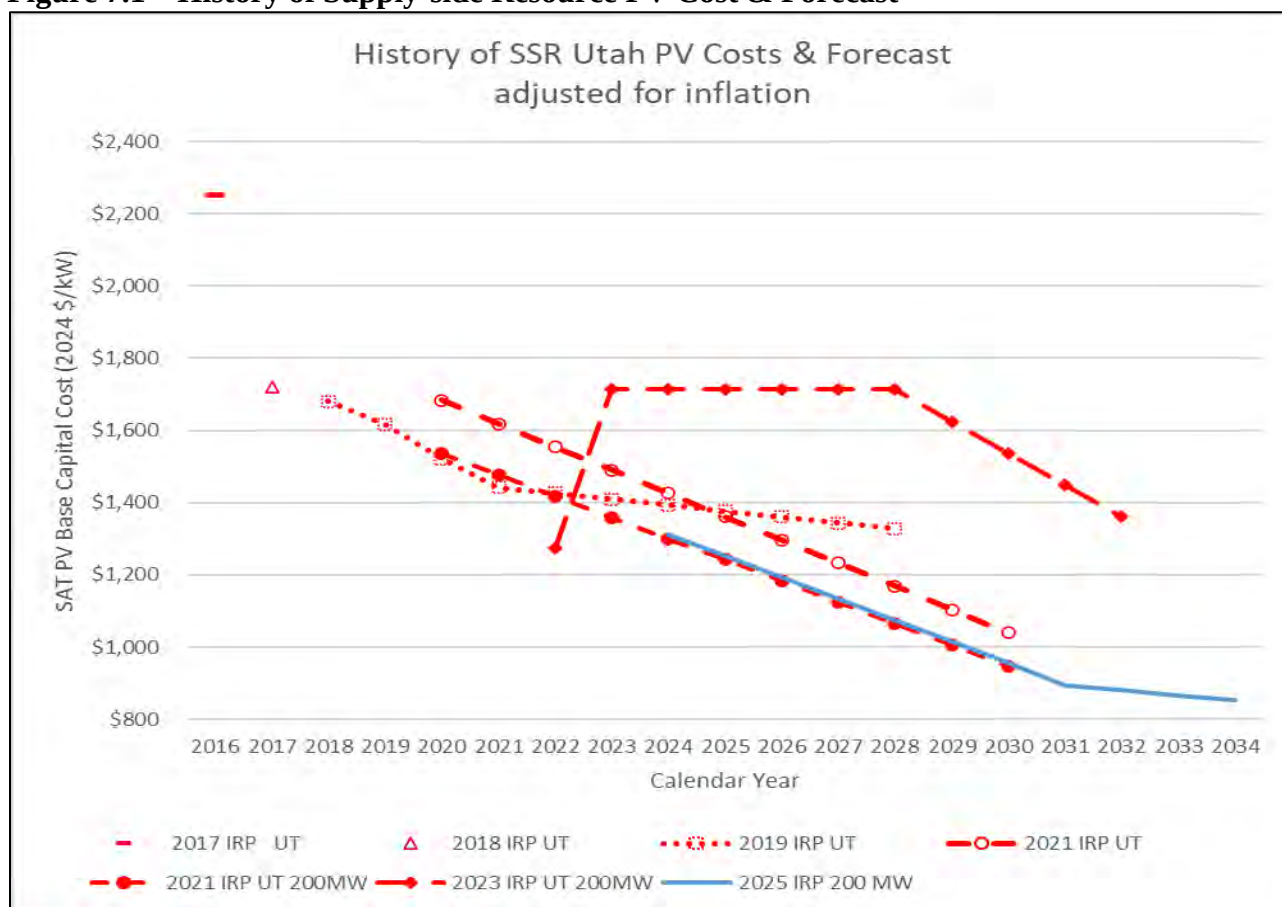
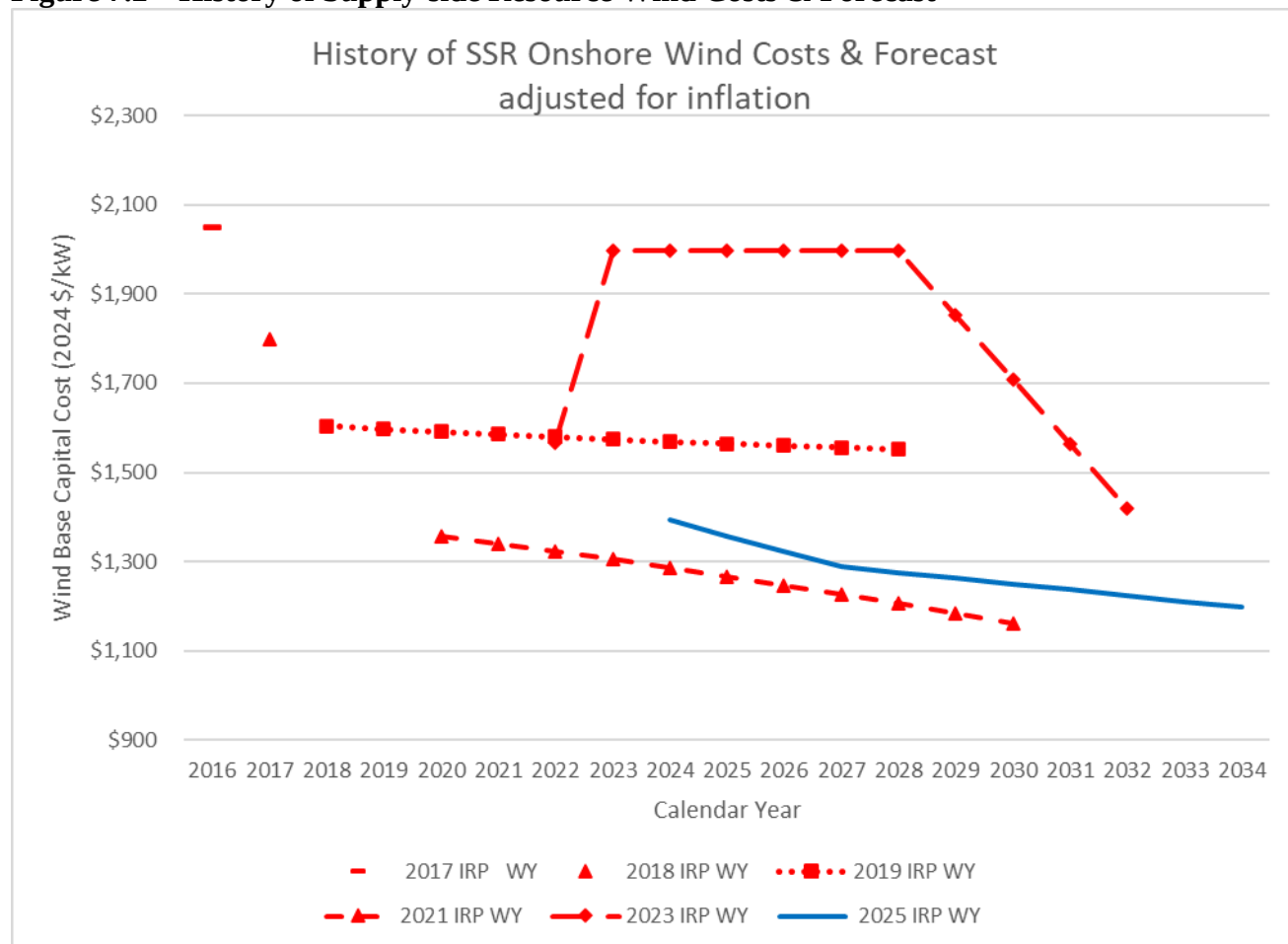
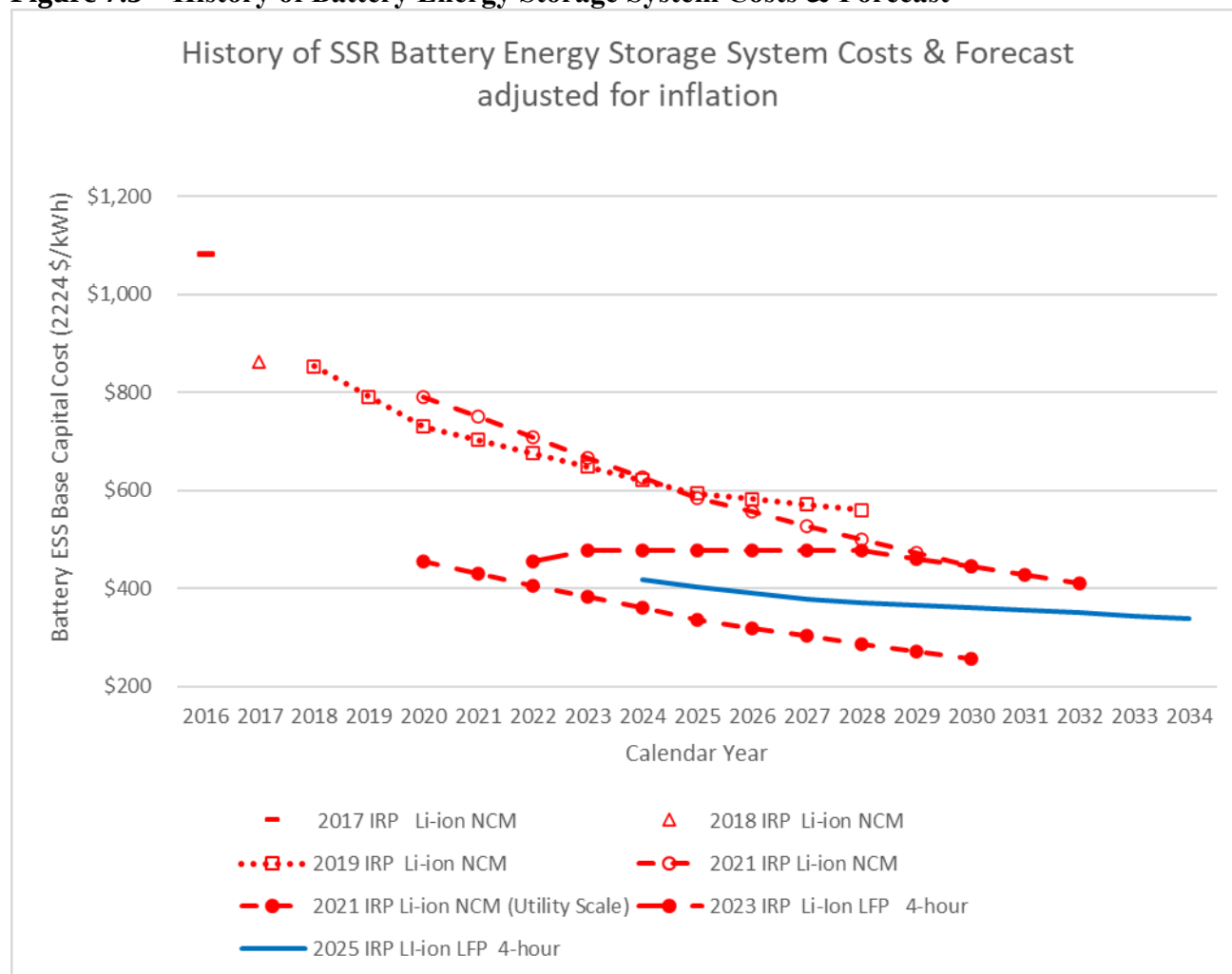
Figure 7.1 – History of Supply-side Resource PV Cost & Forecast**Wind Cost Forecast History**

Figure 7.2 shows a history of capital cost forecasts used in the supply-side resource table for resources in Wyoming from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for wind resources is based on the ATB forecast. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is close to the trend line of the 2021 IRP.

Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast

Energy Storage

Figure 7.3 shows a history of capital cost forecasts used in the supply-side resource table for BESS resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for BESS resources is based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The observed market correction used in the 2023 IRP has been partially mitigated by federal policy changes and the forecast costs are about midway between the less expensive 2021 IRP and the more expensive 2023 IRP.

Figure 7.3 – History of Battery Energy Storage System Costs & Forecast

Utility-scale Energy Storage Resources

PacifiCorp has contracted for the following utility-scale energy storage resources:

- Faraday solar and storage (525 MW solar, 150 MW battery storage with 4-hour duration) is a project supporting customer clean energy goals under Utah Schedule 34.
- Green River solar and storage (400 MW solar, 400 MW battery storage with 4-hour duration) is a project that was originally part of the final shortlist in the 2020 All-Source Request for Proposals. An amendment to the contract expanded the battery from 200 MW with two-hour duration to 400 MW with four-hour duration.
- Dominguez Grid (200 MW battery storage with four-hour duration) is a stand-alone energy storage resource.
- Enterprise/Escalante/Granite Mountain East/Iron Springs storage: each of these contracts is an 80 MW battery storage resource with four-hour duration. Battery storage is being added at existing solar resources and will use surplus interconnection. A surplus interconnection allows for resources to be added at any existing interconnection location so long as the total output to the grid is kept within the existing interconnection capacity.

As a result of the contracts described above, PacifiCorp expects to bring more than one gigawatt of energy storage resources online by the summer of 2026.

Comparison of Lazard's Levelized Cost of Energy Analysis-Version 17 (LCOE+ 17)⁴¹ and NREL's 2024 ATB⁴²

Lazard's LCOE+ 17 and the NREL ATB both inform stakeholders about the economic viability of different energy sources, but they differ in scope, methodology, and the specifics of their cost assumptions. Each report is assumed to use a consistent but distinct methodology across all technologies, with technology specific nuances treated fairly. Table 7.14 provides a side-by-side comparison of pertinent information in the two reports.

Lazard's LCOE+ 17 cost assumptions are based on a standardized financial model with fixed debt and equity costs. The analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost, resulting in an after-tax weighted average cost of capital (WACC) of 7.7%.

NREL's ATB offers a range of financial assumption options to reflect different market conditions and provide a more comprehensive view of potential costs.

Table 7.14 – Comparison of Lazard LCOE+ and NREL ATB

	Lazard LCOE+ 17	NREL ATB
Levelized Cost of Energy (LCOE)	Historic Ranges & Averages	Historic and future "Technology Advancement Scenarios" options
Levelized Cost of Storage (LCOS)	Yes	No
Levelized Cost of Hydrogen (LCOH)	Yes	No
Finance Assumptions	No	Yes
Tax Credits	Yes	Optional
Capital Cost	Yes, but not clearly defined	"Capital Expenditure" (CAPEX)
Construction Cost	Assumed to be included	Yes
Overnight Capital Cost	No	Yes
Grid Connection Cost	Not clear	Yes
Construction Finance Factor	No	Yes
Construction Cashflow Curve	No	No
Weighted Average Cost of Capital	Yes	Yes
Fixed O&M (FOM)	Yes	Yes
Variable O&M (VOM)	Yes	Yes
Capacity Factor (CF)	Yes	Yes
Facility Net Power Capacity	Yes	Yes
Heat Rate	Yes	Yes

⁴¹ Lazard Levelized Cost of Energy +, June 2024, https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf

⁴² <https://atb.nrel.gov/electricity/2024/index>

Construction Time	Yes	Yes
Design Life	Yes	Yes
Energy Storage Duration	Yes	Yes
Energy Storage Round Trip Efficiency (RTE)	Yes	Yes
Energy Storage Degradation	Yes	Included in FOM
Regional Resolution Level	Regional markets, including CAISO but not WECC	Select cites in each state, per referenced reports
Regional Adjustment Factors	No	Included in referenced reports
Effective Load Carrying Capability (ELCC) Analysis	Yes	No
Demolition Costs	No	No
Outage Rates, Forced and Planned	Assumed to be included in CF	Assumed to be included in CF
References or Bibliography	No	Yes

The costs reported by Lazard and NREL can differ due to variations in their methodologies and assumptions. Lazard's LCOE+ 17 tends to provide a more standardized comparison across technologies, which can be useful for high-level decision-making. In contrast, NREL's ATB offers a more detailed and nuanced view, considering different scenarios and market conditions.

Reasons for Cost Differences:

- **Methodological Differences:** Lazard uses a fixed financial model, while NREL incorporates a range of scenarios and assumptions, leading to different cost estimates.
- **Scope of Analysis:** Lazard focuses on a high-level comparison of technologies, whereas NREL provides detailed data for specific scenarios and market conditions.
- **Financial Assumptions:** Differences in debt and equity costs, as well as WACC, can lead to variations in the reported costs.
- **Technology Assumptions:** NREL's ATB includes projections for future technology advancements, which can result in lower cost estimates compared to Lazard's more conservative approach.

In summary, while both Lazard's LCOE+ 17 and NREL's ATB provide valuable insights into the costs of energy technologies, their differences in scope, methodology, and assumptions can lead to varying cost estimates. Understanding these differences is crucial for stakeholders to make informed decisions about energy investments.

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2025-2044, which provided DSM resource opportunity estimates for the 2025 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of

the size, type, location and cost of demand-side resources.⁴³ For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g., products and quantities) based on each resource's competitiveness against alternative resource options.⁴⁴ Due to the timing of the 2025 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2025 DSM program acquisition targets. To ensure that the 2025 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2025. In 2026, energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period.
- Persistence of resource savings (e.g., energy efficiency equipment measure lives).
- Seasonal availability and hours available (e.g., irrigation load control programs).
- The hourly shape of the resource (e.g., load shape of the resource).
- Levelized resource costs (e.g., dollars per kilowatt-hour per year for energy efficiency, or dollars per megawatt over the resource's life for demand response resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

Demand Response: DSM Capacity Supply Curves

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2025, PacifiCorp has launched and expanded several demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2025.

⁴³ The 2025 Conservation Potential Study is available on PacifiCorp's IRP Support & Studies web page: www.pacificorp.com/energy/integrated-resource-plan/support.html.

⁴⁴ Demand-side management modeling and methodology was a frequent topic of discussion in the 2025 IRP public input meeting series and in stakeholder feedback forms.

See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon).

See Appendix M, stakeholder feedback form #36 (Sierra Club).

See Appendix M, stakeholder feedback form #45 (Utah Clean Energy).

Table 7.15 – Demand Response Existing and Planned Programs

Product	State	Existing or Planned Offering
Res – HVAC DLC	UT	Existing
Res – HVAC DLC	OR, WA	Planned
Res – EV Load Control	OR, WA, UT	Planned
Res – Battery DLC	OR, WA	Planned
Res – Battery DLC	ID, UT	Existing
C&I – Battery DLC	ID, UT	Existing
C&I – Third Party	OR, WA, UT	Existing
C&I – Third Party	ID	Planned
Ag – Irrigation DLC	UT, ID, OR, WA	Existing

Table 7.16 and Table 7.16 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2025 CPA.⁴⁵ Potential shown is incremental to the existing DSM resources identified in Table 7.17. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2025. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2026. New program offerings are assumed to be available in 2026 accounting for the time required for program design, regulatory approval, vendor selection, procurement, and implementation.

Table 7.16 – Demand Response Program Attributes West Control Area,^{46*}

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost (\$/kW-yr)	20-Year Potential (MW)	Average Levelized Cost (\$/kW-yr)
Res – EV DLC	15.1	\$412	15.1	\$412
Res – DLC of Smart Home	0.1	\$1,306	0.1	\$686
Res – HVAC DLC	17.4	\$175	81.7	\$73
Res – Pool Pump DLC	0.2	\$742	0.1	\$1,956
Res – Water Heater DLC	2.7	\$134	4.0	\$90
Res – Smart Thermostat	40.2	\$37	28.9	\$29
Res – Grid Interactive Water Heaters	14.6	\$97	24.5	\$66
Battery DLC	6.1	\$31	4.9	\$30
C&I – Third Party	8.5	\$46	12.4	\$54
Ag – Irrigation DLC	1.8	\$24	0.0	\$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

⁴⁵ The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

⁴⁶ Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

Table 7.17 – Demand Response Program Attributes East Control Area,^{47*}

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost (\$/kW-yr)	20-Year Potential (MW)	Levelized Cost (\$/kW-yr)
Res – EV DLC	24.8	\$416	24.8	\$416
Res – DLC of Smart Home	0.1	\$1,601	0.3	\$772
Res – HVAC DLC	234.2	\$158	141.3	\$272
Res – Pool Pump DLC	0.2	\$834	0.1	\$2,199
Res – Water Heater DLC	12.8	\$175	17.5	\$117
Res – Smart Thermostat	90.4	\$38	50.2	\$94
Res – Grid Interactive Water Heaters	1.1	\$209	2.0	\$139
Battery DLC	65.3	\$36	65.2	\$41
C&I – Third Party	66.6	\$52	72.7	\$50
Ag – Irrigation DLC	19.1	\$29	0.0	\$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2025 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g., specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming⁴⁸
- **Measure:**
 - 120 residential measures
 - 146 commercial measures
 - 105 industrial measures
 - 19 irrigation measures
- **Facility type:**⁴⁹
 - 18 residential facility types
 - 28 commercial facility types
 - 30 industrial facility types

⁴⁷ Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

⁴⁸ Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

⁴⁹ Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in Volume 1 of the 2025 CPA.

– Two irrigation facility type

The 2025 CPA levelized total resource costs over the study period at PacifiCorp’s cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e., incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the 20-year CPA planning horizon totaled approximately 15.1 million MWh.⁵⁰ The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 12.8 million MWh for all five states. The technical achievable potential for all six states, i.e., including Oregon, for modeling consideration is 17.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated just over 50,500 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 21-year planning horizon. Consistent with the Northwest Power and Conservation Council’s achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.⁵¹

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2025 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp’s six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency

⁵⁰ The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years’ incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

⁵¹ The Northwest’s achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

resource supply curves. Table 7.18 shows the 21-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

Bundles are classified based on their measure’s temperature dependency, as either heating or cooling. A measure is considered temperature dependent if at least 25% of annual kWh savings are derived from temperature dependent end-uses. Measures that have both heating and cooling savings are classified based on whichever has greater volume. Measures that are not temperature dependent, such as lighting, are classified based on whichever season (summer or winter) the measure has a greater capacity contribution. Measures are then ranked based on their net cost of capacity (\$/kW-yr) and assigned to a bundle with measures of a similar net cost. There is little need to differentiate bundles that will provide value in nearly all conditions. Measures with a net cost less or equal to zero have energy benefits that exceed their costs, such that their capacity value (reliability benefits) are “free.” These measures are assigned to a zero-cost temperature-sensitive bin or a zero-cost non-temperature sensitive bin, which together comprise roughly half of all potential. For non-zero cost measures, roughly equal volumes are distributed among the remaining bundles of heating, cooling, summer, or winter measures. The number of each type of bundle varies by state depending on the potential and load profile used in each state.

Table 7.18 – 2045 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Cooling Measures	34,469	42,040	609,077	1,282,306	102,772	108,946
Heating Measures	28,535	75,471	870,110	751,888	197,253	122,268
Summer Measures	68,513	119,447	1,292,227	1,244,883	366,577	221,926
Winter Measures	221	14,417	103,548	221,229	3,524	347,464
Zero Cost Temperature Dependent Measures	18,360	84,725	295,605	1,550,447	127,775	84,371
Zero Cost Non-Temperature Dependent Measures	33,056	260,493	1,224,970	3,470,030	376,187	626,797

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.19)
- Stochastic risk reduction credit.⁵²
- Northwest Power Act 10-percent credit (Oregon and Washington resources only).⁵³

⁵² PacifiCorp develops this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

⁵³ The formula for calculating the \$/MWh Power Act credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Table 7.19 – State-specific Transmission and Distribution Credits (2024\$)

State	Transmission Deferral Value (\$/kW-year)	Distribution Deferral Value (\$/kW-year)	Total
California	\$5.83	\$11.23	\$17.06
Oregon	\$5.83	\$15.65	\$21.49
Washington	\$5.83	\$18.93	\$24.76
Idaho	\$5.83	\$23.11	\$28.94
Utah	\$5.83	\$18.62	\$24.46
Wyoming	\$5.83	\$9.61	\$15.44

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp’s service territory. Weather is a major driver of PacifiCorp’s load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. As in the 2023 IRP, PacifiCorp has reshaped daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for temperature-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp’s service territory. For temperature dependent measures, the simulated savings are proportionate with the temperature-sensitive load across in each month, so that the highest savings occur on the highest load days in the load forecast. To capture the time-varying impacts of energy efficiency resources, each bundle uses an annual 8,760 hourly load shape. These shapes reflect measure-level annual energy savings, differentiated by state, sector, market segment, and end use. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 275 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME across the Pacific Power and Rocky Mountain Power service areas. This resulted in more than 34 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

These distribution energy efficiency activities were not modeled as potential resources in this IRP.

Transmission Resources

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation).

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations.

Market transactions can encompass a wide variety of product types that can be classified as either forward (entered well in advance of delivery) or spot (entered no more than a day or two before delivery). Currently, the most commonly traded forward products are for heavy load hours (HLH) and/or light load hours (LLH) and are typically for calendar quarters (e.g. “Q3” spanning July, August, and September) or individual months. Other timeframes are less common but could include super-peak products (noon to 8:00 p.m.). All the common forward market products represent undifferentiated system power supplied at a point, but forward transactions can also be based on the costs, availability, options, and/or restrictions of specific physical resources. Some examples include slices of hydropower resources, or a tolling agreement for a natural gas-fired resource.

Examples of spot market transactions include day-ahead HLH and LLH products, day-ahead hourly transactions in the CAISO market, hour-ahead products, and intra-hour products facilitated by the Western Energy Imbalance Market (EIM).

In the next few years, two changes are coming that will change the landscape of markets in both forward and spot timeframes. First, the Western Resource Adequacy Program (WRAP) requires a showing of capacity resources several months in advance of the summer and winter seasons. Current HLH and LLH market products will not count as capacity for WRAP unless the two counterparties agree to a capacity transfer, which may incur a higher cost or reduce a counterparty’s willingness to sell. While contracts for physical resources would count as capacity for WRAP if the seller attests the capacity is surplus to its needs and the resource is registered in the program, it is unclear how much capacity of that sort is likely to be available, particularly as many WRAP participants all seek to become compliant. Second, CAISO’s Enhanced Day-Ahead Market (EDAM) will expand day-ahead resource optimization beyond the current CAISO footprint and will impact spot market participation. While EDAM takes over much of the optimization function in the day-ahead timeframe, to prevent leaning participants will be required to pass balancing tests to ensure they bring sufficient resources to meet their load, and this may necessitate transactions ahead of the EDAM.

In past IRPs, PacifiCorp included front office transactions (FOT) as proxy resource options, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions. Consistent with the current WRAP rules for unspecified-source purchases, FOTs are not included in the calculation of WRAP compliance in the 2025 IRP, so forward market purchases will not count as capacity. While the 2025 IRP does not allow FOTs to meet WRAP compliance requirements, PacifiCorp expects to continue pursuing economic short-term and intermediate term market opportunities that assist with WRAP compliance and/or balancing.

Spot market purchases and sales also provide opportunities to economically balance loads and resources. The economic opportunities are expected to be enhanced by the EDAM, relative to current operations, but it is unclear how the EDAM will compare to the IRP model’s hourly balancing optimization of market purchase and sales volumes against static hourly market prices.

In the EDAM and EIM, market prices are based on marginal supply and demand, so significant increases in supply are likely to reduce prices while increases in demand are likely to increase prices. When demand is high and begins to approach the limits of available supply, economic opportunities will diminish, and adequate capacity will still be needed to participate. The 2025 IRP has incorporated historical relationships between daily prices, loads, and resource supply to better account for the impacts of supply and demand; however, it still relies upon a static forecast of prices that do not account for portfolio selections through time. With these various factors in mind, hourly market purchase volumes have been restricted during key hours on the top five load days within each month. These restrictions apply from 4:00 p.m. to 12:00 a.m. throughout the year, and in the winter an additional restriction applies in the morning, from 4:00 a.m. to 8:00 a.m. Outside of these hours (and all day on lower load days), market purchases are allowed up to modeled transmission limits. Similarly, hourly market sales volumes have been restricted to historical levels, to avoid increasing reliance on wholesale sales at favorable prices that may not persist in an organized market.

Chapter 5 describes the relationship of front office transactions (FOTs) to reliability and WRAP compliance, and FOTs are also considered a resource. Front office transactions can be made years, quarters, or months in advance of use; however, they are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point.

Additional discussion of how FOTs are considered in the 2025 IRP, refer to Chapter 5 and Chapter 8.

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used PLEXOS software to produce unique resource portfolios across a range of different planning cases. Informed by the public input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 21 years.¹
- The PLEXOS long-term (LT) model was used to generate initial portfolios and identify the resulting fixed costs. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three federal carbon dioxide (CO₂) policy scenarios (zero compliance requirements, a high price on CO₂ emissions, and compliance with current Environmental Protection Agency (EPA) CO₂ regulations). An additional CO₂ policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/current EPA regulations, medium gas/zero CO₂, high gas and coal/high CO₂, low gas/zero CO₂, and medium gas/social cost of greenhouse gases).
- Each initial portfolio was also evaluated in the short-term (ST) model to establish system costs over the entire 21-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- A selection of competitive “variant” portfolios was analyzed using the other four price-policy scenarios in PLEXOS modeling to evaluate how each portfolio performs under differing future market and policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp’s preferred portfolio selection process involves evaluating cost and risk metrics reported from ST reporting and stochastic modeling, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO₂ emissions and other criteria.

¹ PacifiCorp’s IRP is typically modeled with a 20-year planning horizon, expanded in the 2025 IRP to 21 years to accommodate a specific Washington State requirement extending through 2045. Some discussions and data graphs in the 2025 IRP will refer to the standard 20-year horizon.

Introduction

IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

As addressed in public input meetings and stakeholder feedback forms, the subject of modeling for portfolio evaluation is highly technical. PacifiCorp consults regularly with the provider of the PLEXOS optimization modeling software as these methods are developed. Interested parties are encouraged to review publicly available materials (including recordings) from the 2025 IRP public input meeting series for additional context and information.²

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 9 (Modeling and Portfolio Selection Results).

Key Changes Since the 2023 IRP

The 2025 IRP public meeting inputs series encompassed many key advancements in modeling and evaluation strategy, many driven by stakeholder input. These changes are described in detail later in this chapter. These enhancements are in addition to standard updates applicable to core data such as load and price forecasting. Each change has been incorporated into the company's engagement strategy via public input meetings and stakeholder feedback.³

In the 2025 IRP:

- Portfolios must achieve regional and system WRAP compliance.
- Existing thermal units can operate indefinitely with ongoing maintenance.
- IRA Tax Credits are extended through the model horizon (21 years).⁴
- Jurisdictional portfolios are used to integrate final portfolios.
 - States are only able to impact the disposition of resources in which they have an active share.
 - Resource additions are considered situs and must be able to serve requirements in their associated jurisdiction.
- Improved granularity and reliability evaluation.
- No federal CO₂ policy adder is assumed in the expected case.
- Transmission representation now includes a distinct bubble for the Wasatch Front.

² For discussion of public materials and feedback, see also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at <https://www.pacifiCorp.com/energy/integrated-resource-plan/public-input-process.html>.

³ See also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at <https://www.pacifiCorp.com/energy/integrated-resource-plan/public-input-process.html>.

⁴ The value of production tax credits (PTCs) is reduced in the last five years of the study horizon, to better represent the value of resource additions in the latter half of the horizon. See Appendix M, stakeholder feedback form #63 (Utah Clean Energy) for additional discussion.

- A new price-policy variation (“MR”, medium gas price with at-risk federal regulation) has been added to account for changing expectations for future federal policy.
- No market purchases are allowed in peak hours on the five days with the highest peak load in each month, market purchases are allowed up to transmission limits in all other hours.
- The stochastic analysis incorporates wide-ranging historical volatility in renewable shapes, thermal outages, load, market prices, and hydro availability.

Modeling and Evaluation Steps

All IRP models are configured and loaded with the best available information at the time a model run is produced. Figure 8.1 summarizes the modeling and evaluation steps for the 2025 IRP. The process flow begins at left with the development of key inputs and assumptions. Next, studies are mathematically optimized using PLEXOS software tools⁵, as illustrated in the six steps at right (“Iterative Optimization”, highlighted in blue). Results are evaluated to determine the least-cost least-risk preferred portfolio from among all eligible portfolios. Finally, the preferred portfolio is used to develop the action plan.⁶

⁵ PLEXOS technical modeling assumptions and parameters were discussed in the 2025 IRP public input meeting series and in stakeholder feedback.

See Appendix M, stakeholder feedback form #21 (Renewable Northwest).

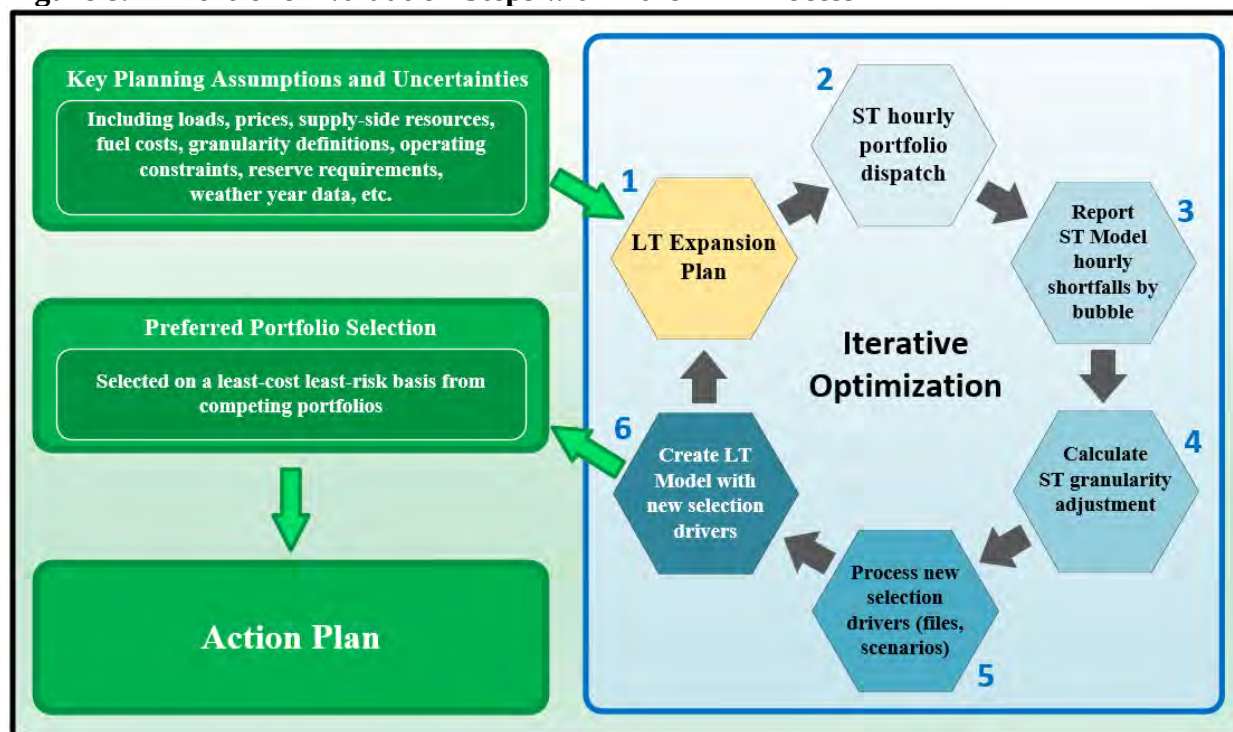
See Appendix M, stakeholder feedback form #42 (First Principals Advisory).

⁶ The topic of portfolio change was discussed extensively in the 2025 IRP public input meeting series. The modeling and evaluation steps explain how updated inputs are processed – such as updated resource costs as presented in Chapter 7 – resulting in new portfolio outcomes.

See Appendix M, stakeholder feedback form #13 (Joan Entwistle).

See Appendix M, stakeholder feedback form #15 (Sierra Club).

See Appendix M, stakeholder feedback form #27 (Vote Solar).

Figure 8.1 – Portfolio Evaluation Steps within the IRP Process

The portfolio development process in the 2025 IRP is an iterative process, whereby PacifiCorp completes initial LT capacity expansion modeling runs for each portfolio. Portfolios are evaluated for cost, reliability and compliance using the ST model, dispatch focused, modeling results. Data regarding resource value and unserved energy quantities from the ST model is fed back into PLEXOS, and the next phase of iterative portfolio optimization is launched. Each cycle through the six steps is one modeling “phase.” Iterations continue until the LT capacity expansion model has produced a portfolio that demonstrates no unserved energy in the ST dispatch model run, and then for several phases thereafter, to identify a range of potentially economic candidate portfolios. Each price-policy scenario and each candidate variant study follows this iterative optimization process. Once a completed portfolio phase achieves reliability, as measured using ST model results, evaluation is completed, and results can be compared to other portfolios.

Overview of Steps in an Iterative Phase

Step 1

For each case, the LT capacity expansion model is run according to the parameters and constraints of the particular study. This results in an expansion plan of selected resources, retirement decisions and transmission option selection. Collectively these selections are called a “portfolio.”

Step 2

The LT model expansion plan is fed into the ST model. The ST model performs an hourly dispatch of the portfolio.

Step 3

The ST model reports shortfalls as megawatts of unserved energy. These megawatts must be covered for each location (or “bubble”) in the IRP transmission topology. Greater detail regarding use of these reported shortfalls to create the reliability adjustment is below.

Step 4

The granularity adjustment is calculated as the difference in resource value between the ST model results and the LT model results. This calculation gives the mathematical magnitude of the ST model's superior granularity. Greater detail regarding the calculations which comprise the granularity adjustment is below.

Step 5

The reliability shortfalls and granularity adjustments are formatted into data files that can be used in the next phase of the LT model to improve its outcomes.

Step 6

The next phase LT model is built in PLEXOS, if necessary, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adjustment (either an increase or decrease in costs) to every resource option.

Granularity Adjustment Detail

The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model uses 4 blocks of hours per month over the 21-year horizon. This means the LT model groups similar hours into a block, calculates the average load and resource parameters specific to each block, and then concurrently solves the entire 21-year horizon. In contrast, the ST model concurrently solves (or dispatches) of a given week, or roughly 52 steps per year of 168 hours each, for a specified portfolio of resources as selected in the LT model. When PLEXOS optimizes the system in the 4-block LT view, it calculates a locational marginal price (LMP) specific to each block of hours. The value of a resource in the LT is equal to its generation in each block, multiplied by the LMP during that block specific to its location, and this value is part of the reported results based on the 48 blocks the LT evaluates during each year (4 blocks per month times 12 months). When the ST model dispatches the same resources at an hourly granularity, it calculates the LMP based on hourly conditions, multiplies by a resource's hourly generation, and reports the resulting value for each resource on an annual basis. The ST model also assigns specific resources to hold operating reserves necessary to meet reliability requirements, calculates the marginal price of reserves, and includes this as part of the reported resource value. The mathematical difference between the ST value and the LT value is the granularity adjustment.

The 4 blocks used by the LT model include the top ten percent highest net load hours (load net of wind and solar generation), the highest wind generating hours, the highest solar generating hours, and the remainder of the hours. While these blocks are intended to help the LT model differentiate between key resource types, they can't capture the full range of hourly conditions.

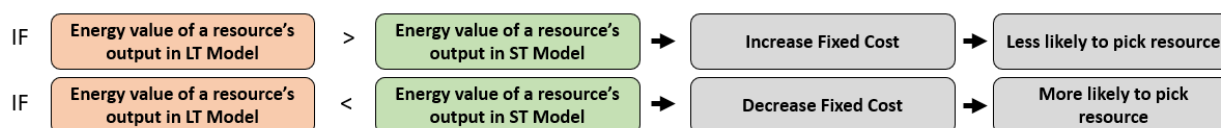
This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

By contrast, in the 2023 IRP, the ST model resource value results were used to inform additional resource selections that were then applied directly in a final run of the ST model. This new iteratively phased approach means that resource selections occur in the LT model using its capacity expansion logic, but with the benefit of the ST model's resource value determinations. Also responsive to stakeholder feedback, a new granularity adjustment is now calculated for every portfolio developed, rather than using one granularity adjustment calculated for each price-policy

scenario. This change, while performance and resource intensive, is responsive to stakeholder concerns regarding the limitations of the prior methodology.

Figure 8.2 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

Figure 8.2 – Granularity Adjustment Determination



This iterative process was conducted for all price-policy scenarios and variant studies. Since each unique granularity adjustment was then fed back into the LT model for the next run, in practice, this means that no two LT model runs have the same granularity adjustment, and each adjustment is wholly dependent upon the performance of resources within that specific portfolio.

Reliability Adjustment Detail

Stakeholders in the 2023 IRP also identified concerns related to the methodology for making reliability adjustments. For the 2025 IRP, in step 3 of each phase, hourly reliability shortfalls are identified by the ST model to be fed back into the LT model to enhance resource selections. As previously noted, the LT model evaluates average conditions during blocks of hours. While this allows the LT model to solve a long horizon in a reasonable time, the average conditions in a block of hours can result in shortfalls in some hours within a block when viewed with hourly granularity. The ST model is able to identify these hours in its evaluation, and these deficiencies are reported by the ST model as hourly shortfalls.

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are now included as an increase in the load forecast. As with the granularity adjustments, these additions are specific to each study's portfolio. However, unlike the granularity adjustment, the shortfall additions to the load file are cumulatively added to the LT need. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours.

In order to avoid diluting singular hourly shortfalls across the entirety of a block, the highest monthly shortfall figure is taken, divided by 4 and applied to each hour in the top ten percent of highest net load hour blocks. The highest shortfall in a month is divided by 4 to avoid overshooting the total amount of resources needed. As an example, suppose the phase zero portfolio (the very first iteration of the six steps for a particular study) reports a maximum shortfall of 400 megawatts in Wasatch Front on June 8, 2032, at 8 PM. The 400-megawatt shortfall is divided by 4 to create a 100-megawatt adder to Wasatch Front load. This 100-megawatt adder is added to the base load file for all of the top ten percent net load hours in Wasatch Front in June of 2032, and phase 1 is run with the adjusted load file. If the portfolio selected in phase 1 reports a maximum shortfall of 100 megawatts in Wasatch Front in 2032, the same process is undertaken and 25 megawatts is added to all ten percent top net load hours, such that the load for that block is now 125 megawatts higher than the original phase zero load forecast. Once no shortfalls are reported by the ST model

(a deterministic run using the base load forecast), the adjusted load file used to select a reliable portfolio continues to be applied so that each later phase includes requirements sufficient to induce the LT model to select a portfolio that is reliable. These adjustments are unique to each price policy scenario/variant.

These reliability and granularity adjustments result in an iterative loop from the LT model to the ST model and back to the LT model, with results that evolve over multiple phases. This process leads to a portfolio that is reliable on a deterministic hourly basis. Additionally, ongoing granularity adjustments will lead to diminishing returns on cost reductions. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios no longer results in additional cost reductions.

Cost and Risk Analysis

Sufficiently reliable resource portfolios developed by the LT model are simulated through stochastics to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. New to the 2025 IRP, stochastic risk modeling of resource portfolios is performed using actual historical conditions as a guide to volatility and stochastic relationships. These conditions, including weather patterns, thermal outages, fuel and market prices, hydro generation, and wind and solar generation profiles, are mapped to historical dates underlying PacifiCorp's chaotic normal load forecast. PacifiCorp has 18 distinct years of historical data and ran each portfolio using each specific historical year for all years of the 21-year horizon.

The reported stochastic results are based on fifty randomized combinations of the forecasted results based on each historical year. In each of the fifty draws, one historical data year is drawn for each of the years of the IRP study horizon (2025-2045). For example, one draw could include 2025 results based on 2006 weather conditions, 2026 results based on 2015 weather conditions, and 2027 results based on 2020 weather conditions. The same randomized historical year draws are used for all portfolios so that all portfolios can be examined on a comparable stochastic basis. Probabilistic analysis therefore depends upon draws from actual historical variance, which is both more volatile and realistic than prior parameterized variance, improving the verisimilitude of outcomes. The results from these runs are used to calculate a risk adjustment which is combined with ST model system costs to achieve a risk-adjusted PVRR to guide portfolio selection.

Responsive to stakeholder feedback, and like consideration made in past IRPs, cases eligible to become the preferred portfolio which report the possibility of significant end-effects are further evaluated to determine if a portfolio represents significant long-term costs or risks compared to other eligible portfolios.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability, resource adequacy, and CO₂ emissions data as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 21-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment step as described above. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO₂ prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

Long-Term (LT) Capacity Expansion Model

In the 2025 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, zero CO₂), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 21-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)⁷ for each load area represented in the model.

The resource portfolios developed using the iterative approach outlined at the beginning of this chapter are appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2025 IRP is based on compliance with the Western Resource Adequacy Program (WRAP) at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2025 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both before and after existing generation resources retire, as well as the years in which to retire existing resources.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2025

⁷ The PLEXOS model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

IRP, each month was split into four blocks of hours based on load, wind, and solar, based on wind and solar generation profiles based on weather conditions during the specific days used to develop PacifiCorp's chaotic normal load forecast:

1. The top ten percent highest net load hours. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
2. The top ten percent highest wind generation hours on a system basis.
3. The top ten percent highest solar generation hours on a system basis.
4. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

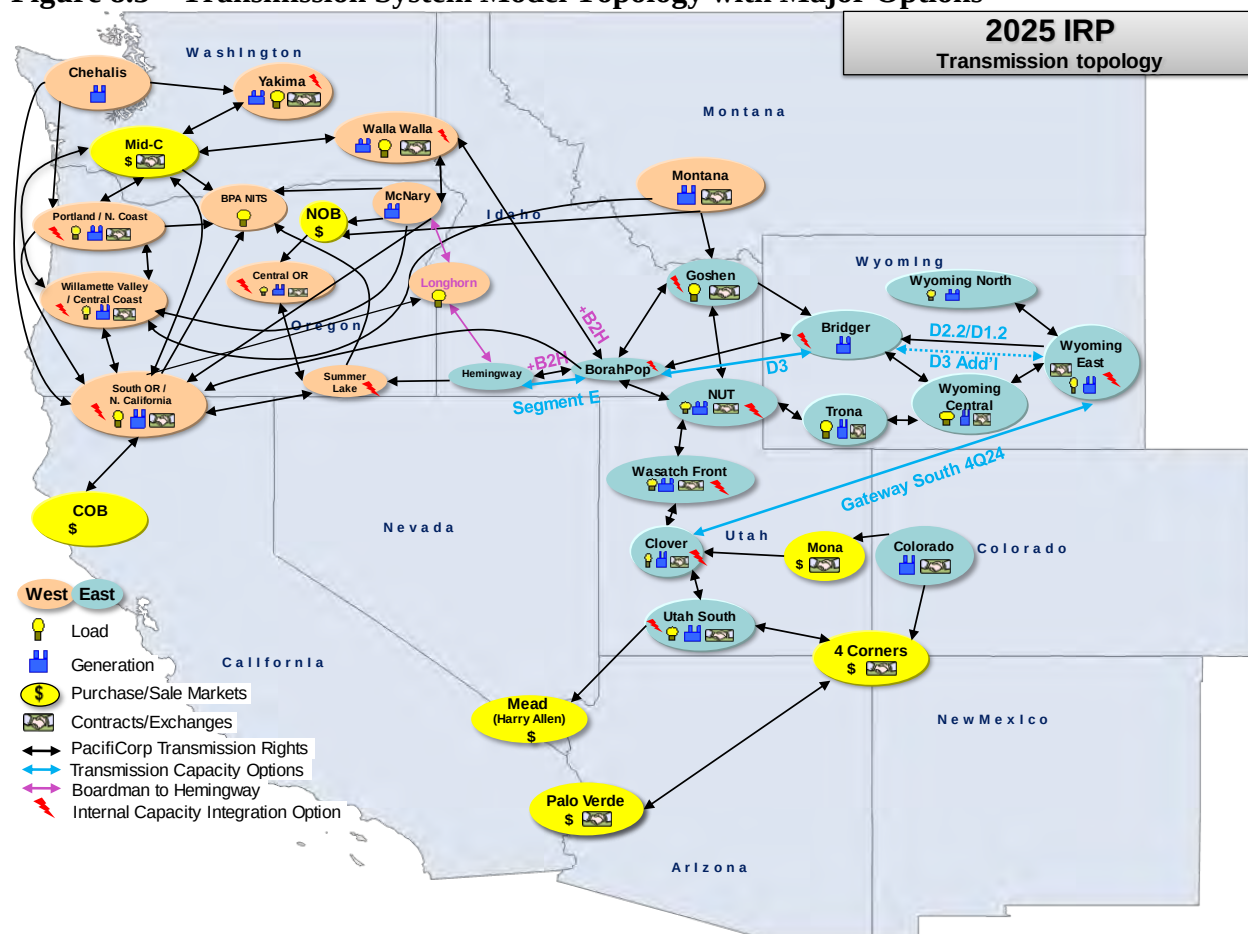
PLEXOS LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, PLEXOS determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths.⁸ Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

⁸ Continued interest was expressed on stakeholder feedback regarding the assumption of a Wyoming market hub to represent the opportunity afforded by certain transmission constraints. In light of the restrictions on the types of market products that can count toward WRAP capacity requirements, PacifiCorp's modeling does not count any short-term market products toward WRAP compliance and has limited market purchases at all points during the highest load conditions in each month, to represent potential market liquidity limits. See Appendix M, stakeholder feedback form #39 (Western Resource Advocates).

Figure 8.3 – Transmission System Model Topology with Major Options

This map is for general reference only regarding IRP topology.

PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Figure 8.3 illustrates the 2025 IRP modeled topology where each transmission area or “bubble” is defined by any load and generation capability, its location on the system and its connections to other bubbles.

Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meetings, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.^{9,10}

“Interconnection” requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be

⁹ Wildfire mitigation in the context of transmission was discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).

¹⁰ Transmission modeling, cluster studies and details of resource-to-transmission relationships were discussed extensively during the 2025 IRP public input meeting series and in stakeholder feedback. See Appendix M, stakeholder feedback form #40 (Renewable Northwest).

impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.
- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Cluster Study 3:** Spring 2023 requests
- **Colstrip:** Interconnection to jointly owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- **Informational Studies:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. For the 2025 IRP, PacifiCorp has transitioned to using cluster studies to indicate the earliest year a resource type is eligible for selection in any given location (as well as using recent cluster study data as compiled by PacifiCorp Transmission to indicate potential transmission upgrades and costs). Cluster studies are described further in Chapter 4.

Surplus Interconnections

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time at that location cannot exceed the original interconnection capacity.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

Transmission Costs

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2025 IRP, PacifiCorp included the monthly planning reserve margin requirements from the Western Resource Adequacy Program (WRAP) in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. While WRAP is expected to enhance reliability, the monthly capacity contribution values assigned to each resource may not be sufficient to meet hourly requirements in every location, so it does not eliminate the need for reliability assessment. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2025 IRP public-input process, the granularity adjustment reflects the difference in economic value in resource options and transmission between an hourly 8760 cost calculation in ST modeling, and the monthly blocking representation used in the LT model.¹¹

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, in a single pass, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger

¹¹ See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon) for responses to questions regarding modeling transmission and granularity adjustments. The method for evaluating granularity value for transmission is the same as for supply-side resources, in that the model reports values used for the granularity adjustments based on the resource's contribution to reducing cost and risk. See also Appendix M, stakeholder feedback form #36 (Sierra Club).

share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

Thermal Resource Options

Continuing best practice from the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection in the 2025 IRP. Other renewable technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when, or whether, they should retire.

Table 8.1 and Table 8.2 report the coal unit options modeled in the 2025 IRP, whereas Table 8.3 summarizes the options available for natural gas-fired units.

Table 8.1 – Majority-Owned Coal Generator Resource Options^{12,13}

Jim Bridger Units 3 and 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)	-	-	-	-	-	Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal-CCS 2030	-	-	-	-	-	CCS+45Q	-	-	-	-	-	-	-	-	-	-	-	CCS	-	-	-
Dave Johnston 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028-2029/Gas Conv. 2029	-	-	-	-	-	Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dave Johnston 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028	-	-	-	-	-	Retired	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dave Johnston 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)	-	-	-	-	-	Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032	-	-	-	-	-	CCS+45Q	-	-	-	-	-	-	-	-	-	-	-	CCS	-	-	-
Wyodak	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)	-	-	-	-	-	Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032	-	-	-	-	-	CCS+45Q	-	-	-	-	-	-	-	-	-	-	-	CCS	-	-	-
Hunter 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)	-	-	-	-	-	Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032	-	-	-	-	-	CCS+45Q	-	-	-	-	-	-	-	-	-	-	-	CCS	-	-	-
Huntington 1-2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)	-	-	-	-	-	Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032	-	-	-	-	-	CCS+45Q	-	-	-	-	-	-	-	-	-	-	-	CCS	-	-	-

Key	Default/current operation	45Q	CCS
	Retirement Option		Alternative Fuel
	Gas conversion option		Assumed retired

¹² While 111(d) compliance can be met with dual fuel operations in 2030-2038, due to engineering uncertainty and modeling complexity, starting in 2030 100% of the fuel input for these options comes from natural gas or alternative fuel. For Hunter and Huntington, which are not located in proximity to natural gas pipeline transport, the alternative fuel modeled in the 2025 IRP is based on the cost of biodiesel, which results in a dispatch price of over \$400/MWh (2024\$).

¹³ After the filing of the 2023 IRP Update on March 31, 2024, a change occurred in the timing of implementation of carbon capture on Jim Bridger Units 3 and 4. CCS assumption for these units is updated for the 2025 IRP. See Appendix M, stakeholder feedback form #5 (Powder River Basin).

Table 8.2 - Minority-Owned Coal Generator Resource Options

Minority-Owned Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Colstrip 3																					
Colstrip 4																					
Craig 1																					
Craig 2																					
Hayden 1																					
Hayden 2																					

Key Default/current operation Assumed retired

Table 8.3 - Natural Gas Generator Resource Options¹⁴

Chehalis	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045																					
Cofire/non-emitting 2030																					
Currant Creek	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045																					
Hermiston 1/2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2039/Alt. Fuel																					
Jim Bridger Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045																					
Lakeside 1	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045																					
Lakeside 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045																					
Naughton Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2026 thru 2045																					
Naughton Unit 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045																					
Gadsby Steam 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045																					
Gadsby CTs 4-6	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045																					

Key Default/current operation Retirement option Assumed retired Alternative Fuel Current (Coal)

New Resource Options

Demand-Side Management

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

¹⁴ PacifiCorp has insufficient detail at this time to evaluate alternative fueling options at its Chehalis and Hermiston natural gas-fired facilities, particularly in light of possible impacts on cost-allocation and market participation and has adopted Action Plan item 1h to advance options for potential implementation by 2030.

Wind and Solar Resources

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources are based on the weather conditions from the same historical days used to develop the load forecast.

The ability for wind and solar resources to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio.

Non-Emitting Resources

Four non-CO₂-emitting thermal resources are considered: nuclear projects, small renewable fuel peaking resources, geothermal resources, and non-emitting hydrogen peaking units leveraging on-site electrolysis with 24 hours of tank storage. Nuclear resources and geothermal are characterized by continuous operation, with the Natrium project combining this operation with storage in the form of heat stored as molten salt. In contrast, peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The small renewable peaking resource for the 2025 IRP is assumed to use biodiesel or renewable diesel, both of which are commercially available. While combustion of these fuels releases CO₂ it is not derived from fossil sources and is eligible to meet compliance requirements in both Oregon and Washington.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period.
- Energy return – energy used to fill (or charge) a storage reservoir.
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or

the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes, income taxes, and demolition costs over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2025 IRP models for a 21-year period beginning January 1, 2025, and ending December 31, 2045. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

Inflation Rates

The 2025 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.18 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2025 through 2045, using PacifiCorp's September 2024 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2025 IRP is 6.38 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.¹⁵ PVRR figures reported in the 2025 IRP are reported in 2024 dollars.

¹⁵ Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

CO₂ Price Scenarios

PacifiCorp used three different CO₂ price scenarios in the 2025 IRP—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG), plus a scenario reflecting compliance with current federal regulations including the currently published EPA rule 111(d). The high greenhouse gas scenario is derived from forecasts of greenhouse gas costs in Washington and California but is applied like a federal obligation throughout the system starting in 2030. Impacts in the scenario which includes current federal regulations also become relevant in 2030, as coal-fired resources must select between retirement, carbon capture, or co-firing by this time.

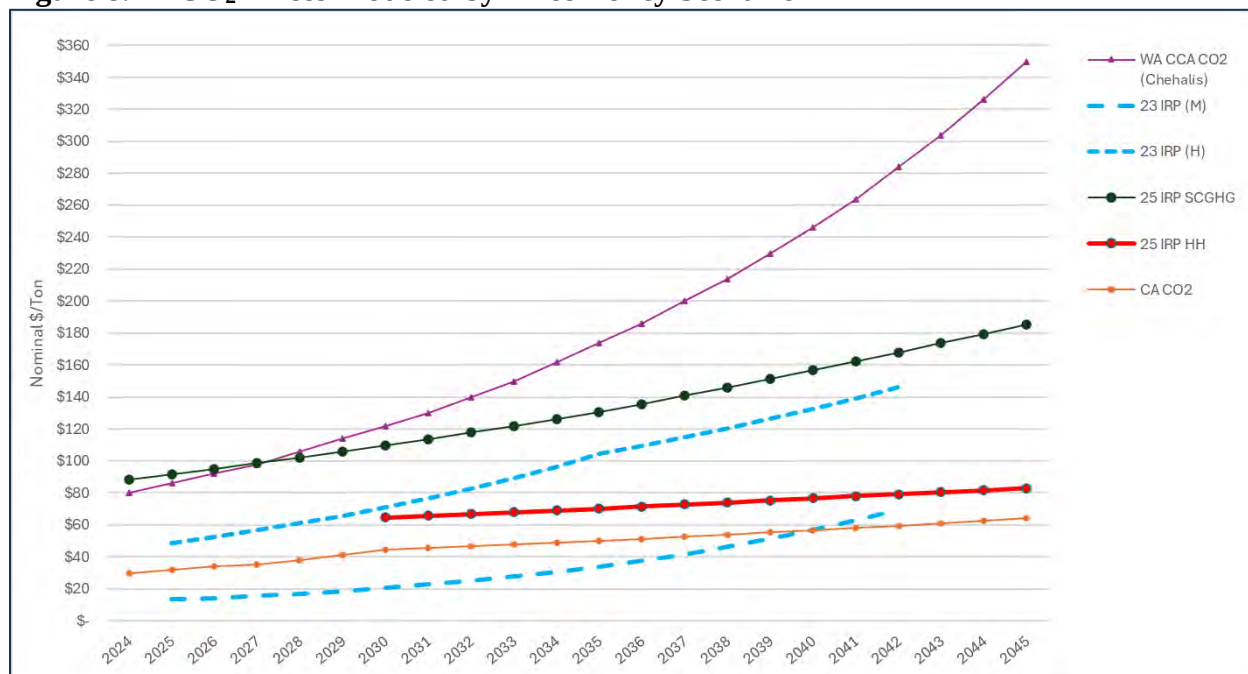
The SCGHG scenario is in compliance with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and Transportation Commission.¹⁶ The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.¹⁷ This is in addition to the assumed federal CO₂ policy represented in the zero, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost is based on the allowance cost cap identified by the Washington Department of Ecology and starts at \$88 metric ton in 2024.¹⁸

¹⁶ Washington Utilities and Transportation Commission, Order 05, Docket No. U-190730, July 25, 2024. Available online at: <https://apiproxy.utc.wa.gov/cases/GetDocument?docID=27&year=2019&docketNumber=190730> (Accessed 11/8/2024).

¹⁷ Stakeholder feedback requested modeling Chehalis without consideration of Washington's Climate Commitment Act. Notwithstanding that certain commissions have declined to allow the company to recover these costs, the company continues to incur these costs, which are therefore modeled. See Appendix M, stakeholder feedback form #19 (Wyoming Office of Consumer Advocate).

¹⁸ Washington Cap-and-Invest Program 2024 Annual Allowance Price Containment Reserve Tier Price and Price Ceiling Unit Price Notice. December 2023. Available online at: <https://apps.ecology.wa.gov/publications/documents/2302066.pdf> (Accessed 11/8/2024).

Figure 8.4 – CO₂ Prices Modeled by Price-Policy Scenario

Wholesale Electricity and Natural Gas Forward Prices

For 2025 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp’s official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp’s 2025 IRP modeling inputs were prepared, the September 2024 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.¹⁹ As such, these 36 months are market forwards as of September 2024. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp²⁰ (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios using high or low gas prices do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also

¹⁹ The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as “balance of month” when the OFPC is released.

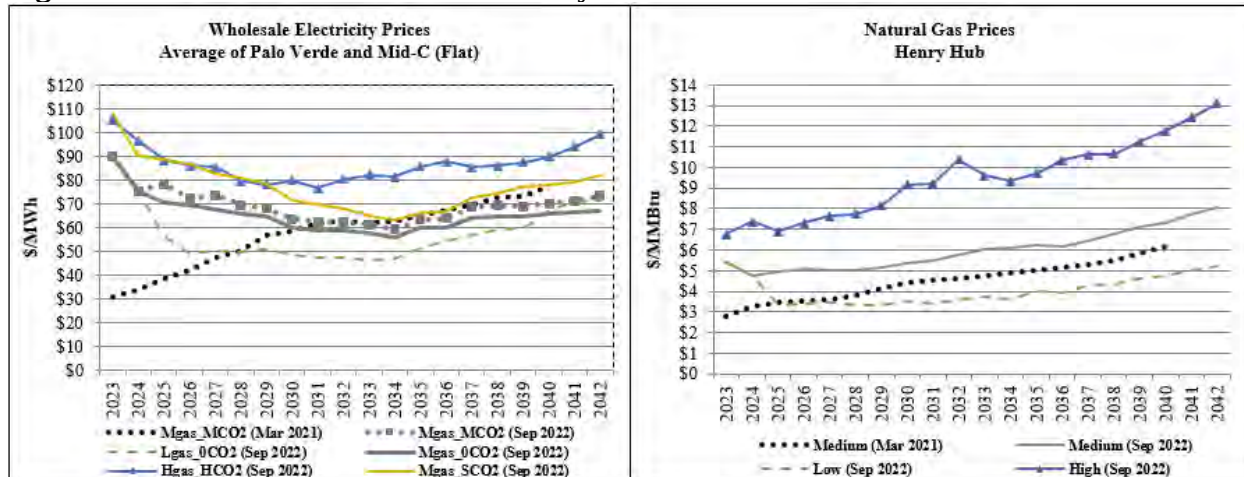
²⁰ AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

derived from an expert third-party forecast. Similarly, the SCGHG scenario does not incorporate any market forwards since that greenhouse gas policy represents an alternative view that applies throughout the study period.

New to the 2025 IRP, in response to stakeholder feedback and requests related to volatility in coal pricing, the high gas and market price-policy scenario also includes an elevated coal fuel supply cost. This represents risks such as supply-chain issues as well as the potential for increased transportation costs or other increased variable coal costs which are not present in the base forecast for coal pricing.²¹ The increased cost calculated for coal pricing was developed by evaluating the percentage difference in the average annual gas prices at Henry Hub between the medium and high cases. Annual percentage differences were then applied to each coal plant's coal supply price over the 21-year horizon.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2025 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model coupled with the portfolio selected by the LT model. LT results provide the initial capacity expansion plan for the ST model to dispatch.

²¹ Coal supply, costs and risks were discussed in the 2025 IRP public input meeting series and stakeholder feedback. In the 2025 IRP, PacifiCorp considers base coal cost assumptions, the Jim Bridger Long-term Fuel Plan sensitivity, and coal-related variant studies. For stakeholder feedback and responses:

See Appendix M, stakeholder feedback form #28 (Utah Citizens Advocating Renewable Energy).

See Appendix M, stakeholder feedback form #29 (Utah Clean Energy).

See Appendix M, stakeholder feedback form #30 (Katie Pappas).

See Appendix M, stakeholder feedback form #31 (Jane Myers).

See Appendix M, stakeholder feedback form #32 (Sara Kenney).

Reliability Assessment and System Cost

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 21 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and the other input assumptions, such as the price-policy scenario.

As discussed at the start of the chapter, these data points are fed back into the LT model to prompt endogenous selections of resources that lead to a reliable portfolio.

Resource Value

PLEXOS calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. PLEXOS also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. PLEXOS then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, utility scale generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options. New for the 2025 IRP, small resources (those with a capacity of fewer than 20 megawatts) are eligible to be sited within any of the load regions and unconstrained by new transmission requirements, as PacifiCorp's studies have shown resources that are sufficiently small and sized consistent with the local grid can be feasible without large transmission investments. Like small resources, PacifiCorp has added a "local" battery option within each of the load areas which is available for selection at a higher cost than those co-located with other resources (per the supply-side resource table). In initial jurisdictional runs, small generator and local battery resources are limited based on the load in each transmission bubble, due to the assumption these are sized to serve local load so as not to require transmission investment.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. Within a transmission constraint, batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

Portfolio Cost

Each run of the ST model produces an optimized dispatch of a portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT model. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual energy not served (ENS)
- Annual CO₂ emissions.

Stochastic Modeling

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. For the 2025 IRP, stochastic risk modeling of resource portfolio alternatives is performed with the ST model.

The standard ST model inputs reflect a normalized view of future conditions and the typical range of outcomes across each month. For stochastic modeling in the 2025 IRP, alternative inputs are used that reflect conditions analogous to actual results in a specific historical year. Stochastic

inputs for the 2025 IRP have been expanded and now include wind and solar generation profiles, along with the energy efficiency profiles for weather-sensitive bundles, in addition to the variables reflected in past IRPs: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

Appendix H (Stochastics) discusses the methodology for developing the stochastic inputs for the 2025 IRP.

Stochastic Conditions

For the 2025 IRP, PacifiCorp has data reflecting eighteen discrete annual conditions, specifically the historical data and variances from 2006-2023 for each of the stochastic inputs. By running eighteen ST model scenarios covering each of these conditions, results can encompass the full range of conditions. However, each of these ST model scenarios represents conditions from a single year repeating in every year of the study horizon, with slight differences from year to year to account for days of the week, plus load growth, climate change impacts on load and hydro, and changes in the resource portfolio. For instance, using historical data based on 2015, every year from 2025-2045 would be a dry hydro year (below average). There are benefits to compiling the results in this way, as it will be easier to identify specific historical weather conditions that are leading to high costs and ENS. But to produce portfolio performance measures, random sampling of the annual results may be appropriate, particularly for assessment of multi-year compliance requirements such as renewable portfolio standards (RPS) and Washington's Clean Energy Transformation Act (CETA).

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the Monte Carlo annual draws include:

- Stochastic mean PVRR
- 5th, 90th and 95th percentile PVRR
- Standard deviation
- Risk-adjustment
- Energy Not Served (ENS)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long-term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO₂ emission costs for any scenarios that include a CO₂ price assumption. The stochastic mean PVRR, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 18 results drawn from the ST runs under 18 distinct stochastic conditions. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 random draws of the 18 runs under stochastic conditions. The production cost is expressed as a net present value of annual costs over the IRP horizon. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The model outcomes of the 50 random draws are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 random draws for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Energy Not Served (ENS)

In past IRPs, the use of the reduced granularity in the PLEXOS MT model limited the relevance of the reported ENS. In the 2025 IRP, the ST model's full 8760 granularity is being reflected in stochastic analysis, so reported ENS is representative of a portfolio's performance in the real-world historical conditions that underlie the stochastic inputs.

Forward Price Curve Scenarios

Preferred portfolio variants developed during the portfolio-development process are analyzed under up to five price-policy scenarios.

Other PLEXOS Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the PLEXOS models. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in normalized and stochastic ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. For the 2025 IRP, PRM and resource contributions based on WRAP are used as part of portfolio selection, but this is not part of resource dispatch. In addition to WRAP compliance, ST reliability modifications to the portfolio evaluate hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level.

Energy Storage Resources

Storage resources have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each PLEXOS model dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO₂ emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity

PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts

To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance

To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 (Modeling and Portfolio Selection Results). Starting in the

2021 IRP, market purchases were restricted compared to past IRPs, as described in Chapter 7 (Resource Options).

Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS, CO₂ emissions, and compliance with state and federal policies. The risk-adjusted PVRR accounts for relative risk of volatility among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include stochastic PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the PLEXOS models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and CO₂ emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2025 IRP, organized here into major development categories:

- Initial Portfolios, including all variants
 - Initial portfolios and variants are evaluated under three distinct sets of jurisdictional requirements:
 - Utah/Idaho/Wyoming/California.
 - Oregon.
 - Washington.

- Integrated Portfolios incorporate selections from the top performing initial portfolios under each set of jurisdictional requirements.
- The preferred portfolio is selected based on the integrated portfolio results.
- Jurisdictional Analysis
- Sensitivity Cases

Additional portfolio detail can be found in Appendix I (Capacity Expansion Results).

Initial Portfolios

Informed by the public-input process, the initial cases explore significant interactions among retirement options including the potential to convert coal units to natural gas or biodiesel operations, install carbon-capture equipment on coal-fired facilities, and retire units during the study horizon. The modeling continues to include a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and zero CO₂ price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of the optimization models within PLEXOS.

Jurisdictional Definitions and Modeling

As discussed above, distinct requirements exist for various jurisdictions, and some of these requires conflict. As a result, initial portfolio modeling is used to separate the requirements as described below, allowing for the development of optimal portfolios of resources to meet jurisdictional needs.

Compared to Oregon and Washington, modeling for Utah/Idaho/Wyoming/California (UIWC) is more focused on least-cost resource selection regardless of fuel type. UIWC resources must meet the Western Resource Adequacy Program (WRAP) requirements for this jurisdiction. As a result, the only modeling constraint for this jurisdiction is one which combines load and requires the model to select enough total resources (including existing resources under current allocation protocols) to meet WRAP planning requirements. All resources are eligible for inclusion in these states and this requirement.

All Washington resource selections are analyzed and optimized assuming the SCGHG price-policy scenario, as required under RCW 19.280.030 for clean energy planning.

Oregon initial portfolios model compliance with House Bill 2021. Oregon participates in existing coal-fired resources through 2029 and existing gas-fired resources (including the gas conversions of Naughton 1 and 2 in 2026 and the endogenously selected conversion of Dave Johnston Units 3 and 4 in 2029) through 2039. Emissions allocated to Oregon from existing resources are calculated based on Oregon's current share of the resources and the appropriate Oregon DEQ emissions factors. Like other jurisdictions, Oregon must be WRAP compliant. PLEXOS models face challenges meeting annual emissions constraints due to the need to model slices of time in each different model (as described earlier in this chapter). This has been addressed by assessing a

shadow price on Oregon allocated emissions as a model driver to ensure HB 2021 compliance is achieved. The shadow price is not reported from the model as a cost to customers, but is instead used to impose a penalty on the model if Oregon allocated resources emit CO₂-E. This price drives the model to reduce emissions (and generation) and select additional resources to meet Oregon load. Compliance for Oregon is measured by determining whether there is enough Oregon-allocated generation to meet Oregon load on an annual basis while also having emissions below the Oregon required thresholds.

Five price-policy scenarios were evaluated in this IRP:

- MN: Medium natural gas/No federal CO₂ regulations
- MR: Medium natural gas/current federal CO₂ regulations under Section 111 of the Clean Air Act.
- LN: Low natural gas/No federal CO₂ regulations.
- HH: High natural gas/High CO₂ cost applied to all generators (updated CO₂ forecast, starting 2030) with no other federal CO₂ regulations.
- SC: Medium natural gas/Social cost of greenhouse gases (starting immediately) from Washington docket U-190730 with no other federal CO₂ regulations.

Table 8.4 provides the price-policy case definitions for the 2025 IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Appendix I (Capacity Expansion Results).

Table 8.4 – Price-Policy Case Definitions

Price-Policy	Existing Coal ^(b)	Existing Gas ^(b)	Other Existing Resources	Proxy Resources ^(c)
MN	Optimized	Optimized	End of Life	All allowed
MR	Optimized	Optimized	End of Life	All allowed
LN	Optimized	Optimized	End of Life	All allowed
HH	Optimized	Optimized	End of Life	All allowed
SC	Optimized	Optimized	End of Life	All allowed

(a) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.

(b) Optimized proxy portfolio selections include renewables, offshore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

In all five price-policy scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021. This cost is incremental to the CO₂ cost included in each price-policy scenario. Where applicable, the price-policy scenarios above represent CO₂ as a cost applicable to all emitting resources, based on the direct emissions associated with the fuel consumed by each generator.

The 2023 IRP included a medium natural gas/medium CO₂ (MM) price-policy scenario. The MM price-policy scenario, which was the price-policy included in the 2023 IRP preferred portfolio, was excluded from the 2025 IRP. In the 2023 IRP, the MM price-policy was included as a proxy to represent potential future federal CO₂ regulations. For the 2025 IRP the MR price-policy scenario, which was not included in the 2023 IRP, encompasses federal CO₂ regulations. This

price-policy scenario was added in response to the final CO₂ regulations issued by EPA on April 25, 2024, which apply to new natural gas-fired combustion turbines and existing coal, oil, and gas-fired steam turbines.

All portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

Certain additional cases were developed based on stakeholder feedback and state requirements to evaluate the impacts of specific future scenarios. These cases are all eligible to be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2025 IRP, there are the following variant portfolio selection cases as shown in Table 8.5.

Table 8.5 – Portfolio Variants

Variant	Description	Refer to Case
No CCS	No coal units are able to select CCS technology	-
No Nuclear	No nuclear resources are eligible for selection	-
No Coal 2032	All coal must retire or convert to gas by January 1, 2032	-
Offshore Wind	Counterfactual to the Preferred Portfolio selection: Offshore wind must be selected	-
No Forward Technology	No nuclear, hydrogen storage, 100-hour storage or biodiesel peaking	-
Geothermal	Counterfactual to the Preferred Portfolio selection: Geothermal must be selected	-
Hunter Retire	Require all Hunter units to retire no later than 1/1/2030	-
All Coal End of Life	Continue 2025 coal technology	See the No CCS variant
No New Gas	No new gas resources allowed	See the Preferred Portfolio
Force All Gas Conversions	Force all coal-to-gas options	See the No Coal 2032 variant

Each variant case begins with the same PLEXOS dataset inputs and assumptions, and adds the constraints to either force a selection, disallow a specific resource or resource type, delay a project or force retirements as outlined below.

No CCS

This variant removes the CCS option at Jim Bridger 3 and 4. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were not a commercially viable

option. This variant was analyzed twice, once using the MN price-policy scenario and once using the MR price-policy scenario.

No Nuclear

This variant removes the Natrium™ demonstration project in 2030 and all other nuclear resources from available resource options. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of the variant is to evaluate resource alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk if nuclear resources are unable to achieve online and operating status for any reason.

No Coal 2032

In this variant all coal plants are assumed to retire no later than 2032. Coal plants are eligible to run past 2032 if gas conversion is selected at that plant. No CCS options are available in this variant. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if external factors required coal plants to cease coal-fired operations by 2032.

Offshore Wind

Offshore wind was available for selection in all portfolios beginning in 2033, based on the timing of necessary transmission upgrades. As offshore wind has not been endogenously selected in the preferred portfolio, a minimum of 1000 MW was required to be selected in this variant. Additionally, the necessary onshore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. This counterfactual is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

No Forward Technology

In this variant all nuclear, hydrogen storage, 100-hour battery, and biodiesel peaking resources are removed from the preferred portfolio and the portfolio is re-optimized without these resource options. The removal of 100-hour battery as an option in this variant is in response to stakeholder request.²² The purpose of this variant is to evaluate the cost and risk impacts of limited new resource types becoming available in the future.

Geothermal Counterfactual

Like the offshore wind case, advanced geothermal units are available for selection in all portfolios in Central Oregon and Southern Utah starting in 2027. These resources require transmission upgrades to be enabled. Pursuant to stakeholder interest²³, as geothermal is not selected for the Preferred Portfolio, a minimum of 707 MW of geothermal resource must be built

²² See Appendix M, stakeholder feedback form #55 (Utah Division of Public Utilities).

²³ See Appendix M, stakeholder feedback form #56 (Utah Clean Energy).

in Central Oregon or Southern Utah. This counterfactual is used to assess system impacts and the magnitude of costs associated with geothermal and its associated transmission requirements.

Hunter Retire

Responsive to stakeholder interest, a variant is considered that forces all three Hunter coal units to cease all operations by 2030.²⁴ This variant forces the retirement of the Hunter Plant in any year from 2028 to 2030. The purpose of this variant is to assess the impact on cost and emissions when Hunter is precluded from continued operation.

All Coal End of Life

The No CCS run selects coal at all current coal sites and does not choose to retire any eligible units. Please refer to the No CCS variant for results.

In this variant all coal plants are assumed to run as coal-fired units using the technology present on the plant as of January 1, 2025, and are not eligible to retire during the study horizon unless otherwise required to do so. Dave Johnston units 1-3 along with Naughton units 1 and 2 still retire or cease coal-fired operation as necessary. Minority owned coal plants are also assumed to retire as necessary for environmental compliance. The purpose of this variant is to evaluate how the preferred portfolio would change if majority-owned coal resources were allowed to run as coal-fired to end-of-life.

No New Gas

The unconstrained integrated MN case does not select new natural gas resources. Please refer to the Preferred Portfolio for results.

This variant assumes no new gas resources are allowed to be selected. This does not include the conversion of coal plants from coal-fired to gas-fired. The purpose of this variant is to evaluate the cost and risk impacts of replacing new gas resources selected in the preferred portfolio with other energy resources.

Force All Gas Conversions

The No Coal 2032 selected all plants eligible for gas conversion. Please refer to the No Coal 2032 variant for results.

In this variant all coal plants eligible for gas conversion are forced to do so. The gas converted coal plants are allowed to retire endogenously, and the portfolio is re-optimized. The purpose of this variant is to evaluate the cost and risk impacts associated with gas conversion becoming the only future option for all coal-fired plants. Hunter and Huntington, which are not eligible for gas conversion, were eligible for alternative fuel conversion but were not forced to convert.

Integrated Portfolios

Portfolio integration involves combining resource selections from each of the initial jurisdictional portfolio results under a given price-policy scenario or variant. Every initial jurisdictional portfolio

²⁴ See Appendix M, stakeholder feedback form #53 (Sierra Club).

evaluates the entire system and all proxy resource options, plus the constraints specific to that jurisdiction. For proxy resources that can be allocated to any jurisdiction, the integration step adopts the largest quantity of each individual resource by year that was included in any of the jurisdictional studies, identified as 1) “UIWC” for Utah, Idaho, Wyoming and California, 2) “OR” for Oregon and 3) “WA” for Washington. Because of interconnection limits, it is generally not possible to sum the selections across the various jurisdictions, and the overall quantity might not be economic. For resources that are specific to a single jurisdiction, including demand-side resources and existing thermal resources, the integration step adopts the quantity from that specific jurisdiction’s initial portfolio result. Given concerns related to the availability of transmission on an hourly basis between the West and East sides of PacifiCorp’s system, the selection of proxy resources on the West is determined jointly by the Oregon and Washington initial jurisdictional portfolios, and the selection of proxy resources on the East is determined by the initial jurisdictional UIWC portfolio. Accordingly, only the jurisdictional portfolios that determine the selection of a given resource are eligible to participate in that resource.

Table 8.6 – Portfolio Integration Resource Example

Jurisdiction	Fixed Share	Initial Portfolio Selection (MW)	Total Allocation (MW)
Oregon	75%	150	112.5
Washington	25%	60	37.5
Total	100%		150

In this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time. Where a proxy resource has additions in multiple years, only the quantity added in a given year is allocated, based on portfolio selections in that year. This integration process is applied to every initial portfolio.

The initial integration step has the potential to result in compliance shortfalls, as a portion of the resources that were identified for compliance may be shared with other jurisdictions. Thus, the final step of the integration process is to identify and remedy any such shortfalls in energy and capacity compliance.

Washington Portfolios

The integrated preferred portfolio reflects Washington customer energy and capacity needs and the CETA clean energy standards from 2030 onwards. The final integrated portfolio presents a CETA-compliant path towards the production of a quantity of clean megawatt hours that meets Washington’s retail sales on an annual basis, as described in further detail in Appendix O (Washington’s Clean Energy Action Plan). This CETA-compliant portfolio is a starting point for the analysis that will be provided in the forthcoming 2025 Clean Energy Implementation Plan (CEIP), expected to be filed with the Washington Utilities and Transportation Commission in October 2025.

The focus of this IRP filing is to present an integrated preferred portfolio that meets all state-specific requirements. As described in this chapter and further in Appendix O the IRP preferred portfolio presents a strategy to get to a portfolio that is optimized to meet Washington CETA clean energy standards over the next twenty years. The following scenarios and sensitivities required by Washington rule are also included.

Per WAC 480-100-620(10): the IRP must also include a range of possible future scenarios and input sensitivities. These include:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to “describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply” with CETA’s Clean Energy Transformation Standards. This case is comparable to the initial SCGHG price-policy scenario study but includes Washington-specific capacity requirements based on WRAP. This sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.
- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to “incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change.” Please see Appendix A for additional detail regarding how climate change is incorporated into the base load forecast. Climate change impacts are also incorporated in the base hydro forecast. Because the base forecast includes climate change, all the IRP analysis reflects impacts related to climate change and a separate sensitivity to include these impacts is not necessary.
- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to “model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals.” The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp’s Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission options and relies on increased small-scale renewables. Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

Sensitivity Case Definitions

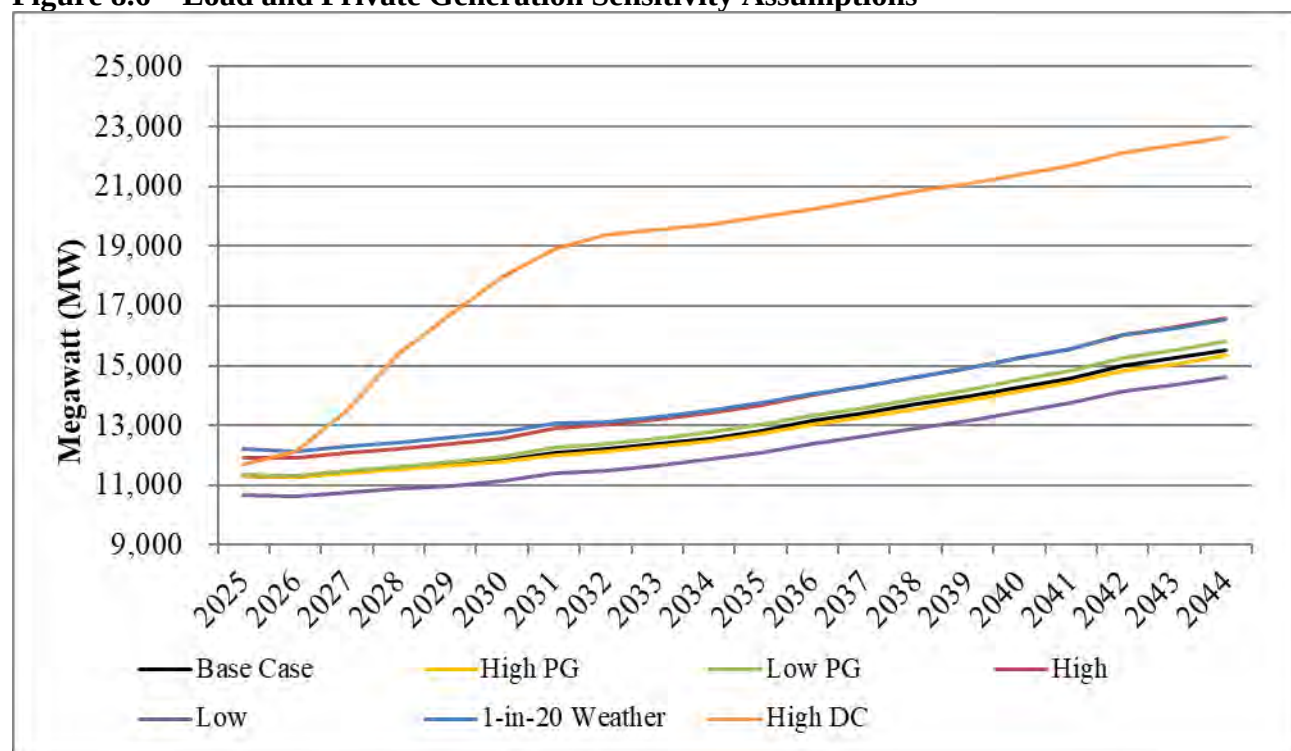
PacifiCorp identified a variety of sensitivities outlined in Table 8.7 and discussed further in Chapter 9.

Table 8.7 – Sensitivity Case Definitions

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20-year highest load
High Private Generation	Assumes lower load due to high private generation adoption
Low Private Generation	Assumes higher load due to low private generation adoption
Large Metered Load Growth	Assumes significant large-metered customer load growth
Low-Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at additional coal units
Business as Usual	Portfolio if no state requirements existed
Business Plan	First 3 years are aligned with the current business plan

Load Sensitivities

The 2025 IRP includes several sensitivities related to load forecast assumptions. Figure 8.6 provides a comparison of load by year for each case, including the base assumption for comparison. Definitions for all sensitivities are then discussed individually, below.

Figure 8.6 – Load and Private Generation Sensitivity Assumptions

High Load Growth

In this sensitivity the base load forecast is replaced with a high load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher loads.

Low Load Growth

In this sensitivity the base load forecast is replaced with a low load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of lower loads.

1 in 20 Peak Load

In this sensitivity the base load forecast based on median load conditions (exceedance in 10 of 20 years) is replaced with a higher load forecast based on peaks that reflect an expected 1 in 20 year exceedance level. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher peak loads.

High Private Generation

In this sensitivity the base load forecast is replaced with a new load forecast incorporating high private generation adoption which reduces load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with high private generation adoption.

Low Private Generation

In this sensitivity the base load forecast is replaced with a new load forecast incorporating low private generation adoption which increases load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with low private generation adoption.

Large-Metered Load Growth

In this sensitivity the base load forecast is replaced with a new load forecast incorporating high large-metered load growth. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of this future. A variety of transmission upgrades are necessary to meet the significant load increases contemplated in this sensitivity, including B2H. This portfolio uses the same integration process as the preferred portfolio to address any state compliance shortfalls.

Low-Cost Renewables

This sensitivity assumes high IRA/IIJA adoption results in significant cost reductions for PTC/ITC eligible resources, making them more likely to displace non-PTC/ITC eligible resources. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how the availability of lower cost renewables might impact cost and risk.

Low PTC and ITC Eligibility

This sensitivity assumes IRA/IIJA changes result in PTC and ITC eligibility ending in 2030. Resources coming online after 2030 do not have the cost reductions associated with PTC and ITC. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how lower than anticipated IRA/IIJA eligible resource availability might impact cost and risk.

All CCS

This sensitivity allows CCS to be selected at Wyodak, Hunter Units 1-3, Huntington Units 1 and 2, and Dave Johnston Unit 4, in addition to the option of CCS at Jim Bridger Units 3 and 4. , This sensitivity relies on the assumption that it is feasible to complete installations at all of these units prior to 2032. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were a commercially viable option at more than one coal site before 2032.

Business As Usual²⁵ (No Pending Legislation or State Requirements; Locked Coal Assumptions)

In this sensitivity, all pending legislation and state requirements are removed so that the only obligations to be met are load and federal policy obligations. Coal outcomes are also set so that coal plants retire no earlier than assumed in the 2017 IRP Update except to the extent that updated commitments or requirements supersede the older assumptions. The portfolio is otherwise fully endogenous. The purpose of this variant is to evaluate how the preferred portfolio would change if no potential state requirements or early economic retirements were considered.

Business Plan Sensitivity

The unconstrained integrated MN case does not select new resources in the first three years, please refer to the Preferred Portfolio for results.

In the 2025 IRP, this case has the same assumptions as the integrated preferred portfolio. For this reason, no additional sensitivity is needed. The case complies with the Utah requirement to perform a business plan sensitivity consistent with the commission’s order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp’s current Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the PLEXOS models.

²⁵ Per the Wyoming Public Service Commission’s (WPSC) 2019 Investigation Order (DOCKET NO. 90000-144-XI-19, and DOCKET NO. 90000-147-XI-19), “reference case” is the formal terminology for the business-as-usual study. Regarding this study, the WPSC mandates the following:

“In the anticipated 2021 IRP, and in IRPs and updates thereto filed by the Company thereafter, Rocky Mountain Power shall:

a) Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and only incorporate environmental investments or costs required by current law”

This case was the subject of stakeholder feedback and discussion in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #35 (Wyoming Energy Authority).

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

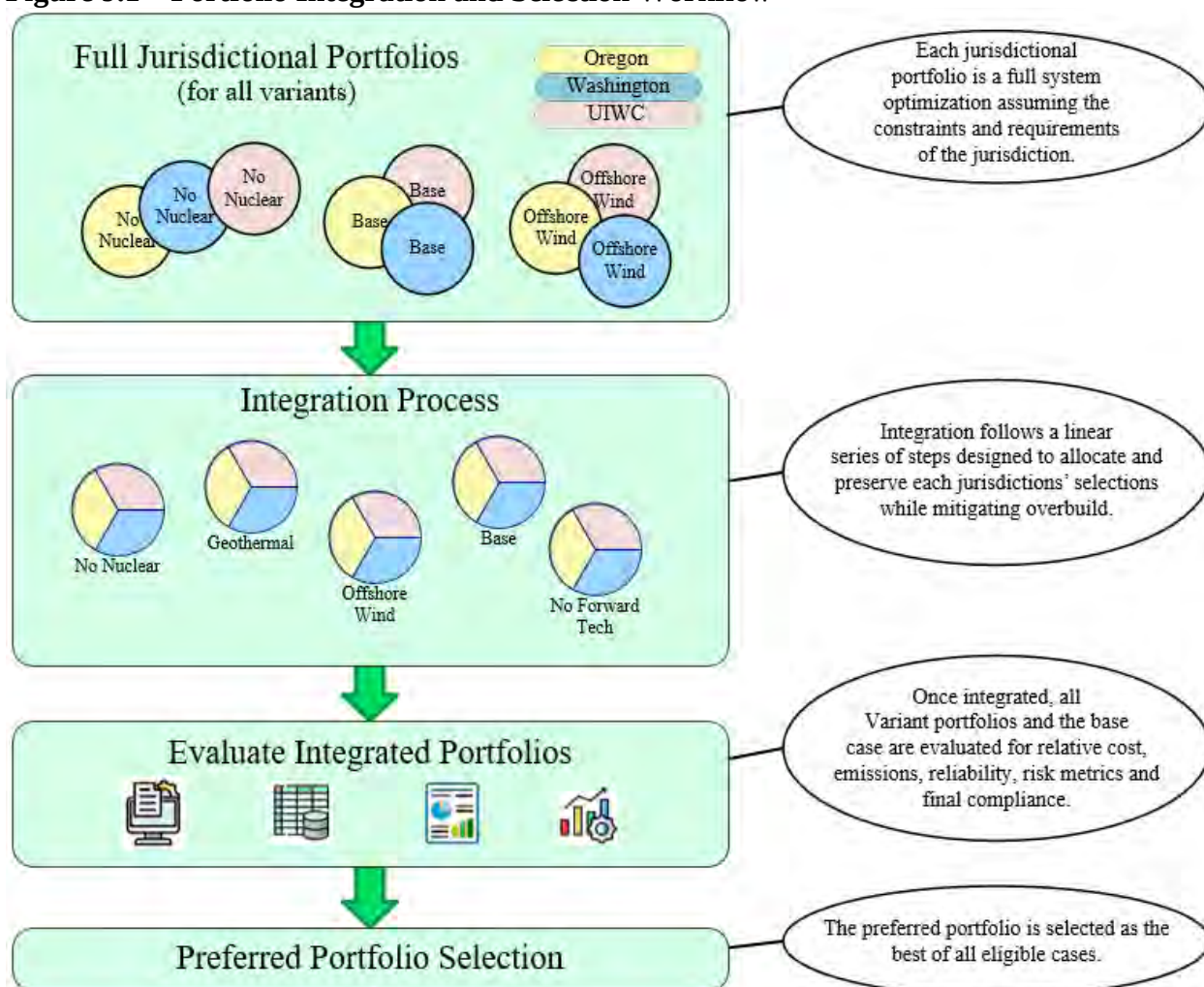
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp’s selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio includes continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The 2025 IRP preferred portfolio builds upon resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that forthcoming RFPs as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by the end of 2031. Over the planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind, and 5,912 MW of new solar, of which 1,147 MW is small-scale.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, and additional upgrades that increase transfer and interconnection capability on the west side of PacifiCorp’s system.
- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation were converted to natural gas where the option was available.
- In the 2025 IRP, four factors related to emitting resources drive a reduction in CO₂ emissions after 2025. These factors are retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities (influenced by additions of renewable resources and energy storage), and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially because of renewable resource additions but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp’s preferred portfolio selection process and presents the 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. As illustrated in Figure 9.1, the final preferred portfolio selection is informed by all relevant modeling results.

Figure 9.1 – Portfolio Integration and Selection Workflow



This chapter also presents discussion of Oregon’s compliance position in the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp’s portfolio evaluation processes. Stochastic analysis is also discussed in Volume II, Appendix H (Stochastics).

Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction’s results for integration. Table 9.1 below shows the various phases of the Oregon MN initial jurisdictional run to show how iterative jurisdictional portfolios were evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase was selected for integration. In Table 9.1, phase 17 was selected as the Oregon initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of \$26,298 million, and the stream of unserved energy costs that led to a total cost of \$0 and had no unserved energy after 2027. Other phases which were considered were phase 11, phase 15, and phase 5, however the higher PVRR of phases 15 and 5, and the fact that phase 17 was more WRAP compliant than phase 11 led to phase 17 being selected.

Table 9.1 – Iterative phases of Oregon MN portfolio

Phase	Jurisdiction	Price-Policy	21 Year PVRR	Unserved Energy Cost
0	OR	Medium Gas, No CO2	26,108	1
1	OR	Medium Gas, No CO2	26,809	0
2	OR	Medium Gas, No CO2	26,314	0
3	OR	Medium Gas, No CO2	26,353	1
4	OR	Medium Gas, No CO2	26,405	0
5	OR	Medium Gas, No CO2	26,372	0
6	OR	Medium Gas, No CO2	26,370	1
7	OR	Medium Gas, No CO2	26,343	0
8	OR	Medium Gas, No CO2	26,442	1
9	OR	Medium Gas, No CO2	26,365	0
10	OR	Medium Gas, No CO2	26,498	2
11	OR	Medium Gas, No CO2	26,298	0
12	OR	Medium Gas, No CO2	26,461	1
13	OR	Medium Gas, No CO2	26,366	0
14	OR	Medium Gas, No CO2	26,447	1
15	OR	Medium Gas, No CO2	26,361	0
16	OR	Medium Gas, No CO2	26,388	2
17	OR	Medium Gas, No CO2	26,298	0
18	OR	Medium Gas, No CO2	26,463	1
19	OR	Medium Gas, No CO2	27,058	0

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal CO₂ policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy CO₂ policy assumptions, resulting in uniquely optimized combinations of resources, transmission, and thermal retirement options.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and preferred portfolio selection also include an assessment of compliance with CETA and Oregon’s HB 2021.

Jurisdictional Shares of the Preferred Portfolio

Table 9.2 through Table 9.4 present each jurisdiction’s assumed *share* of total preferred portfolio resources as contained in the integrated preferred portfolio. These shares are based on the results of full jurisdictional portfolios that reflect planning requirements specific to the different jurisdictions, as discussed in the next section. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

Table 9.2 – Oregon Share^{1, 2, 3}

OR Shares by Resource Type and Year, Installed MW																						
Resource	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	40
DSM - Energy Efficiency	-	-	97	101	107	114	115	110	113	108	109	111	110	106	102	116	123	107	114	92	90	2,044
DSM - Demand Response	-	0	-	48	16	7	-	5	1	3	3	11	-	11	4	23	4	-	9	-	8	153
Renewable - Wind	-	-	-	16	445	939	-	1	-	22	260	30	131	28	0	282	37	-	15	-	72	2,278
Renewable - Utility Solar	-	-	-	167	135	1,268	136	180	302	169	10	-	0	0	416	78	9	-	-	148	56	3,074
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	0	309	-	-	110	-	-	143	36	1,147
Renewable - Battery, < 8 hour	-	-	1	280	100	128	-	119	39	210	20	47	-	46	-	107	55	-	-	-	-	1,152
Renewable - Battery, 24+ hour	-	-	-	-	-	272	88	-	-	-	-	-	7	79	33	934	102	210	397	192	353	2,667
Potential Solar Acceleration²				794	(794)																	

Table 9.3 – Washington Share⁴

WA Shares by Resource Type and Year, Installed MW																						
Resource	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	0	13	16	15	17	18	18	19	19	20	19	19	15	14	12	11	11	10	8	7	280
DSM - Demand Response	-	0	-	15	2	2	-	-	-	-	-	8	-	6	1	1	1	-	1	-	14	51
Renewable - Wind	-	-	-	5	148	313	-	-	-	7	87	10	44	9	0	94	12	-	5	-	24	758
Renewable - Utility Solar	-	-	-	56	45	423	45	60	101	56	3	-	0	0	139	26	3	-	-	49	19	1,025
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
Renewable - Battery, < 8 hour	-	-	-	865	114	168	-	-	-	-	-	-	-	129	67	7	12	-	5	-	-	1,367
Renewable - Battery, 24+ hour	-	-	-	-	-	238	3	3	4	3	4	4	4	4	4	4	4	5	5	5	5	298
Potential Solar Acceleration⁴				212	(212)																	

¹ See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).

² While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving compliance with Oregon's clean energy compliance requirements, PacifiCorp's 2025 CEP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.2. For more details, please refer to Appendix P (Oregon Clean Energy Update)

³ Planned Energy efficiency and demand response selections in 2025 and 2026 are not presented in Tables 9.2 through 9.4.

Table 9.4 – Utah, Idaho, Wyoming, and California Share

UIWC Shares by Resource Type and Year, Installed MW																							
Resource	Installed Capacity, MW																						
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total	
Nuclear	-	-	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338	
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
DSM - Energy Efficiency	-	0	99	103	117	130	196	163	167	168	170	185	218	193	177	172	170	197	114	106	86	2,931	
DSM - Demand Response	-	1	-	-	2	111	99	-	-	-	-	2	112	-	-	0	57	106	19	26	30	566	
Renewable - Wind	-	-	-	-	200	200	344	-	-	-	-	-	0	-	-	-	-	-	-	-	-	744	
Renewable - Utility Solar	-	-	-	-	-	-	668	-	-	-	-	-	0	-	-	-	-	-	-	-	-	668	
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Renewable - Battery, < 8 hour	-	-	1	-	27	-	-	-	-	-	-	-	0	-	-	-	-	713	-	459	733	1,933	
Renewable - Battery, 24+ hour	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	105	

Full Jurisdictional Portfolios

Each jurisdiction’s resource selections begin with a view of the entire system as optimized under that jurisdiction’s particular constraints. These idealized views of the system allow each jurisdiction’s preferred resource selections to be identified. These portfolios are referred to as the ‘full jurisdictional portfolios’ and show the selections prior to integration.

The following portfolios shown in Table 9.5 through Table 9.7 report the entirety of each jurisdictional portfolio’s selections when planning for the entire system, which were then integrated into the preferred portfolio. This same integration process is used to develop integrated portfolios specific to each variant and price-policy scenario, and the preferred portfolio is selected based on the results for the integrated portfolios.

⁴ While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving CETA compliance, PacifiCorp’s 2025 CEIP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.3. For more details, please refer to Appendix O (Washington Clean Energy Action Plan)

Table 9.5 – Oregon Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
Resource	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency	92	89	201	209	220	237	306	280	283	280	300	309	333	303	283	291	266	286	252	230	189	5,239
DSM - Demand Response	18	2	-	53	17	9	53	5	1	3	3	11	259	15	50	23	4	100	9	50	25	710
Renewable - Wind	-	-	-	21	260	1,066	100	51	-	29	347	40	175	37	-	376	50	-	20	-	96	2,668
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	122	99	1,871	19	220	315	225	13	-	-	-	554	104	12	-	-	197	75	3,826
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	876	255	228	31	119	39	210	20	83	-	104	100	314	58	-	2	-	-	2,439
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	224	-	-	-	-	-	241
Renewable - Battery, 24+ hour	-	-	-	-	-	134	-	-	-	-	-	-	-	59	4	752	128	-	341	-	59	1,477
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,949)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
Coal - Gas Conversions	-	46	-	-	-	687	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	315
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(79)
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	110	153	201	1,026	523	3,444	302	1,193	664	765	713	575	667	795	1,008	2,084	249	(140)	581	387	(18)	

Table 9.6 – Washington Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
Resource	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	224	235	215	234	289	287	291	290	316	323	356	324	304	293	278	302	268	234	186	5,430
DSM - Demand Response	18	2	2	197	5	17	-	-	-	-	-	43	-	17	24	8	5	331	31	27	107	834
Renewable - Wind	-	-	-	-	1,607	-	260	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1,868
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	201	138	463	1,437	770	527	418	772	249	100	1	-	-	-	-	-	-	-	5,076
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	38	856	232	1,376	-	-	-	-	-	-	-	129	67	66	129	149	646	170	1,357	5,215
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(906)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(2,679)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,241)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(526)	0
Coal - Gas Conversions	-	311	-	-	205	1,979	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	(448)	1,717
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	110	418	264	548	2,074	1,669	1,447	1,558	818	705	1,088	615	356	439	395	367	14	782	898	198	656	

Table 9.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

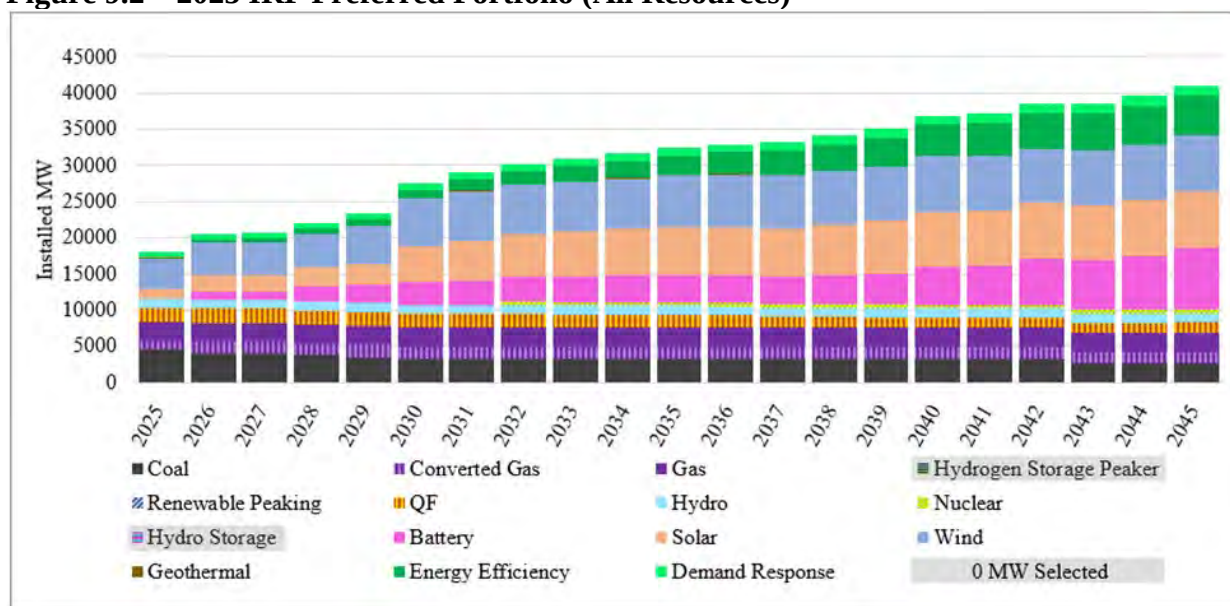
Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
Resource	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	164	170	182	196	270	236	247	251	261	286	312	284	278	257	252	283	216	200	165	4,691
DSM - Demand Response	18	2	-	2	7	112	99	-	-	-	5	39	115	3	-	4	70	106	43	30	32	687
Renewable - Wind	-	-	-	-	306	684	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,334
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	153	12	79	668	-	31	123	133	3	-	-	-	2	-	-	-	65	-	1,269
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	193	71	224	-	-	-	-	85	171	4	474	249	140	469	713	896	1,097	733	5,519
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	104
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
Coal - Gas Conversions	-	251	-	-	144	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	239
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(5)	-	(52)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	110	358	164	263	394	874	1,172	736	278	371	484	499	331	729	527	403	393	1,206	426	1,157	910	

The 2025 IRP Preferred Portfolio

The preferred portfolio is selected from among all of the variant and price-policy portfolios after integration. PacifiCorp’s selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.2 shows that PacifiCorp’s 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear. The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources are scheduled to come online in the 2024 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by fall 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912 MW of new solar.

Figure 9.2 – 2025 IRP Preferred Portfolio (All Resources)



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp’s existing resource mix and were not selected for the preferred portfolio.

New since the 2023 IRP, the 2025 IRP preferred portfolio includes a number of smaller incremental upgrades to enhance transfer capability, including lines between southern Utah and the Wasatch Front in Utah, Walla Walla and Yakima in Washington, Walla Walla and Deschutes County in Oregon, and Summer Lake and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp’s “cluster study” process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Eight out of the fourteen transmission selections are expected to increase interconnection capability only, while the other six transmission selections provide both interconnection capability and increased transfer capability among the transmission areas modeled in the IRP. Table 9.8 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio.

Table 9.8 – Transmission Projects Included in the 2025 IRP Preferred Portfolio ^{1,2}

	Export (MW)	Import (MW)	Interconnect (MW)	Build Investment (\$m)	Build (%)	From	To
2026 Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028 Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	Summer Lake	Hemingway
Cluster 1/2/3: Walla Walla	0	0	393	328	100%	n/a	n/a
Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
Serial/Cluster 1/2: Yakima	0	0	628	64	100%	n/a	n/a
Utah South - Wasatch Front: 138 kV reinforcement #2	200	200	200	12	100%	Utah South	Wasatch Front
2029 Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030 Cluster 2 Area 19: Summer Lake to Central Oregon 500 kV	1,500	1,500	670	1,283	100%	Summer Lake	Central OR
Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031 Serial through Cluster 1 Area 13: Southern Oregon	0	0	231	42	100%	n/a	n/a
2032 Cluster 1 Area 12: Southern Oregon	0	0	300	303	100%	n/a	n/a
2033 Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	518	372	100%	n/a	n/a
2039 Walla Walla - Central Oregon 500 kV	1,500	1,500	670	1,463	100%	Walla Walla	Central OR
Grand Total	4,250	4,250	5,404	4,169			

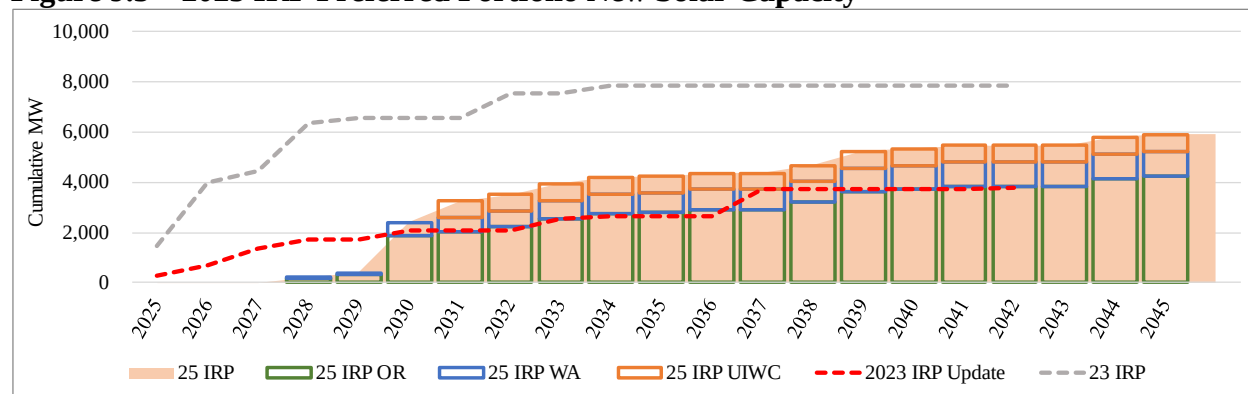
¹ Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

² Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 9.3.

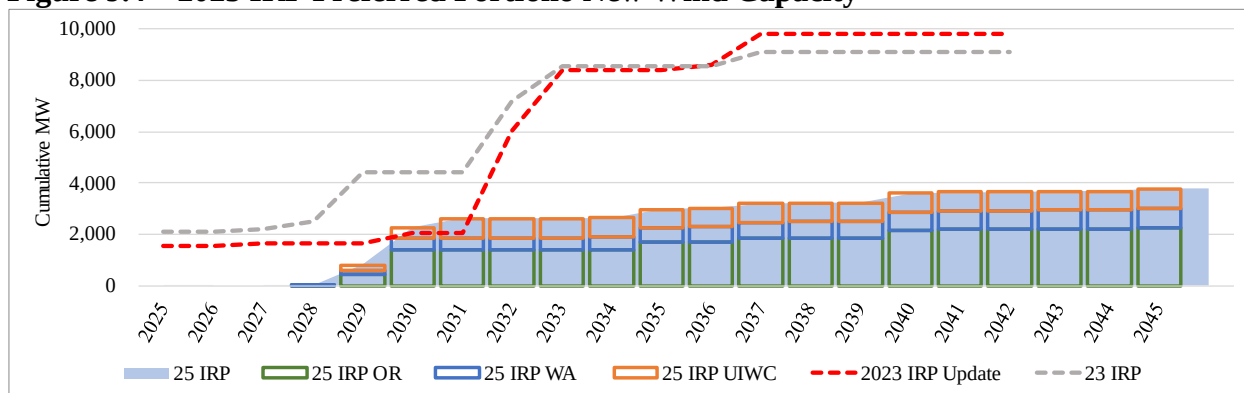
Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 9.4, PacifiCorp’s 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

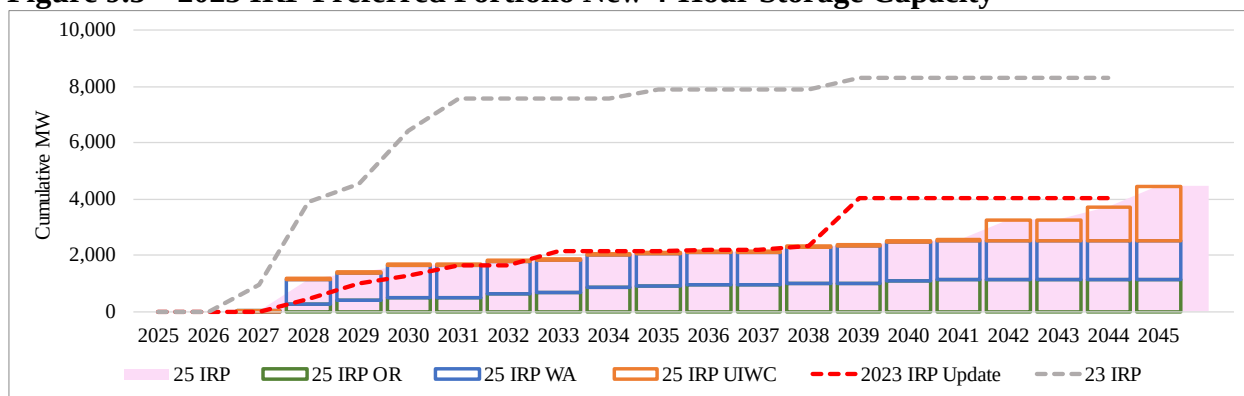
Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

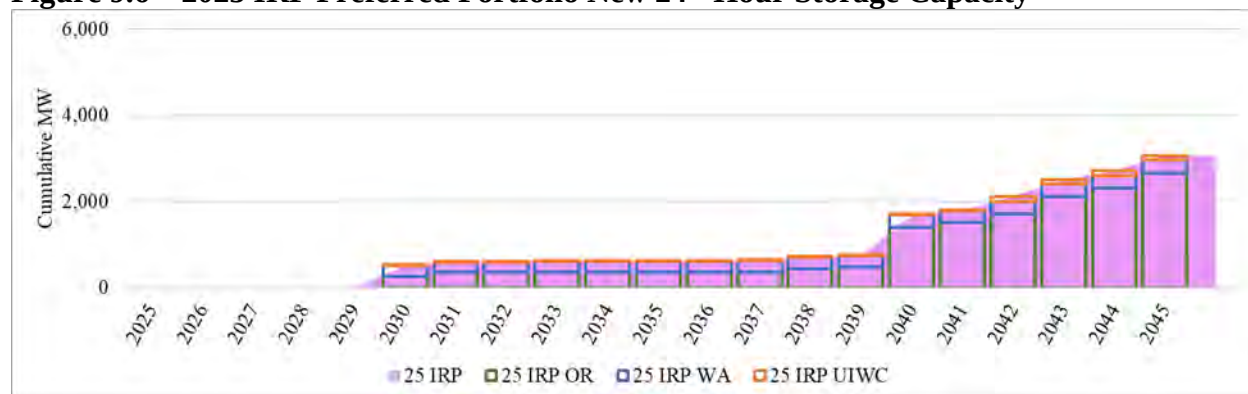
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 9.5 and 9.X. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of storage with at least 24 hours duration by the end of 2030 and growing to 616 MW by 2035 and 3,073 MW by 2045. Cumulative storage selections, inclusive of both short and long duration resources, total 7,524 MW by 2045.

Figure 9.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity^{1,2}



¹ The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not categorized as new storage capacity in the 2025 IRP.

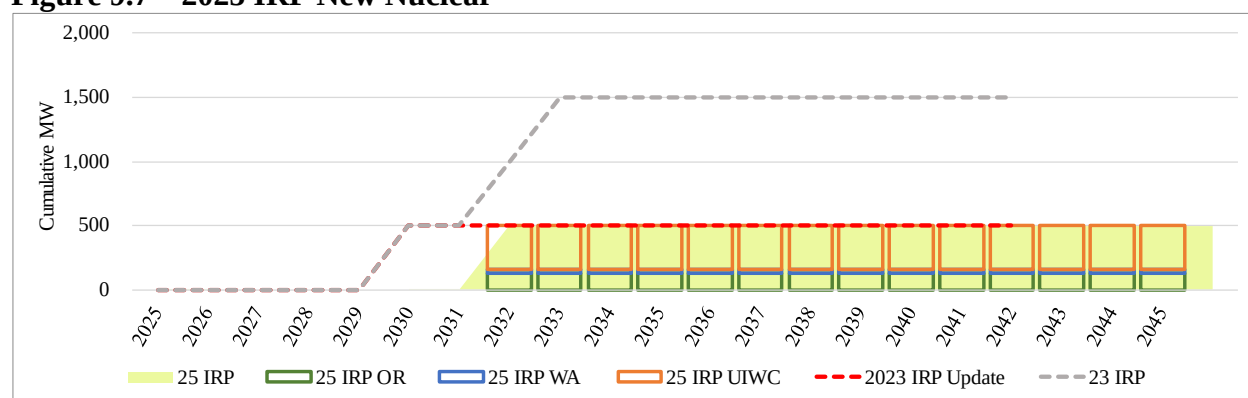
² The 2023 IRP and 2023 IRP Update totals shown in Figure 9.5 include a minimal amount of intermediate duration storage.

Figure 9.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity¹

¹The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

New Nuclear Resources

The 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.7, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by fall 2031.

Figure 9.7 – 2025 IRP New Nuclear¹

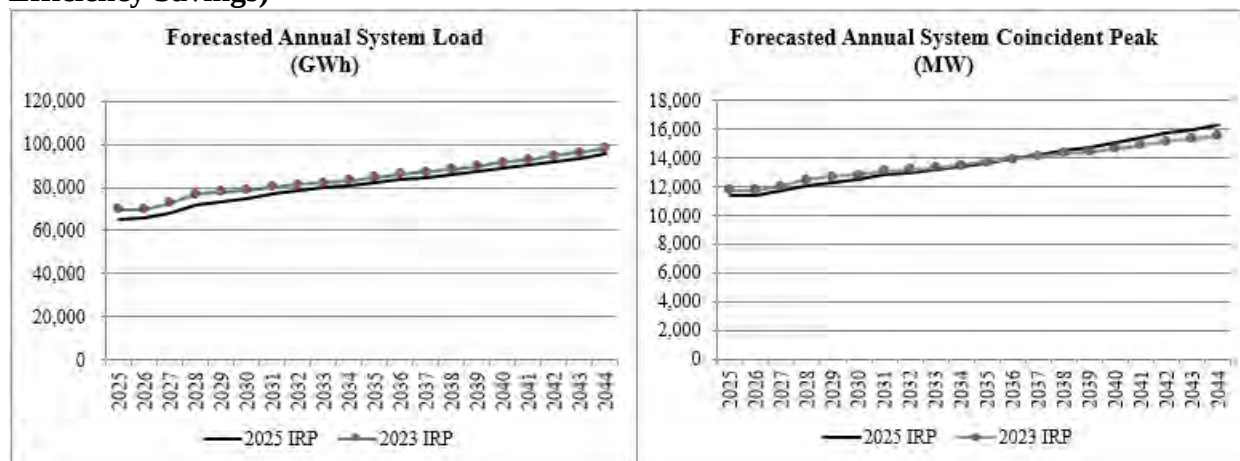
¹ While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.8 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over

the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp’s load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources, thus lowering the commercial forecast.⁵

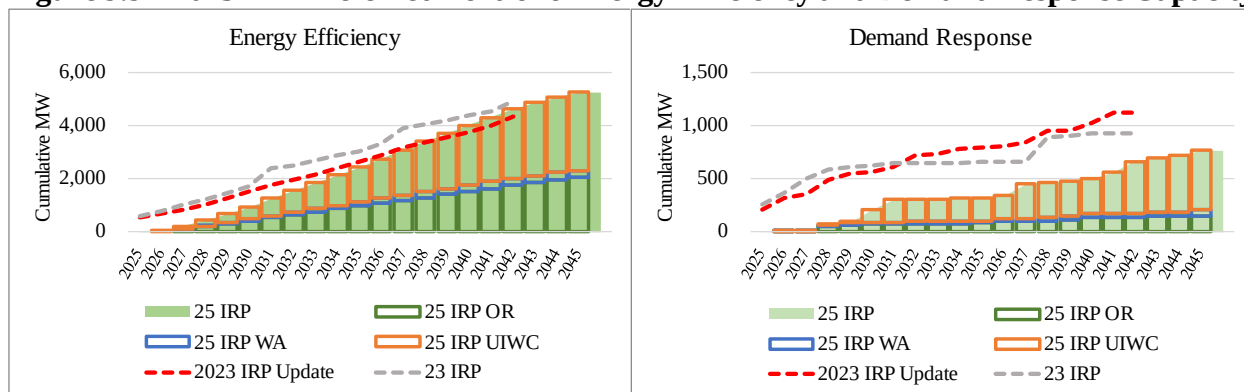
Figure 9.8 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp’s resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 IRP preferred portfolio totals 5,436 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.9 compares cumulative demand response program capacity in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2025 IRP has a cumulative capacity of demand response programs totaling 515 MW by 2040. By year-end 2045, the 2025 IRP preferred portfolio has a cumulative capacity of demand response programs totaling 789 MW.

⁵ A different approach is needed to protect existing customers from sizeable resource and transmission infrastructure investment costs associated with certain new large loads. Consequently, these loads fall outside of the traditional planning process. Should those loads materialize, we are working with certain large customers to ensure they can bring sufficient resources and are prepared to pay for the incremental transmission upgrades required to serve them.

Figure 9.9 – 2025 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity

¹ Energy efficiency and demand response in the 2023 IRP began escalating two years prior to when escalation begins in the 2025 IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP, the end of the planning horizon.

Wholesale Power Market Prices and Purchases

Figure 9.11 illustrates that the 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 9.11 reports that the 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Market transactions in the 2025 IRP are purely economic as market purchases do not contribute to capacity like they did in the 2023 IRP and 2023 IRP Update. In the 2023 IRP and 2023 IRP Update, market purchases were limited to 1,000 MW in the winter and 500 MW in the summer. For the 2025 IRP, economic market purchases for energy could be made up to transmission limits, but market purchases were not allowed on the top five load days during peak hours in peak seasons and could never be used for capacity. Refer to Chapter 5: Reliability and Resiliency for additional details.

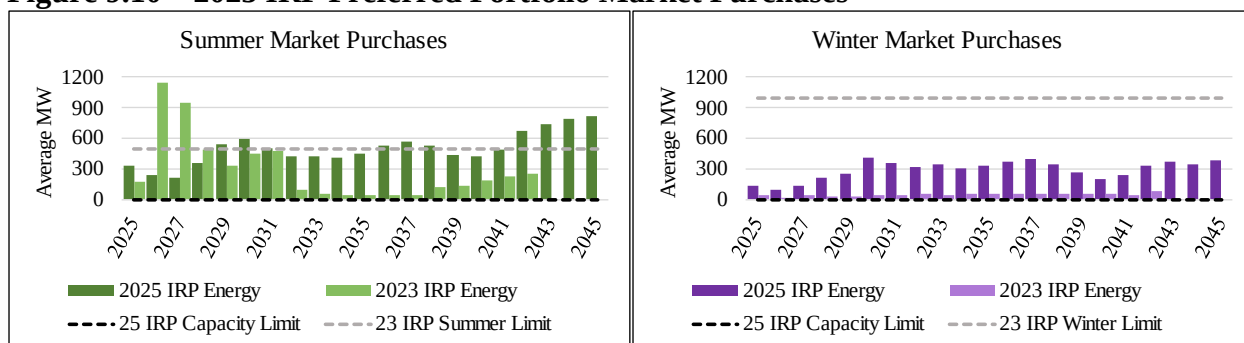
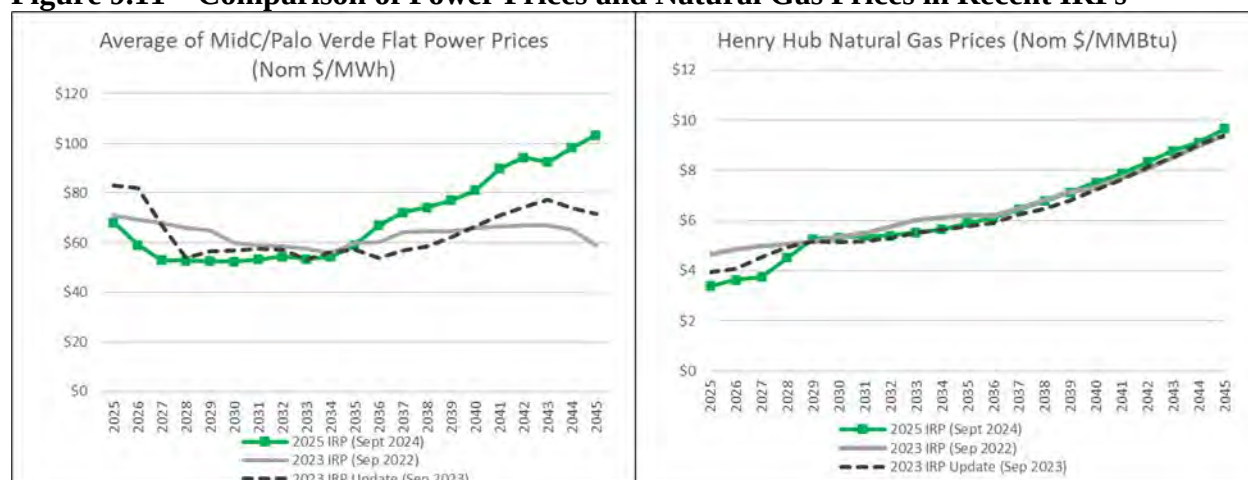
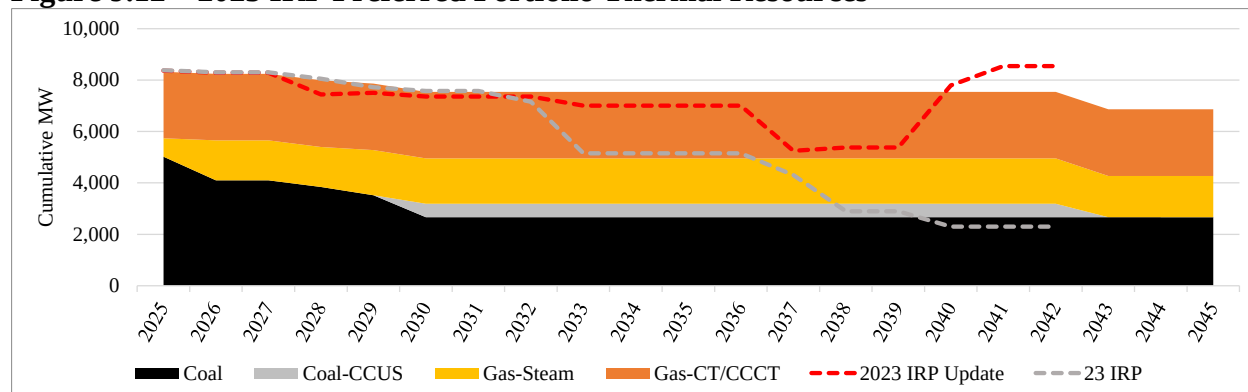
Figure 9.10 – 2025 IRP Preferred Portfolio Market Purchases

Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

Coal and Gas Retirements/Gas Conversions

Coal-fuel plants have been an important contributor to PacifiCorp’s resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that have enabled the company to reduce fuel consumption, associated costs and emissions, and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp’s coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 9.12, the 2025 IRP converts 562 MW of coal-fueled generation to natural gas fueled, exits PacifiCorp’s share in 386 MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

Figure 9.12 – 2025 IRP Preferred Portfolio Thermal Resources

A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 9.9. Also shown in Table 9.9 are

the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.⁶

Table 9.9 – 2025 IRP Coal Resource Results

Majority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	2032	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	2037 (Gas conversion 2024)
Jim Bridger 3 & 4	2042 (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	2042 (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Carbon Dioxide Equivalent Emissions

The 2025 IRP preferred portfolio reflects PacifiCorp’s on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO₂e) emissions decline. PacifiCorp’s emissions have been declining and continue to decline because of several factors including PacifiCorp’s participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new battery storage resources, transmission, and Regional Haze compliance that capitalizes on flexibility.

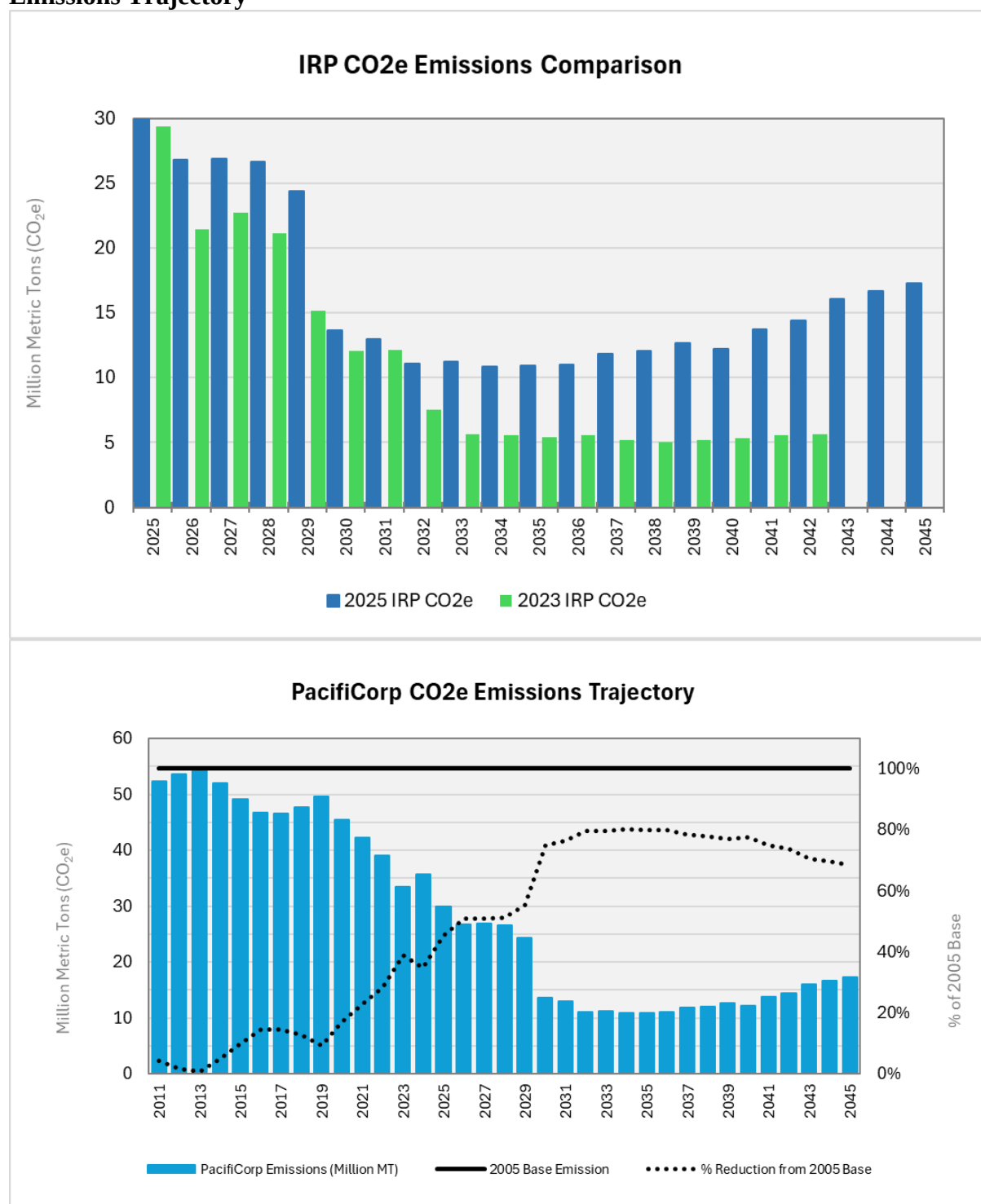
The chart on the top in Figure 9.13 compares projected annual CO₂e emissions across the 2025 IRP and the 2023 IRP preferred portfolios and is inclusive of emissions attributed to market purchases. In the current 2025 IRP preferred portfolio, emissions are generally higher than projected in the 2023 IRP. This relative increase is primarily the result of two differences in modeling assumptions. In the 2023 IRP, a medium CO₂ price was included in the expected price-

⁶ PacifiCorp’s Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

policy scenario used to forecast emissions. No CO₂ price was included in the dispatch of the 2025 IRP preferred portfolio used to forecast emissions. The 2023 IRP also modeled the EPA’s proposed implementation of the Ozone Transport Rule as a significant dispatch target on emissions. No dispatch target was included in the expected price-policy scenario used to forecast emissions in the 2025 IRP. The MR (medium gas price with at-risk federal regulation) price-policy scenario accounts for the effects of possible federal policy, and the portfolio optimized and dispatched under the MR price-policy scenario is a better comparison to the 2023 IRP preferred portfolio.

The difference in emissions between the 2023 IRP and the 2025 IRP is also partly due to an increase in unspecified market purchases, which are assigned a default emission factor of 0.428 MT CO₂e/MWh. This default factor, often established by state regulations and widely used in GHG compliance reporting across multiple states, remains constant throughout the planning period. However, energy industry experts believe the market is trending toward lower emissions as renewable energy and storage capacity expand. As more renewables enter the market, overall emissions are expected to decline, translating to a lower emission factor. PacifiCorp is actively engaging with states to discuss updating this default emission factor to better reflect the market’s transition to cleaner energy. Finally, the difference in emissions from the 2023 IRP reflects the 2025 IRP’s balanced strategy to maintaining low-cost firm capacity by allowing existing coal plants to operate through the planning period at a reduced capacity factor. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals.

The bottom chart in Figure 9.13 presents historical data and assigns emissions to unspecified market purchases at a rate of 0.428 metric tons CO₂ equivalent per MWh – with no credit to market sales. It also accounts for emissions from specified purchases. The graph shows that system CO₂e emissions have declined by approximately 45% in 2025, 75% in 2030, and 77% in 2040, compared to a 2005 baseline of 54.6 million metric tons. In the final five years of the planning horizon, emissions increase moderately due to the factors outlined above.

Figure 9.13 – 2025 IRP Preferred Portfolio CO₂ Emissions and PacifiCorp CO₂ Equivalent Emissions Trajectory¹

¹ PacifiCorp CO₂ equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO₂ equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO₂e/MWh) – emissions from sales are not removed.

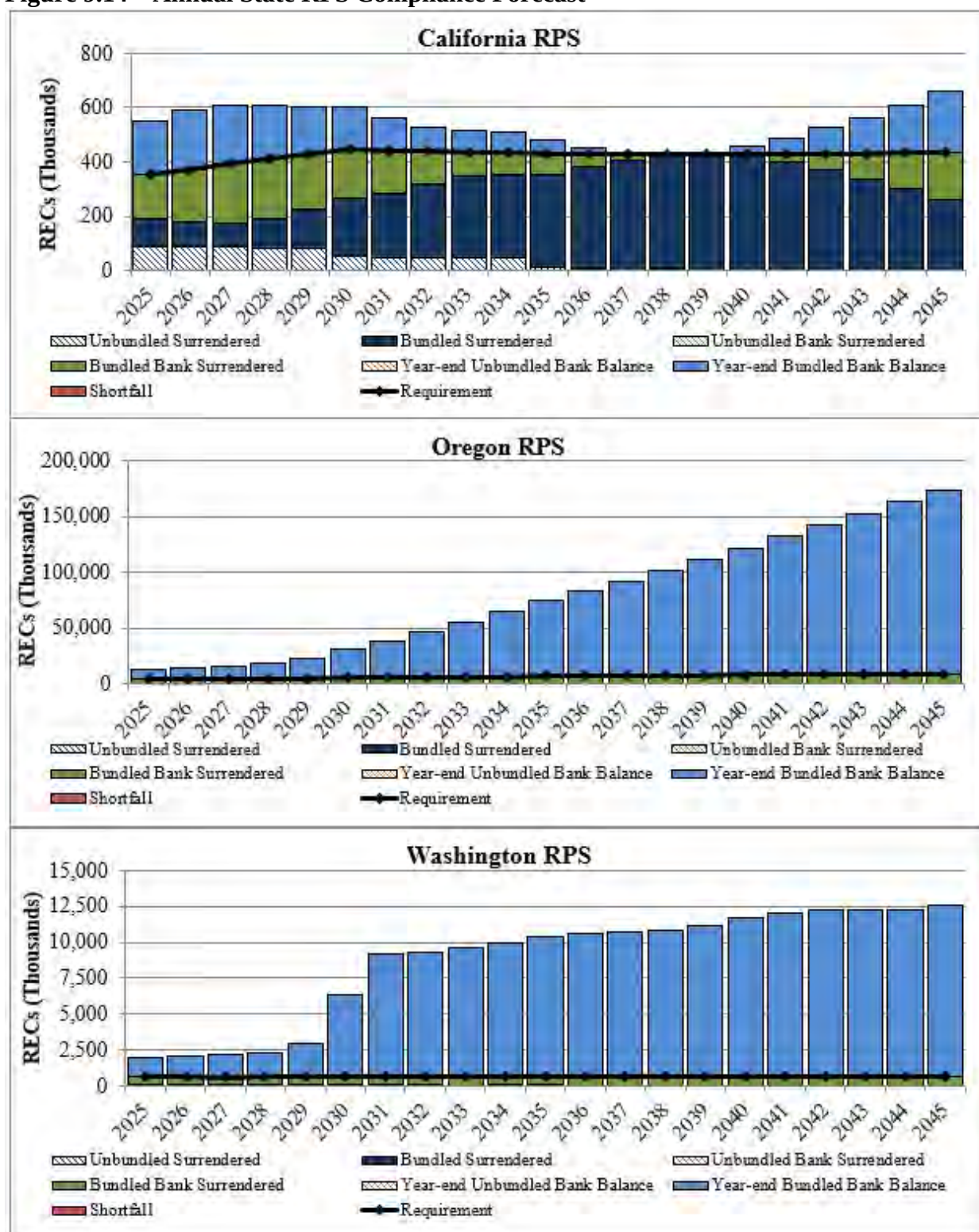
Renewable Portfolio Standards

Figure 9.14 shows PacifiCorp’s renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp’s western states.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2045 with the addition of new renewable resources. Under PacifiCorp’s 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a share of renewable resources across PacifiCorp’s system; however, Washington may also benefit from the situs allocation of new renewable resources as necessary for compliance.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as unbundled REC purchases at various points throughout the 2025 IRP study period. The increasing RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the long term. The company will rely on a combination of new renewable resources from the preferred portfolio and unbundled RECs to meet future shortfalls.

Although not depicted in Figure 9.14, PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the 2025 IRP preferred portfolio.

Figure 9.14 – Annual State RPS Compliance Forecast

Oregon HB 2021 Compliance

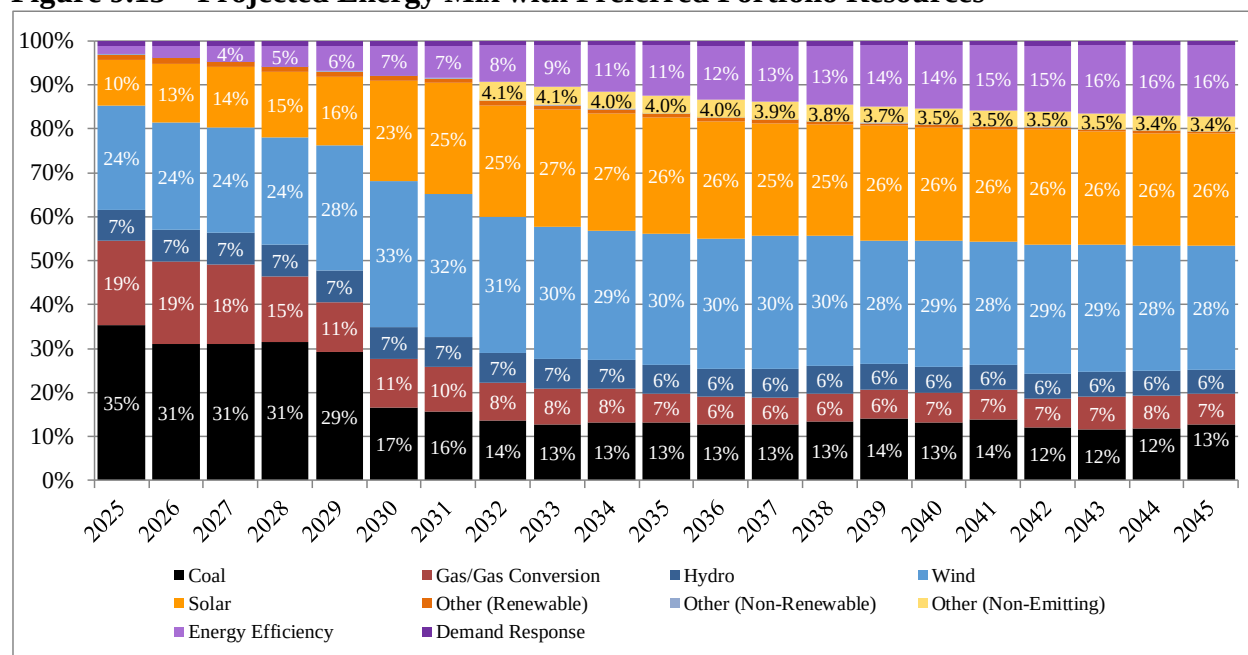
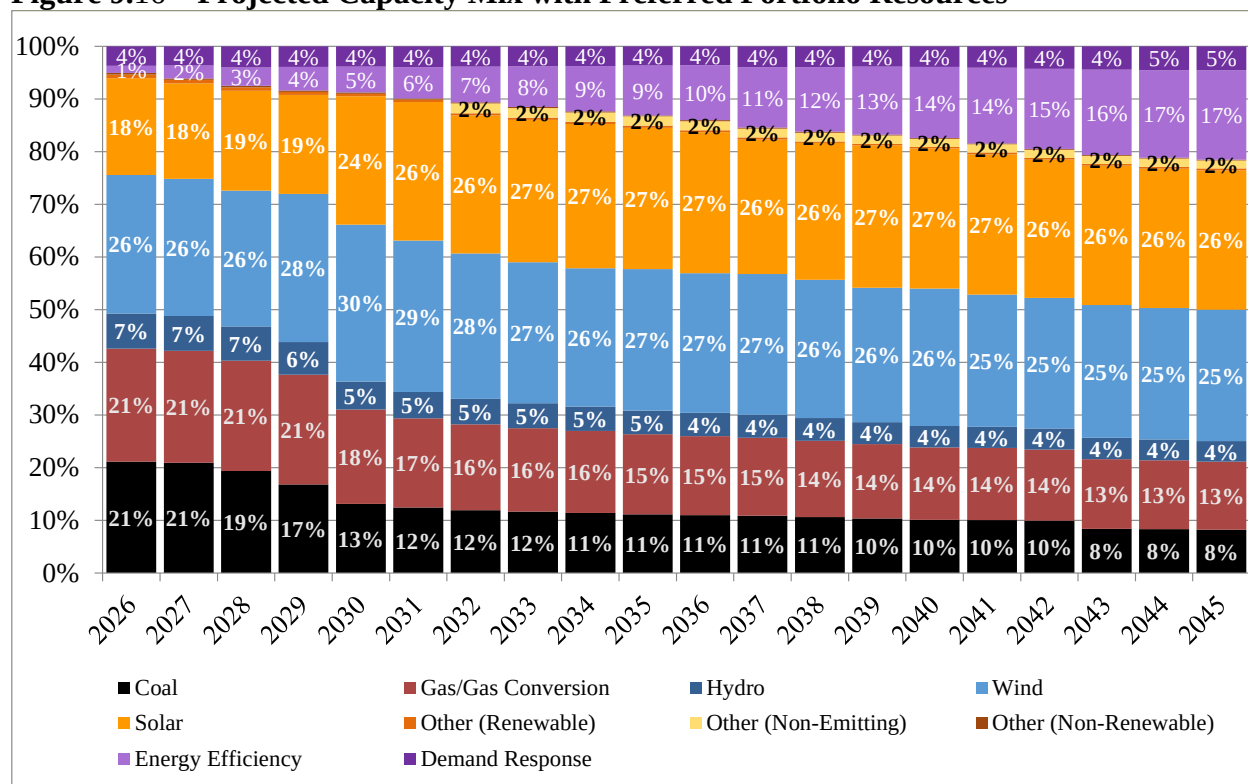
In 2021, Oregon adopted House Bill 2021, an energy policy seeking to reduce emissions from electric generation facilities used to serve customers in the state. HB 2021 sets targets to reduce emissions associated with Oregon retail sales from a baseline, calculated as the average emissions reported from years 2010 through 2012, by 80 percent in 2030, 90 percent by 2035 and 100 percent by 2040. For PacifiCorp, this requires the company to reduce baseline emissions of 8.99 million metric tons (MMT) of carbon dioxide equivalents (CO₂e) to 1.79 MMT CO₂e by 2030, 0.89 MMT CO₂e by 2035, and zero by 2040. The law also increased Oregon’s small-scale renewable energy project purchase requirement from 8 to 10 percent by 2030.

The 2025 IRP preferred portfolio was developed to incorporate resources specifically selected to meet all state-specific requirements, including Oregon’s greenhouse gas emission reduction targets defined by HB 2021. PacifiCorp also modeled the small-scale renewable portfolio requirement to ensure that at least 10 percent of Oregon-allocated capacity will be small-scale (20 MW or less), in each year from 2030 onwards. For more information on Oregon’s planning requirements and the compliance position of the preferred portfolio, refer to Volume II, Appendix P (Oregon Clean Energy Update).

Capacity and Energy

Figure 9.15 and Figure 9.16 show how PacifiCorp’s system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon dispatch under base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.⁷ On an energy basis, coal generation drops below 20 percent in 2030 and remains below 15 percent through the end of the planning period. On a capacity basis, coal resources drop below 10 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, and DSM resources.

⁷The projected PacifiCorp IRP preferred portfolio “energy mix” is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp’s energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp’s IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.15 – Projected Energy Mix with Preferred Portfolio Resources**Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources**

Detailed Preferred Portfolio

Table 9.10 provides line-item detail of PacifiCorp’s 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon. Table 9.11 shows jurisdictional resource selections of PacifiCorp’s 2025 IRP preferred portfolio. Table 9.12 and Table 9.13 report line-item detail of PacifiCorp’s peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon. Table 9.14 and Table 9.15 report line-item detail of PacifiCorp’s peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

Table 9.10 – PacifiCorp’s 2025 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
Resource	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18
DSM - Energy Efficiency	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182
DSM - Demand Response	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52
Renewable - Wind	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)
Total	110	464	209	1,417	1,353	4,229	1,505	1,177	772	783	716	559	546	904	956	1,857	331	1,453	(31)	994	1,530

Table 9.11 – Preferred Portfolio with Jurisdictional Resource Selections

Resource	Installed Capacity, MW																					Total
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
OR	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
WA	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
UIWC	-	-	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	40
WA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UIWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,255
OR	-	-	97	101	107	114	115	110	113	108	109	111	110	106	102	116	123	107	114	92	90	2,044
WA	-	0	13	16	15	17	18	18	19	19	20	19	19	15	14	12	11	11	10	8	7	280
UIWC	-	0	99	103	117	130	196	163	167	168	170	185	218	193	177	172	170	197	114	106	86	2,931
DSM - Demand Response	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	769
OR	-	0	-	48	16	7	-	5	1	3	3	11	-	11	4	23	4	-	9	-	8	153
WA	-	0	-	15	2	2	-	-	-	-	-	8	-	6	1	1	1	-	1	-	14	51
UIWC	-	1	-	-	2	111	99	-	-	-	-	2	112	-	-	0	57	106	19	26	30	566
Renewable - Wind	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
OR	-	-	-	16	445	939	-	1	-	22	260	30	131	28	0	282	37	-	15	-	72	2,278
WA	-	-	-	5	148	313	-	-	-	7	87	10	44	9	0	94	12	-	5	-	24	758
UIWC	-	-	-	-	200	200	344	-	-	-	-	-	0	-	-	-	-	-	-	-	-	744
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
OR	-	-	-	167	135	1,268	136	180	302	169	10	-	0	0	416	78	9	-	-	148	56	3,074
WA	-	-	-	56	45	423	45	60	101	56	3	-	0	0	139	26	3	-	-	49	19	1,025
UIWC	-	-	-	-	-	-	668	-	-	-	-	-	0	-	-	-	-	-	-	-	-	668
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
OR	-	-	-	-	-	320	2	18	26	21	30	132	0	309	-	-	110	-	-	143	36	1,147
WA	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
UIWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
OR	-	-	1	280	100	128	-	119	39	210	20	47	-	46	-	107	55	-	-	-	-	1,152
WA	-	-	-	865	114	168	-	-	-	-	-	-	-	129	67	7	12	-	5	-	-	1,367
UIWC	-	-	1	-	27	-	-	-	-	-	-	-	0	-	-	-	713	-	459	733	-	1,933
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
OR	-	-	-	-	-	272	88	-	-	-	-	-	7	79	33	934	102	210	397	192	353	2,667
WA	-	-	-	-	-	238	3	3	4	3	4	4	4	4	4	4	4	5	5	5	5	298
UIWC	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	104	-	-	-	-	105
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 9.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

East										
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,960	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,294	3,469	3,469	3,469	3,469	3,469	3,469
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	587	613	596	578	561	534	503	487	470	453
Solar	342	499	487	475	463	452	440	428	416	404
Other Renewable	46	45	44	42	41	40	39	37	36	35
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	405	394	383	372	361	351	340	328	314	301
Demand Response	451	446	440	452	450	443	429	423	431	425
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(281)	(1,447)	(1,369)	(1,105)	(973)	0	0	0	0	0
East Existing Resources	8,571	8,426	8,443	8,470	8,433	9,171	9,087	9,024	8,973	8,909
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	0	35	68	124	121	119	117
Solar	0	0	0	0	0	0	151	147	143	139
Storage	0	0	2	2	25	27	27	27	26	26
Nuclear	0	0	0	0	0	0	0	457	454	452
Demand Response	7	7	7	7	8	80	151	149	146	143
East Planned Resources	7	7	9	9	70	177	455	903	891	879
East Total Resources	8,578	8,433	8,452	8,479	8,504	9,348	9,542	9,927	9,863	9,788
Load	7,746	7,655	7,781	7,919	8,068	8,234	8,447	8,609	8,528	8,700
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(321)	(354)
Energy Efficiency	(91)	(141)	(206)	(274)	(349)	(428)	(520)	(631)	(696)	(801)
East Total obligation	7,498	7,372	7,388	7,412	7,433	7,465	7,527	7,520	7,511	7,545
East Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	25.2%	26.8%	32.0%	31.3%	29.7%
West										
Coal	133	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	74	72	70	67	65	63	61	59	57	54
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	232	226	215	209	200	194	187	179	174	170
Demand Response	60	59	58	57	57	56	55	54	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	281	1,447	1,369	1,105	973	0	0	0	0	0
West Existing Resources	2,277	3,433	3,339	3,063	2,916	1,800	1,784	1,771	1,761	1,751
Additional Proxy/Short-Term Purchases	1,910	757	885	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	202	201	201	200	202
Solar	0	0	0	117	205	1,185	1,231	1,306	1,446	1,496
Storage	0	0	1	839	982	1,684	1,759	1,828	1,841	1,969
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	2	2	2	2	2	2	2	2	2	2
West Planned Resources	1,911	759	889	960	1,255	3,072	3,193	3,336	3,488	3,668
West Total Resources	4,189	4,192	4,227	4,022	4,171	4,872	4,977	5,107	5,249	5,419
Load	3,778	3,812	3,905	3,967	4,032	4,103	4,239	4,255	4,288	4,376
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(132)	(148)
Energy Efficiency	(67)	(94)	(135)	(178)	(220)	(263)	(318)	(359)	(389)	(431)
West Total obligation	3,662	3,664	3,695	3,690	3,688	3,688	3,738	3,684	3,767	3,798
West Reserve Margin	14.4%	14.4%	14.4%	9.0%	13.1%	32.1%	33.1%	38.6%	39.4%	42.7%
System										
Total Resources	12,767	12,625	12,680	12,501	12,675	14,220	14,518	15,034	15,113	15,207
Obligation	11,160	11,036	11,084	11,102	11,121	11,153	11,265	11,203	11,278	11,343
Planning Reserves (14.4%)	1,607	1,589	1,596	1,599	1,601	1,606	1,622	1,613	1,624	1,633
Obligation + Reserves	12,767	12,625	12,680	12,701	12,723	12,759	12,887	12,817	12,902	12,977
System Position	0	0	0	(199)	(48)	1,461	1,631	2,217	2,211	2,231
Reserve Margin	14.4%	14.4%	14.4%	12.6%	14.0%	27.5%	28.9%	34.2%	34.0%	34.1%

Table 9.13 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

East											
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,432	2,432	2,432
Gas	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,322	3,322	3,322
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	437	421	404	387	371	355	308	293	278	263	249
Solar	392	381	340	329	319	308	297	286	276	243	233
Other Renewable	33	32	31	12	11	10	10	9	9	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	291	269	221	212	203	192	184	176	169	162	155
Demand Response	422	401	402	398	400	406	398	375	376	389	351
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	8,851	8,763	8,643	8,569	8,519	8,472	8,383	8,310	7,622	7,564	7,472
Additional Proxy/Short-Term Purchase	0	0	0	0	0	0	64	0	672	628	475
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	115	112	110	108	106	104	101	99	97	95	92
Solar	135	131	127	123	120	116	111	107	104	100	96
Storage	26	25	25	25	24	24	23	592	581	858	1,289
Nuclear	450	447	445	442	440	437	435	432	430	427	426
Demand Response	141	138	197	193	189	186	209	253	257	264	270
East Planned Resources	868	856	907	895	882	869	947	1,487	2,144	2,373	2,650
East Total Resources	9,719	9,620	9,550	9,464	9,401	9,340	9,330	9,797	9,766	9,937	10,123
Load	8,893	9,150	9,349	9,567	9,774	9,993	10,214	10,478	10,693	10,891	11,097
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(911)	(983)	(1,112)	(1,227)	(1,325)	(1,407)	(1,501)	(1,482)	(1,547)	(1,570)	(1,588)
East Total obligation	7,596	7,752	7,792	7,865	7,946	8,057	8,156	8,413	8,536	8,686	8,848
East Reserve Margin	27.9%	24.1%	22.6%	20.3%	18.3%	15.9%	14.4%	16.5%	14.4%	14.4%	14.4%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	52	50	48	46	44	41	39	37	35	33	31
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	142	138	132	128	124	120	101	97	95
Demand Response	52	51	51	50	49	48	48	47	46	45	44
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	1,741	1,731	1,708	1,700	1,689	1,681	1,651	1,644	1,621	1,613	1,608
Additional Proxy/Short-Term Purchase	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	238	241	259	262	261	299	303	302	303	302	310
Solar	1,455	1,446	1,383	1,431	1,553	1,510	1,470	1,387	1,307	1,314	1,255
Storage	1,966	1,980	1,971	2,144	2,200	3,176	3,299	3,487	3,863	4,035	4,365
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	2	3	3	3	3	3	3	3	3	3	8
West Planned Resources	3,660	3,670	3,616	3,840	4,016	4,988	5,075	5,179	5,476	5,654	5,938
West Total Resources	5,401	5,401	5,325	5,540	5,705	6,668	6,727	6,823	7,097	7,267	7,545
Load	4,475	4,577	4,692	4,807	4,927	5,049	5,173	5,376	5,430	5,553	5,680
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
Energy Efficiency	(471)	(515)	(571)	(603)	(634)	(661)	(691)	(774)	(591)	(599)	(612)
West Total obligation	3,841	3,885	3,929	3,998	4,073	4,154	4,233	4,340	4,562	4,663	4,764
West Reserve Margin	40.6%	39.0%	35.5%	38.6%	40.1%	60.5%	58.9%	57.2%	55.6%	55.9%	58.4%
System											
Total Resources	15,120	15,021	14,875	15,003	15,106	16,009	16,057	16,620	16,863	17,205	17,668
Obligation	11,438	11,637	11,721	11,863	12,019	12,211	12,388	12,753	13,099	13,349	13,612
Planning Reserves (14.4%)	1,647	1,676	1,688	1,708	1,731	1,758	1,784	1,836	1,886	1,922	1,960
Obligation + Reserves	13,085	13,313	13,409	13,572	13,750	13,969	14,172	14,589	14,985	15,272	15,573
System Position	2,036	1,709	1,465	1,432	1,357	2,040	1,885	2,031	1,878	1,933	2,095
Reserve Margin	32.2%	29.1%	26.9%	26.5%	25.7%	31.1%	29.6%	30.3%	28.7%	28.9%	29.8%

Table 9.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

East										
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,734	3,734	3,499	3,185	3,015	3,015	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	1,837	1,957	1,892	1,829	1,766	1,657	1,523	1,463	1,404	1,346
Solar	38	104	101	98	95	92	89	85	82	79
Other Renewable	41	39	38	37	35	34	33	32	30	29
Storage	1	621	606	591	576	561	546	531	516	500
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	176	171	166	161	156	149	140	124
Demand Response	119	118	118	128	129	128	121	120	128	127
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,226)	(930)	0	0	0	0	0
East Existing Resources	7,804	8,523	8,433	8,495	8,581	9,208	9,042	8,954	8,875	8,780
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	0	90	175	316	306	297	287
Solar	0	0	0	0	0	0	39	37	36	35
Storage	0	0	1	1	17	18	18	18	18	17
Nuclear	0	0	0	0	0	0	0	403	401	398
Demand Response	0	0	0	0	0	0	0	0	0	0
East Planned Resources	0	0	2	2	109	196	374	767	754	740
East Total Resources	7,804	8,523	8,435	8,496	8,689	9,404	9,417	9,722	9,629	9,520
Load	5,898	5,911	6,036	6,164	6,278	6,408	6,569	6,706	6,899	7,084
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(75)	(118)	(157)	(197)	(239)	(283)	(331)	(388)	(450)	(513)
East Total obligation	5,821	5,790	5,876	5,963	6,033	6,119	6,231	6,309	6,440	6,560
East Reserve Margin	34.1%	47.2%	43.5%	42.5%	44.0%	53.7%	51.1%	54.1%	49.5%	45.1%
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	62	59	57	55	53	51	49	47	45
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	2	2	2	2	2	2	2	2	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	70	69	62	61	58	57	57	56	56	56
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,226	930	0	0	0	0	0
West Existing Resources	3,345	3,342	3,333	2,956	2,655	1,574	1,571	1,568	1,566	1,561
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	201	201	200	199	202
Solar	0	0	0	30	52	299	309	326	359	368
Storage	0	0	1	1,091	1,276	2,037	2,104	2,193	2,206	2,369
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	41	51	56	55	58	58	59
West Planned Resources	0	0	2	1,164	1,446	2,594	2,669	2,776	2,821	2,997
West Total Resources	3,345	3,342	3,335	4,120	4,101	4,168	4,240	4,344	4,387	4,559
Load	3,511	3,571	3,640	3,701	3,741	3,805	3,904	3,981	4,068	4,160
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(52)	(65)	(118)	(173)	(229)	(286)	(345)	(401)	(457)	(511)
West Total obligation	3,459	3,506	3,521	3,527	3,511	3,517	3,558	3,578	3,609	3,647
West Reserve Margin	-3.3%	-4.7%	-5.3%	16.8%	16.8%	18.5%	19.2%	21.4%	21.5%	25.0%
System										
Total Resources	11,149	11,865	11,769	12,616	12,790	13,572	13,657	14,066	14,016	14,079
Obligation	9,281	9,296	9,397	9,490	9,544	9,636	9,789	9,888	10,049	10,207
Planning Reserves (16.8%)	1,559	1,562	1,579	1,594	1,603	1,619	1,645	1,661	1,688	1,715
Obligation + Reserves	10,840	10,858	10,975	11,084	11,147	11,255	11,434	11,549	11,738	11,922
System Position	309	1,008	794	1,532	1,643	2,317	2,223	2,517	2,278	2,157
Reserve Margin	20.1%	27.6%	25.2%	32.9%	34.0%	40.8%	39.5%	42.3%	39.5%	37.9%

Table 9.15 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

East											
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	2,503	2,503	2,503
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,378	3,378	3,378
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,285	1,226	1,168	1,107	1,049	990	850	797	744	689	636
Solar	76	73	70	67	64	61	58	55	52	42	39
Other Renewable	28	26	25	9	8	8	7	7	6	6	0
Storage	485	470	455	440	425	410	395	379	365	350	334
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	120	112	99	94	90	86	82	78	75	71	67
Demand Response	128	117	121	121	125	132	129	117	121	132	109
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	8,697	8,600	8,511	8,412	8,336	8,262	8,096	8,008	7,276	7,204	7,101
Additional Proxy/Short-Term Purchase	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	278	268	259	250	240	231	221	212	202	193	183
Solar	33	32	31	30	28	27	26	25	23	22	21
Storage	17	16	16	16	15	15	14	370	360	499	711
Nuclear	396	394	392	389	387	384	381	379	377	374	372
Demand Response	0	0	0	0	0	0	0	0	0	0	1
East Planned Resources	727	713	700	687	673	660	645	988	965	1,091	1,291
East Total Resources	9,423	9,313	9,212	9,099	9,009	8,921	8,742	8,996	8,241	8,294	8,392
Load	7,248	7,421	7,645	7,863	8,087	8,287	8,466	8,705	8,909	9,134	9,224
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(579)	(624)	(700)	(766)	(826)	(886)	(954)	(973)	(1,022)	(1,049)	(1,077)
East Total obligation	6,659	6,786	6,932	7,084	7,248	7,387	7,498	7,717	7,872	8,070	8,131
East Reserve Margin	41.5%	37.2%	32.9%	28.4%	24.3%	20.8%	16.6%	16.6%	4.7%	2.8%	3.2%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	42	40	38	36	34	32	30	28	25	23	21
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	54	53	53	51	51	50	50	50	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	1,559	1,555	1,552	1,550	1,546	1,544	1,541	1,539	1,536	1,534	1,531
Additional Proxy/Short-Term Purchase	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	237	241	258	261	260	298	301	300	301	300	308
Solar	355	349	331	339	363	348	333	309	286	280	260
Storage	2,362	2,379	2,362	2,558	2,619	3,606	3,732	3,910	4,279	4,439	4,761
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	60	67	66	73	75	82	83	82	85	84	87
West Planned Resources	3,013	3,036	3,018	3,231	3,317	4,334	4,450	4,601	4,951	5,103	5,417
West Total Resources	4,572	4,591	4,570	4,781	4,863	5,878	5,991	6,140	6,488	6,636	6,948
Load	4,232	4,334	4,471	4,605	4,720	4,832	4,959	5,143	5,253	5,374	5,365
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(568)	(624)	(668)	(714)	(760)	(819)	(858)	(900)	(786)	(803)	(826)
West Total obligation	3,662	3,707	3,800	3,888	3,957	4,010	4,097	4,239	4,463	4,567	4,535
West Reserve Margin	24.9%	23.9%	20.3%	23.0%	22.9%	46.6%	46.2%	44.8%	45.4%	45.3%	53.2%
System											
Total Resources	13,995	13,904	13,782	13,880	13,872	14,799	14,732	15,136	14,729	14,930	15,340
Obligation	10,321	10,493	10,732	10,973	11,205	11,398	11,596	11,957	12,334	12,637	12,666
Planning Reserves (16.8%)	1,486	1,511	1,545	1,580	1,614	1,641	1,670	1,722	1,776	1,820	1,824
Obligation + Reserves	11,807	12,003	12,278	12,553	12,819	13,039	13,265	13,678	14,110	14,456	14,490
System Position	2,188	1,901	1,505	1,327	1,053	1,760	1,467	1,458	618	474	850
Reserve Margin	35.6%	32.5%	28.4%	26.5%	23.8%	29.8%	27.1%	26.6%	19.4%	18.1%	21.1%

Integrated Portfolio Resource Comparisons by Technology and Year

Table 9.16 through Table 9.28 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 9.29 through Table 9.32 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology. Table 9.33 summarizes how full jurisdictional studies were identified for each variant and price-policy scenario. Full jurisdictional studies are only modified and endogenously developed to the extent the variant relates to resources that can be selected for that jurisdiction. As a result, the Oregon and Washington full jurisdictional portfolios are not modified in the variants that examine coal resource alternatives. Similarly, Washington requires planning under the social cost of greenhouse gases, so its full jurisdictional portfolio is not modified under other price-policy scenarios. Those variants related to clean resources in which all jurisdictions can participate have full jurisdictional portfolios for each jurisdiction.

Table 9.16 – New Gas¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	-	-	99
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	496	496
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.17 - Nuclear¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MR Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No CCS	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - Offshore Wind	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - Hunter Retire	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
LN Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
HH Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
SC Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.18 – Renewable Peaking¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.19 – DSM – Energy Efficiency

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,436
MR Base	92	89	209	221	231	256	329	313	326	315	318	326	369	335	313	308	304	315	254	224	209	5,656
MN - No CCS	92	89	207	218	229	253	326	287	284	282	294	300	333	312	292	289	304	315	260	232	219	5,417
MN - No Nuclear	92	89	210	220	237	256	331	314	310	299	299	314	324	267	283	251	286	299	282	261	220	5,444
MN - No Coal 2032	92	89	210	221	231	251	319	304	308	298	309	325	347	314	293	299	304	315	270	246	220	5,565
MN - Offshore Wind	92	89	209	219	240	260	331	292	306	294	299	322	345	314	310	301	303	314	222	218	182	5,462
MN - No Forward Technology	92	89	210	220	237	256	331	315	310	301	301	315	324	267	283	251	286	299	282	247	219	5,435
MN - Geothermal	92	89	207	217	227	245	306	298	303	293	313	320	354	335	313	308	305	314	270	259	218	5,586
MN - Hunter Retire	92	89	219	232	243	265	332	306	310	307	312	328	358	326	306	301	304	315	258	224	209	5,636
LN Base	92	89	207	223	236	257	325	288	300	289	311	318	343	309	322	305	302	291	272	244	217	5,540
HH Base	92	89	211	223	237	257	309	295	300	289	309	315	347	326	305	302	305	316	259	252	230	5,568
SC Base	92	89	211	226	241	263	329	293	314	305	318	325	357	325	320	308	305	315	270	260	219	5,685

Table 9.20 – DSM – Demand Response

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	789
MR Base	18	2	-	63	19	16	3	5	1	5	3	19	323	18	5	24	114	34	34	25	205	936
MN - No CCS	18	2	-	63	19	34	187	5	1	3	3	21	93	18	5	25	6	176	30	26	50	785
MN - No Nuclear	18	2	-	63	20	136	13	8	26	79	32	4	70	14	151	24	46	31	12	102	48	899
MN - No Coal 2032	18	2	-	63	19	16	-	5	1	3	3	19	328	18	5	25	5	146	33	27	51	787
MN - Offshore Wind	18	2	-	63	20	206	21	8	-	10	4	4	110	29	5	11	8	166	30	31	50	796
MN - No Forward Technology	18	2	-	63	21	131	13	10	26	77	35	6	70	13	151	24	45	31	12	102	57	907
MN - Geothermal	18	2	-	60	20	16	-	8	-	7	5	7	-	13	10	26	450	29	8	7	103	789
MN - Hunter Retire	18	2	-	63	19	211	14	5	1	3	3	23	113	18	129	25	7	147	29	30	87	947
LN Base	18	2	-	63	19	75	149	7	2	4	4	14	110	14	5	24	124	-	8	80	51	773
HH Base	18	2	-	63	22	13	-	5	1	3	3	19	-	18	8	24	5	463	15	157	30	869
SC Base	18	2	2	64	28	191	14	5	1	1	18	11	108	18	10	24	6	150	12	50	46	779

Table 9.21 – Utility Scale Wind¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
MR Base	-	-	-	21	694	1,931	200	382	100	129	447	40	175	37	-	376	50	-	20	-	96	4,698
MN - No CCS	-	-	-	21	594	1,252	276	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,314
MN - No Nuclear	-	-	-	-	500	1,728	300	301	302	322	380	292	2	-	-	-	-	-	-	-	-	4,127
MN - No Coal 2032	-	-	-	21	594	2,914	-	1	-	29	347	40	175	37	-	376	50	-	20	-	96	4,700
MN - Offshore Wind	-	-	100	100	762	630	400	1	1,000	98	100	100	-	-	-	353	95	-	-	-	162	3,901
MN - No Forward Technology	-	-	-	-	694	1,482	302	301	-	22	294	53	176	38	-	367	91	-	1	-	147	3,968
MN - Geothermal	-	-	-	-	594	402	200	1	2	-	169	204	185	89	-	360	62	-	38	-	19	2,325
MN - Hunter Retire	-	-	-	21	894	1,842	340	1	-	29	347	40	175	37	-	376	50	-	20	-	96	4,268
LN Base	-	-	-	-	594	1,265	594	2	-	24	369	1	176	38	-	365	90	-	3	-	150	3,671
HH Base	-	-	-	21	1,214	2,677	-	2	-	29	349	40	175	37	-	376	50	-	20	-	96	5,086
SC Base	-	-	-	20	1,614	1,353	352	1	-	65	293	237	114	26	29	423	47	-	-	11	196	4,781

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.22 – Small Scale Wind¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.23 – Utility Solar¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
MR Base	-	-	-	222	180	1,690	863	934	420	467	213	133	1	-	554	104	12	-	-	197	75	6,065
MN - No CCS	-	-	-	222	180	1,690	614	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,530
MN - No Nuclear	-	-	-	656	-	1,444	962	299	326	395	456	391	1	-	-	-	-	-	-	22	108	5,060
MN - No Coal 2032	-	-	-	222	180	1,690	494	635	545	792	114	100	1	-	554	104	12	-	-	197	75	5,715
MN - Offshore Wind	-	-	103	237	205	1,382	885	249	104	100	100	100	103	392	444	100	-	-	-	116	26	4,646
MN - No Forward Technology	-	-	119	13	-	1,968	962	220	327	316	49	-	1	-	577	85	34	-	-	239	111	5,021
MN - Geothermal	-	-	29	505	1	1,168	200	163	349	199	103	-	2	27	82	229	211	-	-	333	104	3,705
MN - Hunter Retire	-	-	-	222	180	2,352	1,173	240	403	225	13	-	1	-	554	104	12	-	-	197	75	5,751
LN Base	-	-	-	200	138	1,761	517	239	398	230	7	-	1	-	570	93	61	-	-	44	110	4,369
HH Base	-	-	-	222	181	1,813	1,904	734	603	360	196	-	1	-	554	104	12	-	-	197	75	6,956
SC Base	-	-	22	381	144	2,005	1,259	335	400	206	225	90	1	-	471	115	-	-	-	288	92	6,034

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.24 – Small Scale Solar¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MR Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - No CCS	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - No Nuclear	-	-	-	-	-	320	2	18	26	21	26	53	-	307	-	49	153	-	10	126	36	1,147
MN - No Coal 2032	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - Offshore Wind	-	-	-	-	-	416	-	-	-	-	-	-	-	24	29	114	142	-	36	250	26	1,037
MN - No Forward Technology	-	-	-	-	-	320	2	18	26	21	30	127	-	307	-	-	117	-	35	108	36	1,147
MN - Geothermal	-	-	-	-	-	304	-	11	29	17	23	17	15	201	331	13	21	-	35	18	26	1,061
MN - Hunter Retire	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
LN Base	-	-	-	-	-	320	2	18	26	21	31	153	-	306	-	-	97	-	35	101	36	1,146
HH Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
SC Base	-	-	-	-	-	320	2	19	26	23	24	20	9	312	-	42	170	-	-	56	26	1,049

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.25 – Geothermal

Study	Installed Capacity, MW																						
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total	
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - Geothermal	-	-	403	304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	707	
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.26 – Battery, < 8 hour¹

Study	Installed Capacity, MW																						
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total	
MN Base	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451	
MR Base	-	-	-	1,156	215	438	-	119	39	210	20	47	27	175	67	113	582	33	5	305	324	3,875	
MN - No CCS	-	-	2	1,146	215	299	-	119	39	210	20	47	-	175	188	113	67	115	5	758	-	3,518	
MN - No Nuclear	-	-	16	1,399	109	462	-	274	39	209	34	72	313	130	6	937	159	-	605	10	602	5,376	
MN - No Coal 2032	-	-	-	1,145	215	565	-	119	39	210	20	47	-	175	67	113	67	152	5	416	18	3,373	
MN - Offshore Wind	-	-	7	2,291	527	528	-	149	-	131	46	54	2	251	113	1,454	211	675	768	82	834	8,123	
MN - No Forward Technology	-	-	-	1,349	179	316	6	182	41	279	30	83	333	186	112	1,322	272	287	444	251	605	6,277	
MN - Geothermal	-	-	-	1,048	184	650	-	241	4	203	37	70	-	179	37	1,437	473	-	104	53	449	5,169	
MN - Hunter Retire	-	-	4	1,145	215	836	-	119	39	210	20	47	41	175	67	113	67	129	5	109	185	3,526	
LN Base	-	-	-	1,252	220	609	-	99	39	209	23	82	-	239	67	1,126	1,060	-	272	12	1,437	6,746	
HH Base	-	-	2	1,146	302	1,383	-	119	39	210	20	47	-	175	67	113	67	-	5	-	-	3,695	
SC Base	-	-	-	2,147	329	484	-	175	7	194	2	23	-	286	121	1,095	138	245	192	237	531	6,206	

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.27 – Battery, 8-23 hour¹

Study	Installed Capacity, MW																						
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total	
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - No CCS	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - Offshore Wind	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
HH Base	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.28 – Battery, 24+ hour¹

Study	Installed Capacity, MW																						
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total	
MN Base	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073	
MR Base	-	-	-	-	-	510	91	3	4	3	4	4	175	83	37	939	107	510	401	197	455	3,523	
MN - No CCS	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	261	402	197	358	3,015	
MN - No Nuclear	-	-	-	-	-	191	2	3	3	3	3	3	114	3	3	186	78	233	168	118	4	1,115	
MN - No Coal 2032	-	-	-	-	-	510	91	3	4	3	4	4	33	83	37	939	107	390	401	197	358	3,164	
MN - Offshore Wind	-	-	-	-	-	1,577	20	23	23	22	25	26	24	27	28	127	34	142	96	30	34	2,258	
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
MN - Geothermal	-	-	-	-	-	85	1	1	1	1	1	1	1	1	2	13	84	85	316	174	88	855	
MN - Hunter Retire	-	-	-	-	-	837	91	3	4	3	4	4	123	83	146	939	107	455	401	197	537	3,934	
LN Base	-	-	-	-	-	271	95	4	4	3	4	4	17	38	40	132	26	215	137	159	16	1,165	
HH Base	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	641	402	197	598	3,635	
SC Base	-	-	-	-	-	1,410	107	19	19	18	20	21	69	22	34	141	141	442	219	169	94	2,945	

¹ Positive values indicate installed capacity in the first full year of operation.

Table 9.29 – Majority Owned Coal Retirements¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MR Base	-	-	-	(220)	-	-	-	(686)	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
MN - No CCS	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Nuclear	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Coal 2032	-	-	-	(220)	-	-	-	(686)	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
MN - Offshore Wind	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Forward Technology	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - Geothermal	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - Hunter Retire	-	-	-	(220)	-	(1,158)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,378)
LN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
HH Base	-	-	-	(220)	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(488)
SC Base	-	-	-	(488)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(757)

¹ Negative values indicate retirement of coal capacity.

Table 9.30 – Carbon Capture and Sequestration Selections

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MR Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MN - No Forward Technology	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
MN - Geothermal	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
MN - Hunter Retire	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
LN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
HH Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
SC Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526

Table 9.31 – Coal to Gas Conversion Selections

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
MR Base	-	357	-	-	205	1,979	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	2,385
MN - No CCS	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(403)	-	-	159
MN - No Nuclear	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - No Coal 2032	-	357	-	-	205	2,679	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	3,085
MN - Offshore Wind	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
MN - No Forward Technology	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - Geothermal	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - Hunter Retire	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
LN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
HH Base	-	357	-	-	205	599	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	892
SC Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	(99)	-	-	793

Table 9.32 – Gas Retirements¹

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	(167)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(167)

¹Only reports retirements of existing gas plants.

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 7 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. Consequently, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS. As discussed in Chapter 8, some of the studies below were able to fulfill the requirements of another study and are noted as such. Table 9.33 summarizes the jurisdictional studies which were integrated for each of the variants and price-policy scenarios. Variants evaluating technology that is available in all jurisdictions have jurisdictional portfolios developed for each jurisdiction. Where a jurisdiction does not use the applicable technology or assumptions under consideration in the variant, selections for that jurisdiction are held constant at their base scenario. For example, neither Oregon nor Washington participates in coal-fired resources over the long term, so studies that evaluate alternative decisions for coal-fired resources hold Oregon and Washington jurisdictional results constant. Similarly, Washington requires that the SCGHG price-policy scenario be used for planning, so Washington selections under SCGHG are integrated regardless of the price-policy scenario under consideration.

Table 9.33 – Jurisdictional Studies for Variants and Price-Policy Scenarios

Price-policy / Variant	UIWC	OR	WA	Description
MN - Base	Base	Base		MN price-policy scenario
MR - Base	✓			MR price-policy scenario
LN - Base	✓	✓		LN price-policy scenario
HH - Base	✓	✓		HH price-policy scenario
SC - Base	✓	✓	Base	SCGHG price-policy scenario
MN - No CCS	✓			No coal units are able to select CCS technology
MN - No Coal 2032	✓			All coal must retire or convert by January 1, 2032
MN - Hunter Retire	✓			Require all Hunter units to retire no later than 1/1/2030
MN - No Nuclear	✓	✓	✓ (SC)	No nuclear resources are eligible for selection
MN - Offshore Wind	✓	✓	✓ (SC)	Counterfactual to preferred portfolio selection
MN - No Forward Technology	✓	✓	✓ (SC)	No nuclear, hydrogen or 100-hour storage, or biodiesel peaking
MN - Geothermal	✓	✓	✓ (SC)	Counterfactual to preferred portfolio selection
MN - All Coal End of Life	Same as No CCS			Continue 2025 coal technology
MN - No New Gas	Same as Preferred Portfolio			No new gas resources allowed
MN - Force All Gas Conversions	Same as No Coal 2032			All coal must be converted to natural gas where available

Table 9.34 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no CO₂) price-policy scenario. As in previous IRPs, model results can indicate the need to examine costs and risks beyond the model horizon. End effects were applied to all portfolios run under the MN price-policy for a 5-year period after the study horizon, results of which can be seen in this table. The specific trends that led to this examination can be found in the discussion of individual cases below.

Table 9.34 – Integrated Portfolios Under Medium Gas/ Zero CO₂

Case - MN	ST Value			Risk Adjusted			With End Effects			CO2 Emissions		
	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Stochastic PVRR	Change from Lowest Cost Portfolio (\$m)	Rank	PVRR (\$m)	Change from Lowest Portfolio	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base MN	27,233	\$171	4	27,618	\$106	2	34,663	\$0	1	317,054	109,082	9
Integrated No CCS MN	28,345	\$1,283	6	28,886	\$1,374	6	35,768	\$1,105	6	386,023	178,051	13
Integrated No Nuclear MN	28,878	\$1,816	9	29,301	\$1,789	8	36,457	\$1,794	7	320,486	112,515	10
Integrated No Coal Post 2032 MN	28,438	\$1,376	7	29,235	\$1,723	7	36,751	\$2,088	8	215,237	7,265	3
Integrated Offshore Wind MN	34,645	\$7,583	13	35,127	\$7,615	13	42,917	\$8,255	13	310,014	102,043	7
Integrated No Future Tech MN	29,110	\$2,048	10	29,534	\$2,022	10	36,946	\$2,284	10	330,034	122,063	11
Integrated Geothermal MN	29,208	\$2,146	11	29,946	\$2,434	11	37,188	\$2,525	11	310,138	102,167	8
Integrated Hunter Retire MN	27,062	\$0	1	27,765	\$253	3	34,960	\$297	3	269,208	61,237	6
Integrated Base MR	27,176	\$114	3	27,913	\$401	4	35,385	\$723	5	207,971	0	1
Integrated No CCS MR	28,581	\$1,519	8	29,374	\$1,862	9	36,896	\$2,233	9	213,302	5,331	2
Integrated Base LN	27,785	\$723	5	27,970	\$458	5	35,167	\$504	4	340,068	132,096	12
Integrated Base HH	27,119	\$57	2	27,512	\$0	1	34,714	\$51	2	238,450	30,479	4
Integrated Base SC	29,787	\$2,725	12	30,088	\$2,575	12	37,904	\$3,242	12	257,126	49,155	5

Table 9.35, below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero CO₂) price-policy scenario.

Table 9.35 – Integrated Portfolios Under Low Gas/ Zero CO₂

Case - LN	ST Value			CO2 Emissions		
	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base LN	25,113	\$498	4	315,803	54,380	10
Integrated Base MN	25,226	\$611	5	334,470	73,047	12
Integrated No CCS MN	25,847	\$1,232	8	361,938	100,514	13
Integrated No Nuclear MN	28,638	\$4,023	12	315,004	53,580	9
Integrated No Coal Post 2032 MN	25,428	\$814	6	261,423	0	4
Integrated Offshore Wind MN	37,505	\$12,890	13	299,472	38,049	7
Integrated No Future Tech MN	26,507	\$1,892	9	326,791	65,368	11
Integrated Geothermal MN	26,936	\$2,322	10	300,704	39,281	8
Integrated Hunter Retire MN	24,959	\$344	2	273,675	12,251	6
Integrated Base MR	24,615	\$0	1	254,697	(6,726)	2
Integrated No CCS MR	25,580	\$965	7	261,242	(181)	3
Integrated Base HH	24,990	\$375	3	248,840	(12,584)	1
Integrated Base SC	27,805	\$3,190	11	270,860	9,437	5

Table 9.36 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high CO₂) price-policy scenario.

Table 9.36 – Integrated Portfolios Under High Gas and Coal/ High CO₂

Case - HH	ST Value			CO2 Emissions		
	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	31,498	\$0	1	174,521	444	2
Integrated Base MN	34,498	\$3,000	8	232,976	58,900	13
Integrated No CCS MN	35,762	\$4,264	11	219,378	45,302	12
Integrated No Nuclear MN	35,275	\$3,777	10	202,255	28,178	10
Integrated No Coal Post 2032 MN	33,052	\$1,553	4	179,879	5,803	4
Integrated Offshore Wind MN	45,727	\$14,228	13	194,780	20,703	8
Integrated No Future Tech MN	35,902	\$4,404	12	207,187	33,110	11
Integrated Geothermal MN	35,247	\$3,749	9	189,861	15,785	7
Integrated Hunter Retire MN	31,973	\$475	3	179,948	5,871	5
Integrated Base MR	31,796	\$297	2	180,431	6,355	6
Integrated No CCS MR	33,110	\$1,612	5	178,538	4,461	3
Integrated Base LN	33,995	\$2,496	6	201,609	27,532	9
Integrated Base SC	34,207	\$2,709	7	174,077	0	1

Table 9.37 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario.

Table 9.37 – Integrated Portfolios Under Medium Gas/ Social Cost of CO₂

Case - SC	ST Value			CO2 Emissions		
	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base SC	40,268	\$2,628	7	103,326	3,072	3
Integrated Base MN	40,882	\$3,242	8	117,244	16,990	9
Integrated No CCS MN	41,851	\$4,210	11	120,282	20,028	12
Integrated No Nuclear MN	38,899	\$1,258	4	115,060	14,806	8
Integrated No Coal Post 2032 MN	39,186	\$1,545	5	105,996	5,742	5
Integrated Offshore Wind MN	51,719	\$14,079	13	110,124	9,870	7
Integrated No Future Tech MN	41,797	\$4,157	10	117,608	17,354	10
Integrated Geothermal MN	40,942	\$3,302	9	106,062	5,808	6
Integrated Hunter Retire MN	38,034	\$394	2	101,094	840	2
Integrated Base MR	38,708	\$1,067	3	117,634	17,380	11
Integrated No CCS MR	39,227	\$1,586	6	104,731	4,477	4
Integrated Base LN	42,873	\$5,232	12	157,891	57,637	13
Integrated Base HH	37,640	\$0	1	100,254	0	1

Integrated Portfolios Under Medium Gas/ Federal Regulation (MR)

Three variant cases examined compliance under the current language in EPA 111(d): the base MR case, the MR No CCS case, and the No Coal Post-2032 case. Details for each MR case is included with the discussions of the integrated portfolio results below.

Variant Study Analysis**No CCS Variant**

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were found not to be commercially viable at this location. As Jim Bridger 3 and 4 run as coal in this case, the No CCS variant serves as the “All Coal End of Life” variant as well.

Figure 9.17 shows the cumulative (at left) and incremental (at right) portfolio changes when CCS at Jim Bridger 3 and 4 is not allowed on the system starting in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Over the course of the horizon, fewer proxy resources are built. There is reduction of 469 MW of wind, 236 MW of solar and 989 MW of battery, with battery reductions occurring in 2042 and 2045.

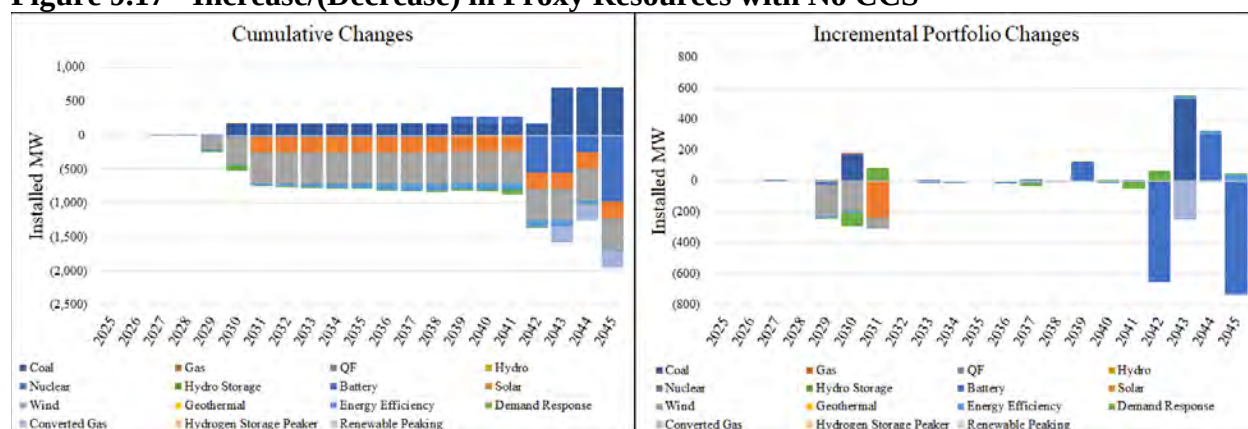
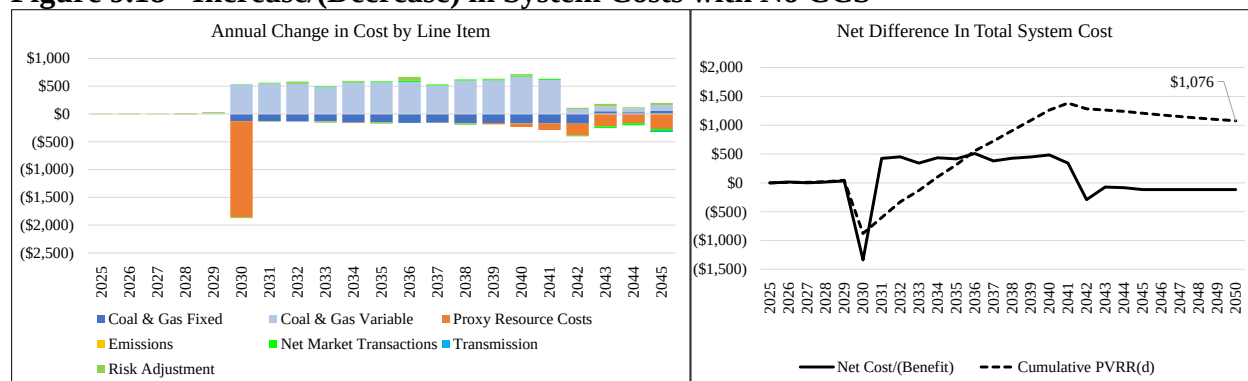
Figure 9.17 - Increase/(Decrease) in Proxy Resources with No CCS

Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a \$1.076 billion increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.18 - Increase/(Decrease) in System Costs with No CCS

No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2032. Additionally, this variant does not allow any proxy nuclear to be selected as a potential replacement for the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the nuclear projects prove unviable.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case does not select small renewable peaking resources and reduces 100-hour battery selection by 1,955 MW. The No Nuclear portfolio does add an additional 923 MW of 4-hour storage, 347 MW

of wind, 296 MW of solar, and 120 MW of DSM. This study also keeps the CCS at Jim Bridger and Naughton 1 gas conversion through the end of the study horizon.

Figure 9.19 - Increase/(Decrease) in Proxy Resources with No Nuclear

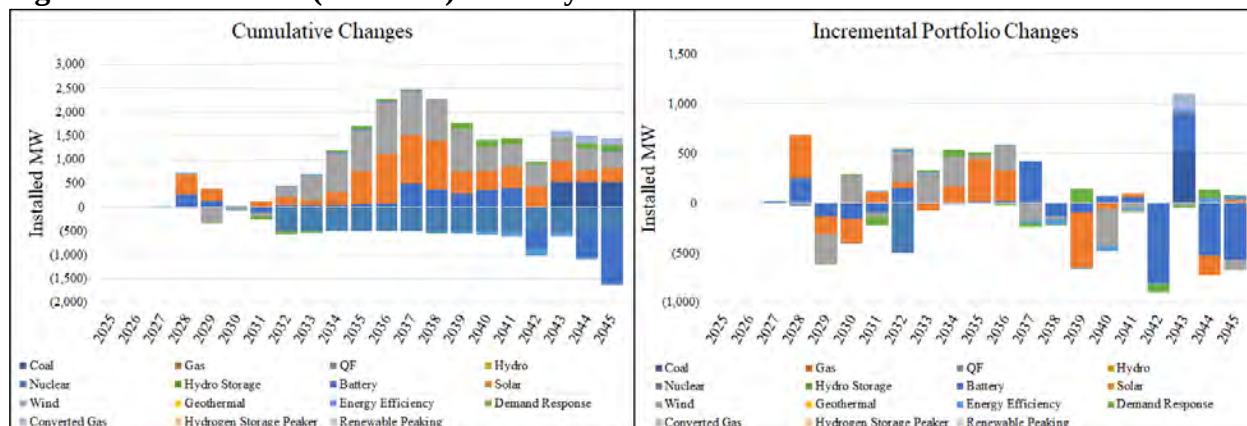
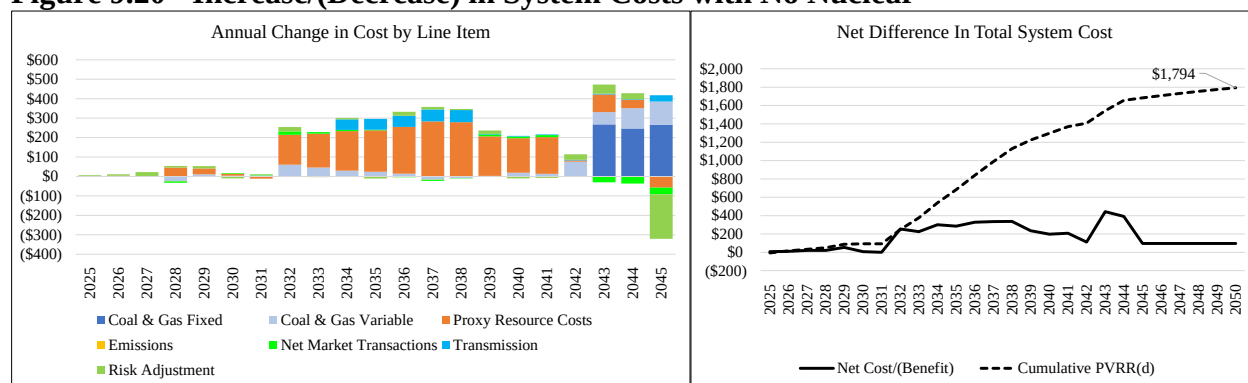


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a \$1.794 billion increase in costs compared to the preferred portfolio. Given that no costs associated with the Natrium™ demonstration project are included in modeling, the increase in costs reflects the loss of all energy and PTC benefits associated with the project.

As seen in Figure 9.20 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.20 - Increase/(Decrease) in System Costs with No Nuclear



No Coal Post-2032 Variant

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is

distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS. Because all units eligible for gas conversion either convert to gas or retire early, this study also serves as the “Force Gas Conversion” variant.

Figure 9.21 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects additional energy efficiency and demand response, over 2,200 MW of additional wind and solar, and a shift in storage from 4-hour to long duration.

Figure 9.21 - Increase/(Decrease) in Proxy Resources with No Coal Post-2032

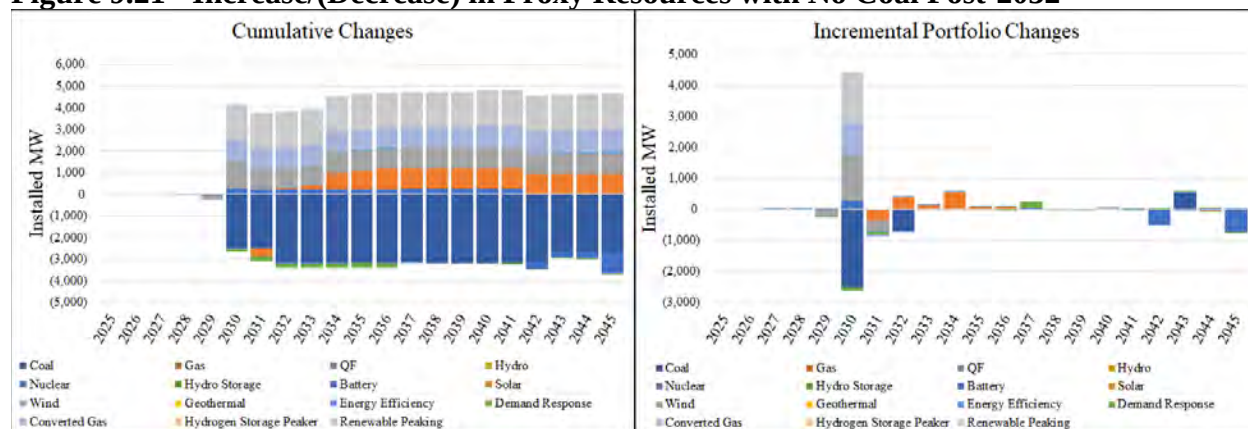
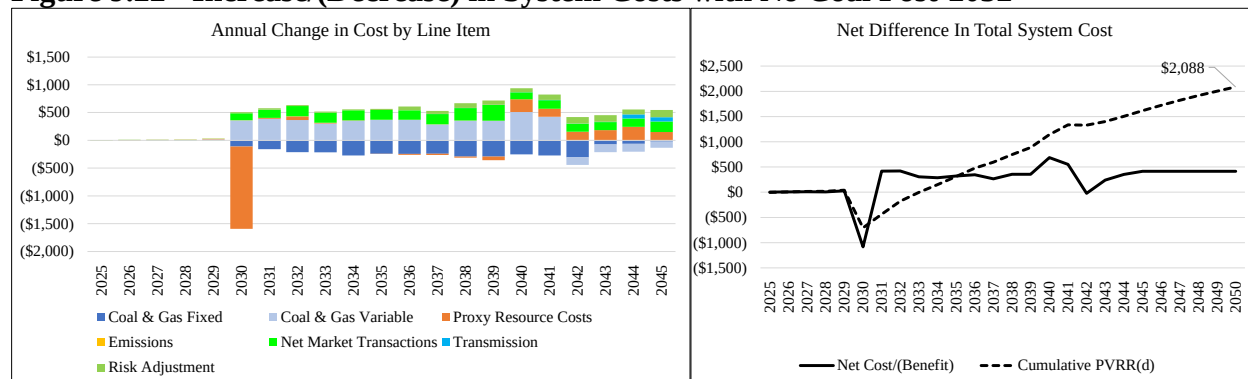


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or converted to gas by 2032, the resulting portfolio has a \$2.088 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.22 below, the system cost increase exceeds the impact of 45Q tax credits and CCS capital cost. Additionally, this case has higher levels of market purchases and has higher proxy resource costs in nearly all years of the study horizon.

Figure 9.22 - Increase/(Decrease) in System Costs with No Coal Post-2032



Force Offshore Wind

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 9.23 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2033. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The portfolio selects and additional 120 total MW of wind, 3,760 MW of 4-hour storage and 35 MW of additional DSM. These increased selections are partially offset by a reduction of 132 MW of solar and 812 MW of 100-hour storage. Retirements are the same between the studies.

Figure 9.23 - Increase/(Decrease) in Proxy Resources with Offshore Wind

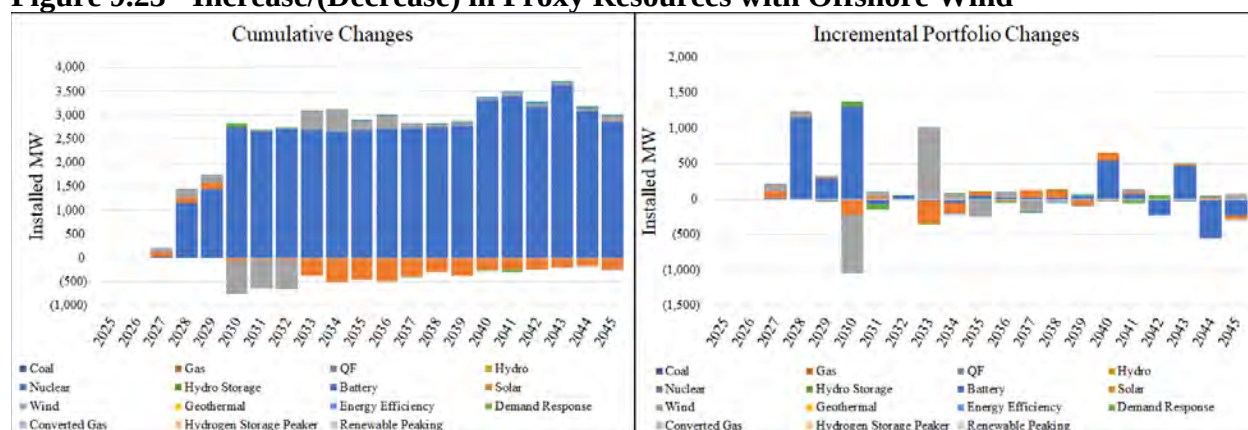
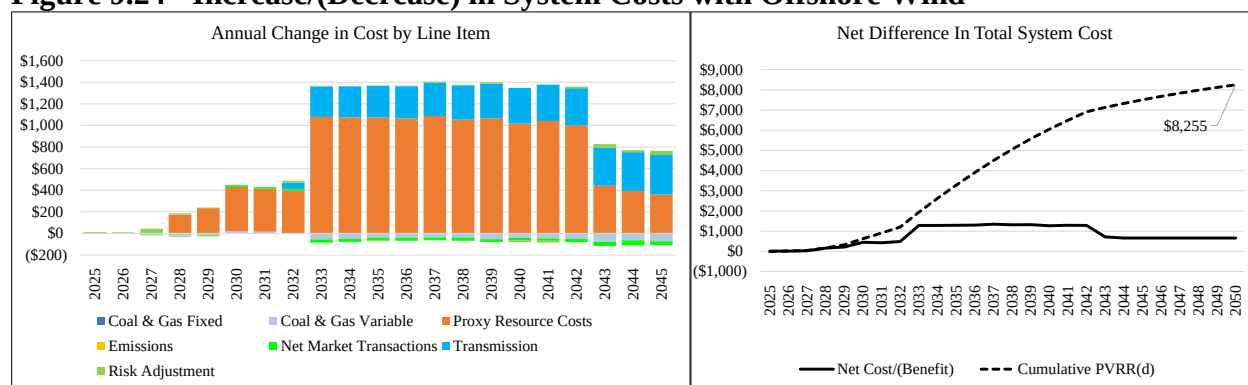


Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a \$8.255 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.24 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

Figure 9.24 - Increase/(Decrease) in System Costs with Offshore Wind

No Forward Technology

This variant does not allow the Natrium™ demonstration nuclear project, hydrogen storage, 100-hour battery or small biodiesel peaking units to be selected as resource options. The analysis explores the potential costs and benefits of replacement resource options should these technologies not become commercially viable during the assumed time frame as modeled.

Figure 9.25 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case selects 120 MW of additional DSM, 187 MW of additional wind and 254 additional MW of solar. The model replaces the 3,073 MW of 100-hour storage with 1,826 MW of 4-hour storage and also does not retire CCS at Jim Bridger or the Naughton 1 gas conversion.

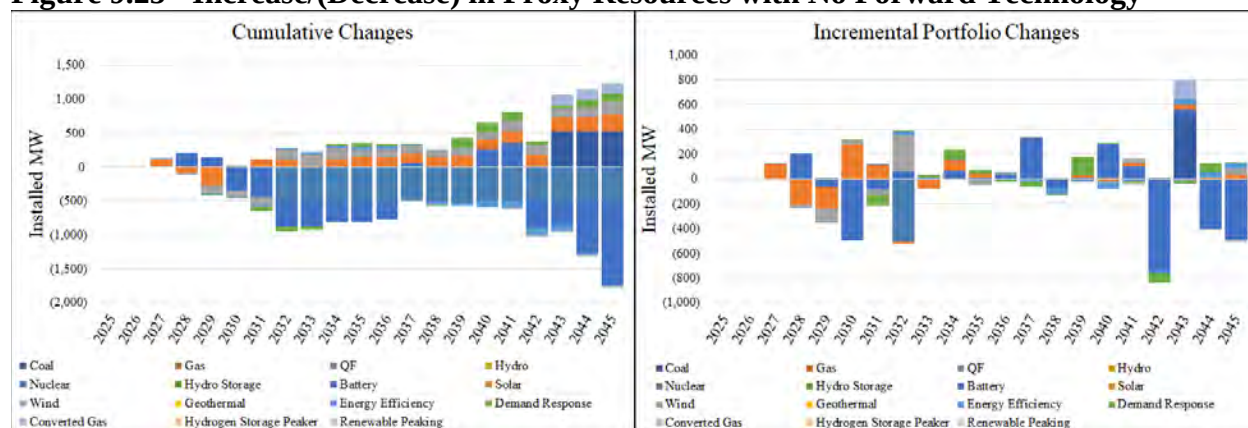
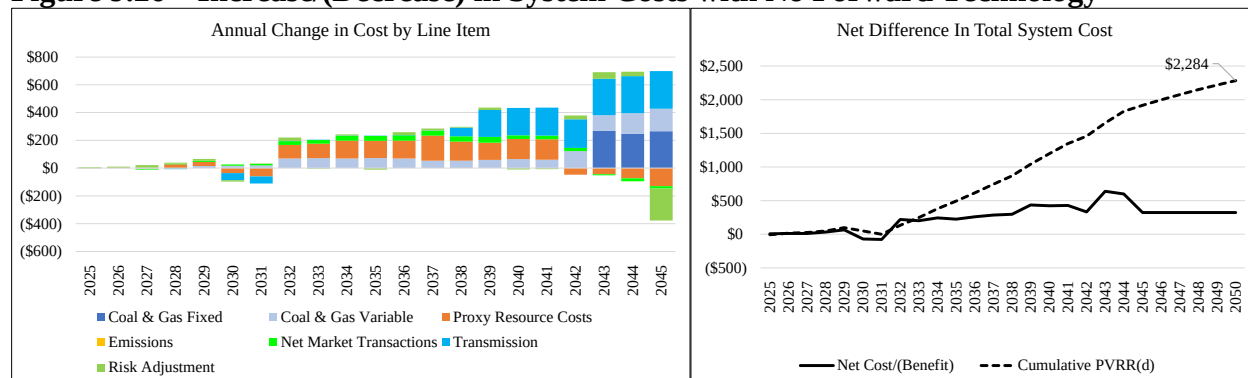
Figure 9.25 - Increase/(Decrease) in Proxy Resources with No Forward Technology

Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all forward technology is removed from the portfolio, the resulting portfolio has a \$2.284 billion increase in costs compared to the preferred portfolio, somewhat higher than the impact of removing Natrium™ alone as shown in Figure 9.20.

As seen in Figure 9.26 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease

in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.26 – Increase/(Decrease) in System Costs with No Forward Technology



Force Geothermal

Since geothermal was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor geothermal resource.

Figure 9.27 shows the cumulative (at left) and incremental (at right) portfolio changes when geothermal is forced into the portfolio by 2028. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The geothermal study does not retire the Naughton 1 gas conversion. Additionally, the firm capacity more than 700 MW of geothermal reduces the need for other renewable resources. Over 2,500 MW of wind and solar are removed, as well as over 2,200 MW of long duration storage. 719 MW of 4-hour storage is selected in the geothermal study.

Figure 9.27 - Increase/(Decrease) in Proxy Resources with Geothermal

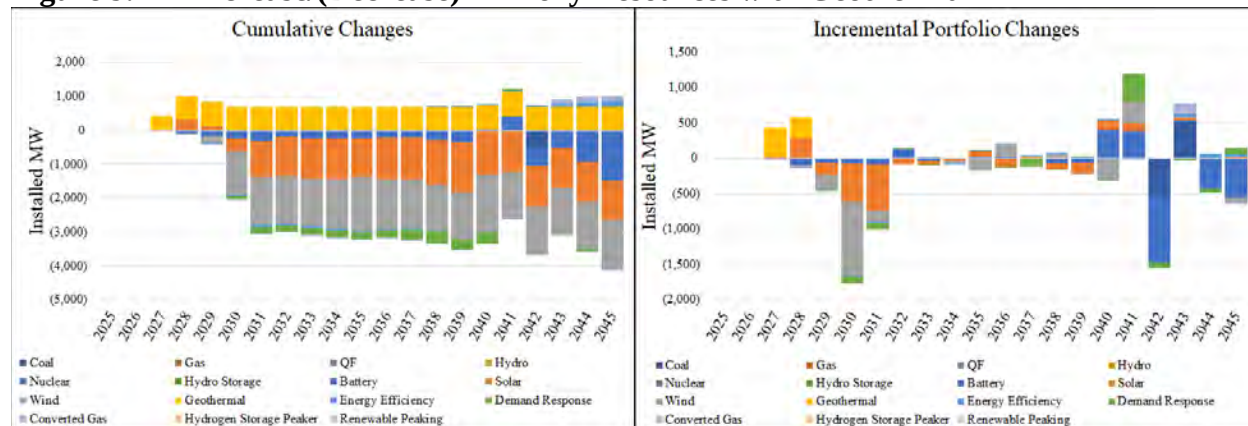
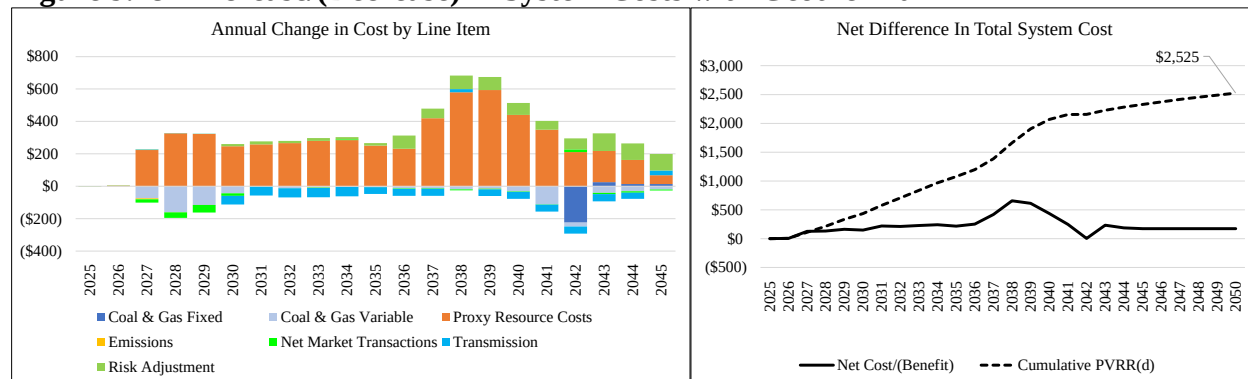


Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the geothermal is forced into the portfolio, the resulting portfolio has a \$2.525 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.28 below, these increases come primarily from increased costs of the geothermal compared to the lower costs of the renewable resources that were replaced by the geothermal.

Figure 9.28 - Increase/(Decrease) in System Costs with Geothermal



Force Hunter Retirement

Responsive to stakeholder request, PacifiCorp performed a variant analysis exploring what the impact of an early retirement of the Hunter plant would be on the portfolio. In this variant, all units at Hunter were required to retire by 2030. The analysis explores the potential costs and benefits of replacing the Hunter plant with resources selected in the UIWC jurisdictional portfolio when Hunter is not available. Additional consideration of Utah regulations would be necessary before the company would be able to move forward with implementing this variant.

Figure 9.29 shows the cumulative (at left) and incremental (at right) portfolio changes when Hunter is forced to retire in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The Hunter study does not retire the Naughton 1 gas conversion. The loss of 1,100 MW of firm capacity in 2030 leads to the selection of over 1,100 MW of wind and solar, coupled with 866 MW of additional storage in 2030. By the end of the study horizon, the model selects 99 MW of new gas, an additional 355 MW of energy efficiency and demand response, and over 1,400 MW of new renewables. Total battery selection over the horizon stays the same but has a shift from 4-hour to 100-hour storage.

Figure 9.29 - Increase/(Decrease) in Proxy Resources with Hunter Retirement

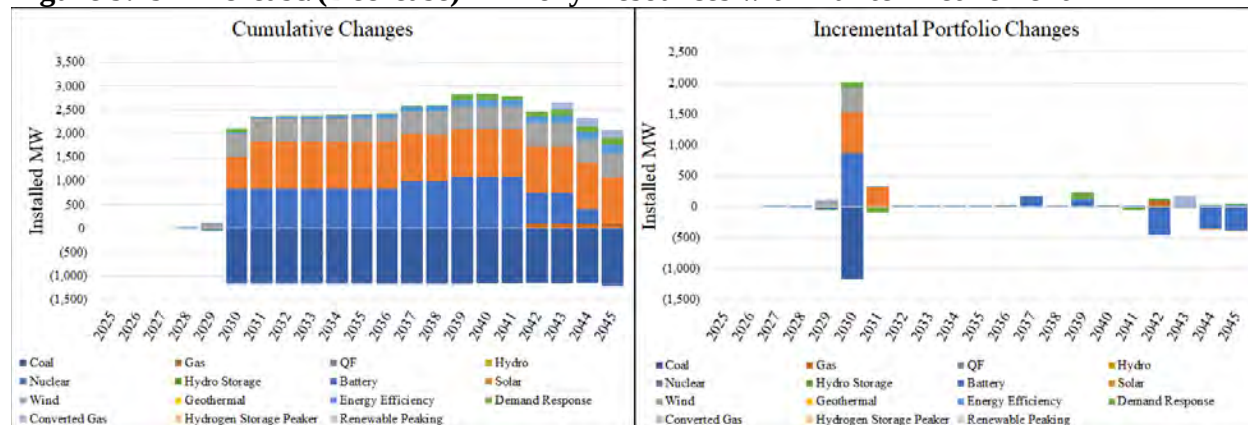
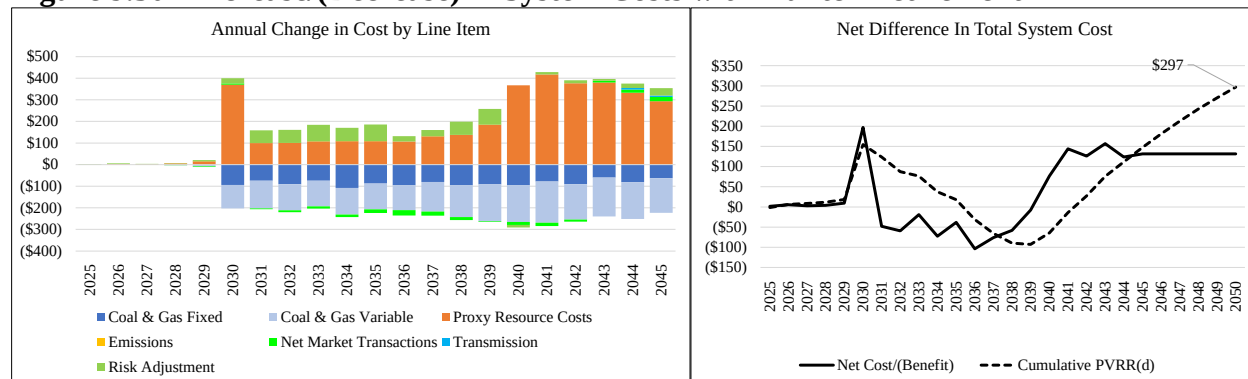


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Hunter is forced to retire in 2030, the resulting portfolio has a \$297 million increase in costs compared to the preferred portfolio.

As seen in Figure 9.30 below, these increases come primarily from the additional proxy resource costs associated with replacing the Hunter plant in 2030.

Figure 9.30 - Increase/(Decrease) in System Costs with Hunter Retirement



MR Portfolio

The MR portfolio evaluates resource selections assuming EPA 111(d) rules remain in effect through the study horizon. This portfolio limits new gas capacity factors and requires either installation of CCS, gas conversion, or retirement of existing coal units by 2032. The purpose of this study is to evaluate a path PacifiCorp would pursue for long-term compliance with this rule.

Figure 9.31 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In an MR future, all plants that are eligible to convert from using coal to using a different fuel type do. Wyodak and Hunter 1 both retire in 2032. This reduction in coal capacity and the significantly lower capacity factor of converted units leads to an additional 1,299 MW of solar, 916 MW of wind and 369 MW of DSM. The portfolio also selects 451 MW of additional 100-hour battery, while removing 575 MW of 4-hour storage.

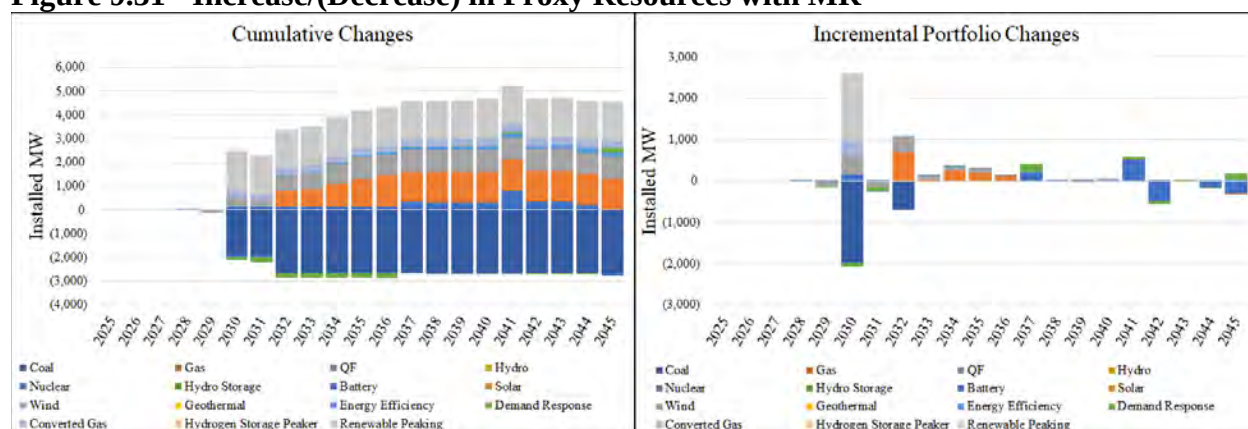
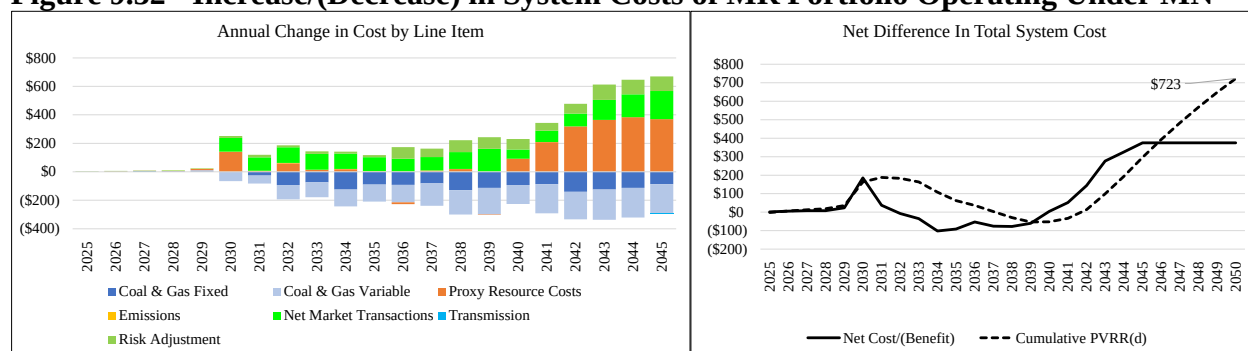
Figure 9.31 - Increase/(Decrease) in Proxy Resources with MR

Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the MR portfolio is operating under the MN price policy, the resulting portfolio has a \$723 million increase in costs compared to the preferred portfolio.

Figure 9.32 - Increase/(Decrease) in System Costs of MR Portfolio Operating Under MN

MR No CCS

The MR No CCS portfolio evaluates what changes would occur to the MR portfolio if CCS at Jim Bridger were to prove to not be a viable option for EPA 111(d) compliance. This portfolio limits new gas capacity factors and requires either gas conversion, or retirement of existing coal units by 2032, precluding CCS selections. The purpose of this study is to evaluate the path PacifiCorp would take to be compliant with this rule in the absence of CCS at Bridger.

Figure 9.33 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Jim Bridger 3 and 4 gas convert in lieu of installing CCS and does not retire Naughton 1 gas conversion. Hunter 1 retires in 2031 instead of 2032. Keeping the Jim Bridger and Naughton units leads to lower proxy resource selections across all generating types. The portfolio reduces wind by 55 MW, DSM by 378 MW and solar by 561 MW. Battery selections remain cumulatively the same with a shift from 24-hour battery to 4-hour battery.

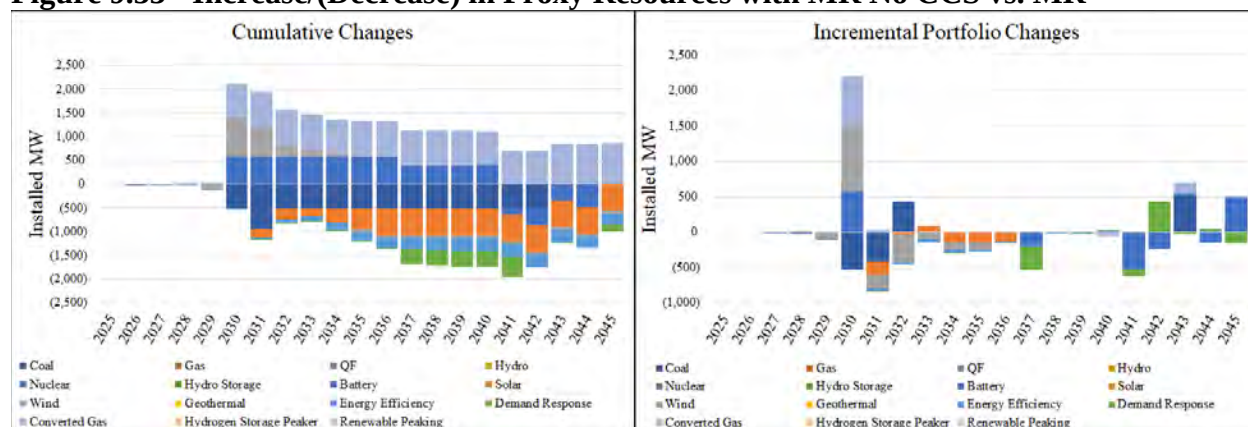
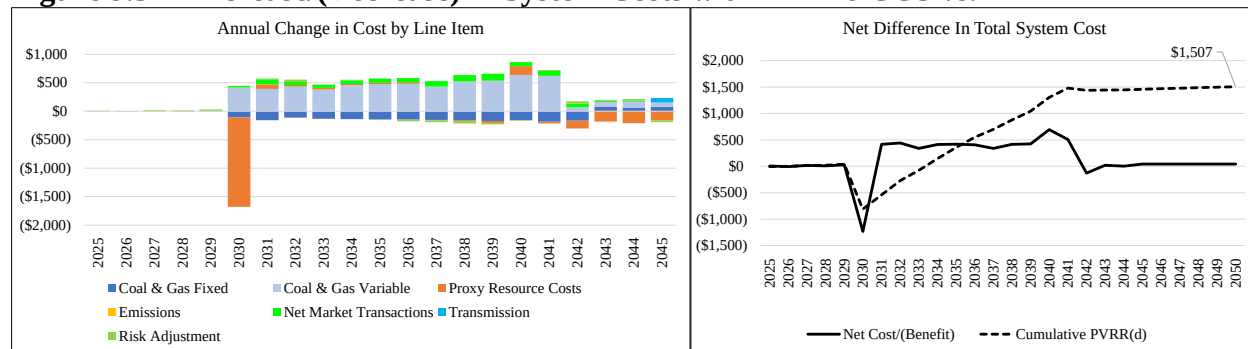
Figure 9.33 - Increase/(Decrease) in Proxy Resources with MR No CCS vs. MR

Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a \$1.507 billion increase in costs compared to the MR portfolio with CCS.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.34 - Increase/(Decrease) in System Costs with MR No CCS vs. MR

HH Portfolio

The HH portfolio evaluates what selections would be made under high future costs, including gas, market, and coal. This portfolio integrated Oregon selections under HH, UIWC selections under HH and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a high-cost future was most likely.

Figure 9.35 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a high price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The HH Portfolio selects Dave Johnston 4 and Hunter 2 to convert from coal to a different fuel in 2030. The HH also retires Hunter 2 in 2033. The model increases brownfield renewable selections by 2007 MW and selects 562 additional MW of 100-hour storage. There is a reduction in 4-hour

storage of 757 MW, however all selections of additional 4-hour storage occur in 2030 in the HH run. An additional 208 MW of DSM is also selected.

Figure 9.35 - Increase/(Decrease) in Proxy Resources with HH

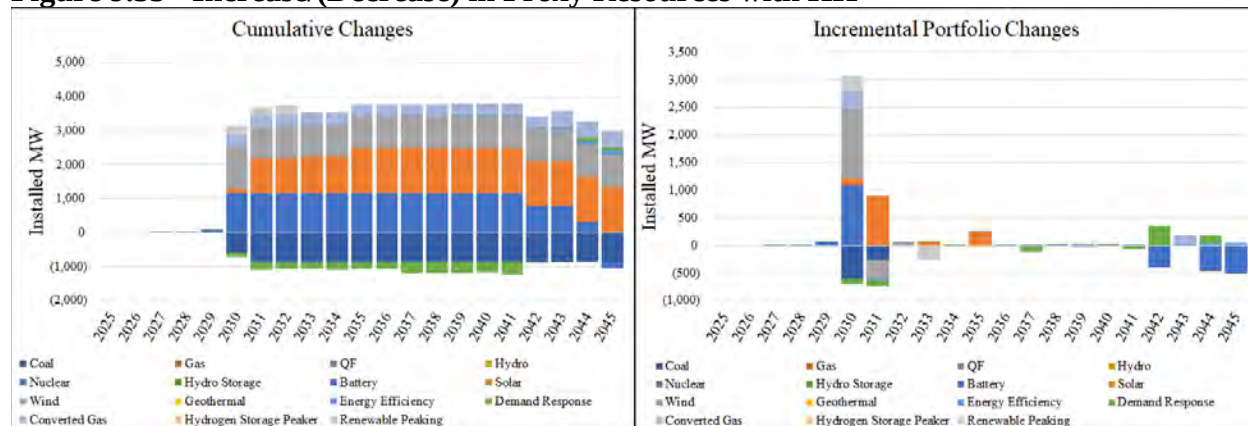
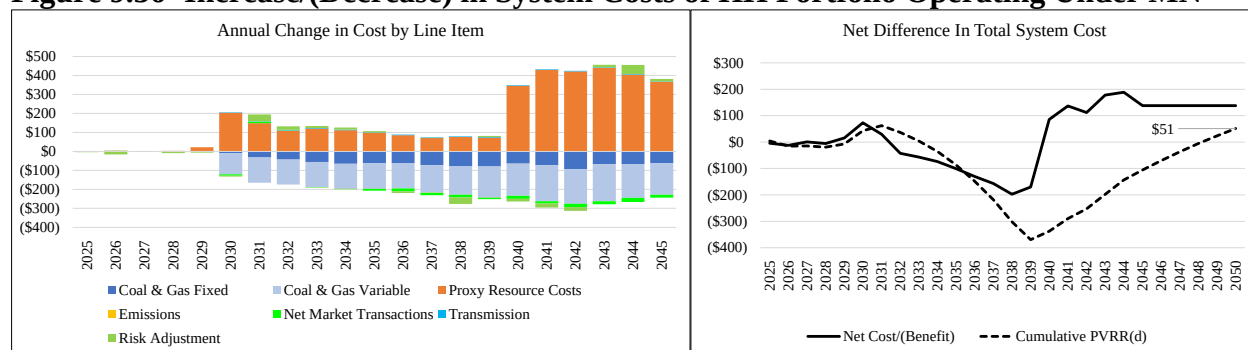


Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the HH portfolio is operating under the MN price policy, the resulting portfolio has a \$51 million increase in costs compared to the preferred portfolio.

Figure 9.36- Increase/(Decrease) in System Costs of HH Portfolio Operating Under MN



LN Portfolio

The LN portfolio evaluates what selections would be made under low future costs, including gas and market with no CO₂ tax adder. This portfolio integrated Oregon selections under LN, UIWC selections under LN and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a low-cost future was most likely.

Figure 9.37 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a low-price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The LN portfolio delays the retirement of the Jim Bridger CCS conversions one year and does not retire Naughton 1. The LN does select 496 MW of new gas peaking units in 2045 in place of the 41 MW of renewable peaking in the preferred portfolio. There is an increase of 91 MW of DSM, and a reduction of 508 MW of new renewable generation. The model selects and additional 389 MW of storage, swapping 100-hour for 4-hour battery.

Figure 9.37 - Increase/(Decrease) in Proxy Resources with LN

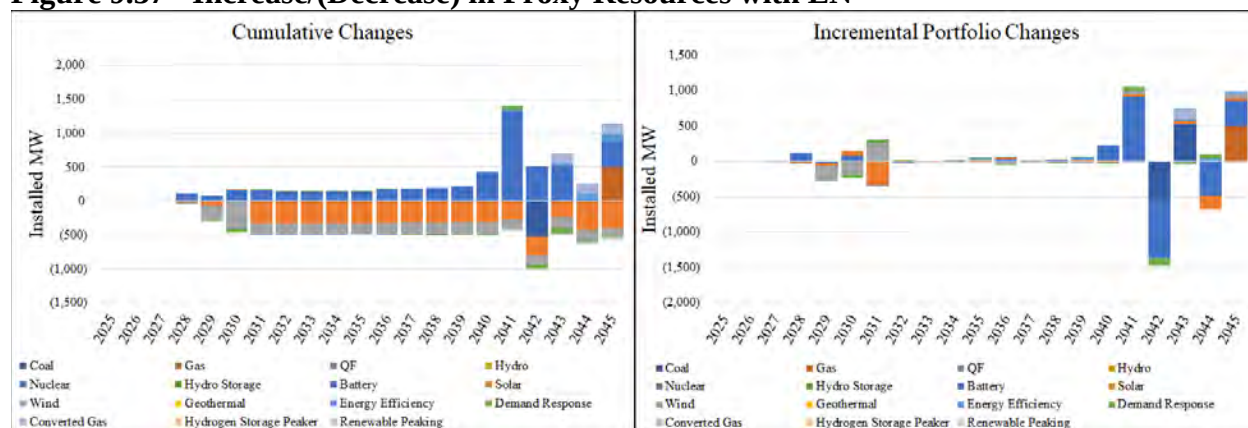
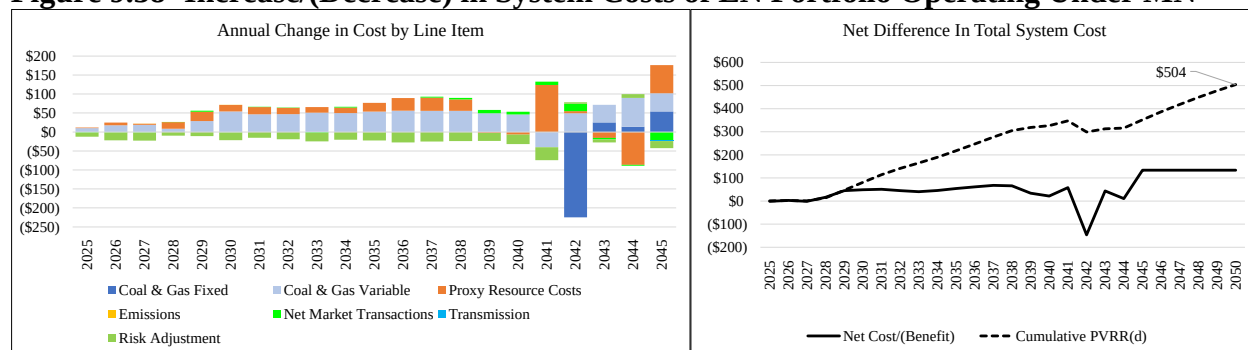


Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the LN portfolio is operating under the MN price policy, the resulting portfolio has a \$504 million increase in costs compared to the preferred portfolio.

Figure 9.38- Increase/(Decrease) in System Costs of LN Portfolio Operating Under MN



SCGHG Portfolio

The SCGHG portfolio evaluates what selections would be made under a Social Cost of Greenhouse Gas future. This portfolio integrated all jurisdiction's selections under SCGHG. The purpose of this study is to evaluate the selections PacifiCorp would make if an SCGHG future was most likely.

Figure 9.39 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and an SCGHG future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The SCGHG portfolio does not retire the Jim Bridger CCS conversions or Naughton 1 but does retire Wyodak in 2028 and the Dave Johnston 1 gas conversion in 2043. Additionally, the SCGHG case chooses gas conversion at Dave Johnston 4 and allows it to continue through the 21-year horizon and does not retire Naughton 1. The SCGHG case selects an additional 999 MW of utility scale wind, 1,269 MW of utility scale solar, 1,756 MW of 4-hour battery and 240 MW of DSM. The portfolio reduces small scale solar selections by 101 MW and 100-hour storage by 126 MW.

Figure 9.39 - Increase/(Decrease) in Proxy Resources with SCGHG

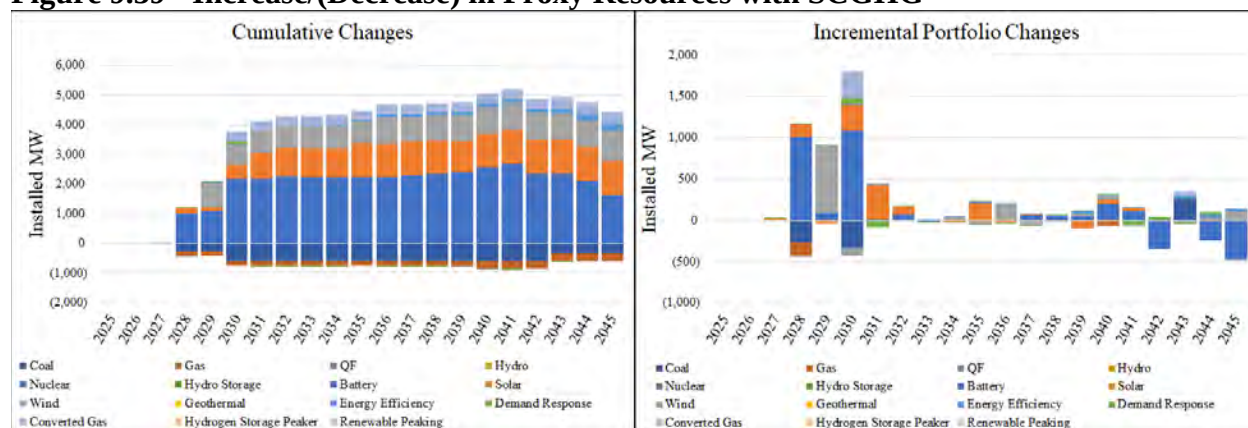
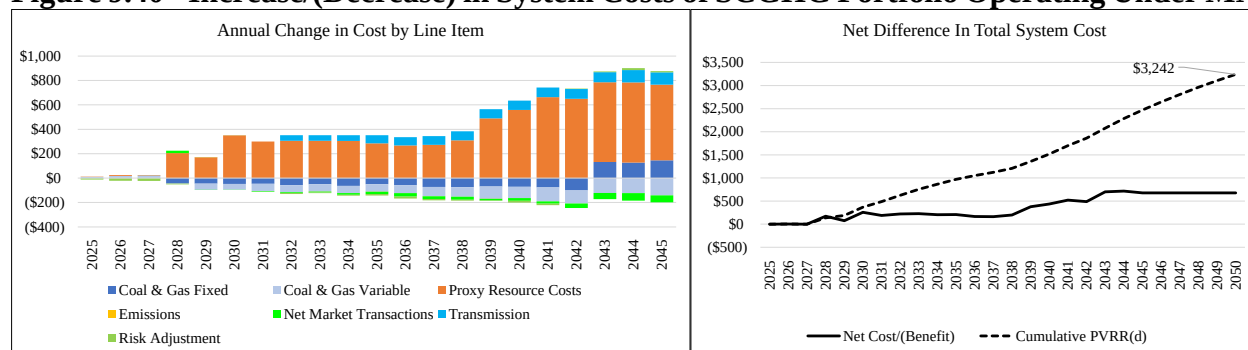


Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the SCGHG portfolio is operating under the MN price policy, the resulting portfolio has a \$3.242 billion increase in costs compared to the preferred portfolio.

Figure 9.40 - Increase/(Decrease) in System Costs of SCGHG Portfolio Operating Under MN



Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases were developed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. It is assumed that state level compliance would still be required to be met in these sensitivities; Oregon would still need to reduce emissions, and Washington would need to meet CETA targets. These sensitivity cases are also useful as “bookend” analysis to aid in understanding how PacifiCorp’s resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risks.

Table S.1 lists additional sensitivity studies to be performed for the 2025 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are evaluated in comparison to the preferred portfolio.

Table S.1– Summary of Additional Sensitivity Cases

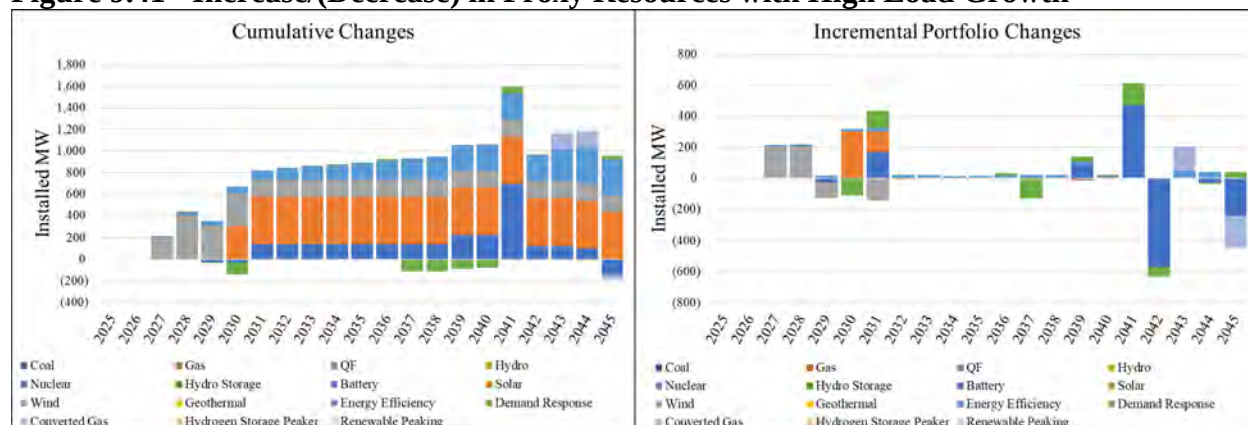
Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20-year highest load
High Distributed Generation	Assumes lower load due to high Distributed Generation adoption
Low Distributed Generation	Assumes higher load due to low Distributed Generation adoption
Large-metered Load Growth	Assumes significant large-metered customer load growth
Low Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at additional coal units
Business as Usual	Portfolio if no state requirements existed
Business Plan ⁸	First 3 years are aligned with the current business plan

High Load Growth

The High Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if load grows faster than anticipated.

Figure 9.41 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high load growth portfolio does not retire Naughton 1 but does retire Naughton 2 in 2045. The higher load growth leads to an additional 319 MW of DSM, 160 MW of wind, and 435 MW of solar. There is a total reduction of 137 MW of storage, with 329 fewer MW of 4-hour storage offset by 100 MW of 8-hour and 92 MW of 100-hour storage.

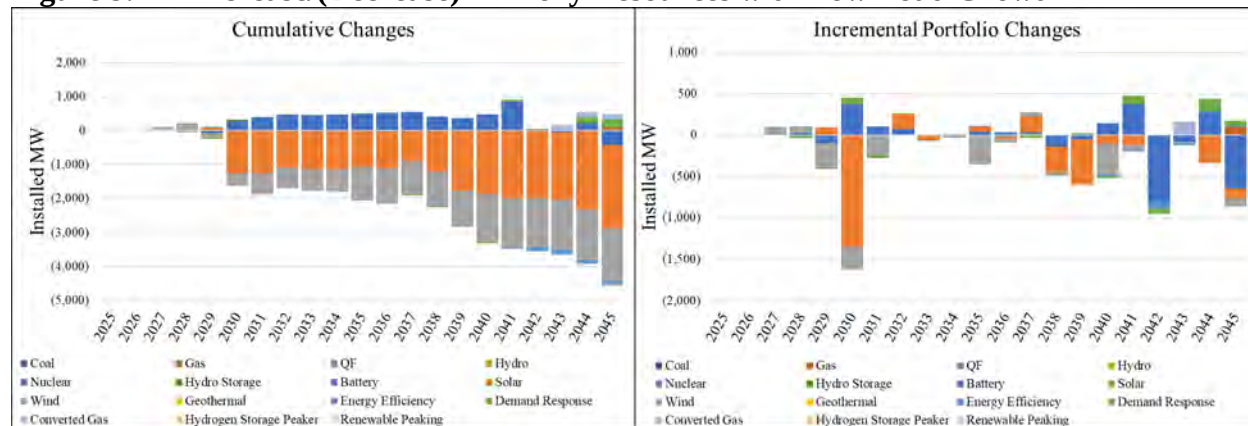
⁸ In the 2025 IRP, the business plan sensitivity is aligned with the integrated preferred portfolio due to the base assumptions being aligned. For this reason, no additional sensitivity is needed.

Figure 9.41 - Increase/(Decrease) in Proxy Resources with High Load Growth

Low Load Growth

The Low Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify which resources might be economic if load grows more slowly than anticipated.

Figure 9.42 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low load growth portfolio does not retire Naughton 1. Due to the lower need, the portfolio selects 1,566 MW less wind, 2,440 MW less solar and 425 MW less storage, with a reduction in 100-hour storage offset by additional 4-hour storage. The portfolio does select an additional 125 MW of DSM.

Figure 9.42 - Increase/(Decrease) in Proxy Resources with Low Load Growth

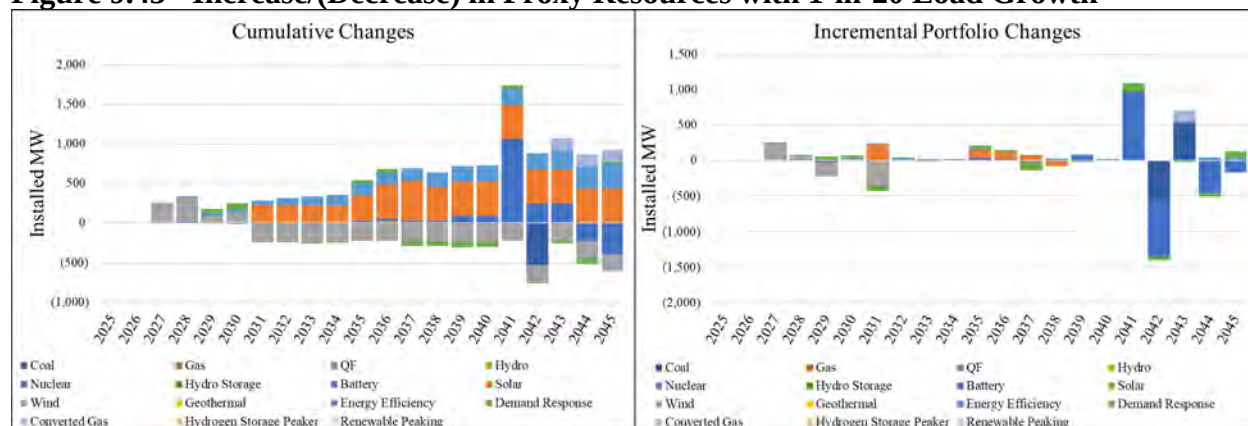
1-in-20 Peak Load Growth

The 1-in-20 Peak Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if peak load is higher than anticipated.

Figure 9.43 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and higher 1-20 peak loads. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The 1-20 peak

load portfolio retires the Jim Bridger CCS conversions 1 year later and does not retire Naughton 1. The higher peak loads lead to an additional 317 MW of DSM and 431 MW of additional solar. There is a reduction of 222 MW of wind and 385 MW of storage.

Figure 9.43 - Increase/(Decrease) in Proxy Resources with 1-in-20 Load Growth

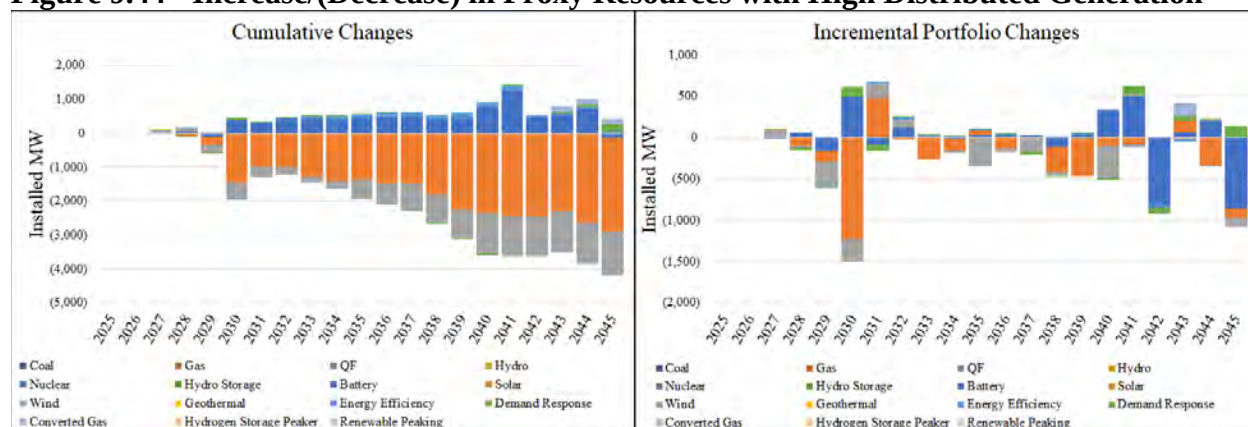


High Distributed Generation Growth

The High Distributed Generation Growth sensitivity evaluates what selections would be made if distributed generation growth were higher than projected (and load was lower as a result). The purpose of this study is to identify which resources would be economic if load is lower than anticipated.

Figure 9.44 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high distributed generation growth portfolio selects an additional 269 MW of DSM. The portfolio reduces renewable resources by 4,078 MW and storage resources by 135 MW over the course of the 21-year horizon.

Figure 9.44 - Increase/(Decrease) in Proxy Resources with High Distributed Generation

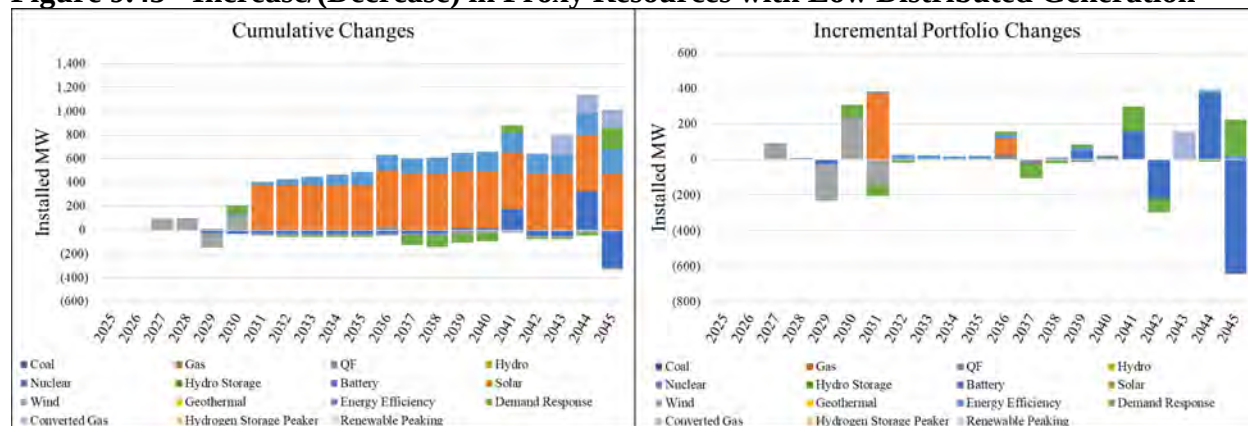


Low Distributed Generation Growth

The low distributed generation growth sensitivity evaluates what selections would be made if distributed generation growth were lower than projected. The purpose of this study is to identify potential additional resource needs if distributed generation growth is lower than anticipated.

Figure 9.45 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low distributed generation portfolio does not retire Naughton 1. The higher load need leads to 349 additional MW of DSM and 471 MW of solar. There is a reduction of 15 MW of wind and 351 MW of 4-hour storage partially offset by an additional 40 MW of 100-hour storage.

Figure 9.45 - Increase/(Decrease) in Proxy Resources with Low Distributed Generation



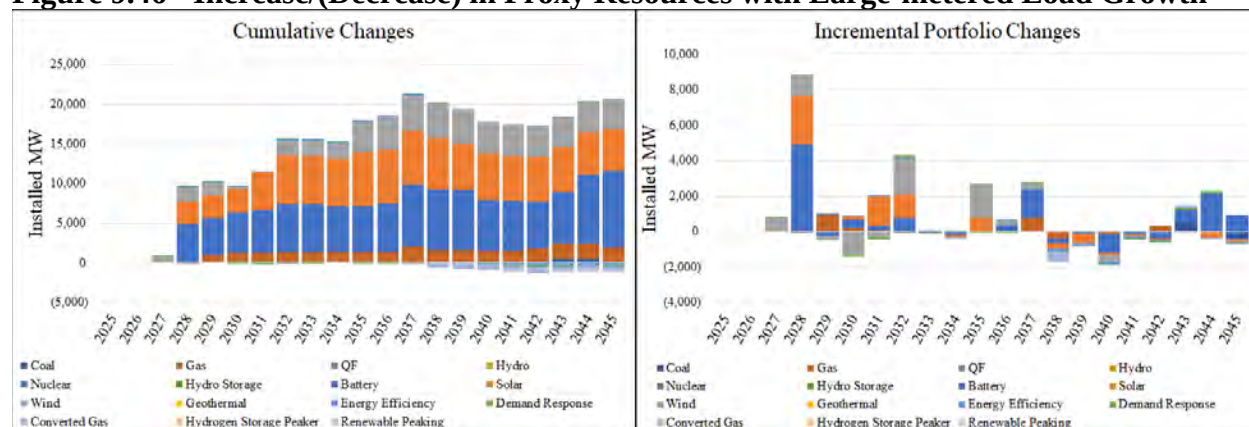
Large-Metered Load Growth

The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the system had to serve all of these large-metered loads.

Figure 9.46 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This sensitivity selects 2,354 MW of gas peaking units, an additional 3,872 MW of utility scale wind, an additional 5,993 MW of utility scale solar and 9,650 MW of additional storage. In 2038, the large-metered load growth portfolio retires 804 MW of existing thermal units that were not retired in the preferred portfolio. In addition to significant resource additions, serving large-metered load requires significant transmission investments. Table 9.38 shows the transmission required in the large-metered load growth study.

Table 9.38 – Large-metered Load Transmission Selections

Line	Year Selected
INC B2H2 Hemingway>Longhorn - 2033	2033
INC BorahPop > Hemingway 2037 Segment E	2037
INC BorahPop > Wasatch Front 2035 D3.2	2044
INC BorahPop > Wasatch Front 2035 D3.3	2035
INC Bridger > BorahPop 2032	2032
INC Bridger > BorahPop 2035 D3.2	2044
INC Bridger > Wyoming East 2032 D2.2	2032
INC Goshen > NUT 2035 1b	2035
INC NUT > Goshen 2029	2029
INC NUT > Wasatch Front 2029	2029
INC NUT > Wasatch Front 2030 2C7 3C6	2030
INC Portland North Coast > Willamette Valley 2037	2037
INC Portland North Coast > Yakima 2029	2029
INC Utah South > Wasatch Front 2028B	2028
INC Utah South > Wasatch Front 2029	2029
INC Utah South > Wasatch Front 2035	2035
INC Willamette Valley > Central OR 2032	2032
INC Willamette Valley > Southern OR 2036	2036
INC Wyoming East > BorahPop 2035 D3.3	2035
INC Wyoming East > Bridger 2032	2032
INC Wyoming East > Clover 2035 GWS2	2044

Figure 9.46 - Increase/(Decrease) in Proxy Resources with Large-metered Load Growth

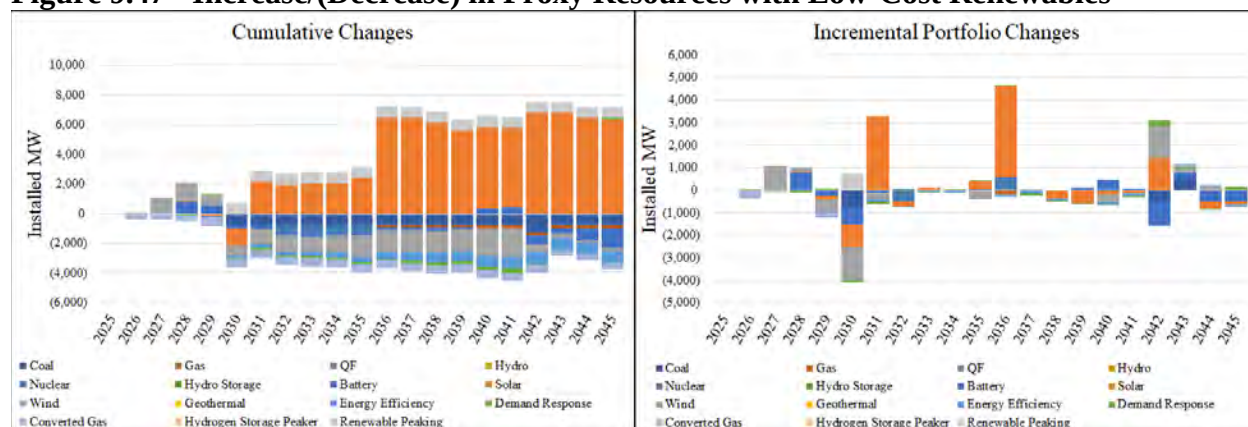
Low-Cost Renewables

The low-cost renewables sensitivity evaluates what selections would be made if renewable resources were lower cost than the current modeling expectations. The purpose of this study is to identify potential additional resources if the company were able to take advantage of all tax credits and assumes advantageous financing to complete projects.

Figure 9.47 shows the cumulative (at left) and incremental (at right) portfolio changes between the preferred portfolio and a portfolio acquiring resources on the advantageous basis described above. A positive value indicates an increase in resources and a negative value indicates a decrease when

a resource is reduced or eliminated. The low-cost renewables portfolio selects 199 MW less wind, but 7,187 MW of additional utility scale solar. The model also selects 950 more MW of short and medium duration storage, but 2,549 MW less 100-hour battery. Of note, coal plants which are able to endogenously retire throughout the horizon convert to alternate fuels but do not retire under this sensitivity.

Figure 9.47 - Increase/(Decrease) in Proxy Resources with Low-Cost Renewables

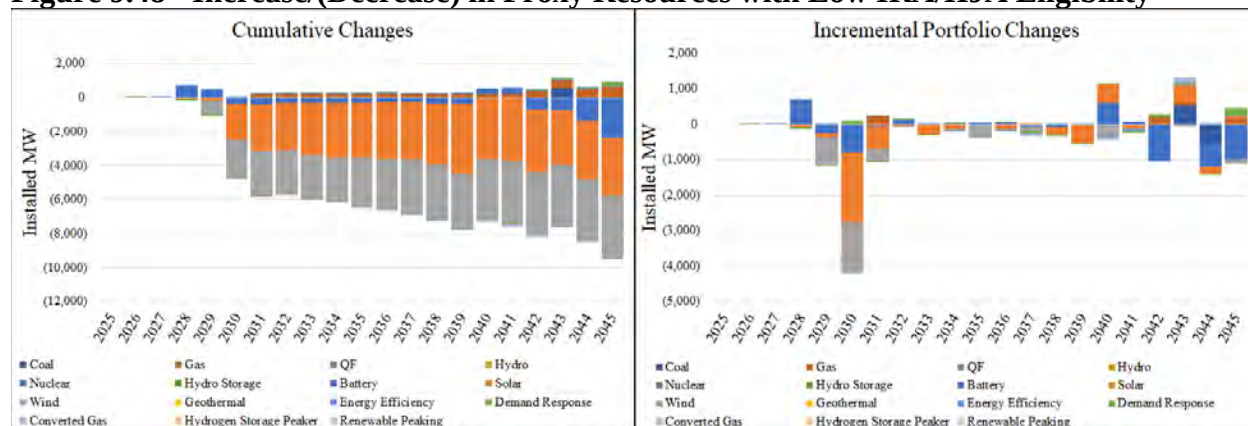


Low IRA/IIJA Eligibility

The low IRA/IIJA sensitivity evaluates what selections would be made if no resources were ever eligible for IRA or IIJA credits. The purpose of this study is to identify the impact if tax credits were not available to any new resources.

Figure 9.48 shows the cumulative (at left) and incremental (at right) portfolio changes between the low IRA/IIJA portfolio and the preferred portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low IRA/IIJA portfolio includes an additional 627 MW of gas peaking units, and 311 more MW of DSM. The low IRA/IIJA portfolio also includes a reduction of 3,782 MW of wind and 3,366 MW of solar, as well as 2,382 MW of storage. This sensitivity delays the Bridger CCS retirement by one year.

Figure 9.48 - Increase/(Decrease) in Proxy Resources with Low IRA/IIJA Eligibility

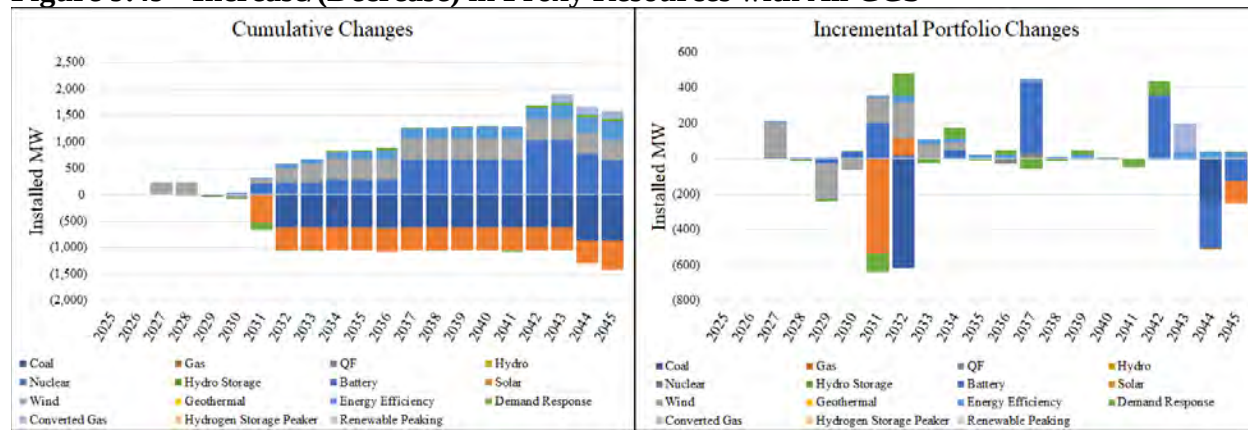


All CCS

The All CCS sensitivity evaluates what selections would change if it were feasible to convert all units to CCS that would be eligible for conversion. The purpose of this study is to identify the impact of installing up to 8 CCS units.

Figure 9.49 shows the cumulative (at left) and incremental (at right) portfolio changes between the base assumption and allowing all CCS. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In this sensitivity, all eligible units except Wyodak convert to CCS. The lower maximum output means that the sensitivity selects additional resources, including 391 MW of DSM, 397 MW of additional wind and 637 more MW of storage. The only significant reduction is 431 MW of solar.

Figure 9.49 - Increase/(Decrease) in Proxy Resources with All CCS

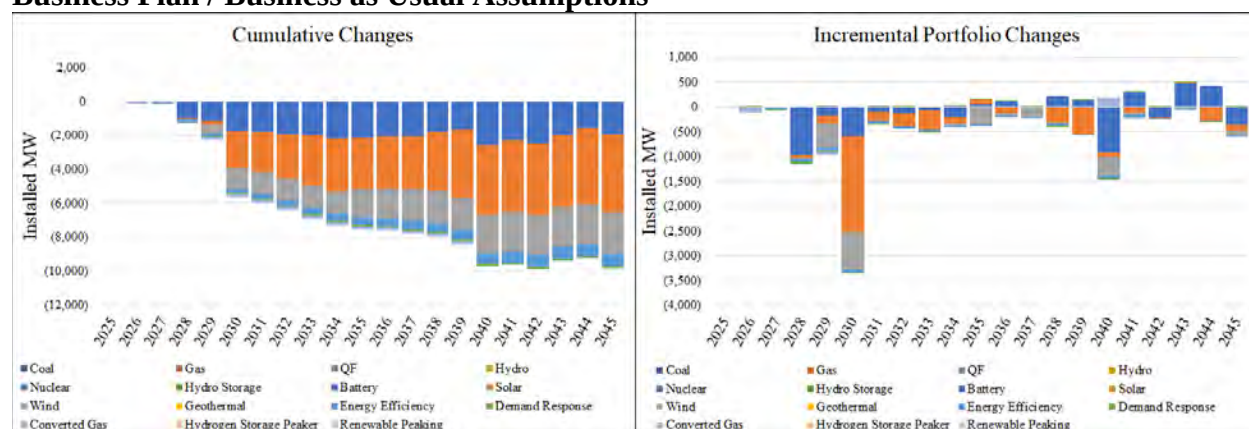


Business as Usual/Business Plan

The business as usual and business plan sensitivities were able to be covered by the same study. The business-as-usual study requires that coal retires no earlier than in the 2017 IRP unless otherwise mandated to do so by law. The business plan study requires that the first three years of the horizon align with the business plan, and then the model is able to endogenously choose any outcomes. These studies explicitly require operation and resource selection in the absence of any state or federal requirements, and the portfolio must be selected only on the basis of economics.

Figure 9.50 shows the cumulative (at left) and incremental (at right) portfolio changes between the preferred portfolio and a business-as-usual case. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This view selects significantly fewer resources. In total, there are 9,879 fewer MW chosen, and coal continues to remain on the system as in the preferred portfolio. This portfolio selects 2,488 MW less wind, 3,496 MW less utility scale solar, 1,147 MW less small scale solar and a total of 1,903 MW less storage (replacing 100-hour battery with 4-hour battery).

Figure 9.50 - Increase/(Decrease) in Proxy Resources with Business Plan / Business as Usual Assumptions



Washington Scenarios

As described in Chapter 8, in addition to the information provided throughout the 2025 IRP, Washington's CETA legislation mandates three key studies for analysis, in addition to the least-cost, least-risk portfolio developed to meet CETA clean energy standards:

- Alternative Lowest Reasonable Cost
- Maximum Customer Benefit
- Climate Change⁹

This analysis plus additional detail related to Washington requirements is found in Appendix O (Washington Clean Energy Action Plan)

⁹ Note: The Washington requirement for a climate change sensitivity, which includes climate change impacts, is met by the incorporation of climate change considerations into all 2025 IRP studies.

CHAPTER 10 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2025 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio. The action plan has been shaped by changes in the planning environment, ongoing review and validation, and stakeholder feedback.
- PacifiCorp’s 2025 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).¹
- The 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO₂) emission policies.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp’s 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

¹ Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2025 IRP Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public input process. Table 10.1 details specific 2025 IRP action items by resource category.

Table 10.1 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	<u>Colstrip Units 3 and 4:</u> • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	<u>Craig Unit 1:</u> • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	<u>Naughton Units 1 and 2:</u> • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	<u>Carbon Capture and Storage / Low Carbon Portfolio Standard:</u> • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming’s low carbon portfolio standard. The Company is pursuing a front-end engineering design study as part of compliance with Wyoming’s low carbon portfolio standard requirements as a site-specific analysis is needed to better understand the feasibility of the project.²
1e	<u>Regional Haze Compliance:</u> • Following the resolution of first planning period regional haze compliance disputes, and the EPA’s determination of the states’ second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

² See Appendix M, stakeholder feedback form #59 (Renewables Northwest).

1f	<u>Natrium™ Demonstration Project:</u> By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	<u>Ozone Transport Rule Compliance:</u> - EPA finalized its approval of Wyoming’s cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. - The Tenth Circuit granted a motion to stay EPA’s disapproval of Utah’s state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	<u>Natural Gas Emissions Compliance Strategies</u> The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon’s HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	<u>Federal Greenhouse Gas Emission Compliance:</u> EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	<u>Dave Johnston Units 1 and 2:</u> PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	<u>Customer Preference Request for Proposals:</u> - PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. - Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	<u>2025 All-Source Request for Proposals:</u> - PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.³ - Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions’ process. - Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

³ Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

Action Item	3. Transmission Action Items
3a	<u>Local Reinforcement Projects</u> Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	<u>Gateway West Support</u> Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

Action Item	4. Demand-Side Management (DSM) Actions															
a	<u>Energy Efficiency & Demand Response Targets:</u>															
	- PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP. - PacifiCorp will pursue cost-effective energy efficiency resources.															
	<table><tr><th>Year</th><th>First-Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr><tr><td>2025</td><td>595</td><td>92</td></tr><tr><td>2026</td><td>573</td><td>89</td></tr><tr><td>2027</td><td>597</td><td>209</td></tr><tr><td>2028</td><td>648</td><td>220</td></tr></table>	Year	First-Year Energy Efficiency (GWh)	Annual Capacity (MW)	2025	595	92	2026	573	89	2027	597	209	2028	648	220
	Year	First-Year Energy Efficiency (GWh)	Annual Capacity (MW)													
	2025	595	92													
	2026	573	89													
	2027	597	209													
	2028	648	220													
	PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.⁴ Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.⁵															
	<table><tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr><tr><td>2025</td><td>18</td></tr><tr><td>2026</td><td>2</td></tr><tr><td>2027</td><td>0</td></tr><tr><td>2028</td><td>63</td></tr></table>	Year	Annual Incremental Capacity (MW)	2025	18	2026	2	2027	0	2028	63					
Year	Annual Incremental Capacity (MW)															
2025	18															
2026	2															
2027	0															
2028	63															

⁴ A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

⁵ See Appendix D, Table D.3 for the split out between summer and winter capacity.

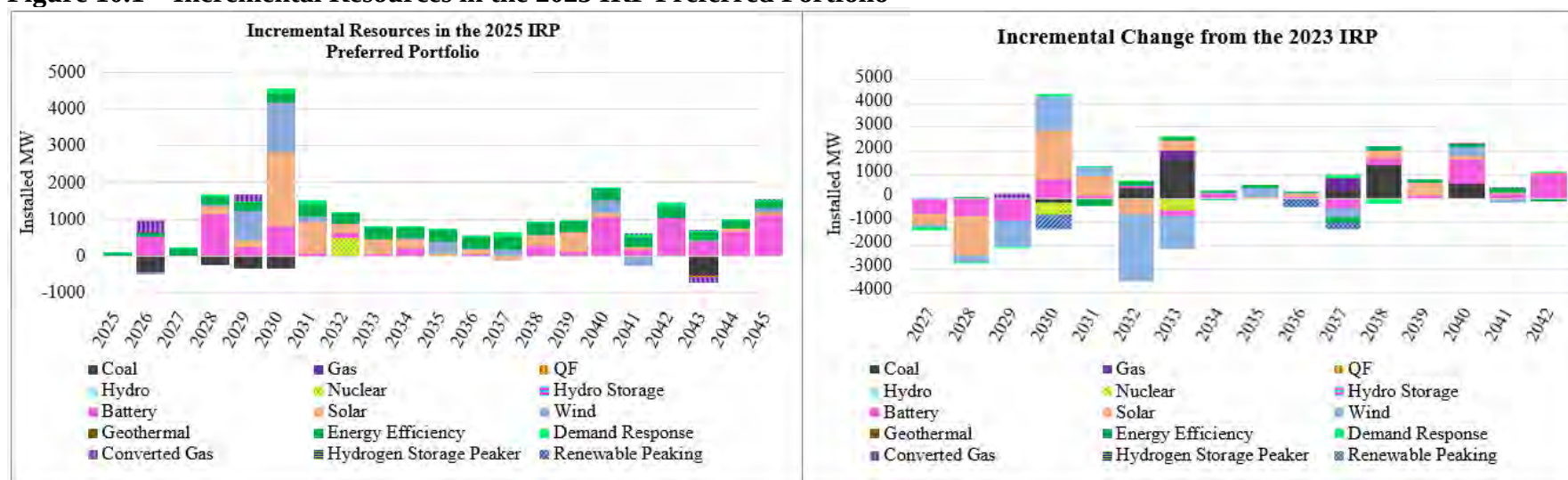
Action Item	5. Market Purchases
5a	<u>Market Purchases:</u> • PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: ○ Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. ○ Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. ○ Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	6. Renewable Energy Credit (REC) Actions
6a	<u>Renewable Portfolio Standards (RPS):</u> • PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	<u>Renewable Energy Credit Sales:</u> • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the 2025 IRP action plan. The status for all action items from the 2025 IRP is summarized in Table 10.2.

Figure 10.1 below presents two views of incremental resource changes in the 2025 IRP preferred portfolio. The figure at left reports the incremental resource additions from the 2025 IRP preferred portfolio, whereas the figure at right illustrates how these selections differ from the incremental changes in the 2023 IRP preferred portfolio.^{6, 7}

Figure 10.1 – Incremental Resources in the 2025 IRP Preferred Portfolio



⁶ The timeframe presented in these charts shows only years where expansion resources were selected.

⁷ These figures support Wyoming Public Service Commission Guideline E, “Changes in expected resource acquisitions and load growth from that presented in the utility’s previous IRP”. A load comparison is provided in Appendix A (Load Forecast), Figure A.1.

Table 10.2 – 2023 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	<u>Colstrip Units 3 and 4:</u> PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.	PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	<u>Craig Unit 1:</u> PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025.	PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1c	<u>Naughton Units 1 and 2 Gas Conversion:</u> - PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. - PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.	- PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas. - Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025.
1d	<u>Jim Bridger Units 1 and 2 Gas Conversion:</u> - PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023. - By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	- PacifiCorp received an approval order on December 7, 2023, from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas. - PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023. - Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed in Q2 2024.

1e	<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u> • PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	<u>Regional Haze Compliance:</u> • Following the resolution of first planning period regional haze compliance disputes, and the EPA’s determination of the states’ second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• Utah’s first planning period disputes have been resolved. • Naughton and Wyodak’s first planning period disputes have been resolved. The Tenth Circuit found EPA’s disapproval of Wyoming’s plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date.
1g	<u>Natrium™ Demonstration Project:</u>	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the

	• PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	Natrium™ project and expects to finalize these arrangements by the end of 2025.
1h	<u>Ozone Transport Rule Compliance:</u> • PacifiCorp will assess the impact of EPA’s finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	• EPA finalized its approval of Wyoming’s cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA’s disapproval of Utah’s state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

Action Item	2. New Resource Actions	Status
2a	<u>Customer Preference Request for Proposals:</u> • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024.
2b	<u>2025 All-Source Request for Proposals:</u> • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2030. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation	The 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term.

	Commission, of PacifiCorp’s need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.	
2c	<u>2022 All-Source Request for Proposals:</u> • In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027. • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file	• PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities. • EPA’s approval of Wyoming’s cross-state ozone transport rule plan and the Tenth Circuit Court’s stay of Utah’s ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource

	certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.	procurement needs coming out of the 2022 All-Source Request for Proposals. • PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals.
Action Item	3. Transmission Action Items	Status
3a	<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u> • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.	The Energy Gateway South transmission project is in-service.
3b	<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u> • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service in Q4 2024 •	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
3c	<u>Boardman-to-Hemingway (500 kV transmission line):</u> • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in “pre-construction” activities in support of the 2026-2027 in-service date.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date.

	Continue negotiations for plan of service post B2H for parties to the permitting agreement.	
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

Action Item	4. Demand-Side Management (DSM) Actions	Status															
4a	<u>Energy Efficiency Targets:</u> PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP. <table border="1"> <thead> <tr> <th>Year</th><th>1st year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr> </thead> <tbody> <tr> <td>2023</td><td>543</td><td>123</td></tr> <tr> <td>2024</td><td>559</td><td>220</td></tr> <tr> <td>2025</td><td>568</td><td>259</td></tr> <tr> <td>2026</td><td>628</td><td>197</td></tr> </tbody> </table>	Year	1st year Energy Efficiency (GWh)	Annual Capacity (MW)	2023	543	123	2024	559	220	2025	568	259	2026	628	197	For energy efficiency, PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and achieved 96.2% of the 2024 target, excluding HERs. Since the 2023 IRP, PacifiCorp launched demand response programs and expanded offerings within its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023-24 incremental capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs.
Year	1st year Energy Efficiency (GWh)	Annual Capacity (MW)															
2023	543	123															
2024	559	220															
2025	568	259															
2026	628	197															

	PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio as summarized in Appendix D in Volume II of the 2023 IRP. <table><tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr><tr><td>2023</td><td>72</td></tr><tr><td>2024</td><td>39</td></tr><tr><td>2025</td><td>152</td></tr><tr><td>2026</td><td>109</td></tr></table>	Year	Annual Incremental Capacity (MW)	2023	72	2024	39	2025	152	2026	109	
Year	Annual Incremental Capacity (MW)											
2023	72											
2024	39											
2025	152											
2026	109											
Action Item	5. Market Purchases	Status										
5a	<u>Market Purchases:</u> - Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. - Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. - Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions. Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.										
Action Item	6. Renewable Energy Credit (REC) Actions	Status										

6a	<u>Renewable Portfolio Standards (RPS):</u> • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.
6b	<u>Renewable Energy Credit Sales:</u> • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions policies. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, state and federal environmental policy also influences resource selections in the 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event in Table 10.3, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide “[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds.”⁸ PacifiCorp’s decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

PacifiCorp’s 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

⁸ Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher sustained load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “High Load Growth”	• A new load forecast incorporating higher than anticipated load growth increases load relative to the base forecast. • Through 2030, resource additions would be similar to the preferred portfolio with a small amount of additional wind and solar added to the portfolio to meet higher than anticipated loads. • From 2031 through 2034, small amounts of solar, 4-hour battery and DSM resources are added to meet higher than anticipated loads.	• In the long-term acquisition window, slightly fewer incremental resources are required due to additional incremental resources shifting into the near-term window to meet higher than anticipated loads compared to the preferred portfolio.
Lower sustained load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “Low Load Growth”.	• A new load forecast incorporating lower than anticipated load growth decreases load relative to the base forecast. • In the near-term acquisition window, far fewer incremental resources are required to meet load compared to the preferred portfolio. • Through 2034, significant amounts of wind and solar along with moderate amounts of small-scale solar and 100-hour battery fall out of the portfolio while additional 4-hour battery is added compared to the preferred portfolio. • Fewer incremental transmission options are required to meet fewer incremental resources while the timing of some incremental transmission options is shifted outward compared to the preferred portfolio.	• In the long-term acquisition window, even fewer incremental resources are required due to lower loads compared to the preferred portfolio. • From 2035-2045, significant amounts of wind, solar, small-scale solar and 100-hour battery fall out of the portfolio compared to the preferred portfolio and would not need to be procured.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher sustained private generation penetration levels	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “High Private Generation”	• A new load forecast incorporating higher than anticipated private generation adoption decreases load relative to the base forecast. • In response to high private generation adoption, far fewer incremental resource selections are required in the action plan window compared to the preferred portfolio. • Through 2030, significant amounts of wind, solar, small-scale solar and moderate amounts of 100-hour battery fall out of the preferred portfolio while a significant amount of 4-hour battery is selected. • Through the remainder of the near-term acquisition window, resource additions are similar to the preferred portfolio. • Transmission selections are similar to the preferred portfolio with the location and timing of incremental transmission changing depending on incremental resource selections.	• From 2035-2045, higher private generation results in 2,696 MW of resource additions falling out of the portfolio compared to the preferred portfolio. • On average, far less wind, solar and 100-hour air battery are selected while additional 4-hour battery is selected in similar amounts compared to the preferred portfolio.
Lower sustained private generation penetration levels	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “Low Private Generation”	• A new load forecast incorporating lower than anticipated private generation adoption increases load relative to the base forecast. • To counteract low private generation adoption, minimal additional resources are required relative to the preferred portfolio through 2029. • From 2030 through 2034, moderate amounts of wind and solar are added to what is selected in the preferred portfolio.	• In the long-term resource acquisition window, resource selections are similar to the preferred portfolio as lower private generation levels cause incremental resource builds in the near-term acquisition window. • 156 MW of Naughton gas conversion would remain online compared to retiring in 2043 in the preferred portfolio.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher than expected large-metered load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “Large Metered Load Growth”	• A new load forecast incorporating higher than anticipated large-metered load growth beginning in 2027 increases load relative to the base forecast. • High large-metered load growth results in significant resource additions compared to the preferred portfolio, including significant resource additions in the near-term acquisition window. • By 2028, nearly 10,000 MW of additional resources are selected compared to the preferred portfolio including significant amounts of wind, solar, small-scale solar, 4-hour battery and a moderate amount of 8-hour battery. • By the end of 2034, a significant amount of new gas is added to the portfolio, along with nearly 4,500 MW of additional incremental renewable resources. • Significant transmission investment would be required to serve new resource additions.	• From 2035-2045, significant additional resources are required compared to the preferred portfolio including more than 1,000 MW of new gas and 5,000 MW of new renewables.
Changes to IRA/IIJA result in lower-than-expected renewable costs	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “Low-Cost Renewables”	• High adoption of the IRA/IIJA resulting in lower-than-expected new renewable resource costs would result in significantly more incremental renewable resource additions than selected in the preferred portfolio. • Significant incremental wind, solar and 4-hour battery additions would result in lower thermal output and less 100-hour battery storage additions. • Significant transmission investment would be required to serve new resource additions.	• From 2035-20445, significant additional incremental renewable resources would be built along with more incremental transmission. • Thermal resources would run at lower capacity factors with some thermal capacity retiring in the long-term acquisition window.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Changes to IRA/IIJA result in higher-than-expected renewable costs	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “Low PTC/ITC eligibility”	• In the absence of tax credits from the IRA/IIJA resulting in higher-than-expected renewable resource costs, significant amounts of incremental renewable resource additions would fall out of the portfolio compared to the preferred portfolio. • By 2030, significant wind, solar, small-scale solar and 100-hour iron battery would fall out from the portfolio. • By the end of 2034, significant additional incremental renewable capacity falls out of the portfolio while some new gas is selected. • If renewable resources become more expensive in the absence of IRA/IIJA benefits, very little capacity would be needed to replace renewable capacity as thermal resources would run at higher capacity factors to meet load obligations.	• In the long-term acquisition window, additional new gas is built along with a small amount of gas peaking to replace lost renewables from the preferred portfolio. • Existing thermal resources would remain online past retirement dates selected in the preferred portfolio to continue providing energy and capacity.
No legislation under consideration is adopted and state environmental requirements impacting thermal plants are unwound	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity “Business as Usual” (also called the Wyoming Reference Case).	• With only load requirements to meet (no other federal or state requirements), far fewer resources are selected compared to the preferred portfolio as existing thermal resources are able to run at higher capacity factors and less capacity and energy is needed on the system. • In the near-term acquisition window, significantly fewer MW are selected compared to the preferred portfolio, including less wind, solar, small-scale solar, 4-hour battery and 100-hour battery. • With far fewer new resources compared to the preferred portfolio, “business as usual” would require significantly fewer incremental transmission interconnect MW in the near-term acquisition window.	• From 2035-2045, significantly fewer MW are selected compared to the preferred portfolio including less wind, solar, small-scale solar and 100-hour battery. • Additional 4-hour battery is added from 2035 through 2045 compared to the preferred portfolio, revealing that in a “business as usual” scenario, 4-hour batteries remain valuable new resource options in the absence of other new renewables.
Legislation forces all coal to retire or gas convert by 2032	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant “No Coal 2032”	• With all coal units forced to retire or gas convert by 1/1/2032, 2,679 MW of nameplate capacity would convert to natural gas in 2030. Jim Bridger units 3 and 4 were assumed to not be allowed to install CCS, and in this case, units 3 and 4 would convert to natural gas in 2030 instead of retiring. • By 1/1/2032, 686 MW of coal retires. • Significant additional incremental renewable resources are added to the portfolio including wind, solar, 4-hour battery and 100-hour battery within the near-term acquisition window.	• In the long-term acquisition window resource additions are similar to the preferred portfolio.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
No Natrium™ Advanced Nuclear Demonstration Project in 2032, and no other nuclear projects	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant “No Nuclear”	- Without the 500 MW Natrium™ demonstration project in 2032, moderate amounts of renewable resources are added to the portfolio by 2032. - In 2033 and 2034, additional incremental renewable resources are added to the portfolio.	- While the type, timing and location of resources change, the amount of incremental resource additions in the long-term acquisition window without Natrium™ is similar to the preferred portfolio. - Batteries and other renewables would fall out of the portfolio in 2041 through 2045 as incremental amounts of these resources are built earlier to replace Natrium™. 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion.
Technologies such as nuclear, hydrogen storage, 100-hour battery storage and biodiesel peaking do not become commercially viable	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant “No Forward Technology”	- Without nuclear, hydrogen storage, 100-hour battery or biodiesel peaking, nuclear and 100-hour battery selected in the preferred portfolio are replaced by a significant amount of 4-hour battery and moderate amounts of wind and solar. - In the near-term acquisition window, the capacity of future technology that falls out of the portfolio is greater than the capacity of incremental resources needed to replace the lost capacity.	- While the type, timing and location of resources change as is required by the absence of nuclear and 100-hour battery, the amount of incremental resource additions in the long-term acquisition window is similar to the preferred portfolio. 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Legislation requires the Hunter plant to retire no later than 1/1/2030	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant “Hunter Retire”	• By 1/1/2030, 1,158 MW of nameplate coal capacity retires at Hunter. • To replace the lost Hunter capacity, by 2030, moderate amounts of wind and solar would be added to the portfolio, including solar at Hunter. Additionally, a significant amount of 4-hour battery and moderate amount of 100-hour battery would be added to the portfolio.	• From 2035-2045, moderate amounts of incremental resource additions would be added to the portfolio, including new gas. • In 2043, 156 MW of nameplate capacity at Naughton 1 running as gas remains online through the end of the planning horizon instead of retiring as it does in the preferred portfolio.
No CCS available at Jim Bridger in 2030	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant “No CCS”	• Incremental resource selections with Jim Bridger CCS unavailable are similar to the preferred portfolio with slight changes in the location and timing of incremental resources. • By 1/1/2030, 174 MW of nameplate capacity remains available at Jim Bridger without the installation of CCS. • Moderate amounts of wind and solar, some of which is sited at Jim Bridger, falls out of the portfolio, along with some 4-hour battery.	• From 2039-2045 fewer 4-hour battery resources are selected. • In 2043, 247 MW of Naughton gas conversion retires without CCS in the portfolio.

Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable resilient grid operations and statutory compliance. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, there may be insufficient potential resource development deliverable to the jurisdiction with resource need, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

As the range of events is unknowable, these potential impacts are represented by broad sensitivity studies such as those which raise or lower resource availability (such as natrium, carbon capture, coal, offshore wind) and competition for resources (load, distributed generation, IRA adoption, DSM). In addition, IRP resource potential availability is informed by an assessment of publicly available data derived from the cluster study process.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.

- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Consequently, please refer to the 2025 IRP preferred portfolio as described in Chapter 9.

Resource Procurement Strategy

To acquire resources outlined in the 2025 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates if jurisdictional need is warranted. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs to include but not limited to load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2025 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management⁹

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings and has continued Wattsmart outreach and communications. Educating customers regarding

⁹ Class 1 DSM is most commonly referred to as “demand response” in the 2023 IRP; Class 2 DSM is most commonly referred to as “energy efficiency”. Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in June 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by December 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is discussed in Appendix P (Oregon Clean Energy Update) and will be further addressed in PacifiCorp's 2025 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. The level of debt imputation associated with long-term contracts will have an impact on PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO₂ reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO₂ emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO₂ reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO₂ tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO₂ capture with sequestration. As mentioned above, plant CO₂ emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes

recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not fully reflected in rates and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission

infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO₂ policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-106:
EIA Annual 2024



Independent Statistics and Analysis

**U.S. Energy Information
Administration**

Electric Power Annual 2024

October 2025

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government.



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Washington, DC 20585

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Chapter 1

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		Total (All Sectors)			Electric Power Sector				Commercial		Industrial		Residential	
					Electric Utilities		Independent Power Producers							
Fuel	Facility Type	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
Net Generation (Thousand Megawatthours)														
Coal	Utility Scale Facilities	652,156	675,115	-3.4%	508,149	518,330	139,527	152,238	204	220	4,276	4,327	0	0
Petroleum Liquids	Utility Scale Facilities	11,456	11,397	0.5%	8,504	8,254	2,567	2,573	12	76	372	494	0	0
Petroleum Coke	Utility Scale Facilities	3,629	4,836	-25.0%	1,946	3,146	1,377	1,415	4	2	302	273	0	0
Natural Gas	Utility Scale Facilities	1,869,902	1,806,063	3.5%	953,446	895,910	812,528	803,945	7,157	7,744	96,771	98,463	0	0
Other Fossil Gas	Utility Scale Facilities	10,845	11,778	-7.9%	0	0	2,976	3,340	0	0	7,870	8,438	0	0
Nuclear	Utility Scale Facilities	781,865	774,873	0.9%	444,521	441,391	337,345	333,482	0	0	0	0	0	0
Hydroelectric Conventional	Utility Scale Facilities	242,896	245,002	-0.9%	220,163	220,003	21,612	23,862	311	293	810	844	0	0
Renewable Sources Excluding Hydroelectric	Utility Scale Facilities	733,567	650,239	12.8%	123,555	106,543	582,350	516,694	4,441	4,545	23,220	22,456	0	0
... Wind	Utility Scale Facilities	451,904	421,141	7.3%	89,056	80,120	362,616	340,780	133	130	99	112	0	0
... Solar Thermal and Photovoltaic	Utility Scale Facilities	219,834	165,530	32.8%	30,347	22,230	188,376	142,360	566	615	546	326	0	0
... Wood and Wood-Derived Fuels	Utility Scale Facilities	31,564	31,615	-0.2%	2,436	2,549	7,218	7,637	111	107	21,800	21,320	0	0
... Other Biomass	Utility Scale Facilities	14,858	15,585	-4.7%	804	862	9,647	10,332	3,631	3,693	776	698	0	0
... Geothermal	Utility Scale Facilities	15,407	16,367	-5.9%	914	782	14,493	15,586	0	0	0	0	0	0
Hydroelectric Pumped Storage	Utility Scale Facilities	-5,852	-5,990	-2.3%	-4,232	-4,545	-1,619	-1,445	0	0	0	0	0	0
Other Energy Sources	Utility Scale Facilities	8,170	9,957	-17.9%	285	580	1,627	2,823	3,130	3,185	3,127	3,369	0	0
All Energy Sources	Utility Scale Facilities	4,308,634	4,183,270	3.0%	2,256,336	2,189,614	1,900,291	1,838,927	15,258	16,066	136,749	138,664	0	0
Estimated Small Scale Solar Photovoltaic	Small Scale Facilities	83,918	73,406	14.3%	0	0	0	0	21,652	19,751	4,719	4,382	57,547	49,273
Estimated Total Solar Photovoltaic	All Facilities	300,634	236,090	27.3%	30,347	22,230	185,257	139,513	22,218	20,366	5,265	4,708	57,547	49,273
Estimated Total Solar	All Facilities	303,752	238,937	27.1%	30,347	22,230	188,376	142,360	22,218	20,366	5,265	4,708	57,547	49,273
Consumption of Fossil Fuels for Electricity Generation														
Coal (1000 tons)	Utility Scale Facilities	372,931	386,626	-3.5%	284,849	291,034	86,586	94,063	65	69	1,431	1,460	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	20,787	21,335	-2.6%	16,058	16,366	4,137	4,253	179	200	414	517	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	1,662	2,028	-18.0%	960	1,328	596	594	1	1	104	105	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	13,754,749	13,245,495	3.8%	7,282,518	6,821,490	5,831,864	5,766,810	47,993	49,069	592,373	608,127	0	0
Consumption of Fossil Fuels for Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	8,883	9,363	-5.1%	1,485	1,580	338	527	356	331	6,703	6,925	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	2,238	3,133	-28.6%	66	65	612	330	440	363	1,120	2,374	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	608	622	-2.2%	0	8	103	115	5	3	499	495	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	1,246,683	1,210,187	3.0%	48,851	46,531	313,214	306,058	80,431	69,832	804,187	787,767	0	0
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	381,814	395,989	-3.6%	286,334	292,615	86,924	94,591	422	400	8,134	8,384	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	23,025	24,468	-5.9%	16,124	16,431	4,748	4,583	619	563	1,534	2,891	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	2,270	2,649	-14.3%	960	1,336	699	709	6	4	604	600	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	15,001,432	14,455,682	3.8%	7,331,369	6,868,021	6,145,078	6,072,868	128,424	118,901	1,396,561	1,395,893	0	0

Sales, Revenue, and Average Price of Electricity to Ultimate Customers for January through December									
Total U.S. Electric Power Industry									
Sales of Electricity to Ultimate Customers (million kWh)				Revenue from Sales of Electricity to Ultimate Customers (million dollars)			Average Price of Electricity to Ultimate Customers (cents/kWh)		
Sector	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Percentage Change
Residential	1,482,874	1,450,025	2.3%	244,367	231,993	5.3%	16.48	16.00	3.0%
Commercial	1,450,941	1,408,109	3.0%	185,043	177,342	4.3%	12.75	12.59	1.3%
Industrial	1,034,584	1,009,256	2.5%	84,095	81,159	3.6%	8.13	8.04	1.1%
Transportation	6,983	6,864	1.7%	890	877	1.6%	12.75	12.77	-0.2%
All Sectors	3,975,382	3,874,253	2.6%	514,396	491,370	4.7%	12.94	12.68	2.1%

NM = Not meaningful due to large relative standard error.

W = Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Coal generation and consumption includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal, synthetic coal, and coal-derived synthesis gas.

Petroleum Liquids includes distillate fuel oil, residual fuel oil, jet fuel, kerosene, propane, and waste oil.

Petroleum Coke includes petroleum coke and synthesis gas derived from petroleum coke.

Natural gas includes a small amount of supplemental gaseous fuels that cannot be identified separately.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Wood and Wood-Derived Fuels include wood, black liquor, and other wood waste.

Other Biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, and other biomass.

Other Energy Sources includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, fire-derived fuel, and other miscellaneous energy sources.

Coal stocks include anthracite, bituminous, subbituminous, lignite, refined coal, and synthetic coal; waste coal is excluded.

Sales of electricity to ultimate customers and net generation may not correspond exactly for a particular month for a variety of reasons (e.g., sales data may include imported electricity).

Net generation is presented for the calendar month while sales of electricity to ultimate customers and associated revenue accumulate from bills collected for periods of time that vary depending

Table 1.2. Summary Statistics for the United States, 2014 - 2024

(From Table 2.1.) Number of Ultimate Customers

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	128,680,416	17,853,995	839,212	79	N/A	147,373,702
2015	129,811,718	17,985,690	835,536	78	N/A	148,633,022
2016	131,068,760	18,148,353	838,059	86	N/A	150,055,258
2017	132,579,747	18,359,427	840,329	86	N/A	151,779,589
2018	133,893,321	18,605,393	840,321	83	N/A	153,339,118
2019	135,249,616	18,694,240	954,222	83	N/A	154,898,161
2020	136,682,001	18,848,813	992,311	83	N/A	156,523,208
2021	138,308,772	19,102,304	1,022,212	82	N/A	158,433,370
2022	139,854,178	19,257,529	1,049,983	86	N/A	160,161,776
2023	141,282,713	19,381,328	1,078,249	85	N/A	161,742,375
2024	143,144,185	19,480,886	1,115,974	81	N/A	163,741,126

(From Table 2.2.) Sales to Ultimate Customers

(Thousand Megawatthours)

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	1,407,208	1,352,158	997,576	7,758	N/A	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	N/A	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	N/A	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	N/A	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	N/A	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	N/A	3,811,150
2020	1,464,605	1,287,440	959,082	6,548	N/A	3,717,674
2021	1,470,487	1,328,439	1,000,613	6,334	N/A	3,805,874
2022	1,509,233	1,390,873	1,020,464	6,599	N/A	3,927,169
2023	1,450,025	1,408,109	1,009,256	6,864	N/A	3,874,253
2024	1,482,874	1,450,941	1,034,584	6,983	N/A	3,975,382

(From Table 2.3.) Revenue From Ultimate Customers

(Million Dollars)

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	176,178	145,253	70,855	810	N/A	393,096
2015	177,624	144,781	68,166	771	N/A	391,341
2016	177,077	142,643	66,068	722	N/A	386,509
2017	177,661	144,242	67,691	728	N/A	390,322
2018	189,033	147,425	69,218	744	N/A	406,420
2019	187,436	145,280	68,285	737	N/A	401,738
2020	192,663	136,372	63,956	648	N/A	393,639
2021	200,834	149,008	71,835	646	N/A	422,323
2022	226,990	172,600	84,895	765	N/A	485,249
2023	231,993	177,342	81,159	877	N/A	491,370

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2024	244,367	185,043	84,095	890	N/A	514,396
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(From Table 2.4.) Average Price

(Cents per Kilowatthour)

Year	Residential	Commer-cial	Industrial	Transpor-tation	Other	Total
2014	12.52	10.74	7.10	10.45	N/A	10.44
2015	12.65	10.64	6.91	10.09	N/A	10.41
2016	12.55	10.43	6.76	9.63	N/A	10.27
2017	12.89	10.66	6.88	9.68	N/A	10.48
2018	12.87	10.67	6.92	9.70	N/A	10.53
2019	13.01	10.68	6.81	9.66	N/A	10.54
2020	13.15	10.59	6.67	9.90	N/A	10.59
2021	13.66	11.22	7.18	10.20	N/A	11.10
2022	15.04	12.41	8.32	11.59	N/A	12.36
2023	16.00	12.59	8.04	12.77	N/A	12.68
2024	16.48	12.75	8.13	12.75	N/A	12.94

(From Tables 2.12. - 2.14.) Trade

(Thousand Megawatthours)

Year	Purchases	Sales for Resale	Imports	Exports
2014	4,802,227	4,908,839	66,510	13,298
2015	4,761,523	4,797,395	75,770	9,100
2016	4,723,571	4,746,967	72,716	6,214
2017	4,861,257	4,889,947	65,685	9,371
2018	5,168,874	5,127,276	58,261	13,804
2019	5,371,635	5,172,430	59,052	20,008
2020	5,224,580	5,145,459	61,449	14,135
2021	5,067,170	4,938,756	53,167	13,855
2022	5,130,963	5,105,520	56,970	15,758
2023	4,795,772	4,866,463	38,917	20,013
2024	4,610,886	4,715,342	33,254	19,437

(From Tables 3.1.A. and 3.1.B.) Net Generation (Thousand Megawatthours)

Generation at Utility Scale Facilities									
Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Geothermal	Wind
2014	1,581,710	30,232	1,126,635	12,022	797,166	259,367	-6,174	15,877	181,655
2015	1,352,398	28,249	1,334,668	13,117	797,178	249,080	-5,091	15,918	190,719
2016	1,239,149	24,205	1,379,271	12,807	805,694	267,812	-6,686	15,826	226,993
2017	1,205,835	21,390	1,297,703	12,469	804,950	300,333	-6,495	15,927	254,303
2018	1,149,487	25,226	1,471,843	13,463	807,084	292,524	-5,905	15,967	272,667
2019	964,957	18,341	1,588,533	12,591	809,409	287,874	-5,261	15,473	295,882
2020	773,393	17,341	1,626,790	11,818	789,879	285,274	-5,321	15,890	337,938
2021	897,999	19,173	1,579,190	11,397	779,645	251,585	-5,112	15,975	378,197
2022	831,512	22,931	1,687,065	11,722	771,537	254,789	-6,028	16,087	434,297
2023	675,115	16,233	1,806,063	11,778	774,873	245,002	-5,990	16,367	421,141

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2024	652,156	15,084	1,869,902	10,845	781,865	242,896	-5,852	15,407	451,904
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Generation at Utility Scale Facilities							Small Scale Generation	Utility and Small Scale Generation	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Generation	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2014	15,250	2,441	42,340	21,650	13,393	4,093,564	11,233	26,482	28,924
2015	21,666	3,227	41,929	21,703	13,955	4,078,714	14,139	35,805	39,032
2016	32,670	3,384	40,947	21,813	13,689	4,077,574	18,812	51,483	54,866
2017	50,018	3,269	41,124	21,610	13,008	4,035,443	23,990	74,008	77,277
2018	60,234	3,592	40,936	20,896	12,973	4,180,988	29,539	89,773	93,365
2019	68,719	3,218	38,543	18,964	13,331	4,130,574	34,957	103,676	106,894
2020	86,066	3,133	36,219	18,493	12,855	4,009,767	41,522	127,588	130,721
2021	112,335	2,924	36,463	17,790	12,140	4,109,699	49,164	161,499	164,422
2022	140,793	2,999	35,466	16,383	11,114	4,230,668	61,282	202,075	205,074
2023	162,683	2,847	31,615	15,585	9,957	4,183,270	73,406	236,090	238,937
2024	216,715	3,118	31,564	14,858	8,170	4,308,634	83,918	300,634	303,752

(From Tables 4.2.A. and 4.2.B.) Net Summer Generating Capacity (Megawatts)

Utility Scale Capacity									
Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Geothermal	Wind
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	22,485.1	2,514.3	64,231.5
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	22,575.1	2,541.5	72,573.4
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	22,778.7	2,516.6	81,286.6
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	22,810.4	2,483.3	87,597.5
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	22,830.2	2,444.3	94,417.7
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	22,778.3	2,555.4	103,571.2
2020	215,554.2	27,569.3	485,807.2	2,275.2	96,500.6	79,924.3	23,016.2	2,571.9	118,378.7
2021	209,825.7	28,204.5	491,870.2	1,888.0	95,546.4	79,909.7	23,007.7	2,596.7	132,753.4
2022	189,316.3	30,775.3	502,396.9	1,728.2	94,658.9	80,067.6	23,043.9	2,648.6	141,402.2
2023	178,441.7	29,440.7	507,535.8	1,866.8	95,712.2	79,985.3	23,147.4	2,695.8	147,444.7
2024	174,177.6	28,649.7	506,371.0	1,678.1	98,391.2	79,896.5	23,156.6	2,695.5	152,097.3

Utility Scale Capacity							Small Scale Capacity	Utility and Small Scale Capacity	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Capacity	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2014	8,656.6	1,666.7	8,368.1	5,166.5	2,792.6	1,068,422.2	7,326.6	15,983.2	17,649.9
2015	11,905.4	1,757.9	8,968.9	5,124.5	1,795.6	1,064,054.5	9,778.5	21,683.9	23,441.8
2016	20,192.9	1,757.9	8,936.1	5,088.8	2,015.1	1,074,332.8	12,765.1	32,958.0	34,715.9
2017	25,209.0	1,757.9	8,830.9	5,129.5	2,886.3	1,084,369.6	16,147.8	41,356.8	43,114.7
2018	30,120.5	1,757.9	8,694.6	5,038.6	2,346.7	1,094,739.8	19,547.1	49,667.6	51,425.5

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2019	35,710.2	1,758.1	8,374.5	4,738.8	2,606.4	1,099,109.3	23,213.6	58,923.8	60,681.9
2020	46,306.2	1,747.9	8,326.5	4,623.3	3,079.3	1,115,680.8	27,584.8	73,891.0	75,638.9
2021	60,070.1	1,480.0	7,923.2	4,469.2	6,311.3	1,145,856.1	33,081.0	93,151.1	94,631.1
2022	71,381.5	1,480.0	7,804.5	4,322.3	10,405.6	1,161,431.8	39,828.0	111,209.5	112,689.5
2023	90,517.8	1,480.0	7,693.1	4,133.2	17,450.9	1,187,545.4	47,774.7	138,292.5	139,772.5
2024	122,061.8	1,392.0	7,414.8	3,996.9	28,436.4	1,230,415.2	53,228.1	175,289.9	176,681.9

(From Chapter 5.) Consumption of Fossil Fuels

Year	For Electricity Generation				For Useful Thermal Output			
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Fossil Gas (Millions of BTU)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Fossil Gas (Millions of BTU)
2014	853,634	53,593	8,544,387	110,010	18,107	9,513	865,146	194,088
2015	739,594	49,145	10,016,576	105,997	16,632	8,864	935,098	183,596
2016	677,371	43,671	10,170,110	73,785	16,586	7,770	1,151,866	221,835
2017	663,911	39,144	9,508,062	70,721	14,667	6,899	1,168,544	227,981
2018	636,213	46,727	10,842,129	78,757	13,813	7,261	1,205,962	274,612
2019	537,620	34,454	11,612,858	71,854	12,397	6,357	1,196,025	209,000
2020	435,351	33,391	11,928,104	69,609	10,402	5,629	1,292,624	199,076
2021	500,367	36,982	11,502,569	65,137	11,301	5,873	1,221,841	198,379
2022	471,576	43,684	12,384,086	64,285	11,356	7,769	1,206,250	194,981
2023	386,626	31,474	13,245,495	65,145	9,363	6,241	1,210,187	211,645
2024	372,931	29,096	13,754,749	58,777	8,883	5,277	1,246,683	210,613

Year	Total			
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Fossil Gas (Millions of BTU)
2014	871,741	63,106	9,409,532	304,098
2015	756,226	58,009	10,951,674	289,593
2016	693,958	51,441	11,321,975	295,619
2017	678,578	46,043	10,676,606	298,702
2018	650,027	53,988	12,048,091	353,369
2019	550,017	40,811	12,808,883	280,854
2020	445,753	39,020	13,220,728	268,685
2021	511,669	42,855	12,724,410	263,515
2022	482,931	51,452	13,590,336	259,266
2023	395,989	37,714	14,455,682	276,790
2024	381,814	34,373	15,001,432	269,390

(From Tables 6.1. and 7.1)

Year End Stocks, Annual Receipts and Average Costs

Year	Electric Power Sector Year End Stocks		Annual Receipts at All Electricity Generators			Average Cost of Fuel at All Electricity Generators		
	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Coal (Dollars per MMBtu)	Petroleum (Dollars per MMBtu)	Natural Gas (Dollars per MMBtu)

Table 1.2. Summary Statistics for the United States, 2014 - 2024

2014	151,548	36,459	854,560	54,488	8,431,423	2.37	11.60	5.00
2015	195,548	38,396	782,929	48,804	9,842,581	2.22	6.74	3.23
2016	162,009	34,818	650,770	37,637	10,271,180	2.11	5.24	2.87
2017	137,687	32,407	642,364	32,672	9,628,733	2.06	7.10	3.37
2018	102,793	28,674	596,215	37,341	10,894,849	2.06	9.68	3.55
2019	128,102	28,317	560,153	24,556	11,704,743	2.02	9.07	2.88
2020	131,431	27,552	439,636	24,846	11,981,552	1.92	5.98	2.40
2021	91,884	27,513	461,477	27,783	11,578,254	1.98	10.08	5.20
2022	88,861	24,404	469,718	30,792	12,436,074	2.36	16.53	7.21
2023	133,028	26,539	431,375	25,590	13,237,380	2.51	15.98	3.36
2024	127,826	25,204	369,134	19,275	13,741,165	2.47	14.70	2.76

**(From Table 9.1.) Emissions
(Thousand Metric Tons)**

Year	Carbon Dioxide (CO2)	Sulfur Dioxide (SO2)	Nitrogen Oxides (NOx)
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,599	1,493
2018	1,872,330	1,517	1,474
2019	1,724,873	1,267	1,342
2020	1,553,586	1,023	1,211
2021	1,651,911	1,168	1,253
2022	1,650,367	1,079	1,230
2023	1,531,554	848	1,117
2024	1,537,073	808	1,112

(From Tables 10.1. and 10.2.) Energy Efficiency

Year	Savings		Incremental Costs		Life Cycle Savings		Life Cycle Costs	
	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2014	26,466,020	6,453	3,410,854	2,209,098	301,956,123	8,040	4,007,452	3,120,898
2015	26,129,489	5,952	3,448,286	2,283,300	296,346,403	7,096	4,255,368	3,710,453
2016	27,500,224	5,658	3,570,950	2,522,854	354,347,692	7,050	4,126,758	3,432,717
2017	29,899,028	6,071	3,664,407	2,297,957	374,826,892	5,951	4,849,803	3,162,995
2018	28,415,037	6,309	3,484,767	2,165,981	359,446,175	6,075	4,177,905	4,179,320
2019	28,562,529	7,135	3,657,477	2,288,028	355,216,512	6,931	4,351,926	3,655,607
2020	28,167,459	6,287	3,152,372	2,112,261	367,829,206	6,003	3,561,148	3,349,318
2021	25,760,657	5,801	3,375,805	2,240,600	300,327,216	5,631	3,678,879	2,466,541
2022	24,384,518	5,445	3,374,379	2,216,696	273,589,534	5,216	4,019,332	2,666,853
2023	24,221,289	5,761	3,850,362	2,538,191	270,451,419	5,655	4,413,487	2,919,623
2024	23,838,965	6,264	4,208,481	2,692,606	281,386,727	6,152	4,744,110	3,040,059

(From Tables 10.3. and 10.4.) Demand Response

Yearly Energy and Demand Savings	Program Costs
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Table 1.2. Summary Statistics for the United States, 2014 - 2024

Year	Customers	Energy (MWh)	Potential Peak Demand (MW)	Actual Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2014	9,265,629	1,436,449	31,191	12,683	1,217,796	447,659
2015	9,094,138	1,251,006	32,875	13,036	1,120,446	381,918
2016	9,839,355	1,336,136	35,924	11,841	1,039,890	379,707
2017	9,440,938	1,310,862	31,508	12,248	1,003,124	370,700
2018	9,752,238	1,426,211	30,895	12,522	1,189,284	360,718
2019	10,932,845	1,462,735	31,020	11,334	1,118,882	343,214
2020	11,665,663	1,509,124	29,470	10,387	987,653	326,872
2021	10,492,584	1,153,791	29,222	12,211	1,188,390	312,091
2022	10,319,774	1,292,980	30,448	13,827	1,149,280	329,053
2023	10,567,254	407,255	30,542	10,752	1,118,770	311,943
2024	10,950,828	409,404	31,491	12,322	1,224,694	362,073

Coal includes anthracite, bituminous, subbituminous and lignite coal. Starting in 2002 waste coal is included in all coal metrics except for year-end stocks. Starting in 2002 Synthetic coal is included in all coal metrics. Starting in 2011 Coal-derived synthesis gas is included in all coal metrics.

Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum includes Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil. Prior to 2011 propane was in the Other Fossil Gas category. Beginning in 2004 small quantities of waste oil were excluded from petroleum stocks.

Natural gas includes a small number of generators for which waste heat is the primary energy source. Natural gas also includes a small amount of supplemental gaseous fuels that cannot be identified separately.

Prior to 2011, synthesis gas derived from petroleum coke was in the Other Fossil Gas category. Other Fossil Gas includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

Conventional hydroelectric power excludes pumped storage facilities.

Wood and wood derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases). The reported summer capacity for other biomass also includes non-biogenic municipal solid waste.

Pumped storage is the capacity to generate electricity from water previously pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level. The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping.

Other energy sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Costs of fuels for 2002 through 2007 include data from the Form EIA-423 for independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Beginning in 2008, data are collected on the Form EIA-923 for utilities, independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Receipts, cost, and quality data are collected from plants above a 50 MW threshold, and imputed for plants between 1 and 50 MW. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data. Receipts of coal include imported coal.

UNIT CONVERSIONS:

Notes: See Glossary reference for definitions. See Technical Notes Appendix for conversion to different units of measure. Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. Dual-fired capacity returned to respective fuel categories for current and all historical years. New fuel switchable capacity tables have replaced dual-fired breakouts. Totals may not equal sum of components because of independent rounding. In 2013, EIA revised its approach to estimating imports from Mexico.

Table 1.2. Summary Statistics for the United States, 2014 - 2024

Sources: U.S. Energy Information Administration Form EIA-411, 'Coordinated Bulk Power Supply Program Report;' Form EIA-412, 'Annual Electric Industry Financial Report'. The Form EIA-412 was terminated in 2003; Form EIA-767, 'Steam-Electric Plant Operation and Design Report' was suspended; Form EIA-860, 'Annual Electric Generator Report;' Form EIA-861, 'Annual Electric Power Industry Report;' Form EIA-923, 'Power Plant Operations Report' replaces several form(s) including: Form EIA-906, 'Power Plant Report;' Form EIA-920 'Combined Heat and Power Plant Report;' Form EIA-423, 'Monthly Cost and Quality of Fuels for Electric Plants Report;' and FERC Form 423, 'Monthly Report of Cost and Quality of Fuels for Electric Plants,' and their predecessor forms. Federal Energy Regulatory Commission, FERC Form 1, 'Annual Report of Major Utilities, Licensees and Others;' FERC Form 1-F, 'Annual Report for Nonmajor Public Utilities and Licensees;' Rural Utilities Service (RUS) Form 7, 'Operating Report;' RUS Form 12, 'Operating Report;' Imports and Exports: National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates

Table 1.3. Supply and Disposition of Electricity, 2014 through 2024

(From Chapter 3.) Supply (Thousand Megawatthours)

	Generation						
Year	Electric Utilities	IPP (Non-CHP)	IPP (CHP)	Commercial Sector	Industrial Sector	Total Imports	Total Supply
2014	2,382,500	1,404,256	150,205	12,520	144,083	66,510	4,160,074
2015	2,316,508	1,448,726	155,173	12,595	145,712	75,770	4,154,484
2016	2,305,887	1,459,558	153,532	12,706	145,890	72,716	4,150,290
2017	2,275,539	1,464,503	138,584	13,060	143,758	65,685	4,101,128
2018	2,339,960	1,538,235	142,682	13,312	146,798	58,261	4,239,248
2019	2,268,723	1,559,801	139,824	13,689	148,537	59,052	4,189,626
2020	2,170,316	1,546,400	136,940	13,046	143,064	61,449	4,071,216
2021	2,211,643	1,612,655	132,883	12,768	139,750	53,167	4,162,866
2022	2,229,605	1,714,779	129,503	16,737	140,043	56,970	4,287,638
2023	2,189,614	1,703,467	135,460	16,066	138,664	38,917	4,222,188
2024	2,256,336	1,763,678	136,613	15,258	136,749	33,254	4,341,889

(From Chapter 2.) Disposition (Thousand Megawatthours)

	Sales to Ultimate Customers						
Year	Full-Service Providers	Energy-Only Providers	Facility Direct	Direct Use	Total Exports	Losses and Unaccounted For	Total Disposition
2014	3,184,841	563,441	16,418	138,574	13,298	243,502	4,160,074
2015	3,191,425	554,944	12,624	141,168	9,100	245,224	4,154,484
2016	3,189,541	560,015	12,905	139,837	6,214	241,778	4,150,290
2017	3,149,973	559,727	13,656	140,959	9,371	227,442	4,101,128
2018	3,260,944	584,077	14,164	143,904	13,804	222,355	4,239,248
2019	3,213,129	583,431	14,591	143,270	20,008	215,198	4,189,626
2020	3,144,898	558,832	13,944	138,703	14,135	200,704	4,071,216
2021	3,215,297	575,567	15,011	138,915	13,855	204,222	4,162,866
2022	3,346,987	565,117	15,064	139,726	15,758	204,985	4,287,638
2023	3,294,907	562,573	16,773	136,918	20,013	191,003	4,222,188
2024	3,364,435	593,516	17,430	135,041	19,437	212,029	4,341,889

N/A = Not Available.

Facility Direct Sales to ultimate customers typically represent bilateral electric power sales between industrial and commercial generating facilities.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions. Losses and Unaccounted For includes: (1) reporting by utilities and power marketers that represent losses incurred in transmission and distribution, as well as volumes unaccounted for in their own energy balance; and (2) discrepancies among the differing categories upon balancing the table.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-861, "Annual Electric Power Industry Report;" and predecessor forms. Imports and Exports: Mexico data - DOE, Fossil Fuels, Office of Fuels Programs, Form OE-781R, "Annual Report of International Electrical Export/Import Data;" Canada data - National Energy Board of Canada (metered energy firm and interruptible).

Chapter 2

Electricity Sales

Table 2.1. Number of Ultimate Customers Served by Sector, by Provider, 2014 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2014	128,680,416	17,853,995	839,212	79	147,373,702
2015	129,811,718	17,985,690	835,536	78	148,633,022
2016	131,068,760	18,148,353	838,059	86	150,055,258
2017	132,579,747	18,359,427	840,329	86	151,779,589
2018	133,893,321	18,605,393	840,321	83	153,339,118
2019	135,249,616	18,694,240	954,222	83	154,898,161
2020	136,682,001	18,848,813	992,311	83	156,523,208
2021	138,308,772	19,102,304	1,022,212	82	158,433,370
2022	139,854,178	19,257,529	1,049,983	86	160,161,776
2023	141,282,713	19,381,328	1,078,249	85	161,742,375
2024	143,144,185	19,480,886	1,115,974	81	163,741,126
Full-Service Providers					
2014	117,230,661	15,942,158	789,803	50	133,962,672
2015	119,477,949	16,108,931	787,466	48	136,374,394
2016	120,875,548	16,197,174	788,641	53	137,861,416
2017	121,964,414	16,329,808	789,732	52	139,084,006
2018	122,767,933	16,415,207	794,548	49	139,977,737
2019	122,422,722	16,367,082	904,443	50	139,694,297
2020	123,575,349	16,466,429	940,350	52	140,982,180
2021	125,145,266	16,631,306	971,419	51	142,748,042
2022	126,936,159	16,800,418	1,001,592	53	144,738,222
2023	127,697,761	16,885,126	1,027,326	53	145,610,266
2024	128,358,886	16,854,267	1,046,810	50	146,260,013
Energy-Only Providers					
2014	11,449,755	1,911,837	49,409	29	13,411,030
2015	10,333,769	1,876,759	48,070	30	12,258,628
2016	10,193,212	1,951,179	49,418	33	12,193,842
2017	10,615,333	2,029,619	50,597	34	12,695,583
2018	11,125,388	2,190,186	45,773	34	13,361,381
2019	12,826,894	2,327,158	49,779	33	15,203,864
2020	13,106,652	2,382,384	51,961	31	15,541,028
2021	13,163,506	2,470,998	50,793	31	15,685,328
2022	12,918,019	2,457,111	48,391	33	15,423,554
2023	13,584,952	2,496,202	50,923	32	16,132,109
2024	14,785,299	2,626,619	69,164	31	17,481,113

N/A = Not Available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." and Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.2. Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 2014 through 2024 (Megawatthours)

Year	Residential	Commercial	Industrial	Transportation	Total	Direct Use	Total End Use
Total Electric Industry							
2014	1,407,208,311	1,352,158,263	997,576,138	7,757,555	3,764,700,267	138,573,884	3,903,274,151
2015	1,404,096,499	1,360,751,527	986,507,732	7,636,632	3,758,992,390	141,167,519	3,900,159,909
2016	1,411,058,153	1,367,191,386	976,715,181	7,496,910	3,762,461,630	139,836,699	3,902,298,329
2017	1,378,647,742	1,352,887,694	984,297,945	7,522,593	3,723,355,974	140,959,389	3,864,315,363
2018	1,469,093,059	1,381,754,845	1,000,672,553	7,664,804	3,859,185,261	143,903,731	4,003,088,992
2019	1,440,288,909	1,360,876,555	1,002,352,849	7,632,150	3,811,150,463	143,270,338	3,954,420,801
2020	1,464,605,046	1,287,439,583	959,082,028	6,547,824	3,717,674,481	138,702,540	3,856,377,021
2021	1,470,486,882	1,328,439,498	1,000,613,490	6,334,383	3,805,874,253	138,915,068	3,944,789,321
2022	1,509,233,162	1,390,872,813	1,020,463,986	6,599,108	3,927,169,069	139,725,701	4,066,894,770
2023	1,450,025,184	1,408,108,755	1,009,255,634	6,863,789	3,874,253,362	136,918,155	4,011,171,517
2024	1,482,873,586	1,450,941,216	1,034,584,190	6,982,840	3,975,381,832	135,040,521	4,110,422,353
Full-Service Providers							
2014	1,301,458,851	1,083,806,639	814,206,541	1,787,408	3,201,259,439	N/A	3,201,259,439
2015	1,307,918,081	1,089,268,864	805,111,979	1,749,450	3,204,048,374	N/A	3,204,048,374
2016	1,316,113,416	1,091,957,177	792,712,354	1,663,475	3,202,446,422	N/A	3,202,446,422
2017	1,285,787,376	1,078,679,288	797,505,332	1,656,960	3,163,628,956	N/A	3,163,628,956
2018	1,368,032,531	1,096,773,561	808,613,290	1,688,442	3,275,107,824	N/A	3,275,107,824
2019	1,335,937,347	1,078,046,650	811,871,096	1,864,134	3,227,719,227	N/A	3,227,719,227
2020	1,355,779,174	1,023,022,155	778,352,070	1,688,885	3,158,842,284	N/A	3,158,842,284
2021	1,364,227,749	1,051,202,406	813,202,989	1,674,150	3,230,307,294	N/A	3,230,307,294
2022	1,410,779,678	1,110,251,412	839,329,783	1,690,901	3,362,051,774	N/A	3,362,051,774
2023	1,354,990,246	1,128,111,069	826,674,586	1,904,230	3,311,680,131	N/A	3,311,680,131
2024	1,375,013,511	1,160,639,617	844,599,508	1,612,799	3,381,865,435	N/A	3,381,865,435
Energy-Only Providers							
2014	105,749,460	268,351,624	183,369,597	5,970,147	563,440,828	N/A	563,440,828
2015	96,178,418	271,482,663	181,395,753	5,887,182	554,944,016	N/A	554,944,016
2016	94,944,737	275,234,209	184,002,827	5,833,435	560,015,208	N/A	560,015,208
2017	92,860,366	274,208,406	186,792,613	5,865,633	559,727,018	N/A	559,727,018
2018	101,060,528	284,981,284	192,059,263	5,976,362	584,077,437	N/A	584,077,437
2019	104,351,562	282,829,905	190,481,753	5,768,016	583,431,236	N/A	583,431,236
2020	108,825,872	264,417,428	180,729,958	4,858,939	558,832,197	N/A	558,832,197
2021	106,259,133	277,237,092	187,410,501	4,660,233	575,566,959	N/A	575,566,959
2022	98,453,484	280,621,401	181,134,203	4,908,207	565,117,295	N/A	565,117,295
2023	95,034,938	279,997,686	182,581,048	4,959,559	562,573,231	N/A	562,573,231
2024	107,860,075	290,301,599	189,984,682	5,370,041	593,516,397	N/A	593,516,397

N/A = Not Available.

Starting in 2023- Many of the changes in the industrial and commercial sector retail sales are the result of improved reporting practices for data center and cryptocurrency mining operations.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report.", Form EIA-861S, "Annual Electric Power Industry Report (Short Form)" and Form EIA-923, "Power Plant Operations Report"

**Table 2.3. Revenue from Sales of Electricity to Ultimate Customers
by Sector, by Provider, 2014 through 2024 (Million Dollars)**

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
2020	192,663	136,372	63,956	648	393,639
2021	200,834	149,008	71,835	646	422,323
2022	226,990	172,600	84,895	765	485,249
2023	231,993	177,342	81,159	877	491,370
2024	244,367	185,043	84,095	890	514,396
Full-Service Providers					
2014	160,637	113,880	57,140	187	331,845
2015	162,857	113,225	54,787	170	331,038
2016	162,395	111,218	52,958	164	326,735
2017	162,762	112,576	54,412	171	329,921
2018	172,556	114,007	55,058	176	341,797
2019	169,967	112,036	54,782	190	336,876
2020	173,742	105,065	51,346	178	330,331
2021	181,387	113,630	57,714	183	352,913
2022	206,032	131,400	68,249	220	405,902
2023	208,850	134,213	64,748	262	408,072
2024	217,175	138,072	65,408	205	420,861
Competitive Service Providers					
2014	15,541	31,373	13,715	623	61,251
2015	14,767	31,557	13,379	601	60,303
2016	14,682	31,425	13,110	557	59,774
2017	14,899	31,666	13,279	557	60,402
2018	16,477	33,418	14,161	567	64,623
2019	17,569	33,244	13,502	547	64,863
2020	18,921	31,307	12,610	470	63,309
2021	19,447	35,379	14,121	463	69,410
2022	20,957	41,199	16,645	545	79,347
2023	23,143	43,130	16,411	615	83,298
2024	27,192	46,971	18,687	685	93,535
Energy-Only Providers					
2014	9,079	19,948	10,813	436	40,277
2015	8,428	19,657	10,298	407	38,791
2016	7,947	18,850	9,896	360	37,053
2017	7,666	18,368	9,829	363	36,227
2018	8,438	19,279	10,424	378	38,518
2019	8,718	18,436	9,738	360	37,253
2020	9,017	16,485	8,829	305	34,636
2021	8,750	18,223	10,024	295	37,292
2022	10,100	22,791	12,458	360	45,709
2023	11,640	24,381	11,966	413	48,401
2024	12,769	25,386	12,797	447	51,400
Delivery-Only Providers					
2014	6,462	11,425	2,901	187	20,975
2015	6,339	11,900	3,081	193	21,512
2016	6,735	12,575	3,213	197	22,720
2017	7,232	13,298	3,450	194	24,174
2018	8,039	14,139	3,737	190	26,105
2019	8,850	14,809	3,764	187	27,610
2020	9,904	14,823	3,781	165	28,672
2021	10,697	17,155	4,097	168	32,118
2022	10,857	18,408	4,187	185	33,638
2023	11,503	18,749	4,445	201	34,898
2024	14,423	21,584	5,890	238	42,135

N/A = Not Available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery.

Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.4. Average Price of Electricity to Ultimate Customers

by End-Use Sectors 2014 through 2024 (Cents per kilowatthour)

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
2020	13.15	10.59	6.67	9.90	10.59
2021	13.66	11.22	7.18	10.20	11.10
2022	15.04	12.41	8.32	11.59	12.36
2023	16.00	12.59	8.04	12.77	12.68
2024	16.48	12.75	8.13	12.75	12.94
Full-Service Providers					
2014	12.34	10.51	7.02	10.49	10.37
2015	12.45	10.39	6.80	9.71	10.33
2016	12.34	10.19	6.68	9.87	10.20
2017	12.66	10.44	6.82	10.32	10.43
2018	12.61	10.39	6.81	10.44	10.44
2019	12.72	10.39	6.75	10.20	10.44
2020	12.81	10.27	6.60	10.53	10.46
2021	13.30	10.81	7.10	10.92	10.93
2022	14.60	11.84	8.13	13.02	12.07
2023	15.41	11.90	7.83	13.75	12.32
2024	15.79	11.90	7.74	12.72	12.44
Competitive Service Providers					
2014	14.70	11.69	7.48	10.44	10.87
2015	15.35	11.62	7.38	10.20	10.87
2016	15.46	11.42	7.12	9.56	10.67
2017	16.04	11.55	7.11	9.50	10.79
2018	16.30	11.73	7.37	9.49	11.06
2019	16.84	11.75	7.09	9.49	11.12
2020	17.39	11.84	6.98	9.68	11.33
2021	18.30	12.76	7.53	9.94	12.06
2022	21.29	14.68	9.19	11.10	14.04
2023	24.35	15.40	8.99	12.39	14.81
2024	25.21	16.18	9.84	12.76	15.76
Energy-Only Providers					
2014	8.59	7.43	5.90	7.31	7.15
2015	8.76	7.24	5.68	6.92	6.99
2016	8.37	6.85	5.38	6.17	6.62
2017	8.26	6.70	5.26	6.19	6.47
2018	8.35	6.77	5.43	6.32	6.59
2019	8.35	6.52	5.11	6.25	6.39
2020	8.29	6.23	4.89	6.29	6.20
2021	8.23	6.57	5.35	6.33	6.48
2022	10.26	8.12	6.88	7.33	8.09
2023	12.25	8.71	6.55	8.33	8.60
2024	11.84	8.74	6.74	8.33	8.66
Delivery-Only Providers					
2014	6.11	4.26	1.58	3.12	3.72
2015	6.59	4.38	1.70	3.28	3.88
2016	7.09	4.57	1.75	3.38	4.06
2017	7.79	4.85	1.85	3.31	4.32
2018	7.95	4.96	1.95	3.17	4.47
2019	8.48	5.24	1.98	3.24	4.73
2020	9.10	5.61	2.09	3.40	5.13
2021	10.07	6.19	2.19	3.61	5.58
2022	11.03	6.56	2.31	3.77	5.95
2023	12.10	6.70	2.43	4.06	6.20
2024	13.37	7.44	3.10	4.43	7.10

N/A = Not Available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery.

Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

**Table 2.5. Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2014 - December 2024 (Thousand Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	1,407,208	1,352,158	997,576	7,758	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	3,811,150
2020	1,464,605	1,287,440	959,082	6,548	3,717,674
2021	1,470,487	1,328,439	1,000,613	6,334	3,805,874
2022	1,509,233	1,390,873	1,020,464	6,599	3,927,169
2023	1,450,025	1,408,109	1,009,256	6,864	3,874,253
2024	1,482,874	1,450,941	1,034,584	6,983	3,975,382
Year 2022					
January	140,504	113,605	83,982	565	338,656
February	125,342	103,063	76,893	566	305,863
March	111,439	108,603	83,679	579	304,300
April	97,432	104,566	82,422	513	284,933
May	110,071	113,007	86,090	529	309,697
June	136,310	121,567	88,716	513	347,106
July	164,277	133,952	90,420	566	389,214
August	160,271	135,676	93,143	536	389,626
September	129,241	124,195	86,550	558	340,544
October	99,792	111,851	85,017	535	297,196
November	103,152	106,858	81,701	546	292,258
December	131,402	113,929	81,852	593	327,776
Year 2023					
January	131,638	112,790	80,408	579	325,415
February	112,105	103,830	76,449	561	292,946
March	110,417	112,643	82,817	577	306,454
April	96,196	104,091	80,011	513	280,811
May	100,231	113,243	84,704	529	298,706
June	121,320	120,707	86,193	579	328,798
July	159,715	136,394	90,526	621	387,256
August	161,460	138,390	92,009	578	392,436
September	132,807	126,546	86,472	652	346,476
October	103,314	118,208	85,978	565	308,065
November	101,907	109,756	82,036	549	294,248
December	118,917	111,512	81,652	561	312,642
Year 2024					
January	142,354	118,234	82,517	612	343,717
February	115,477	108,967	78,277	538	303,258
March	102,203	111,382	83,100	593	297,278
April	94,674	108,972	82,078	532	286,257
May	107,605	117,864	87,901	592	313,961
June	138,920	127,949	88,446	566	355,882
July	164,833	139,551	92,848	641	397,873
August	159,098	140,632	93,848	621	394,199
September	127,340	127,248	87,920	563	343,071
October	106,083	120,899	88,354	566	315,902
November	98,782	112,091	84,369	554	295,796
December	125,504	117,152	84,927	605	328,188

Starting in 2023- Many of the changes in the industrial and commercial sector retail sales are the result of improved reporting practices for data center and cryptocurrency mining operations.

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.6. Revenue from Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2014 - December 2024 (Million Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
2020	192,663	136,372	63,956	648	393,639
2021	200,834	149,008	71,835	646	422,323
2022	226,990	172,600	84,895	765	485,249
2023	231,993	177,342	81,159	877	491,370
2024	244,367	185,043	84,095	890	514,396
Year 2022					
January	19,163	12,794	6,037	60	38,053
February	17,247	12,019	5,601	62	34,929
March	16,062	12,647	6,164	63	34,936
April	14,194	12,355	6,343	58	32,950
May	16,394	13,561	7,099	57	37,112
June	20,850	15,506	7,854	62	44,272
July	25,155	17,435	8,422	70	51,082
August	25,354	18,199	8,739	69	52,361
September	20,930	16,492	7,841	70	45,333
October	15,961	14,418	7,184	63	37,627
November	16,041	13,179	6,654	63	35,937
December	19,637	13,996	6,955	68	40,656
Year 2023					
January	20,371	14,228	6,578	73	41,249
February	17,910	13,013	6,125	74	37,123
March	17,716	13,923	6,460	71	38,171
April	15,492	12,572	6,009	62	34,136
May	16,176	13,769	6,472	66	36,483
June	19,515	15,248	6,987	72	41,821
July	25,336	17,603	7,563	79	50,582
August	25,693	18,102	8,185	77	52,057
September	21,602	16,538	7,291	94	45,525
October	17,022	15,047	6,883	71	39,024
November	16,501	13,646	6,394	69	36,610
December	18,659	13,653	6,210	69	38,591
Year 2024					
January	21,942	14,785	6,663	77	43,467
February	18,595	13,658	6,078	71	38,401
March	17,036	13,888	6,382	71	37,377
April	15,966	13,457	6,397	66	35,886
May	17,649	14,521	6,921	73	39,164
June	22,757	16,498	7,434	72	46,761
July	27,389	18,654	8,110	84	54,237
August	26,417	18,508	8,135	83	53,143
September	21,424	16,832	7,428	74	45,758
October	18,127	15,583	7,162	70	40,943
November	16,644	13,844	6,623	69	37,180
December	20,422	14,813	6,763	81	42,079

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.7. Average Price of Electricity to Ultimate Customers:
Total by End-Use Sector, 2014 - December 2024 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
2020	13.15	10.59	6.67	9.90	10.59
2021	13.66	11.22	7.18	10.20	11.10
2022	15.04	12.41	8.32	11.59	12.36
2023	16.00	12.59	8.04	12.77	12.68
2024	16.48	12.75	8.13	12.75	12.94
Year 2022					
January	13.64	11.26	7.19	10.54	11.24
February	13.76	11.66	7.28	10.95	11.42
March	14.41	11.65	7.37	10.87	11.48
April	14.57	11.82	7.70	11.26	11.56
May	14.89	12.00	8.25	10.79	11.98
June	15.30	12.75	8.85	12.10	12.75
July	15.31	13.02	9.31	12.39	13.12
August	15.82	13.41	9.38	12.90	13.44
September	16.19	13.28	9.06	12.57	13.31
October	15.99	12.89	8.45	11.81	12.66
November	15.55	12.33	8.14	11.56	12.30
December	14.94	12.28	8.50	11.48	12.40
Year 2023					
January	15.47	12.61	8.18	12.54	12.68
February	15.98	12.53	8.01	13.14	12.67
March	16.04	12.36	7.80	12.28	12.46
April	16.10	12.08	7.51	12.05	12.16
May	16.14	12.16	7.64	12.43	12.21
June	16.09	12.63	8.11	12.41	12.72
July	15.86	12.91	8.36	12.77	13.06
August	15.91	13.08	8.90	13.26	13.27
September	16.27	13.07	8.43	14.45	13.14
October	16.48	12.73	8.01	12.65	12.67
November	16.19	12.43	7.79	12.60	12.44
December	15.69	12.24	7.61	12.34	12.34
Year 2024					
January	15.41	12.50	8.07	12.66	12.65
February	16.10	12.53	7.76	13.12	12.66
March	16.67	12.47	7.68	11.95	12.57
April	16.86	12.35	7.79	12.46	12.54
May	16.40	12.32	7.87	12.29	12.47
June	16.38	12.89	8.41	12.68	13.14
July	16.62	13.37	8.73	13.18	13.63
August	16.60	13.16	8.67	13.30	13.48
September	16.82	13.23	8.45	13.09	13.34
October	17.09	12.89	8.11	12.43	12.96
November	16.85	12.35	7.85	12.37	12.57
December	16.27	12.64	7.96	13.38	12.82

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions. Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month. Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report; Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report; Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

Table 2.8. Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	48,025	46,664	48,994	49,271	14,376	14,909	504	484	111,899	111,329
Connecticut	12,942	12,553	11,663	11,374	2,556	2,579	191	179	27,351	26,685
Maine	4,901	4,919	4,118	4,017	2,322	2,400	0	0	11,342	11,336
Massachusetts	19,993	19,366	23,489	24,276	5,645	6,091	291	279	49,419	50,012
New Hampshire	4,847	4,655	4,105	4,051	1,961	1,926	0	0	10,914	10,631
Rhode Island	3,111	2,995	3,666	3,651	615	629	22	26	7,414	7,301
Vermont	2,230	2,176	1,952	1,904	1,277	1,284	0	0	5,459	5,364
Middle Atlantic	134,823	130,856	146,688	143,307	70,987	71,544	3,678	3,523	356,175	349,230
New Jersey	29,693	28,415	37,087	36,083	6,351	6,224	401	375	73,531	71,097
New York	50,857	50,113	71,053	71,422	15,805	15,174	2,782	2,713	140,498	139,422
Pennsylvania	54,273	52,328	38,548	35,802	48,831	50,147	495	434	142,147	138,711
East North Central	185,595	179,525	180,205	174,691	187,138	184,688	498	463	553,436	539,367
Illinois	44,851	43,320	45,240	45,576	42,694	41,267	442	415	133,227	130,578
Indiana	33,049	31,739	23,664	23,016	42,489	41,229	18	11	99,220	95,995
Michigan	33,505	32,534	37,191	36,534	28,290	28,515	5	5	98,991	97,589
Ohio	52,174	49,714	50,814	46,351	50,688	50,546	32	30	153,707	146,641
Wisconsin	22,017	22,219	23,296	23,213	22,977	23,131	1	1	68,291	68,564
West North Central	106,070	107,369	109,950	107,264	101,064	99,248	41	42	317,125	313,923
Iowa	14,469	14,582	12,815	12,601	27,647	27,217	0	0	54,930	54,400
Kansas	13,840	13,815	15,791	15,727	11,628	11,509	0	0	41,258	41,052
Minnesota	22,063	23,023	22,468	22,614	20,016	20,561	15	18	64,562	66,216
Missouri	35,227	34,965	29,570	29,174	12,954	12,813	25	24	77,776	76,976
Nebraska	10,391	10,671	12,885	11,261	11,915	11,640	0	0	35,191	33,571
North Dakota	4,911	5,067	11,309	10,855	13,550	12,280	0	0	29,770	28,202
South Dakota	5,170	5,246	5,111	5,033	3,356	3,227	0	0	13,637	13,506
South Atlantic	385,618	370,594	355,825	341,272	134,841	136,603	1,252	1,177	877,536	849,646
Delaware	5,175	4,932	4,282	4,149	1,917	2,001	0	0	11,374	11,082
District of Columbia	2,446	2,372	7,193	7,030	187	176	316	301	10,143	9,880
Florida	138,371	135,805	99,197	97,255	17,457	17,809	70	71	255,095	250,940
Georgia	62,063	58,412	55,173	51,405	32,617	32,068	152	144	150,004	142,029
Maryland	27,327	26,108	27,773	27,062	3,502	3,456	416	408	59,019	57,033
North Carolina	61,745	58,738	49,524	48,197	25,623	26,144	12	13	136,905	133,091
South Carolina	32,545	30,898	26,306	25,194	25,110	25,110	0	0	83,961	81,202
Virginia	45,273	43,096	78,711	73,807	13,776	15,176	286	240	138,045	132,319
West Virginia	10,675	10,234	7,665	7,174	14,651	14,663	0	0	32,991	32,071
East South Central	121,405	115,857	93,344	90,842	98,826	96,872	0	0	313,576	303,571
Alabama	32,899	31,410	22,862	22,213	31,762	31,257	0	0	87,523	84,880
Kentucky	26,086	24,553	20,314	19,303	28,006	27,367	0	0	74,406	71,223
Mississippi	18,593	18,544	14,172	14,231	15,919	15,647	0	0	48,685	48,422
Tennessee	43,828	41,351	35,996	35,094	23,139	22,601	0	0	102,962	99,046
West South Central	238,936	242,549	225,086	224,347	258,724	238,748	22	179	722,768	705,823
Arkansas	18,581	18,374	11,789	11,694	19,526	18,581	0	0	49,896	48,649
Louisiana	30,975	31,747	23,652	23,743	40,720	39,874	10	10	95,357	95,374
Oklahoma	24,328	23,818	25,412	23,117	22,343	22,044	0	0	72,084	68,979
Texas	165,052	168,611	164,233	165,792	176,135	158,249	12	169	505,431	492,820
Mountain	113,434	109,662	112,525	105,323	86,373	84,248	157	162	312,489	299,394
Arizona	40,435	38,992	36,100	32,620	14,298	14,297	10	10	90,843	85,919
Colorado	20,694	19,999	21,172	20,698	14,892	14,779	86	90	56,843	55,566
Idaho	9,832	9,793	6,964	6,842	9,574	9,039	0	0	26,370	25,674
Montana	5,700	5,756	5,034	5,063	4,832	4,686	0	0	15,567	15,505
Nevada	14,631	13,509	14,259	12,367	11,766	12,367	8	7	40,665	38,249
New Mexico	7,348	7,336	9,593	9,349	13,356	11,662	0	0	30,296	28,347
Utah	11,825	11,328	14,129	13,338	8,681	8,623	53	54	34,688	33,344
Wyoming	2,968	2,948	5,275	5,046	8,974	8,796	0	0	17,217	16,790
Pacific Contiguous	144,245	142,206	172,890	166,389	77,414	77,589	831	834	395,379	387,018
California	85,851	82,821	115,126	112,936	44,026	42,999	715	725	245,717	239,480
Oregon	19,768	20,445	24,662	23,084	15,228	14,434	22	23	59,681	57,985
Washington	38,627	38,940	33,102	30,370	18,159	20,156	94	86	89,982	89,553
Pacific Noncontiguous	4,722	4,744	5,434	5,402	4,843	4,806	0	0	14,999	14,952
Alaska	2,071	2,051	2,604	2,603	1,372	1,371	0	0	6,047	6,025
Hawaii	2,652	2,693	2,830	2,799	3,470	3,435	0	0	8,952	8,927
U.S. Total	1,482,874	1,450,025	1,450,941	1,408,109	1,034,584	1,009,256	6,983	6,864	3,975,382	3,874,253

Starting in 2023- Many of the changes in the industrial and commercial sector retail sales are the result of improved reporting practices for data center and cryptocurrency mining operations.

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

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Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.

Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 2.9. Revenue from Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2024 and 2023 (Million Dollars)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	13,293	13,407	10,070	9,570	2,341	2,357	66	63	25,769	25,396
Connecticut	3,720	3,751	2,474	2,273	438	405	34	39	6,665	6,468
Maine	1,190	1,349	750	718	289	295	0	0	2,230	2,362
Massachusetts	5,868	5,734	4,908	4,763	1,027	1,089	27	20	11,830	11,607
New Hampshire	1,135	1,310	796	827	318	304	0	0	2,249	2,441
Rhode Island	891	809	773	645	121	119	5	5	1,790	1,579
Vermont	488	453	369	343	148	145	0	0	1,005	940
Middle Atlantic	27,810	25,650	23,020	21,951	6,049	5,656	503	516	57,381	53,774
New Jersey	5,744	5,031	5,431	5,052	758	727	45	46	11,977	10,856
New York	12,424	11,148	13,337	12,866	1,450	1,042	409	426	27,621	25,482
Pennsylvania	9,642	9,472	4,252	4,033	3,841	3,886	49	44	17,784	17,436
East North Central	30,587	29,072	21,860	20,855	15,124	14,670	40	33	67,612	64,630
Illinois	7,118	6,804	5,345	5,124	3,768	3,385	34	29	16,265	15,342
Indiana	4,880	4,741	2,944	2,889	3,461	3,399	2	1	11,287	11,031
Michigan	6,466	6,130	5,210	4,895	2,336	2,326	1	1	14,013	13,351
Ohio	8,340	7,647	5,418	4,984	3,597	3,554	2	2	17,358	16,187
Wisconsin	3,783	3,750	2,943	2,963	1,962	2,007	0	0	8,689	8,719
West North Central	14,283	13,979	11,274	11,065	7,804	7,715	4	5	33,365	32,764
Iowa	1,939	1,940	1,310	1,302	1,881	1,880	0	0	5,130	5,122
Kansas	1,958	1,849	1,767	1,707	899	879	0	0	4,624	4,435
Minnesota	3,409	3,392	2,729	2,801	1,831	1,893	2	2	7,971	8,088
Missouri	4,548	4,398	3,034	2,958	1,020	1,012	3	2	8,605	8,370
Nebraska	1,198	1,195	1,081	986	913	888	0	0	3,193	3,070
North Dakota	565	558	813	801	982	905	0	0	2,360	2,263
South Dakota	665	647	539	511	278	259	0	0	1,482	1,416
South Atlantic	55,964	53,552	38,032	36,933	10,461	10,358	125	120	104,582	100,963
Delaware	857	776	522	491	163	157	0	0	1,542	1,424
District of Columbia	433	390	1,228	1,191	20	19	31	30	1,712	1,630
Florida	19,561	20,652	10,903	11,621	1,484	1,673	8	8	31,955	33,953
Georgia	8,740	7,997	5,995	5,498	2,352	2,206	12	11	17,099	15,711
Maryland	4,880	4,333	3,601	3,456	350	344	48	46	8,879	8,179
North Carolina	8,727	7,593	5,230	4,662	1,990	1,868	1	1	15,948	14,125
South Carolina	4,632	4,228	2,798	2,618	1,718	1,677	0	0	9,148	8,523
Virginia	6,524	6,146	6,865	6,604	1,239	1,353	26	25	14,655	14,128
West Virginia	1,609	1,438	891	791	1,144	1,061	0	0	3,644	3,291
East South Central	16,264	15,194	11,538	11,020	6,645	6,511	0	0	34,447	32,725
Alabama	4,993	4,594	3,118	2,924	2,304	2,221	0	0	10,415	9,739
Kentucky	3,335	3,106	2,335	2,196	1,820	1,793	0	0	7,490	7,096
Mississippi	2,490	2,453	1,746	1,760	1,085	1,089	0	0	5,321	5,302
Tennessee	5,445	5,041	4,338	4,140	1,437	1,408	0	0	11,220	10,589
West South Central	33,551	33,184	19,994	20,478	15,664	15,441	2	14	69,211	69,116
Arkansas	2,289	2,251	1,207	1,209	1,291	1,276	0	0	4,786	4,736
Louisiana	3,633	3,666	2,473	2,481	2,286	2,345	1	1	8,394	8,494
Oklahoma	2,977	2,877	2,268	2,158	1,305	1,380	0	0	6,550	6,415
Texas	24,652	24,389	14,046	14,629	10,782	10,441	1	12	49,481	49,471
Mountain	16,021	15,003	12,411	11,525	6,654	6,604	17	20	35,102	33,152
Arizona	6,028	5,466	4,415	3,845	1,130	1,159	1	1	11,573	10,471
Colorado	3,087	2,859	2,480	2,409	1,284	1,256	8	12	6,859	6,537
Idaho	1,133	1,083	639	601	737	648	0	0	2,508	2,331
Montana	722	722	597	613	367	366	0	0	1,686	1,700
Nevada	2,194	2,252	1,453	1,473	1,016	1,281	1	1	4,664	5,006
New Mexico	1,043	1,016	1,011	999	725	671	0	0	2,780	2,685
Utah	1,444	1,269	1,326	1,135	682	603	6	7	3,459	3,012
Wyoming	370	338	489	451	714	621	0	0	1,573	1,409
Pacific Contiguous	34,945	31,320	35,201	32,310	11,904	10,379	134	106	82,184	74,114
California	27,444	24,440	29,400	27,007	9,478	8,014	120	94	66,442	59,555
Oregon	2,906	2,603	2,494	2,291	1,226	1,085	3	3	6,629	5,982
Washington	4,596	4,277	3,307	3,012	1,200	1,279	11	9	9,114	8,577
Pacific Noncontiguous	1,651	1,632	1,642	1,635	1,449	1,468	0	0	4,742	4,735
Alaska	514	490	562	543	265	256	0	0	1,341	1,290
Hawaii	1,137	1,142	1,081	1,092	1,184	1,212	0	0	3,402	3,446
U.S. Total	244,367	231,993	185,043	177,342	84,095	81,159	890	877	514,396	491,370

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

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See Technical Notes for a discussion of the sample design for the Form EIA-826.

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Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 2.10. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, 2024 and 2023 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	27.68	28.73	20.55	19.42	16.28	15.81	12.99	13.01	23.03	22.81
Connecticut	28.75	29.88	21.21	19.99	17.12	15.69	17.77	21.55	24.37	24.24
Maine	24.29	27.42	18.22	17.88	12.46	12.30	--	--	19.66	20.84
Massachusetts	29.35	29.61	20.90	19.62	18.19	17.88	9.22	7.15	23.94	23.21
New Hampshire	23.40	28.15	19.40	20.40	16.21	15.76	--	--	20.60	22.96
Rhode Island	28.65	27.02	21.09	17.68	19.70	18.98	21.53	17.29	24.15	21.62
Vermont	21.90	20.82	18.89	18.00	11.58	11.27	--	--	18.41	17.53
Middle Atlantic	20.63	19.60	15.69	15.32	8.52	7.91	13.67	14.65	16.11	15.40
New Jersey	19.34	17.70	14.64	14.00	11.93	11.68	11.11	12.22	16.29	15.27
New York	24.43	22.24	18.77	18.01	9.17	6.87	14.70	15.70	19.66	18.28
Pennsylvania	17.77	18.10	11.03	11.26	7.87	7.75	9.96	10.21	12.51	12.57
East North Central	16.48	16.19	12.13	11.94	8.08	7.94	7.99	7.08	12.22	11.98
Illinois	15.87	15.71	11.81	11.24	8.83	8.20	7.76	6.90	12.21	11.75
Indiana	14.77	14.94	12.44	12.55	8.15	8.24	12.31	12.73	11.38	11.49
Michigan	19.30	18.84	14.01	13.40	8.26	8.16	14.09	13.67	14.16	13.68
Ohio	15.99	15.38	10.66	10.75	7.10	7.03	7.32	5.91	11.29	11.04
Wisconsin	17.18	16.88	12.63	12.76	8.54	8.68	18.36	17.21	12.72	12.72
West North Central	13.47	13.02	10.25	10.32	7.72	7.77	10.98	10.89	10.52	10.44
Iowa	13.40	13.31	10.22	10.33	6.80	6.91	--	--	9.34	9.42
Kansas	14.15	13.38	11.19	10.85	7.73	7.64	--	--	11.21	10.80
Minnesota	15.45	14.73	12.15	12.39	9.15	9.20	12.71	12.35	12.35	12.21
Missouri	12.91	12.58	10.26	10.14	7.87	7.90	9.94	9.77	11.06	10.87
Nebraska	11.53	11.20	8.39	8.76	7.66	7.63	--	--	9.07	9.14
North Dakota	11.51	11.01	7.19	7.38	7.25	7.37	--	--	7.93	8.03
South Dakota	12.86	12.32	10.55	10.16	8.28	8.01	--	--	10.87	10.49
South Atlantic	14.51	14.45	10.69	10.82	7.76	7.58	10.02	10.23	11.92	11.88
Delaware	16.57	15.73	12.20	11.83	8.49	7.85	--	--	13.56	12.85
District of Columbia	17.71	16.45	17.07	16.94	10.85	9.66	9.94	9.94	16.88	16.50
Florida	14.14	15.21	10.99	11.95	8.50	9.39	10.87	11.33	12.53	13.53
Georgia	14.08	13.69	10.87	10.70	7.21	6.88	7.64	7.29	11.40	11.06
Maryland	17.86	16.60	12.96	12.77	10.01	9.94	11.55	11.23	15.04	14.34
North Carolina	14.13	12.93	10.56	9.67	7.77	7.15	10.28	8.86	11.65	10.61
South Carolina	14.23	13.68	10.64	10.39	6.84	6.68	--	--	10.90	10.50
Virginia	14.41	14.26	8.72	8.95	8.99	8.92	9.25	10.42	10.62	10.68
West Virginia	15.07	14.05	11.62	11.03	7.81	7.24	--	--	11.05	10.26
East South Central	13.40	13.11	12.36	12.13	6.72	6.72	--	--	10.99	10.78
Alabama	15.18	14.63	13.64	13.16	7.25	7.10	--	--	11.90	11.47
Kentucky	12.79	12.65	11.50	11.38	6.50	6.55	--	--	10.07	9.96
Mississippi	13.39	13.23	12.32	12.37	6.81	6.96	--	--	10.93	10.95
Tennessee	12.42	12.19	12.05	11.80	6.21	6.23	--	--	10.90	10.69
West South Central	14.04	13.68	8.88	9.13	6.05	6.47	7.76	7.53	9.58	9.79
Arkansas	12.32	12.25	10.24	10.34	6.61	6.87	13.23	14.93	9.59	9.73
Louisiana	11.73	11.55	10.46	10.45	5.61	5.88	11.54	11.00	8.80	8.91
Oklahoma	12.24	12.08	8.92	9.34	5.84	6.26	--	--	9.09	9.30
Texas	14.94	14.46	8.55	8.82	6.12	6.60	4.35	7.30	9.79	10.04
Mountain	14.12	13.68	11.03	10.94	7.70	7.84	10.61	12.69	11.23	11.07
Arizona	14.91	14.02	12.23	11.79	7.90	8.11	10.95	10.01	12.74	12.19
Colorado	14.92	14.30	11.71	11.64	8.62	8.50	9.66	13.23	12.07	11.76
Idaho	11.52	11.05	9.17	8.78	7.69	7.17	--	--	9.51	9.08
Montana	12.66	12.54	11.87	12.11	7.59	7.80	--	--	10.83	10.97
Nevada	15.00	16.67	10.19	11.91	8.64	10.36	10.66	12.75	11.47	13.09
New Mexico	14.20	13.85	10.54	10.68	5.43	5.75	--	--	9.18	9.47
Utah	12.22	11.20	9.39	8.51	7.86	6.99	12.07	12.28	9.97	9.03
Wyoming	12.47	11.46	9.27	8.94	7.96	7.06	--	--	9.14	8.39
Pacific Contiguous	24.23	22.02	20.36	19.42	15.38	13.38	16.10	12.67	20.79	19.15
California	31.97	29.51	25.54	23.91	21.53	18.64	16.79	13.01	27.04	24.87
Oregon	14.70	12.73	10.11	9.92	8.05	7.52	12.54	11.41	11.11	10.32
Washington	11.90	10.98	9.99	9.92	6.61	6.35	11.64	10.17	10.13	9.58
Pacific Noncontiguous	34.95	34.40	30.22	30.28	29.93	30.55	--	--	31.62	31.67
Alaska	24.82	23.90	21.57	20.87	19.31	18.70	--	--	22.17	21.41
Hawaii	42.86	42.39	38.18	39.03	34.13	35.28	--	--	38.00	38.60
U.S. Total	16.48	16.00	12.75	12.59	8.13	8.04	12.75	12.77	12.94	12.68

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

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Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 2.11. Number of Ultimate Customers by Sector
by State, 2023 and 2024

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	6,653,781	6,579,669	945,130	943,130	21,150	21,474	6	6	7,620,067	7,544,279
Connecticut	1,552,746	1,541,895	156,818	156,310	3,864	3,936	3	3	1,713,431	1,702,144
Maine	742,549	731,969	111,084	108,745	1,925	2,040	--	--	855,558	842,754
Massachusetts	2,924,535	2,886,203	438,014	443,991	10,353	10,510	2	2	3,372,904	3,340,706
New Hampshire	652,608	647,007	112,277	111,302	3,116	3,125	--	--	768,001	761,434
Rhode Island	457,383	450,190	62,629	60,297	1,649	1,606	1	1	521,662	512,094
Vermont	323,960	322,405	64,308	62,485	243	257	--	--	388,511	385,147
Middle Atlantic	16,690,432	16,603,564	2,444,687	2,455,311	40,817	33,989	18	21	19,175,954	19,092,885
New Jersey	3,735,638	3,702,963	540,221	539,427	11,251	11,246	7	8	4,287,117	4,253,644
New York	7,420,214	7,384,444	1,163,769	1,180,841	16,605	7,178	6	8	8,600,594	8,572,471
Pennsylvania	5,534,580	5,516,157	740,697	735,043	12,961	15,565	5	5	6,288,243	6,266,770
East North Central	20,951,042	20,833,849	2,574,768	2,547,590	54,769	55,099	10	11	23,580,589	23,436,549
Illinois	5,392,477	5,394,659	638,510	626,171	5,686	5,541	3	4	6,036,676	6,026,375
Indiana	3,056,216	3,018,496	374,858	371,773	19,345	19,291	1	1	3,450,420	3,409,561
Michigan	4,516,367	4,496,300	564,574	559,552	5,762	5,589	2	2	5,086,705	5,061,443
Ohio	5,142,108	5,110,814	627,393	624,926	18,237	19,087	2	2	5,787,740	5,754,829
Wisconsin	2,843,874	2,813,580	369,433	365,168	5,739	5,591	2	2	3,219,048	3,184,341
West North Central	10,017,809	9,915,499	1,526,285	1,517,734	132,146	131,428	3	3	11,676,243	11,564,664
Iowa	1,448,818	1,436,037	251,716	250,532	9,477	9,451	--	--	1,710,011	1,696,020
Kansas	1,317,095	1,306,777	245,169	245,544	23,963	24,106	--	--	1,586,227	1,576,427
Minnesota	2,581,180	2,551,574	308,460	308,285	9,410	9,351	1	1	2,899,051	2,869,211
Missouri	2,933,314	2,906,438	403,957	399,085	9,443	9,831	2	2	3,347,316	3,315,356
Nebraska	905,415	893,123	161,501	160,540	64,672	63,824	--	--	1,131,588	1,117,487
North Dakota	397,839	395,002	77,191	76,700	10,864	10,628	--	--	485,894	482,330
South Dakota	433,548	426,548	78,291	77,048	4,317	4,237	--	--	516,156	507,833
South Atlantic	30,673,496	30,090,394	4,040,023	4,000,173	88,735	88,038	13	13	34,802,267	34,178,618
Delaware	473,508	468,358	60,653	59,839	1,169	876	--	--	535,330	529,073
District of Columbia	318,780	312,982	27,521	27,387	1	1	3	3	346,305	340,373
Florida	10,443,373	10,222,476	1,309,027	1,292,988	26,610	26,085	2	2	11,779,012	11,541,551
Georgia	4,815,501	4,703,796	619,171	609,978	24,336	24,366	1	1	5,459,009	5,338,141
Maryland	2,451,753	2,432,423	261,469	260,822	9,286	9,226	5	5	2,722,513	2,702,476
North Carolina	5,067,762	4,951,380	751,027	746,025	8,930	9,082	1	1	5,827,720	5,706,488
South Carolina	2,581,882	2,518,272	413,387	410,802	3,604	3,634	--	--	2,998,873	2,932,708
Virginia	3,654,481	3,615,939	445,756	441,468	3,794	3,673	1	1	4,104,032	4,061,081
West Virginia	866,456	864,768	152,012	150,864	11,005	11,095	--	--	1,029,473	1,026,727
East South Central	8,981,949	8,853,035	1,507,151	1,484,981	25,513	24,411	--	--	10,514,613	10,362,427
Alabama	2,398,172	2,353,274	389,925	384,122	7,246	7,239	--	--	2,795,343	2,744,635
Kentucky	2,077,215	2,057,705	327,448	323,183	4,846	5,136	--	--	2,409,509	2,386,024
Mississippi	1,340,459	1,335,278	246,813	246,032	12,415	11,023	--	--	1,599,687	1,592,333
Tennessee	3,166,103	3,106,778	542,965	531,644	1,006	1,013	--	--	3,710,074	3,639,435
West South Central	18,051,370	17,711,160	2,363,886	2,400,621	451,075	419,810	6	6	20,866,337	20,531,597
Arkansas	1,476,944	1,459,802	207,035	205,526	36,772	36,612	2	2	1,720,753	1,701,942
Louisiana	2,147,745	2,137,199	301,288	300,640	18,203	18,790	1	1	2,467,237	2,456,630
Oklahoma	1,878,818	1,857,151	298,476	304,896	20,002	19,874	--	--	2,197,296	2,181,921
Texas	12,547,863	12,257,008	1,557,087	1,589,559	376,098	344,534	3	3	14,481,051	14,191,104
Mountain	10,925,227	10,725,657	1,532,262	1,502,127	100,429	100,935	5	6	12,557,923	12,328,725
Arizona	3,134,733	3,068,552	348,423	344,059	7,555	7,614	2	2	3,490,713	3,420,227
Colorado	2,557,732	2,517,452	405,693	397,348	14,750	15,358	1	2	2,978,176	2,930,160
Idaho	868,141	845,896	123,982	121,675	29,658	29,322	--	--	1,021,781	996,893
Montana	557,432	549,248	123,483	116,235	11,624	12,019	--	--	692,539	677,502
Nevada	1,311,755	1,288,498	177,740	174,042	4,786	4,784	1	1	1,494,282	1,467,325
New Mexico	936,098	928,216	148,104	147,632	9,256	9,339	--	--	1,093,458	1,085,187
Utah	1,272,861	1,244,066	145,854	142,545	10,805	10,719	1	1	1,429,521	1,397,331
Wyoming	286,475	283,729	58,983	58,591	11,995	11,780	--	--	357,453	354,100
Pacific Contiguous	19,454,170	19,227,491	2,430,030	2,412,748	199,328	201,091	20	19	22,083,548	21,841,349
California	14,217,180	14,063,972	1,777,305	1,766,915	146,327	148,000	13	12	16,140,825	15,978,899
Oregon	1,868,012	1,843,683	247,412	244,410	26,616	26,545	2	2	2,142,042	2,114,640
Washington	3,368,978	3,319,836	405,313	401,423	26,385	26,546	5	5	3,800,681	3,747,810
Pacific Noncontiguous	744,909	742,395	116,664	116,913	2,012	1,974	--	--	863,585	861,282
Alaska	298,397	296,192	57,009	56,796	1,191	1,161	--	--	356,597	354,149
Hawaii	446,512	446,203	59,655	60,117	821	813	--	--	506,988	507,133
U.S. Total	143,144,185	141,282,713	19,480,886	19,381,328	1,115,974	1,078,249	81	85	163,741,126	161,742,375

**Table 2.12. Electric Power Industry - Electricity Purchases,
2014 through 2024 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2014	2,145,378	2,559,875	17,000	79,975	4,802,227
2015	2,101,788	2,506,185	54,046	99,505	4,761,523
2016	2,089,540	2,438,204	8,520	187,307	4,723,571
2017	2,102,971	2,552,146	9,372	196,768	4,861,257
2018	2,187,615	2,713,174	8,730	259,354	5,168,874
2019	2,231,042	2,778,349	9,391	352,854	5,371,635
2020	2,146,608	2,792,233	9,458	276,281	5,224,580
2021	2,258,989	2,541,686	5,950	260,545	5,067,170
2022	2,407,972	2,436,300	11,634	275,057	5,130,963
2023	2,247,163	2,329,456	19,670	199,483	4,795,772
2024	2,302,830	2,118,199	21,095	168,762	4,610,886

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" and Form EIA-923, "Power Plant Operations Report"

**Table 2.13. Electric Power Industry - Electricity Sales for Resale,
2014 through 2024 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2014	1,485,964	2,081,235	1,301,724	39,916	4,908,839
2015	1,393,396	2,033,705	1,331,181	39,113	4,797,395
2016	1,391,873	1,947,036	1,372,928	35,131	4,746,967
2017	1,396,838	2,066,455	1,389,083	37,571	4,889,947
2018	1,431,952	2,193,414	1,463,236	38,674	5,127,276
2019	1,402,200	2,259,028	1,466,561	44,641	5,172,430
2020	1,364,031	2,284,266	1,457,591	39,572	5,145,459
2021	1,481,890	2,020,031	1,402,064	34,772	4,938,756
2022	1,526,810	1,909,697	1,626,033	42,980	5,105,520
2023	1,394,671	1,785,875	1,638,113	47,804	4,866,463
2024	1,433,061	1,534,145	1,708,929	39,207	4,715,342

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" and Form EIA-923, "Power Plant Operations Report"

Table 2.14. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 2014-2024 (Megawatthours)

Year	Canada		Mexico		U.S. Total	
	Imports from	Exports to	Imports from	Exports to	Imports	Exports
2014	59,369,660	12,860,889	7,140,624	437,364	66,510,284	13,298,253
2015	68,462,277	8,707,873	7,308,192	392,016	75,770,469	9,099,889
2016	65,173,818	2,682,381	7,542,445	3,531,636	72,716,263	6,214,017
2017	59,909,320	3,312,798	5,775,597	6,058,005	65,684,917	9,370,803
2018	51,494,627	7,290,070	6,765,975	6,514,422	58,260,602	13,804,492
2019	52,309,254	13,532,067	6,743,207	6,475,965	59,052,461	20,008,032
2020	57,001,240	9,855,106	4,447,623	4,279,573	61,448,863	14,134,679
2021	48,140,438	10,067,396	5,026,570	3,788,022	53,167,008	13,855,418
2022	52,187,403	10,651,209	4,782,900	5,107,113	56,970,303	15,758,322
2023	33,225,087	18,384,320	5,692,121	1,628,726	38,917,208	20,013,046
2024	27,201,095	17,343,144	6,053,393	2,093,903	33,254,488	19,437,047

Notes: As of November 2017, the data for 2016 and going forward will be published using data from the Form EIA-111, "Quarterly Electricity Imports and Exports Report." During 2013-2015, EIA revised its approach to estimating imports from Mexico.

Sources: 2016-2024, U.S. Energy Information Administration, Form EIA-111, "Quarterly Electricity Imports and Exports Report"; 2006-2015 data, National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates.

Chapter 3

Net Generation

Table 3.1.A. Net Generation by Energy Source: Total (All Sectors), 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2014	1,581,710	18,276	11,955	1,126,636	12,022	797,166	259,367	17,691	261,522	-6,174	13,393	4,093,564	11,233	26,482	28,924
2015	1,352,398	17,372	10,877	1,334,668	13,117	797,178	249,080	24,893	270,268	-5,091	13,955	4,078,714	14,139	35,805	39,032
2016	1,239,149	13,008	11,197	1,379,271	12,807	805,694	267,812	36,054	305,579	-6,686	13,689	4,077,574	18,812	51,483	54,866
2017	1,205,835	12,414	8,976	1,297,703	12,469	804,950	300,333	53,287	332,963	-6,495	13,008	4,035,443	23,990	74,008	77,277
2018	1,149,487	16,245	8,981	1,471,843	13,463	807,084	292,524	63,825	350,467	-5,905	12,973	4,180,988	29,539	89,773	93,365
2019	964,957	11,522	6,819	1,588,533	12,591	809,409	287,874	71,937	368,862	-5,261	13,331	4,130,574	34,957	103,676	106,894
2020	773,393	9,662	7,679	1,626,790	11,818	789,879	285,274	89,199	408,539	-5,321	12,855	4,009,767	41,522	127,588	130,721
2021	897,999	11,663	7,511	1,579,190	11,397	779,645	251,585	115,258	448,424	-5,112	12,140	4,109,699	49,164	161,499	164,422
2022	831,512	15,805	7,126	1,687,065	11,722	771,537	254,789	143,792	502,234	-6,028	11,114	4,230,668	61,282	202,075	205,074
2023	675,115	11,397	4,836	1,806,063	11,778	774,873	245,002	165,530	484,708	-5,990	9,957	4,183,270	73,406	236,090	238,937
2024	652,156	11,456	3,629	1,869,902	10,845	781,865	242,896	219,834	513,733	-5,852	8,170	4,308,634	83,918	300,634	303,752
Year 2022															
January	87,588	3,105	564	134,948	1,005	70,577	24,198	7,822	43,424	-493	1,029	373,766	3,376	11,065	11,198
February	70,966	1,114	621	114,945	886	61,852	21,321	9,027	43,090	-412	900	324,311	3,717	12,585	12,744
March	61,019	959	500	112,477	963	63,154	24,436	11,694	48,677	-318	979	324,530	5,121	16,560	16,815
April	55,329	749	528	105,506	921	55,290	20,066	13,402	51,528	-265	941	303,994	5,671	18,751	19,073
May	62,532	834	596	127,091	1,036	63,382	23,359	15,120	47,729	-467	971	342,184	6,236	20,985	21,356
June	73,463	897	683	155,517	987	65,715	25,988	16,052	39,461	-589	959	379,134	6,229	21,910	22,281
July	86,415	1,045	488	189,042	1,083	68,857	24,567	15,765	35,499	-768	982	422,975	6,438	21,915	22,203
August	85,215	1,001	576	188,860	1,008	68,897	21,133	14,502	30,657	-640	924	412,133	6,194	20,418	20,697
September	64,998	942	648	156,948	987	63,733	17,026	13,286	32,840	-598	845	351,655	5,544	18,545	18,930
October	54,228	952	610	133,492	968	58,945	14,367	11,942	38,036	-434	844	313,949	5,022	16,674	16,964
November	56,377	911	568	127,523	911	62,041	17,898	8,403	46,779	-495	864	321,780	4,035	12,289	12,438
December	73,381	3,296	744	140,716	978	69,094	20,430	6,777	44,514	-548	876	360,257	3,698	10,377	10,475
Year 2023															
January	61,357	983	421	138,503	945	70,870	22,754	7,806	44,043	-620	889	347,950	3,989	11,711	11,795
February	46,374	1,233	395	125,036	891	60,807	19,961	9,435	46,467	-456	778	310,922	4,387	13,713	13,822
March	50,096	924	314	133,699	1,028	62,820	21,331	12,213	49,007	-519	790	331,704	6,005	18,064	18,218
April	40,233	868	301	120,012	866	56,662	19,820	15,062	47,626	-290	744	301,903	6,742	21,509	21,803
May	43,804	880	330	137,394	1,011	61,155	27,651	17,281	37,570	-459	857	327,474	7,543	24,525	24,824
June	57,772	878	389	161,981	974	64,819	21,572	17,834	32,728	-551	838	359,234	7,405	24,874	25,239
July	78,903	964	651	199,522	1,046	69,888	21,978	18,894	33,394	-656	872	425,455	7,720	26,234	26,614
August	78,112	958	651	199,221	1,088	69,744	21,293	17,744	33,882	-653	865	422,905	7,504	24,938	25,248
September	59,959	894	592	166,311	983	65,560	16,916	15,583	33,470	-553	775	360,490	6,604	21,894	22,187
October	50,933	990	293	140,825	924	61,436	15,673	14,121	41,060	-372	837	326,718	6,076	19,910	20,196
November	51,209	906	179	135,531	959	62,258	17,026	10,446	41,774	-347	844	320,785	4,938	15,218	15,384
December	56,385	920	318	148,029	1,062	68,854	19,028	9,113	43,688	-514	869	347,732	4,494	13,500	13,606
Year 2024															
January	75,618	1,469	360	161,667	1,074	69,080	21,554	9,583	40,334	-414	799	381,122	4,726	14,230	14,309
February	44,137	740	217	131,845	931	64,584	20,795	12,540	46,108	-404	720	322,214	5,342	17,763	17,882
March	38,505	784	207	131,137	882	63,346	23,363	16,019	50,354	-349	689	324,938	7,113	22,911	23,132
April	37,246	866	278	121,532	913	57,542	20,916	19,241	51,940	-338	644	310,780	7,832	26,741	27,073
May	45,812	850	304	143,993	889	64,973	24,477	22,371	44,360	-284	738	348,485	8,539	30,496	30,910
June	61,339	890	389	169,156	941	68,192	22,397	24,459	43,755	-579	694	391,632	8,553	32,598	33,012
July	71,565	997	451	205,959	949	69,851	21,384	24,484	33,593	-639	723	429,317	8,778	32,901	33,262
August	68,760	993	432	202,915	911	69,760	20,491	24,328	34,653	-798	682	423,127	8,412	32,387	32,741
September	54,559	839	236	169,671	836	62,660	15,911	20,538	34,165	-637	619	359,397	7,511	27,714	28,049
October	46,890	929	232	146,711	801	58,773	15,352	19,828	44,334	-439	570	333,980	6,736	26,331	26,564
November	44,924	875	220	137,687	800	61,904	16,723	13,841	45,214	-490	652	322,351	5,393	19,098	19,234
December	62,800	1,224	304	147,630	919	71,200	19,533	12,601	44,923	-481	639	361,292	4,984	17,465	17,585

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.1.B. Net Generation from Renewable Sources: Total (All Sectors), 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	181,655	15,250	2,441	42,340	11,220	7,228	3,202	15,877	259,367	538,579	11,233	26,482	28,924
2015	190,719	21,666	3,227	41,929	11,291	7,211	3,201	15,918	249,080	544,241	14,139	35,805	39,032
2016	226,993	32,670	3,384	40,947	11,218	7,265	3,331	15,826	267,812	609,445	18,812	51,483	54,866
2017	254,303	50,018	3,269	41,124	11,543	6,951	3,115	15,927	300,333	686,583	23,990	74,008	77,277
2018	272,667	60,234	3,592	40,936	11,036	7,136	2,724	15,967	292,524	706,816	29,539	89,773	93,965
2019	295,882	68,719	3,218	38,543	10,468	6,093	2,402	15,473	287,874	728,673	34,957	103,676	106,894
2020	337,938	86,066	3,133	36,219	10,212	6,080	2,201	15,890	285,274	783,012	41,522	127,588	130,721
2021	378,197	112,335	2,924	36,463	9,421	6,101	2,267	15,975	251,585	815,267	49,164	161,499	164,422
2022	434,297	140,793	2,999	35,466	8,535	5,776	2,073	16,087	254,789	900,814	61,282	202,075	205,074
2023	421,141	162,683	2,847	31,615	7,935	5,568	2,082	16,367	245,002	895,241	73,406	236,090	238,937
2024	451,904	216,715	3,118	31,564	7,341	5,402	2,115	15,407	242,896	976,463	83,918	300,634	303,752
Year 2022													
January	37,416	7,689	133	3,106	748	492	192	1,470	24,198	75,443	3,376	11,065	11,198
February	37,645	8,868	159	2,897	701	432	173	1,243	21,321	73,438	3,717	12,585	12,744
March	43,031	11,439	255	2,934	773	465	188	1,296	24,436	84,808	5,121	16,560	16,815
April	46,167	13,080	321	2,736	699	482	161	1,282	20,066	84,995	5,671	18,751	19,073
May	42,124	14,749	371	2,907	722	492	157	1,327	23,359	86,208	6,236	20,985	21,356
June	33,768	15,681	372	3,045	710	498	166	1,276	25,988	81,501	6,229	21,910	22,281
July	29,475	15,477	288	3,276	723	510	173	1,341	24,567	75,831	6,438	21,915	22,203
August	24,718	14,223	279	3,206	707	498	174	1,354	21,133	66,293	6,194	20,418	20,697
September	27,331	13,001	285	2,864	686	470	159	1,329	17,026	63,152	5,544	18,545	18,830
October	32,745	11,652	289	2,624	714	473	182	1,298	14,367	64,345	5,022	16,674	16,964
November	41,199	8,254	149	2,865	678	473	167	1,397	17,898	73,079	4,035	12,289	12,438
December	38,680	6,679	99	3,005	674	493	181	1,482	20,430	71,721	3,698	10,377	10,475
Year 2023													
January	38,358	7,722	84	2,920	694	483	168	1,420	22,754	74,603	3,989	11,711	11,795
February	41,424	9,326	109	2,533	614	420	174	1,302	19,961	75,863	4,387	13,713	13,822
March	43,584	12,059	154	2,704	670	446	162	1,442	21,331	82,552	6,005	18,064	18,218
April	42,746	14,767	295	2,336	623	409	157	1,356	19,820	82,507	6,742	21,509	21,803
May	32,227	16,981	300	2,654	692	475	176	1,345	27,651	82,502	7,543	24,525	24,824
June	27,547	17,469	365	2,579	666	483	159	1,293	21,572	72,134	7,405	24,874	25,239
July	28,005	18,514	380	2,758	674	497	165	1,296	21,978	74,266	7,720	26,234	26,614
August	28,394	17,435	309	2,884	680	482	174	1,267	21,293	72,919	7,504	24,938	25,248
September	28,353	15,290	293	2,573	629	441	160	1,315	16,916	65,968	6,604	21,894	22,187
October	36,020	13,834	287	2,317	649	463	191	1,420	15,673	70,853	6,076	19,910	20,196
November	36,445	10,280	166	2,584	651	471	183	1,440	17,026	69,246	4,938	15,218	15,384
December	38,038	9,006	106	2,774	693	498	213	1,473	19,028	71,829	4,494	13,500	13,606
Year 2024													
January	34,791	9,504	79	2,849	642	467	186	1,399	21,554	71,471	4,726	14,230	14,309
February	40,982	12,421	119	2,621	605	421	176	1,303	20,795	79,444	5,342	17,763	17,882
March	45,102	15,798	221	2,651	638	422	181	1,359	23,363	89,736	7,113	22,911	23,132
April	47,088	18,909	332	2,423	583	408	158	1,280	20,916	92,097	7,832	26,741	27,073
May	39,256	21,957	414	2,575	638	469	176	1,246	24,477	91,209	8,539	30,496	30,910
June	38,661	24,045	414	2,681	593	450	168	1,202	22,397	90,610	8,553	32,598	33,012
July	28,304	24,122	361	2,806	624	475	166	1,218	21,384	79,460	8,778	32,901	33,262
August	29,290	23,974	354	2,839	641	480	175	1,227	20,491	79,472	8,412	32,387	32,741
September	29,178	20,203	335	2,563	604	447	170	1,201	15,911	70,614	7,511	27,714	28,049
October	39,592	19,595	233	2,240	608	448	187	1,261	15,352	79,514	6,736	26,331	26,564
November	40,133	13,705	136	2,550	577	456	180	1,317	16,723	75,779	5,393	19,098	19,234
December	39,527	12,481	120	2,765	588	457	192	1,393	19,533	77,057	4,984	17,465	17,585

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. N/A=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.2.A. Net Generation by Energy Source: Electric Utilities, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities											Total
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	
Annual Totals												
2014	1,173,073	10,696	9,147	501,440	112	419,871	238,185	1,218	33,278	-5,144	622	2,382,500
2015	996,385	10,386	8,278	619,003	199	416,680	229,640	1,494	35,992	-4,105	558	2,316,508
2016	922,399	9,969	8,861	655,744	154	424,400	247,787	1,995	40,666	-5,629	421	2,305,887
2017	893,039	8,567	6,711	625,094	149	424,485	275,677	3,348	42,763	-5,448	553	2,275,539
2018	863,505	10,108	6,617	722,916	151	424,251	267,336	4,916	44,184	-4,785	561	2,339,960
2019	722,885	8,313	5,112	787,745	154	430,672	262,364	6,785	48,403	-4,261	551	2,268,723
2020	582,374	7,182	5,663	815,414	45	429,953	264,650	9,945	59,797	-4,326	618	2,170,316
2021	674,804	8,791	5,728	777,057	12	430,683	228,689	13,911	75,338	-3,876	508	2,211,643
2022	621,853	9,356	5,383	832,421	0	427,933	232,953	17,692	86,233	-4,752	534	2,229,605
2023	518,330	8,254	3,146	895,910	0	441,391	220,003	22,230	84,313	-4,545	580	2,189,614
2024	508,149	8,504	1,946	953,446	0	444,521	220,163	30,347	93,209	-4,232	285	2,256,336
Year 2022												
January	63,823	1,254	388	66,875	0	39,295	22,395	1,066	8,258	-420	58	202,990
February	50,911	629	453	55,560	0	34,300	19,408	1,188	7,998	-301	51	170,198
March	43,015	691	324	54,831	0	34,385	21,943	1,533	8,561	-214	55	165,124
April	40,123	548	361	51,428	0	30,252	17,583	1,714	8,652	-164	43	150,540
May	47,965	639	503	62,462	0	35,037	21,195	1,850	7,488	-375	53	176,816
June	56,910	652	545	79,183	0	36,908	24,296	1,836	6,114	-460	40	206,024
July	66,531	678	388	95,206	0	38,888	23,132	1,811	5,104	-623	40	231,355
August	64,386	661	423	93,582	0	38,921	19,776	1,717	4,993	-495	36	223,900
September	49,704	680	460	59,375	0	35,914	15,593	1,499	5,846	-493	33	185,222
October	41,060	676	440	64,375	0	32,085	12,963	1,460	6,736	-370	46	159,472
November	41,209	673	446	63,004	0	33,612	16,315	1,046	8,593	-398	40	164,537
December	56,116	1,575	636	69,839	0	38,335	18,352	982	7,992	-437	39	193,428
Year 2023												
January	47,822	749	265	69,060	0	40,507	19,961	1,198	7,368	-496	50	186,483
February	34,662	721	257	61,273	0	34,281	17,914	1,480	8,665	-359	44	158,939
March	37,670	678	166	66,443	0	36,091	18,841	1,928	8,423	-389	47	169,897
April	29,082	634	176	59,851	0	33,574	17,367	1,992	9,198	-191	41	151,724
May	32,611	657	166	70,281	0	34,559	25,345	2,322	6,601	-336	44	172,249
June	46,228	687	257	81,588	0	37,005	19,980	2,288	4,812	-420	52	192,477
July	62,726	678	484	99,498	0	39,977	19,811	2,325	4,726	-519	51	229,758
August	61,744	733	491	100,846	0	40,065	19,175	2,301	5,570	-499	59	230,484
September	46,714	653	441	81,426	0	37,575	15,262	1,965	5,788	-415	47	189,456
October	38,830	695	176	68,791	0	34,541	14,167	1,873	7,410	-294	47	166,235
November	37,358	669	100	63,741	0	34,719	15,453	1,403	8,015	-245	47	161,261
December	42,884	699	167	73,111	0	38,497	16,728	1,154	7,737	-379	53	180,651
Year 2024												
January	58,491	1,028	200	80,561	0	39,090	19,005	1,291	7,117	-287	32	206,527
February	34,812	590	91	66,015	0	36,601	18,487	1,993	8,381	-268	27	166,728
March	31,039	609	40	66,011	0	35,957	20,610	2,413	9,619	-213	20	166,104
April	28,360	643	137	61,043	0	32,153	18,197	3,022	10,124	-231	15	153,463
May	35,539	649	153	74,969	0	36,822	22,074	3,303	7,979	-144	27	181,372
June	48,750	652	252	87,902	0	38,907	20,702	3,216	7,676	-439	25	207,643
July	56,197	699	285	107,213	0	40,398	19,685	3,164	5,187	-472	24	232,380
August	53,679	770	277	105,880	0	39,992	18,685	3,084	5,824	-638	24	227,576
September	42,774	665	142	87,049	0	35,308	14,867	2,536	6,359	-501	22	189,221
October	35,531	728	137	74,370	0	33,821	14,374	2,554	8,548	-328	25	169,761
November	34,323	675	85	69,701	0	35,228	15,766	1,901	8,027	-351	24	165,377
December	48,654	796	147	72,734	0	40,244	17,712	1,870	8,368	-359	21	190,186

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.2.B. Net Generation from Renewable Sources: Electric Utilities, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	27,671	1,094	124	3,050	1,068	191	182	1,116	238,185	272,681	0	1,094	1,218
2015	30,412	1,388	106	3,018	1,061	195	218	1,089	229,640	267,125	0	1,388	1,494
2016	35,070	1,920	75	3,038	1,040	201	237	1,080	247,787	290,448	0	1,920	1,995
2017	37,068	3,326	22	3,226	1,103	184	161	1,022	275,677	321,788	0	3,326	3,348
2018	38,466	4,865	51	3,364	1,004	203	138	1,009	267,336	316,436	0	4,865	4,916
2019	43,636	6,757	28	2,784	964	122	126	771	262,364	317,552	0	6,757	6,785
2020	55,554	9,915	30	2,077	1,006	126	120	915	264,650	334,392	0	9,915	9,945
2021	70,338	13,883	29	2,796	973	108	116	1,007	228,689	317,938	0	13,883	13,911
2022	80,962	17,664	28	3,263	813	111	58	1,026	232,953	336,878	0	17,664	17,692
2023	80,120	22,230	0	2,549	653	115	94	782	220,003	326,546	0	22,230	22,230
2024	89,056	30,347	0	2,436	597	113	93	914	220,163	343,718	0	30,347	30,347
Year 2022													
January	7,790	1,057	9	281	76	9	6	96	22,395	31,718	0	1,057	1,066
February	7,537	1,187	1	292	71	9	3	96	19,408	28,594	0	1,187	1,188
March	8,171	1,531	2	224	77	6	4	79	21,943	32,037	0	1,531	1,533
April	8,302	1,711	3	182	69	9	3	87	17,583	27,948	0	1,711	1,714
May	7,057	1,845	4	254	70	12	6	89	21,195	30,532	0	1,845	1,850
June	5,665	1,834	2	281	67	10	5	84	24,296	32,247	0	1,834	1,836
July	4,587	1,809	2	347	68	11	6	87	23,132	30,046	0	1,809	1,811
August	4,364	1,715	2	360	65	11	4	88	19,778	26,388	0	1,715	1,717
September	5,420	1,488	2	263	64	8	6	86	15,593	22,929	0	1,488	1,489
October	6,352	1,459	1	222	65	10	5	82	12,963	21,159	0	1,459	1,460
November	8,206	1,046	0	231	62	9	6	79	16,315	25,953	0	1,046	1,046
December	7,511	982	0	326	59	8	5	83	18,352	27,326	0	982	982
Year 2023													
January	6,934	1,198	0	279	58	9	9	79	19,961	28,527	0	1,198	1,198
February	8,273	1,480	0	245	50	6	8	82	17,914	28,060	0	1,480	1,480
March	8,122	1,928	0	169	58	8	6	60	18,841	29,193	0	1,928	1,928
April	8,930	1,992	0	121	53	8	9	76	17,367	28,557	0	1,992	1,992
May	6,291	2,322	0	180	58	9	7	56	25,345	34,267	0	2,322	2,322
June	4,459	2,288	0	245	56	11	5	36	19,980	27,079	0	2,288	2,288
July	4,279	2,325	0	293	55	10	7	82	19,811	26,862	0	2,325	2,325
August	5,121	2,301	0	293	54	11	6	83	19,175	27,046	0	2,301	2,301
September	5,447	1,965	0	215	49	10	8	59	15,262	23,016	0	1,965	1,965
October	7,143	1,873	0	133	52	11	12	59	14,167	23,450	0	1,873	1,873
November	7,721	1,403	0	166	53	10	7	58	15,453	24,871	0	1,403	1,403
December	7,399	1,154	0	211	56	11	10	50	16,728	25,619	0	1,154	1,154
Year 2024													
January	6,694	1,291	0	298	49	8	5	62	19,005	27,413	0	1,291	1,291
February	8,036	1,993	0	224	50	7	5	59	18,487	28,861	0	1,993	1,993
March	9,356	2,413	0	134	51	5	8	65	20,610	32,642	0	2,413	2,413
April	9,793	3,022	0	199	46	4	6	76	18,197	31,343	0	3,022	3,022
May	7,648	3,303	0	176	50	12	8	83	22,074	33,356	0	3,303	3,303
June	7,271	3,216	0	257	48	12	10	78	20,702	31,594	0	3,216	3,216
July	4,785	3,164	0	253	51	11	11	77	19,685	28,036	0	3,164	3,164
August	5,401	3,084	0	270	54	11	12	77	18,685	27,592	0	3,084	3,084
September	6,072	2,536	0	145	51	11	7	73	14,867	23,763	0	2,536	2,536
October	8,304	2,554	0	93	50	11	8	83	14,374	25,476	0	2,554	2,554
November	7,739	1,901	0	131	49	11	6	90	15,766	25,693	0	1,901	1,901
December	7,957	1,870	0	255	48	10	7	91	17,712	27,950	0	1,870	1,870

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. N/A=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.3.A. Net Generation by Energy Source: Independent Power Producers, 2014 - 2024
(Thousand Megawatthours)

	Generation at Utility Scale Facilities												
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total	
Annual Totals													
2014	395,701	6,789	1,410	531,758	3,246	377,295	19,861	16,086	196,723	-1,030	6,622	1,554,462	
2015	342,608	6,240	1,601	619,839	3,517	380,498	17,996	22,962	202,858	-987	6,765	1,603,898	
2016	307,263	3,360	1,401	624,600	3,758	381,294	18,539	33,502	233,553	-1,057	6,876	1,613,090	
2017	304,198	3,281	1,480	572,919	3,978	380,465	23,034	49,376	258,982	-1,047	6,439	1,603,086	
2018	278,688	5,487	1,516	645,616	3,935	382,833	23,812	58,337	275,154	-1,119	6,677	1,680,917	
2019	235,847	2,669	1,125	692,113	3,883	378,738	24,288	64,480	290,343	-1,000	7,138	1,699,625	
2020	185,328	1,984	1,504	706,885	3,129	360,925	19,409	78,567	319,633	-995	6,971	1,683,340	
2021	217,636	2,378	1,413	699,547	3,292	348,961	21,702	100,612	344,784	-1,235	6,449	1,745,538	
2022	204,243	5,734	1,354	750,266	3,451	343,604	20,673	125,155	387,590	-1,276	3,487	1,844,282	
2023	152,238	2,573	1,415	803,945	3,340	333,482	23,862	142,360	374,335	-1,445	2,823	1,838,927	
2024	139,527	2,567	1,377	812,528	2,976	337,345	21,612	188,376	393,974	-1,619	1,627	1,900,291	
Year 2022													
January	23,291	1,778	144	58,734	292	31,282	1,702	6,707	32,672	-73	337	156,865	
February	19,627	438	131	51,382	251	27,552	1,808	7,781	32,824	-111	276	141,960	
March	17,526	222	145	49,110	270	28,768	2,358	10,085	37,718	-103	307	146,406	
April	14,792	154	137	46,169	291	25,037	2,360	11,598	40,541	-101	296	141,274	
May	14,096	149	58	56,228	365	28,345	2,054	13,172	37,838	-92	289	152,501	
June	16,076	192	108	67,698	281	28,807	1,601	14,109	30,941	-129	309	159,993	
July	19,305	311	71	84,262	342	29,969	1,357	13,851	27,884	-146	312	177,519	
August	20,347	295	124	85,697	277	29,976	1,272	12,685	23,314	-145	298	174,141	
September	14,860	210	140	72,435	306	27,819	1,354	11,709	24,739	-105	275	153,744	
October	12,745	228	136	60,642	276	26,860	1,338	10,406	29,126	-64	255	141,947	
November	14,768	190	84	55,774	236	28,430	1,504	7,299	35,838	-97	252	144,278	
December	16,810	1,566	76	62,134	264	30,759	1,966	5,753	34,153	-111	284	153,654	
Year 2023													
January	13,093	166	123	60,766	285	30,363	2,679	6,565	34,358	-122	280	148,554	
February	11,333	444	112	55,594	238	26,526	1,935	7,898	35,759	-97	223	139,965	
March	12,063	191	117	58,519	280	26,730	2,356	10,209	38,364	-130	227	148,927	
April	10,796	191	107	52,576	202	23,088	2,336	12,968	36,407	-99	217	138,789	
May	10,816	186	143	58,727	308	26,596	2,196	14,853	28,754	-123	270	142,728	
June	11,172	149	114	71,301	273	27,814	1,505	15,445	25,822	-132	252	153,716	
July	15,778	243	140	90,386	305	29,910	2,075	16,463	26,509	-137	240	181,912	
August	15,990	183	138	88,699	333	29,679	2,037	15,347	26,048	-154	239	178,539	
September	12,872	200	132	75,669	289	27,985	1,589	13,534	25,576	-137	195	157,903	
October	11,746	255	98	63,236	249	26,895	1,443	12,176	31,570	-78	214	147,803	
November	13,493	193	59	62,888	262	27,538	1,507	8,985	31,544	-102	228	146,593	
December	13,087	173	130	65,586	316	30,357	2,205	7,916	33,623	-135	238	153,496	
Year 2024													
January	16,710	399	133	71,562	292	29,990	2,431	8,246	30,935	-127	217	160,788	
February	9,956	112	98	57,404	244	27,983	2,191	10,482	35,573	-135	197	143,102	
March	7,068	144	138	56,708	227	27,389	2,633	13,514	38,488	-135	177	146,350	
April	8,579	187	117	52,269	256	25,389	2,599	16,111	39,662	-107	143	145,205	
May	9,925	174	128	60,666	210	28,151	2,286	18,942	34,139	-140	165	154,645	
June	12,231	203	112	72,845	291	29,285	1,613	21,114	33,890	-140	115	171,560	
July	14,966	267	135	89,542	265	29,453	1,627	21,195	26,131	-167	127	183,541	
August	14,696	194	131	87,422	224	29,768	1,731	21,125	26,541	-160	114	181,787	
September	11,422	148	75	73,993	264	27,353	988	17,902	25,655	-136	102	157,765	
October	11,001	173	72	64,449	246	24,952	896	17,185	33,735	-111	69	152,666	
November	10,232	170	112	59,828	217	26,676	885	11,879	34,944	-138	107	144,913	
December	13,742	396	127	65,840	238	30,956	1,733	10,681	34,281	-123	96	157,968	

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.3.B. Net Generation from Renewable Sources: Independent Power Producers, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	153,825	13,769	2,317	11,977	9,062	5,838	1,261	14,761	19,861	232,670	0	13,769	16,086
2015	160,135	19,841	3,121	11,545	9,202	5,806	1,342	14,829	17,996	243,816	0	19,841	22,962
2016	191,720	30,194	3,308	10,382	9,255	5,965	1,486	14,746	18,539	285,594	0	30,194	33,502
2017	217,006	46,128	3,248	10,416	9,505	5,652	1,479	14,905	23,034	331,372	0	46,128	49,376
2018	233,931	54,796	3,540	10,021	9,162	5,891	1,226	14,924	23,812	357,303	0	54,796	58,337
2019	251,968	61,290	3,190	9,237	8,739	5,096	1,043	14,260	24,288	379,111	0	61,290	64,480
2020	281,599	75,464	3,103	9,135	8,417	5,117	839	14,526	19,409	417,609	0	75,464	78,567
2021	307,579	97,717	2,895	9,101	7,717	5,019	900	14,466	21,702	467,098	0	97,717	100,612
2022	353,032	122,184	2,971	8,739	7,077	2,904	776	15,061	20,673	533,418	0	122,184	125,155
2023	340,790	139,513	2,847	7,637	6,646	2,858	828	15,596	23,862	540,557	0	139,513	142,360
2024	362,616	185,257	3,118	7,218	6,161	2,734	752	14,493	21,612	603,962	0	185,257	188,376
Year 2022													
January	29,596	6,583	124	760	613	259	70	1,374	1,702	41,080	0	6,583	6,707
February	30,076	7,624	157	727	578	217	69	1,157	1,808	42,413	0	7,624	7,781
March	34,827	9,832	253	740	639	237	67	1,208	2,358	50,161	0	9,832	10,085
April	37,831	11,279	319	643	586	232	53	1,195	2,360	54,499	0	11,279	11,598
May	35,040	12,805	367	675	601	237	47	1,238	2,054	53,064	0	12,805	13,172
June	28,081	13,740	369	755	590	251	71	1,192	1,601	46,650	0	13,740	14,109
July	24,872	13,565	286	823	600	260	74	1,255	1,357	43,092	0	13,565	13,851
August	20,341	12,409	277	797	585	254	71	1,266	1,272	37,271	0	12,409	12,685
September	21,896	11,426	283	730	567	241	63	1,243	1,354	37,803	0	11,426	11,709
October	26,369	10,117	289	648	593	232	69	1,216	1,338	40,870	0	10,117	10,406
November	32,961	7,150	149	709	565	231	54	1,318	1,504	44,641	0	7,150	7,299
December	31,142	5,654	99	732	560	254	66	1,399	1,966	41,872	0	5,654	5,753
Year 2023													
January	31,400	6,481	84	715	581	254	66	1,341	2,679	43,601	0	6,481	6,565
February	33,123	7,790	109	600	513	227	76	1,219	1,935	45,592	0	7,790	7,898
March	35,432	10,056	154	691	557	242	59	1,382	2,356	50,929	0	10,056	10,209
April	33,788	12,673	295	554	517	210	59	1,279	2,336	51,712	0	12,673	12,968
May	25,915	14,554	300	660	582	246	62	1,289	2,196	45,803	0	14,554	14,853
June	23,074	15,080	365	630	557	243	61	1,257	1,505	42,772	0	15,080	15,445
July	23,717	16,083	380	696	565	252	66	1,214	2,075	45,047	0	16,083	16,463
August	23,260	15,038	309	715	570	246	73	1,184	2,037	43,433	0	15,038	15,347
September	22,895	13,241	293	604	528	221	72	1,255	1,589	40,699	0	13,241	13,534
October	28,858	11,889	287	501	549	231	71	1,361	1,443	45,189	0	11,889	12,176
November	28,701	8,818	166	613	546	235	67	1,382	1,507	42,036	0	8,818	8,985
December	30,617	7,810	106	657	580	251	96	1,422	2,205	43,744	0	7,810	7,916
Year 2024													
January	28,077	8,167	79	681	541	233	67	1,337	2,431	41,613	0	8,167	8,246
February	32,931	10,362	119	616	506	213	63	1,244	2,191	48,245	0	10,362	10,482
March	35,727	13,293	221	662	535	218	52	1,295	2,633	54,635	0	13,293	13,514
April	37,272	15,779	332	448	491	203	43	1,204	2,599	58,372	0	15,779	16,111
May	31,588	18,528	414	566	540	230	52	1,163	2,286	55,367	0	18,528	18,942
June	31,372	20,700	414	604	502	223	64	1,124	1,613	56,617	0	20,700	21,114
July	23,506	20,834	361	658	525	244	58	1,141	1,627	48,953	0	20,834	21,195
August	23,875	20,771	354	666	538	242	70	1,151	1,731	49,397	0	20,771	21,125
September	23,091	17,567	335	632	506	228	69	1,128	988	44,545	0	17,567	17,902
October	31,270	16,952	233	479	508	225	75	1,178	896	51,816	0	16,952	17,185
November	32,367	11,743	136	569	479	238	63	1,227	895	47,708	0	11,743	11,879
December	31,540	10,561	120	636	491	236	75	1,302	1,733	46,695	0	10,561	10,681

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.A. Net Generation by Energy Source: Commercial Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2014	595	247	9	7,227	0	0	38	371	2,862	0	1,171	12,520	5,146	5,516	5,516
2015	509	183	8	7,471	0	0	35	416	2,803	0	1,170	12,595	5,689	6,106	6,106
2016	383	77	6	7,730	0	0	217	529	2,697	0	1,068	12,706	6,158	6,687	6,687
2017	329	103	8	8,042	0	0	240	521	2,729	0	1,088	13,060	7,685	8,206	8,206
2018	303	132	7	8,419	0	0	227	525	2,688	0	1,010	13,312	9,798	10,324	10,324
2019	268	116	5	8,610	0	0	188	587	2,840	0	1,076	13,689	11,002	11,588	11,588
2020	240	97	2	8,110	0	0	214	586	2,761	0	1,035	13,046	12,859	13,445	13,445
2021	280	94	4	7,346	0	0	258	598	2,978	0	1,209	12,768	15,124	15,722	15,722
2022	287	101	10	7,830	0	0	263	669	4,185	0	3,391	16,737	17,724	18,393	18,393
2023	220	76	2	7,744	0	0	293	615	3,930	0	3,185	16,066	19,751	20,366	20,366
2024	204	12	4	7,157	0	0	311	566	3,875	0	3,130	15,258	21,652	22,218	22,218
Year 2022															
January	29	23	1	655	0	0	24	36	358	0	276	1,403	1,012	1,048	1,048
February	19	6	1	563	0	0	21	42	324	0	254	1,232	1,116	1,158	1,158
March	18	5	1	606	0	0	24	56	346	0	271	1,328	1,521	1,576	1,576
April	13	6	1	559	0	0	21	66	349	0	295	1,308	1,662	1,728	1,728
May	10	6	1	611	0	0	26	71	358	0	298	1,381	1,816	1,887	1,887
June	27	8	1	672	0	0	27	74	354	0	291	1,455	1,819	1,893	1,893
July	26	7	1	807	0	0	26	72	359	0	294	1,592	1,894	1,966	1,966
August	29	8	0	822	0	0	22	69	360	0	286	1,595	1,801	1,871	1,871
September	30	5	0	696	0	0	18	61	335	0	272	1,417	1,608	1,668	1,668
October	28	5	0	571	0	0	15	52	345	0	284	1,300	1,383	1,435	1,435
November	28	6	1	601	0	0	18	40	350	0	286	1,330	1,086	1,126	1,126
December	30	18	1	668	0	0	20	29	347	0	284	1,397	1,007	1,037	1,037
Year 2023															
January	28	9	1	624	0	0	29	28	327	0	270	1,316	1,119	1,147	1,147
February	26	19	0	587	0	0	26	38	290	0	230	1,215	1,234	1,272	1,272
March	20	7	0	611	0	0	30	51	305	0	240	1,264	1,680	1,731	1,731
April	21	4	0	564	0	0	30	67	295	0	234	1,214	1,855	1,923	1,923
May	17	5	0	594	0	0	26	71	333	0	271	1,317	2,023	2,095	2,095
June	9	4	0	660	0	0	19	66	343	0	281	1,381	2,011	2,077	2,077
July	12	5	0	784	0	0	24	70	346	0	289	1,529	2,087	2,156	2,156
August	12	4	0	746	0	0	24	62	346	0	277	1,471	2,010	2,072	2,072
September	15	4	0	706	0	0	18	53	317	0	257	1,370	1,796	1,849	1,849
October	18	5	0	627	0	0	23	46	332	0	271	1,323	1,558	1,604	1,604
November	18	5	0	609	0	0	22	37	340	0	277	1,308	1,225	1,262	1,262
December	23	6	1	633	0	0	23	25	358	0	288	1,358	1,153	1,178	1,178
Year 2024															
January	34	0	1	620	0	0	30	23	346	0	278	1,330	1,218	1,241	1,241
February	23	-1	0	567	0	0	28	34	305	0	247	1,204	1,386	1,420	1,420
March	19	2	0	565	0	0	31	48	313	0	243	1,221	1,821	1,869	1,869
April	15	3	0	533	0	0	30	56	305	0	245	1,187	2,007	2,063	2,063
May	7	0	1	525	0	0	32	64	338	0	278	1,245	2,216	2,280	2,280
June	10	6	1	613	0	0	23	67	323	0	264	1,308	2,213	2,280	2,280
July	14	1	0	728	0	0	24	63	335	0	270	1,435	2,297	2,360	2,360
August	15	0	0	699	0	0	23	61	330	0	280	1,409	2,204	2,265	2,265
September	16	-1	0	602	0	0	20	48	316	0	255	1,257	1,969	2,018	2,018
October	14	-2	0	563	0	0	21	46	315	0	258	1,215	1,709	1,755	1,755
November	17	2	0	563	0	0	23	31	321	0	254	1,210	1,336	1,367	1,367
December	19	1	1	580	0	0	25	25	328	0	259	1,238	1,276	1,300	1,300

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.B. Net Generation from Renewable Sources: Commercial Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2014	107	371	0	74	905	1,202	575	0	38	3,271	5,146	5,516	5,516
2015	118	416	0	48	847	1,199	592	0	35	3,255	5,689	6,106	6,106
2016	131	529	0	69	753	1,093	649	0	217	3,443	6,158	6,687	6,687
2017	144	521	0	70	753	1,114	648	0	240	3,490	7,685	8,206	8,206
2018	174	525	0	77	703	1,038	664	33	227	3,441	9,798	10,324	10,324
2019	179	587	0	90	626	869	634	442	188	3,615	11,002	11,588	11,588
2020	166	586	0	91	657	832	565	449	214	3,561	12,859	13,445	13,445
2021	166	598	0	153	612	973	571	502	258	3,834	15,124	15,722	15,722
2022	173	669	0	175	517	2,761	560	0	263	5,118	17,724	18,393	18,393
2023	130	615	0	107	509	2,595	589	0	293	4,838	19,751	20,366	20,366
2024	133	566	0	111	459	2,554	617	0	311	4,752	21,652	22,218	22,218
Year 2022													
January	18	36	0	15	48	225	52	0	24	418	1,012	1,048	1,048
February	17	42	0	14	42	206	43	0	21	388	1,116	1,158	1,158
March	19	56	0	10	46	221	50	0	24	426	1,521	1,576	1,576
April	19	66	0	11	35	240	44	0	21	435	1,662	1,728	1,728
May	16	71	0	17	40	243	43	0	26	455	1,816	1,887	1,887
June	13	74	0	20	42	237	43	0	27	456	1,819	1,893	1,893
July	9	72	0	18	45	240	47	0	26	457	1,894	1,966	1,966
August	7	69	0	27	46	233	47	0	22	451	1,801	1,871	1,871
September	10	61	0	12	45	221	47	0	18	414	1,608	1,668	1,668
October	13	52	0	6	45	231	50	0	15	412	1,383	1,435	1,435
November	18	40	0	11	41	233	47	0	18	408	1,086	1,126	1,126
December	15	29	0	12	43	231	46	0	20	396	1,007	1,037	1,037
Year 2023													
January	13	28	0	11	44	220	39	0	29	384	1,119	1,147	1,147
February	15	38	0	7	40	187	41	0	26	353	1,234	1,272	1,272
March	16	51	0	7	42	196	44	0	30	386	1,680	1,731	1,731
April	16	67	0	5	42	191	41	0	30	392	1,855	1,923	1,923
May	13	71	0	3	41	221	55	0	26	430	2,023	2,095	2,095
June	7	66	0	11	42	229	54	0	19	428	2,011	2,077	2,077
July	4	70	0	10	44	236	52	0	24	439	2,087	2,156	2,156
August	6	62	0	14	46	225	54	0	24	432	2,010	2,072	2,072
September	7	53	0	12	43	209	45	0	18	388	1,796	1,849	1,849
October	9	46	0	8	39	221	55	0	23	402	1,558	1,604	1,604
November	11	37	0	9	42	226	52	0	22	398	1,225	1,262	1,262
December	12	25	0	11	44	235	55	0	23	406	1,153	1,178	1,178
Year 2024													
January	10	23	0	16	41	226	53	0	30	398	1,218	1,241	1,241
February	10	34	0	6	38	201	50	0	28	367	1,386	1,420	1,420
March	14	48	0	4	40	199	56	0	31	392	1,821	1,869	1,869
April	16	56	0	0	36	200	52	0	30	392	2,007	2,063	2,063
May	13	64	0	5	39	227	55	0	32	434	2,216	2,280	2,280
June	12	67	0	10	35	215	52	0	23	413	2,213	2,280	2,280
July	8	63	0	18	38	220	51	0	24	423	2,297	2,360	2,360
August	8	61	0	10	39	228	45	0	23	415	2,204	2,265	2,265
September	9	48	0	14	37	208	47	0	20	384	1,969	2,018	2,018
October	9	46	0	6	38	211	51	0	21	382	1,709	1,755	1,755
November	11	31	0	12	39	207	52	0	23	374	1,336	1,367	1,367
December	13	25	0	10	40	212	54	0	25	378	1,276	1,300	1,300

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.A. Net Generation by Energy Source: Industrial Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities											Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic
Annual Totals														
2014	12,341	544	1,389	86,209	8,664	0	1,282	16	28,659	0	4,978	144,083	1,139	1,156
2015	10,896	563	990	88,355	9,401	0	1,410	21	28,614	0	5,462	145,712	1,451	1,472
2016	9,103	503	909	91,197	8,895	0	1,269	27	28,663	0	5,324	145,890	2,060	2,087
2017	7,669	463	776	91,647	8,343	0	1,382	42	28,508	0	4,928	143,758	2,364	2,406
2018	7,011	517	640	94,892	9,377	0	1,149	47	28,440	0	4,725	146,798	2,636	2,683
2019	5,957	424	576	100,065	8,554	0	1,033	85	27,276	0	4,567	148,537	3,041	3,127
2020	5,451	398	510	96,381	8,644	0	1,001	101	26,348	0	4,231	143,064	3,484	3,586
2021	5,278	400	367	95,240	8,093	0	936	137	25,324	0	3,975	139,750	3,858	3,994
2022	5,128	614	379	96,548	8,271	0	899	276	24,226	0	3,702	140,043	4,048	4,324
2023	4,327	494	273	98,463	8,438	0	844	326	22,130	0	3,369	138,664	4,382	4,708
2024	4,276	372	302	96,771	7,870	0	810	546	22,675	0	3,127	136,749	4,719	5,265
Year 2022														
January	445	51	31	8,683	713	0	77	13	2,137	0	359	12,508	230	243
February	409	NM	36	7,440	635	0	83	15	1,944	0	319	10,921	244	259
March	459	41	30	7,931	683	0	111	21	2,051	0	347	11,673	348	369
April	402	42	28	7,350	630	0	102	24	1,986	0	308	10,871	377	401
May	461	40	35	7,790	671	0	84	28	2,045	0	332	11,485	413	441
June	450	45	29	7,964	706	0	63	32	2,053	0	319	11,661	413	446
July	453	48	28	8,667	741	0	53	31	2,152	0	336	12,510	426	458
August	453	38	31	8,759	731	0	61	30	2,091	0	303	12,498	411	441
September	404	47	29	7,842	680	0	60	26	1,919	0	265	11,272	368	395
October	396	43	33	7,903	692	0	51	24	1,828	0	260	11,230	333	357
November	372	43	38	8,144	675	0	62	18	1,998	0	287	11,635	256	273
December	425	137	31	8,075	714	0	92	13	2,023	0	270	11,779	229	242
Year 2023														
January	414	59	32	8,052	660	0	85	16	1,989	0	290	11,597	244	260
February	354	50	25	7,582	654	0	86	18	1,753	0	281	10,803	259	277
March	343	48	31	8,127	748	0	104	24	1,916	0	276	11,616	370	395
April	334	39	17	7,021	665	0	87	34	1,725	0	252	10,176	408	442
May	359	32	20	7,791	703	0	84	35	1,882	0	273	11,180	447	481
June	362	38	18	8,433	701	0	69	35	1,751	0	253	11,660	446	481
July	387	38	27	8,854	741	0	69	37	1,813	0	292	12,255	461	497
August	366	38	23	8,930	755	0	57	34	1,918	0	290	12,410	444	478
September	358	36	19	8,511	694	0	46	30	1,789	0	276	11,760	400	429
October	340	36	20	8,171	675	0	40	26	1,747	0	304	11,358	363	389
November	340	38	21	8,293	697	0	45	21	1,875	0	293	11,622	286	307
December	370	41	20	8,699	746	0	72	17	1,971	0	290	12,226	254	271
Year 2024														
January	383	42	27	8,925	782	0	88	23	1,936	0	273	12,477	268	290
February	346	39	28	7,860	687	0	89	32	1,849	0	250	11,181	296	329
March	380	29	30	7,853	655	0	89	43	1,935	0	249	11,263	406	449
April	293	32	24	7,687	657	0	89	52	1,849	0	242	10,925	440	492
May	341	27	22	7,834	680	0	85	62	1,904	0	268	11,224	478	540
June	348	29	23	7,795	649	0	58	62	1,866	0	291	11,122	476	539
July	388	30	32	8,475	684	0	48	61	1,939	0	302	11,960	490	551
August	371	28	23	8,914	687	0	51	59	1,958	0	264	12,354	473	532
September	346	27	19	8,027	572	0	36	52	1,835	0	240	11,154	433	485
October	344	30	22	7,330	555	0	62	44	1,736	0	217	10,338	390	433
November	352	28	23	7,595	583	0	51	31	1,922	0	267	10,852	303	334
December	385	32	29	8,476	681	0	63	25	1,946	0	263	11,900	267	292

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.B. Net Generation from Renewable Sources: Industrial Sector, 2014 - 2024
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2014	53	16	0	27,239	185	-2	1,185	0	1,282	29,957	1,139	1,156	1,156
	2015	53	21	0	27,318	182	12	1,049	0	1,410	30,045	1,451	1,472	1,472
	2016	71	27	0	27,458	170	6	959	0	1,269	29,960	2,060	2,087	2,087
	2017	84	42	0	27,412	183	1	827	0	1,382	29,932	2,364	2,406	2,406
	2018	97	47	0	27,475	168	4	697	0	1,149	29,636	2,636	2,683	2,683
	2019	100	85	0	26,433	139	5	598	0	1,033	28,395	3,041	3,127	3,127
	2020	617	101	0	24,916	133	5	676	0	1,001	27,450	3,484	3,586	3,586
	2021	112	137	0	24,413	119	1	680	0	936	26,397	3,858	3,994	3,994
	2022	130	276	0	23,289	128	0	678	0	899	25,401	4,048	4,324	4,324
	2023	112	326	0	21,320	127	0	571	0	844	23,300	4,382	4,708	4,708
	2024	99	546	0	21,800	123	0	652	0	810	24,031	4,719	5,265	5,265
Year 2022														
	January	12	13	0	2,049	10	0	65	0	77	2,226	230	243	243
	February	14	15	0	1,864	10	0	57	0	83	2,042	244	259	259
	March	15	21	0	1,960	11	0	66	0	111	2,183	348	369	369
	April	14	24	0	1,901	10	0	62	0	102	2,112	377	401	401
	May	12	28	0	1,961	10	0	62	0	84	2,157	413	441	441
	June	8	32	0	1,988	11	0	46	0	63	2,148	413	446	446
	July	7	31	0	2,088	11	0	46	0	53	2,236	426	458	458
	August	5	30	0	2,022	11	0	52	0	61	2,182	411	441	441
	September	6	26	0	1,860	11	0	42	0	60	2,006	368	395	395
	October	11	24	0	1,748	11	0	58	0	51	1,904	333	357	357
	November	14	18	0	1,914	10	0	59	0	62	2,077	256	273	273
	December	12	13	0	1,936	12	0	64	0	92	2,127	229	242	242
Year 2023														
	January	11	16	0	1,914	10	0	54	0	85	2,091	244	260	260
	February	13	18	0	1,680	11	0	48	0	86	1,858	259	277	277
	March	13	24	0	1,838	13	0	52	0	104	2,044	370	395	395
	April	11	34	0	1,655	11	0	48	0	87	1,846	408	442	442
	May	9	35	0	1,811	10	0	52	0	84	2,001	447	481	481
	June	7	35	0	1,693	11	0	40	0	69	1,855	446	481	481
	July	5	37	0	1,758	10	0	40	0	69	1,918	461	497	497
	August	6	34	0	1,862	10	0	40	0	57	2,009	444	478	478
	September	5	30	0	1,741	9	0	34	0	46	1,865	400	429	429
	October	10	26	0	1,675	9	0	53	0	40	1,813	363	389	389
	November	12	21	0	1,796	10	0	57	0	45	1,941	286	307	307
	December	10	17	0	1,896	12	0	52	0	72	2,060	254	271	271
Year 2024														
	January	9	23	0	1,854	11	0	61	0	88	2,047	268	290	290
	February	5	32	0	1,774	12	0	59	0	89	1,971	296	329	329
	March	6	43	0	1,852	12	0	65	0	89	2,067	406	449	449
	April	7	52	0	1,775	10	0	57	0	89	1,990	440	492	492
	May	7	62	0	1,828	8	0	61	0	85	2,052	478	540	540
	June	7	62	0	1,809	9	0	41	0	58	1,986	476	539	539
	July	5	61	0	1,878	11	0	45	0	48	2,048	490	551	551
	August	5	59	0	1,894	11	0	48	0	51	2,068	473	532	532
	September	6	52	0	1,772	10	0	47	0	36	1,923	433	485	485
	October	8	44	0	1,662	12	0	54	0	62	1,841	390	433	433
	November	17	31	0	1,837	9	0	59	0	51	2,004	303	334	334
	December	17	25	0	1,863	9	0	56	0	63	2,034	267	292	292

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.6. Net Generation by Energy Source: Residential Sector, 2014 - 2024
(Thousand Megawatthours)

Period	Small Scale Generation
	Estimated Small Scale Solar Photovoltaic Generation
Annual Totals	
2014	4,947
2015	6,999
2016	10,595
2017	13,942
2018	17,105
2019	20,914
2020	25,179
2021	30,182
2022	39,510
2023	49,273
2024	57,547
Year 2022	
January	2,135
February	2,357
March	3,252
April	3,632
May	4,007
June	3,997
July	4,118
August	3,982
September	3,569
October	3,306
November	2,693
December	2,462
Year 2023	
January	2,625
February	2,894
March	3,954
April	4,478
May	5,073
June	4,948
July	5,173
August	5,049
September	4,409
October	4,155
November	3,428
December	3,087
Year 2024	
January	3,240
February	3,659
March	4,885
April	5,385
May	5,845
June	5,863
July	5,991
August	5,735
September	5,108
October	4,638
November	3,754
December	3,442

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Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources:

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.7. Utility Scale Facility Net Generation
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	109,310	102,611	6.5%	1,591	1,658	103,672	96,713	2,060	2,129	1,987	2,110
Connecticut	44,761	40,666	10.1%	134	135	43,782	39,582	189	294	656	655
Maine	14,655	12,512	17.1%	3	5	13,599	11,361	41	47	1,013	1,099
Massachusetts	20,915	19,696	6.2%	547	529	18,493	17,323	1,727	1,673	148	172
New Hampshire	16,942	16,825	0.7%	7	17	16,852	16,719	60	62	23	27
Rhode Island	9,777	10,431	-6.3%	0	0	9,589	10,223	41	50	147	157
Vermont	2,259	2,480	-8.9%	900	973	1,356	1,504	2	2	0	0
Middle Atlantic	430,689	424,194	1.5%	36,583	35,522	385,352	379,475	3,521	3,834	5,233	5,362
New Jersey	60,175	64,229	-6.3%	264	282	58,144	62,260	1,138	1,107	630	580
New York	129,015	124,040	4.0%	36,207	35,157	90,153	85,934	1,798	2,145	857	804
Pennsylvania	241,499	235,925	2.4%	112	84	237,055	231,282	585	581	3,746	3,978
East North Central	614,249	584,213	5.1%	222,905	210,067	379,644	361,790	1,752	1,794	9,948	10,562
Illinois	185,013	177,738	4.1%	4,245	4,104	178,405	170,954	401	435	1,963	2,244
Indiana	97,013	90,047	7.7%	59,952	54,096	32,195	30,705	230	238	4,636	5,007
Michigan	124,200	120,657	2.9%	90,700	88,209	31,495	30,476	721	717	1,284	1,255
Ohio	142,747	133,223	7.1%	15,750	13,608	125,959	118,678	293	273	744	664
Wisconsin	65,276	62,549	4.4%	52,258	50,050	11,589	10,976	108	130	1,321	1,392
West North Central	354,289	351,225	0.9%	254,885	258,247	94,121	88,242	613	590	4,670	4,145
Iowa	70,464	69,837	0.9%	55,445	55,970	12,638	11,744	133	128	2,248	1,994
Kansas	57,696	58,457	-1.3%	30,081	33,224	27,227	24,863	13	13	375	357
Minnesota	58,595	57,277	2.3%	40,859	40,376	16,037	15,431	256	247	1,443	1,222
Missouri	66,876	66,703	0.3%	60,065	59,453	6,578	7,025	192	182	40	43
Nebraska	37,229	39,446	-5.6%	24,876	27,292	12,006	11,830	20	19	327	304
North Dakota	42,557	42,069	1.2%	32,738	32,582	9,648	9,321	0	0	171	166
South Dakota	20,872	17,436	19.7%	10,821	9,350	9,987	8,028	NM	NM	65	58
South Atlantic	835,080	800,717	4.3%	689,706	659,687	126,929	122,815	2,572	2,774	15,873	15,441
Delaware	4,799	4,772	0.6%	73	25	3,561	3,479	5	7	1,161	1,262
District of Columbia	187	172	8.9%	1	3	30	21	156	147	0	0
Florida	266,119	259,798	2.4%	249,531	243,421	12,096	11,636	994	1,097	3,499	3,644
Georgia	139,805	129,222	8.2%	115,578	105,782	19,369	19,110	3	2	4,856	4,327
Maryland	35,425	36,001	-1.6%	2,974	4,431	32,074	31,164	322	346	56	59
North Carolina	134,965	126,553	6.6%	112,771	104,306	20,621	20,481	263	263	1,311	1,504
South Carolina	100,485	100,853	-0.4%	94,347	95,650	4,515	3,717	3	2	1,621	1,485
Virginia	102,699	97,059	12.8%	76,211	68,967	23,450	19,136	828	910	2,210	2,047
West Virginia	50,595	52,287	-3.2%	38,220	37,103	11,214	14,070	0	0	1,161	1,114
East South Central	363,376	353,377	2.8%	314,219	301,637	39,474	42,486	206	201	9,476	9,053
Alabama	142,921	139,435	2.5%	104,915	97,501	32,981	37,210	0	0	5,025	4,725
Kentucky	66,951	63,217	5.9%	65,646	62,094	793	587	2	1	510	535
Mississippi	77,337	72,933	6.0%	71,679	68,027	3,806	3,004	0	0	1,852	1,902
Tennessee	76,167	77,791	-2.1%	71,980	74,015	1,893	1,685	205	200	2,089	1,892
West South Central	821,737	797,511	3.0%	260,797	246,870	488,572	475,533	703	833	71,666	74,274
Arkansas	61,542	63,196	-2.6%	54,386	57,015	6,096	5,219	50	55	1,010	906
Louisiana	99,623	97,785	1.9%	64,884	60,863	6,997	7,028	58	92	27,683	29,802
Oklahoma	94,069	89,236	5.4%	46,638	43,593	46,589	44,864	-6	-18	849	796
Texas	566,503	547,295	3.5%	94,889	85,398	428,890	418,422	601	704	42,123	42,771
Mountain	382,802	372,230	2.8%	258,581	258,965	120,408	109,550	620	614	3,193	3,101
Arizona	116,027	111,839	3.7%	86,749	86,637	29,091	25,017	153	151	34	34
Colorado	58,798	57,542	2.2%	37,598	39,336	20,931	17,962	22	24	248	220
Idaho	20,035	17,842	12.3%	13,475	11,701	5,954	5,527	77	70	529	544
Montana	26,873	26,896	-0.1%	11,663	10,516	15,183	16,354	0	0	26	26
Nevada	45,528	42,164	8.0%	26,478	25,302	18,460	16,249	110	111	481	502
New Mexico	39,697	39,269	1.1%	20,683	20,503	18,836	18,592	110	107	69	67
Utah	35,134	33,497	4.9%	27,900	27,811	6,735	5,332	150	150	349	203
Wyoming	40,709	43,181	-5.7%	34,035	37,159	5,217	4,517	0	0	1,457	1,505
Pacific Contiguous	381,250	381,281	0.0%	205,473	205,332	158,927	159,101	2,469	2,579	14,382	14,269
California	214,191	216,629	-1.1%	75,922	77,633	124,107	124,804	2,372	2,504	11,791	11,688
Oregon	64,661	61,692	4.8%	41,616	40,869	22,209	20,119	80	67	756	637
Washington	102,398	102,961	-0.5%	87,935	86,831	12,611	14,177	17	9	1,835	1,944
Pacific Noncontiguous	15,851	15,912	-0.4%	11,598	11,628	3,193	3,220	740	718	320	346
Alaska	6,691	6,718	-0.4%	6,020	6,023	182	194	395	384	93	117
Hawaii	9,161	9,194	-0.4%	5,577	5,606	3,011	3,027	345	334	228	228
U.S. Total	4,308,634	4,183,270	3.0%	2,256,336	2,189,614	1,900,291	1,838,927	15,258	16,066	136,749	138,664

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.8. Utility Scale Facility Net Generation from Coal
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	254	203	24.8%	0	0	254	203	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	29	43	-32.0%	0	0	29	43	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	224	160	40.2%	0	0	224	160	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	13,042	12,835	1.6%	0	0	12,954	12,745	0	0	88	90
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	13,042	12,835	1.6%	0	0	12,954	12,745	0	0	88	90
East North Central	144,073	144,159	-0.1%	89,438	87,049	53,890	56,070	21	41	723	999
Illinois	26,965	27,150	-0.7%	1,174	1,273	25,124	24,977	10	16	657	884
Indiana	40,526	40,932	-1.0%	37,156	36,822	3,359	4,085	11	25	0	0
Michigan	25,738	23,555	9.3%	25,569	23,349	166	205	0	0	3	0
Ohio	30,080	31,436	-4.3%	4,839	4,632	25,241	26,804	0	0	0	0
Wisconsin	20,763	21,087	-1.5%	20,700	20,972	0	0	0	0	64	114
West North Central	118,904	127,850	-7.0%	116,882	125,969	0	0	13	14	2,009	1,866
Iowa	14,464	16,414	-11.9%	13,030	15,121	0	0	2	7	1,432	1,286
Kansas	13,079	16,291	-19.7%	13,079	16,291	0	0	0	0	0	0
Minnesota	11,430	12,794	-10.7%	11,279	12,641	0	0	6	5	145	148
Missouri	38,832	40,347	-3.8%	38,826	40,345	0	0	6	2	0	0
Nebraska	16,352	17,916	-8.7%	16,050	17,618	0	0	0	0	302	298
North Dakota	23,183	22,525	2.9%	23,054	22,390	0	0	0	0	129	135
South Dakota	1,563	1,563	0.0%	1,563	1,563	0	0	0	0	0	0
South Atlantic	107,283	105,731	1.5%	98,187	94,578	8,778	10,830	21	11	297	312
Delaware	144	-6	NM	0	0	144	-6	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	7,846	11,691	-32.9%	7,827	11,665	0	0	0	0	19	27
Georgia	17,837	16,769	6.4%	17,716	16,664	0	0	0	0	121	105
Maryland	2,466	1,709	44.3%	0	0	2,466	1,709	0	0	0	0
North Carolina	17,079	14,205	20.2%	17,025	14,126	0	0	21	11	33	68
South Carolina	16,842	15,150	11.2%	16,829	15,066	0	62	0	0	13	22
Virginia	1,972	1,415	39.4%	1,860	1,325	0	0	0	0	113	90
West Virginia	43,098	44,798	-3.8%	36,929	35,732	6,169	9,065	0	0	0	0
East South Central	86,534	82,459	4.9%	84,194	79,522	1,868	2,538	0	0	473	399
Alabama	20,936	19,182	9.1%	20,936	19,182	0	0	0	0	0	0
Kentucky	44,829	43,447	3.2%	44,829	43,447	0	0	0	0	0	0
Mississippi	3,334	4,037	-17.4%	1,466	1,499	1,868	2,538	0	0	0	0
Tennessee	17,435	15,793	10.4%	16,962	15,394	0	0	0	0	473	399
West South Central	91,041	98,491	-7.6%	43,970	46,458	46,989	51,981	0	0	83	52
Arkansas	15,660	16,844	-7.0%	12,515	13,440	3,113	3,371	0	0	32	33
Louisiana	3,700	4,834	-23.5%	2,920	3,483	780	1,350	0	0	0	0
Oklahoma	6,135	5,199	18.0%	6,085	5,180	0	0	0	0	50	19
Texas	65,545	71,615	-8.5%	22,450	24,355	43,095	47,260	0	0	0	0
Mountain	87,181	98,285	-11.3%	74,997	84,321	11,849	13,588	0	0	335	376
Arizona	9,815	12,069	-18.7%	9,815	12,069	0	0	0	0	0	0
Colorado	16,478	18,788	-12.3%	16,478	18,788	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	9,785	11,553	-15.3%	0	0	9,781	11,548	0	0	5	5
Nevada	2,323	2,060	12.8%	1,160	975	1,163	1,084	0	0	0	0
New Mexico	8,432	7,372	14.4%	8,432	7,372	0	0	0	0	0	0
Utah	15,967	15,600	2.3%	15,617	15,286	349	314	0	0	0	0
Wyoming	24,382	30,844	-21.0%	23,495	29,831	556	642	0	0	331	371
Pacific Contiguous	3,092	4,371	-29.3%	0	0	2,825	4,138	0	0	268	233
California	246	209	17.6%	0	0	0	0	0	0	246	209
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	2,847	4,163	-31.6%	0	0	2,825	4,138	0	0	22	24
Pacific Noncontiguous	752	731	3.0%	483	434	121	143	148	154	0	0
Alaska	752	731	3.0%	483	434	121	143	148	154	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	652,156	675,115	-3.4%	508,149	518,330	139,527	152,238	204	220	4,276	4,327

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NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.9. Utility Scale Facility Net Generation from Petroleum Liquids
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	314	390	-19.5%	43	34	292	316	-35	22	14	18
Connecticut	20	124	-84.3%	4	5	75	115	-62	1	2	3
Maine	60	67	-11.0%	0	0	47	53	0	0	12	14
Massachusetts	177	97	81.3%	36	27	127	63	15	7	-1	1
New Hampshire	47	68	-31.4%	0	0	36	56	11	12	0	0
Rhode Island	8	31	-72.7%	0	0	7	29	NM	NM	0	0
Vermont	3	3	18.1%	3	3	0	0	0	0	0	0
Middle Atlantic	430	504	-14.6%	155	126	249	339	13	22	14	18
New Jersey	31	42	-26.7%	0	0	30	40	1	1	0	0
New York	313	413	-24.3%	152	125	145	259	9	15	7	13
Pennsylvania	87	49	77.6%	3	1	74	39	3	5	7	4
East North Central	433	383	13.3%	294	248	127	122	2	1	11	11
Illinois	21	26	-21.1%	6	6	15	20	0	0	0	0
Indiana	120	97	24.1%	119	90	0	6	1	0	0	1
Michigan	87	97	-10.0%	84	92	0	0	NM	0	3	5
Ohio	141	114	23.1%	25	14	112	96	0	1	NM	4
Wisconsin	64	48	33.8%	60	47	0	0	0	0	5	2
West North Central	417	418	-0.3%	409	411	2	2	3	2	3	3
Iowa	43	62	-30.4%	41	60	2	2	1	NM	0	0
Kansas	97	59	65.0%	97	59	0	0	0	0	0	0
Minnesota	21	54	-60.7%	16	50	0	1	2	1	3	3
Missouri	148	132	12.0%	147	132	0	0	0	0	0	0
Nebraska	48	35	36.2%	48	35	0	0	0	0	0	0
North Dakota	44	53	-17.9%	43	53	0	0	0	0	0	0
South Dakota	16	23	-30.8%	16	23	0	0	NM	NM	0	0
South Atlantic	1,135	942	20.5%	688	607	345	137	14	17	88	181
Delaware	18	-2	NM	0	1	18	-3	0	0	0	0
District of Columbia	0	0	-35.1%	0	0	0	0	0	0	0	0
Florida	168	220	-23.8%	158	204	5	10	0	0	5	6
Georgia	145	182	-20.5%	49	29	32	5	1	1	63	147
Maryland	212	64	229.3%	-2	-2	213	66	NM	0	0	NM
North Carolina	157	84	87.1%	127	62	21	6	3	1	6	15
South Carolina	106	96	9.8%	95	86	2	3	0	0	8	7
Virginia	205	135	52.1%	136	66	54	49	9	14	5	6
West Virginia	125	163	-23.4%	125	161	0	2	0	0	0	0
East South Central	200	195	2.8%	187	181	NM	0	0	0	13	14
Alabama	12	25	-49.3%	3	13	NM	0	0	0	9	11
Kentucky	58	61	-5.1%	58	61	0	0	0	0	0	0
Mississippi	9	7	21.3%	5	5	0	0	0	0	4	2
Tennessee	121	102	18.7%	121	102	0	0	0	0	0	1
West South Central	263	250	5.2%	147	105	109	141	0	0	6	4
Arkansas	55	45	22.5%	48	34	7	10	0	0	0	0
Louisiana	10	9	4.7%	10	9	0	0	0	0	0	0
Oklahoma	27	20	36.6%	24	18	0	0	0	0	3	2
Texas	171	176	-2.7%	66	43	102	131	0	0	4	3
Mountain	177	172	3.0%	158	157	19	14	0	0	0	0
Arizona	30	32	-5.2%	30	32	0	0	0	0	0	0
Colorado	42	48	-12.2%	39	47	3	0	0	0	0	0
Idaho	0	0	-63.5%	0	0	0	0	0	0	0	0
Montana	19	10	96.5%	6	0	13	10	0	0	0	0
Nevada	6	8	-27.9%	4	6	1	2	0	0	0	0
New Mexico	1	1	-46.7%	1	1	0	0	0	0	0	0
Utah	33	29	14.1%	32	27	1	2	0	0	0	0
Wyoming	46	44	4.8%	46	44	0	0	0	0	0	0
Pacific Contiguous	113	99	14.2%	80	47	13	11	9	5	11	35
California	57	75	-24.6%	33	32	6	6	8	5	10	32
Oregon	13	0	NM	13	0	0	0	0	0	0	0
Washington	43	24	82.6%	34	15	7	5	0	0	2	3
Pacific Noncontiguous	7,973	8,045	-0.9%	6,344	6,338	1,412	1,491	6	6	212	209
Alaska	919	885	3.8%	866	835	0	0	2	2	51	48
Hawaii	7,054	7,159	-1.5%	5,477	5,503	1,412	1,491	4	5	161	161
U.S. Total	11,456	11,397	0.5%	8,504	8,254	2,567	2,573	12	76	372	494

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.10. Utility Scale Facility Net Generation from Petroleum Coke
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	2,411	2,235	7.9%	1,263	1,141	1,001	934	0	0	147	160
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	1,406	1,257	11.9%	1,260	1,098	0	0	0	0	146	159
Ohio	1,002	935	7.1%	0	0	1,001	934	0	0	1	1
Wisconsin	3	43	-92.8%	3	43	0	0	0	0	0	0
West North Central	5	2	129.7%	0	0	0	0	4	2	1	0
Iowa	5	2	129.7%	0	0	0	0	4	2	1	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	743	1,036	-28.3%	646	982	0	0	0	0	96	54
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	646	982	-34.2%	646	982	0	0	0	0	0	0
Georgia	96	54	78.2%	0	0	0	0	0	0	96	54
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	-100.0%	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	-100.0%	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	95	1,082	-91.2%	37	1,023	0	0	0	0	58	59
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	37	1,023	-96.4%	37	1,023	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	58	59	-1.3%	0	0	0	0	0	0	58	59
Mountain	375	481	-22.0%	0	0	375	481	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	375	481	-22.0%	0	0	375	481	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	3,629	4,836	-25.0%	1,946	3,146	1,377	1,415	4	2	302	273

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.11. Utility Scale Facility Net Generation from Natural Gas
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	61,851	57,482	7.6%	273	176	59,384	55,017	1,079	1,056	1,115	1,233
Connecticut	26,036	24,952	4.3%	96	91	25,041	23,925	245	289	654	648
Maine	6,399	3,975	61.0%	0	0	6,222	3,710	31	31	146	234
Massachusetts	16,203	14,774	9.7%	176	84	15,126	13,843	757	680	145	167
New Hampshire	4,421	4,226	4.6%	0	0	4,385	4,186	13	13	23	27
Rhode Island	8,791	9,554	-8.0%	0	0	8,611	9,354	33	43	147	157
Vermont	1	1	-15.5%	1	0	0	0	1	1	0	0
Middle Atlantic	235,907	230,740	2.2%	13,124	11,855	218,219	213,752	715	1,159	3,848	3,973
New Jersey	29,649	33,056	-10.3%	137	156	28,852	32,244	252	236	408	420
New York	62,346	58,428	6.7%	12,962	11,682	48,442	45,417	316	757	626	573
Pennsylvania	143,913	139,256	3.3%	26	18	140,925	136,092	148	167	2,814	2,980
East North Central	237,114	221,688	7.0%	90,219	81,915	140,722	133,424	1,539	1,563	4,633	4,785
Illinois	30,137	28,445	6.0%	2,934	2,667	25,932	24,515	384	417	888	846
Indiana	39,860	34,849	14.4%	20,021	15,593	17,588	16,841	209	205	2,042	2,210
Michigan	55,734	54,068	3.1%	31,349	30,333	23,227	22,550	623	623	535	562
Ohio	85,137	78,705	8.2%	10,584	8,659	73,975	69,518	274	258	304	269
Wisconsin	26,246	25,621	2.4%	25,331	24,664	0	0	50	60	865	898
West North Central	46,155	44,054	4.8%	36,833	34,798	7,276	7,448	362	356	1,683	1,451
Iowa	9,765	10,241	-4.7%	8,911	9,494	0	0	118	111	736	637
Kansas	5,318	4,369	21.7%	4,960	4,027	0	0	0	0	358	342
Minnesota	15,889	13,824	14.9%	10,338	8,770	4,983	4,574	99	103	468	376
Missouri	9,100	9,260	-1.7%	6,631	6,205	2,293	2,874	139	140	37	40
Nebraska	1,381	1,411	-2.1%	1,349	1,403	0	0	7	2	25	6
North Dakota	2,442	2,833	-13.8%	2,428	2,826	0	0	0	0	14	8
South Dakota	2,261	2,116	6.9%	2,216	2,074	0	0	0	0	45	42
South Atlantic	422,751	406,806	3.9%	355,485	341,918	61,581	59,136	682	666	5,004	5,086
Delaware	4,206	4,383	-4.0%	66	17	3,221	3,289	0	0	919	1,077
District of Columbia	100	89	11.6%	0	0	0	0	100	89	0	0
Florida	204,507	197,191	3.7%	193,943	186,966	9,087	8,709	119	105	1,358	1,411
Georgia	56,937	60,044	-5.2%	47,168	48,880	8,870	10,397	0	0	899	768
Maryland	13,910	15,336	-9.3%	2,968	4,425	10,577	10,530	309	322	56	59
North Carolina	55,503	51,788	7.2%	47,078	43,156	8,170	8,336	128	135	127	160
South Carolina	22,809	23,691	-3.7%	21,485	23,115	1,192	429	0	0	131	148
Virginia	60,998	50,605	20.5%	42,271	34,878	17,861	14,884	25	15	840	827
West Virginia	3,782	3,680	2.8%	506	483	2,604	2,562	0	0	673	635
East South Central	158,375	147,135	7.6%	122,093	107,051	32,309	36,456	201	196	3,772	3,432
Alabama	64,599	61,848	4.4%	31,054	24,273	31,766	35,992	0	0	1,779	1,584
Kentucky	17,267	15,090	14.4%	16,518	14,426	535	457	0	0	214	206
Mississippi	60,026	55,168	8.8%	59,444	54,592	NM	7	0	0	574	568
Tennessee	16,483	15,030	9.7%	15,077	13,760	0	0	201	196	1,206	1,074
West South Central	440,925	428,273	3.0%	171,601	158,955	203,800	201,551	656	797	64,868	66,970
Arkansas	24,725	26,487	-6.7%	23,409	25,055	1,081	1,220	33	37	201	175
Louisiana	75,263	74,414	1.1%	47,037	43,877	4,084	4,635	58	92	24,085	25,811
Oklahoma	47,742	45,213	5.6%	32,057	30,195	15,206	14,500	0	-1	479	520
Texas	293,193	282,159	3.9%	69,097	59,829	183,428	181,197	565	669	40,103	40,464
Mountain	134,011	129,519	3.5%	106,822	101,455	24,934	25,928	443	430	1,813	1,707
Arizona	55,090	52,818	4.3%	38,128	36,354	16,825	16,332	137	131	0	0
Colorado	17,927	17,220	4.1%	15,170	14,844	2,582	2,207	5	2	170	167
Idaho	6,285	5,686	10.5%	4,709	3,700	1,373	1,810	40	39	164	137
Montana	995	1,002	-0.6%	808	885	187	116	0	0	1	1
Nevada	24,999	24,599	1.6%	23,380	22,869	1,087	1,176	62	65	471	489
New Mexico	11,648	14,231	-18.2%	8,705	9,881	2,764	4,177	110	105	69	67
Utah	11,640	11,834	-1.6%	11,209	11,490	116	111	89	86	227	148
Wyoming	5,426	2,129	154.8%	4,713	1,431	1	1	0	0	712	698
Pacific Contiguous	129,679	137,183	-5.5%	53,905	54,673	64,303	71,232	1,479	1,521	9,992	9,757
California	86,656	94,390	-8.2%	27,900	28,299	48,343	55,779	1,425	1,484	8,987	8,829
Oregon	24,926	23,385	6.6%	13,284	13,228	11,462	10,011	47	36	133	111
Washington	18,097	19,408	-6.8%	12,721	13,147	4,497	5,442	7	1	872	817
Pacific Noncontiguous	3,134	3,182	-1.5%	3,092	3,113	0	0	0	0	42	69
Alaska	3,134	3,182	-1.5%	3,092	3,113	0	0	0	0	42	69
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,869,902	1,806,063	3.5%	953,446	895,910	812,528	803,945	7,157	7,744	96,771	98,463

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.12. Utility Scale Facility Net Generation from Other Fossil Gas
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	710	739	-3.9%	0	0	24	30	0	0	686	709
New Jersey	168	161	4.0%	0	0	24	29	0	0	144	132
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	542	578	-6.1%	0	0	0	0	0	0	542	577
East North Central	4,093	4,684	-12.6%	0	0	1,581	2,032	0	0	2,512	2,652
Illinois	177	248	-28.6%	0	0	0	0	0	0	177	248
Indiana	2,114	2,272	-7.0%	0	0	0	0	0	0	2,114	2,272
Michigan	946	1,377	-31.3%	0	0	946	1,377	0	0	0	0
Ohio	856	787	8.7%	0	0	635	655	0	0	221	132
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	28	23	17.9%	0	0	0	0	0	0	28	23
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	28	23	17.9%	0	0	0	0	0	0	28	23
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	261	204	27.9%	0	0	0	0	0	0	261	204
Delaware	221	172	28.5%	0	0	0	0	0	0	221	172
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	34.6%	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	40	32	24.9%	0	0	0	0	0	0	40	32
East South Central	12	11	6.0%	0	0	0	0	0	0	12	11
Alabama	0	0	-84.2%	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	12	11	6.3%	0	0	0	0	0	0	12	11
West South Central	3,980	4,132	-3.7%	0	0	1,365	1,269	0	0	2,614	2,863
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,448	1,804	-19.8%	0	0	0	0	0	0	1,448	1,804
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	2,532	2,327	8.8%	0	0	1,365	1,269	0	0	1,166	1,059
Mountain	331	365	-9.3%	0	0	5	10	0	0	325	355
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	5	10	-42.9%	0	0	5	10	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	1	3	-51.5%	0	0	0	0	0	0	1	3
Wyoming	324	352	-8.0%	0	0	0	0	0	0	324	352
Pacific Contiguous	1,431	1,620	-11.7%	0	0	0	0	0	0	1,431	1,620
California	1,209	1,382	-12.5%	0	0	0	0	0	0	1,209	1,382
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	223	238	-6.6%	0	0	0	0	0	0	223	238
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	10,845	11,778	-7.9%	0	0	2,976	3,340	0	0	7,870	8,438

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.13. Utility Scale Facility Net Generation from Nuclear Energy
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	26,547	23,204	14.4%	0	0	26,547	23,204	0	0	0	0
Connecticut	16,870	13,669	23.4%	0	0	16,870	13,669	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	9,677	9,535	1.5%	0	0	9,677	9,535	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	130,155	131,165	-0.8%	0	0	130,155	131,165	0	0	0	0
New Jersey	27,677	28,335	-2.3%	0	0	27,677	28,335	0	0	0	0
New York	27,073	27,525	-1.6%	0	0	27,073	27,525	0	0	0	0
Pennsylvania	75,404	75,305	0.1%	0	0	75,404	75,305	0	0	0	0
East North Central	153,586	151,445	1.4%	26,281	27,996	127,306	123,449	0	0	0	0
Illinois	99,212	97,559	1.7%	0	0	99,212	97,559	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	26,281	27,996	-6.1%	26,281	27,996	0	0	0	0	0	0
Ohio	17,947	16,207	10.7%	0	0	17,947	16,207	0	0	0	0
Wisconsin	10,147	9,683	4.8%	0	0	10,147	9,683	0	0	0	0
West North Central	37,670	38,331	-1.7%	37,670	38,331	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	9,204	10,302	-10.7%	9,204	10,302	0	0	0	0	0	0
Minnesota	11,845	11,924	-0.7%	11,845	11,924	0	0	0	0	0	0
Missouri	10,526	9,180	14.7%	10,526	9,180	0	0	0	0	0	0
Nebraska	6,096	6,926	-12.0%	6,096	6,926	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	217,819	209,922	3.8%	203,095	194,938	14,724	14,984	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	29,054	29,940	-3.0%	29,054	29,940	0	0	0	0	0	0
Georgia	47,976	37,377	28.4%	47,976	37,377	0	0	0	0	0	0
Maryland	14,724	14,984	-1.7%	0	0	14,724	14,984	0	0	0	0
North Carolina	43,349	42,336	2.4%	43,349	42,336	0	0	0	0	0	0
South Carolina	53,770	55,622	-3.3%	53,770	55,622	0	0	0	0	0	0
Virginia	28,945	29,663	-2.4%	28,945	29,663	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	87,327	95,266	-8.3%	87,327	95,266	0	0	0	0	0	0
Alabama	44,487	45,579	-2.4%	44,487	45,579	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	10,653	11,750	-9.3%	10,653	11,750	0	0	0	0	0	0
Tennessee	32,186	37,937	-15.2%	32,186	37,937	0	0	0	0	0	0
West South Central	68,027	67,864	0.2%	29,414	27,184	38,613	40,680	0	0	0	0
Arkansas	14,763	14,972	-1.4%	14,763	14,972	0	0	0	0	0	0
Louisiana	14,652	12,211	20.0%	14,652	12,211	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	38,613	40,680	-5.1%	0	0	38,613	40,680	0	0	0	0
Mountain	32,388	31,523	2.7%	32,388	31,523	0	0	0	0	0	0
Arizona	32,388	31,523	2.7%	32,388	31,523	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	28,346	26,153	8.4%	28,346	26,153	0	0	0	0	0	0
California	18,379	17,718	3.7%	18,379	17,718	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	9,967	8,435	18.2%	9,967	8,435	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	781,865	774,873	0.9%	444,521	441,391	337,345	333,482	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.14. Utility Scale Facility Net Generation from Hydroelectric (Conventional) Power by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	6,799	8,601	-20.9%	685	874	6,064	7,625	3	5	47	97
Connecticut	369	465	-20.7%	31	39	337	426	0	0	0	0
Maine	2,952	3,832	-25.6%	3	5	2,802	3,730	0	0	47	97
Massachusetts	881	1,165	-24.4%	226	304	652	857	3	5	0	0
New Hampshire	1,411	1,592	-11.3%	7	17	1,405	1,575	0	0	0	0
Rhode Island	3	8	-63.8%	0	0	3	8	0	0	0	0
Vermont	1,284	1,539	-16.6%	418	510	866	1,029	0	0	0	0
Middle Atlantic	30,670	31,229	-1.8%	23,589	23,566	7,011	7,607	3	5	66	61
New Jersey	4	12	-69.5%	0	0	4	12	0	0	0	0
New York	27,945	28,434	-1.7%	23,505	23,490	4,371	4,878	3	5	66	61
Pennsylvania	2,721	2,783	-2.2%	84	66	2,637	2,718	0	0	0	0
East North Central	4,244	4,384	-3.2%	3,744	3,868	380	405	7	6	113	105
Illinois	75	92	-18.6%	42	64	33	29	0	0	0	0
Indiana	375	464	-19.1%	368	458	0	0	7	6	0	0
Michigan	1,255	1,395	-10.0%	1,180	1,328	67	57	0	0	8	10
Ohio	468	507	-7.8%	293	292	175	215	0	0	0	0
Wisconsin	2,072	1,926	7.6%	1,860	1,726	106	104	0	0	106	96
West North Central	10,783	10,055	7.2%	10,483	9,799	236	198	0	0	63	58
Iowa	1,030	948	8.7%	1,025	944	5	4	0	0	0	0
Kansas	20	13	49.1%	0	0	20	13	0	0	0	0
Minnesota	868	750	15.6%	594	513	211	180	0	0	63	58
Missouri	1,020	785	30.0%	1,020	785	0	0	0	0	0	0
Nebraska	1,183	1,143	3.5%	1,183	1,143	0	0	0	0	0	0
North Dakota	2,061	2,119	-2.8%	2,061	2,119	0	0	0	0	0	0
South Dakota	4,601	4,296	7.1%	4,601	4,296	0	0	0	0	0	0
South Atlantic	14,822	14,291	3.7%	11,376	10,784	2,978	3,040	13	11	455	456
Delaware	0	0	-	0	0	0	0	0	0	0	0
District of Columbia	0	0	-	0	0	0	0	0	0	0	0
Florida	177	224	-20.9%	177	224	0	0	0	0	0	0
Georgia	2,941	2,872	2.4%	2,929	2,857	5	6	0	0	7	9
Maryland	1,848	1,849	0.0%	0	0	1,848	1,849	0	0	0	0
North Carolina	4,829	4,225	14.3%	4,138	3,552	681	664	10	9	0	0
South Carolina	2,412	2,199	9.7%	2,358	2,140	51	57	2	2	0	0
Virginia	1,253	1,391	-9.9%	1,143	1,284	110	107	0	0	0	0
West Virginia	1,361	1,530	-11.0%	631	727	283	357	0	0	448	446
East South Central	21,382	20,426	4.7%	20,660	19,746	723	680	0	0	0	0
Alabama	8,357	8,430	-0.9%	8,357	8,430	0	0	0	0	0	0
Kentucky	4,114	3,955	4.0%	4,099	3,943	14	11	0	0	0	0
Mississippi	0	0	-	0	0	0	0	0	0	0	0
Tennessee	8,911	8,042	10.8%	8,203	7,373	708	669	0	0	0	0
West South Central	6,378	6,178	3.2%	5,396	5,371	982	807	0	0	0	0
Arkansas	3,134	3,229	-2.9%	3,074	3,172	60	56	0	0	0	0
Louisiana	885	708	25.1%	0	0	885	708	0	0	0	0
Oklahoma	1,582	1,483	6.6%	1,582	1,483	0	0	0	0	0	0
Texas	777	758	2.5%	741	715	36	43	0	0	0	0
Mountain	28,879	27,817	3.8%	27,551	26,520	1,263	1,234	65	64	0	0
Arizona	5,314	5,937	-10.5%	5,314	5,937	0	0	0	0	0	0
Colorado	1,660	1,597	4.0%	1,423	1,376	223	207	14	14	0	0
Idaho	9,150	8,378	9.2%	8,322	7,566	828	812	0	0	0	0
Montana	9,220	8,792	4.9%	9,103	8,672	118	120	0	0	0	0
Nevada	1,606	1,319	21.8%	1,532	1,246	74	73	0	0	0	0
New Mexico	153	108	42.1%	153	108	0	0	0	0	0	0
Utah	759	769	-1.3%	697	707	11	12	51	50	0	0
Wyoming	1,017	917	10.8%	1,007	908	10	9	0	0	0	0
Pacific Contiguous	117,123	120,156	-2.5%	115,161	117,897	1,944	2,246	18	13	0	0
California	29,454	32,381	-9.0%	27,966	30,525	1,470	1,843	18	13	0	0
Oregon	26,933	26,329	2.3%	26,673	26,110	259	219	0	0	0	0
Washington	60,736	61,446	-1.2%	60,521	61,262	215	184	0	0	0	0
Pacific Noncontiguous	1,816	1,867	-2.7%	1,518	1,589	30	20	201	190	66	67
Alaska	1,715	1,773	-3.3%	1,514	1,584	0	0	201	190	0	0
Hawaii	100	93	7.7%	4	5	30	20	0	0	66	67
U.S. Total	242,896	245,002	-0.9%	220,163	220,003	21,612	23,862	311	293	810	844

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.15. Utility Scale Facility Net Generation from Renewable Sources Excluding Hydroelectric by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	12,351	11,419	8.2%	588	572	10,577	9,692	513	528	673	627
Connecticut	1,038	1,022	1.6%	2	0	1,030	1,012	6	5	0	5
Maine	5,035	4,320	16.6%	0	0	4,361	3,694	4	7	669	618
Massachusetts	3,221	3,111	3.5%	110	115	2,648	2,520	459	472	4	4
New Hampshire	1,113	1,194	-6.8%	0	0	1,076	1,157	36	37	0	0
Rhode Island	975	839	16.2%	0	0	969	834	6	6	0	0
Vermont	970	934	3.8%	476	457	492	476	2	1	0	0
Middle Atlantic	18,865	16,047	17.6%	127	358	16,919	13,903	1,360	1,298	459	489
New Jersey	2,272	2,233	1.7%	127	126	1,670	1,637	471	465	5	6
New York	10,752	8,663	24.1%	0	232	9,922	7,649	671	625	159	157
Pennsylvania	5,841	5,151	13.4%	0	0	5,327	4,616	219	208	295	326
East North Central	68,488	55,069	24.4%	12,624	8,565	54,606	45,278	129	131	1,129	1,095
Illinois	28,192	23,961	17.7%	88	95	28,095	23,863	6	3	2	NM
Indiana	13,587	10,953	24.0%	2,290	1,134	11,248	9,774	2	2	47	43
Michigan	13,635	11,584	17.7%	5,953	4,822	7,049	6,201	44	42	589	519
Ohio	7,115	4,526	57.2%	11	12	6,877	4,250	19	14	208	249
Wisconsin	5,958	4,046	47.3%	4,282	2,503	1,336	1,190	58	70	283	283
West North Central	139,829	130,196	7.4%	52,301	48,823	86,458	80,452	191	180	879	741
Iowa	45,158	42,170	7.1%	32,439	30,352	12,631	11,738	9	8	80	71
Kansas	29,972	27,420	9.3%	2,741	2,546	27,207	24,850	13	13	12	11
Minnesota	18,232	17,628	3.4%	6,665	6,354	10,695	10,534	109	102	764	638
Missouri	7,103	7,049	0.8%	2,767	2,855	4,284	4,150	48	40	3	3
Nebraska	12,169	12,015	1.3%	150	167	12,006	11,830	13	18	0	0
North Dakota	14,763	14,477	2.0%	5,114	5,155	9,648	9,321	0	0	0	0
South Dakota	12,432	9,439	31.7%	2,426	1,395	9,987	8,028	0	0	20	17
South Atlantic	69,604	60,851	14.4%	22,811	18,491	37,373	33,468	944	1,056	8,475	7,835
Delaware	210	226	-6.9%	7	7	178	199	5	7	21	13
District of Columbia	88	83	6.0%	1	3	30	21	56	58	0	0
Florida	21,615	17,183	25.8%	17,752	13,478	2,185	1,994	403	457	1,274	1,254
Georgia	14,551	12,501	16.4%	503	640	10,465	8,707	2	2	3,581	3,153
Maryland	1,927	1,746	10.4%	7	8	1,907	1,715	13	24	0	0
North Carolina	13,828	13,680	1.1%	1,058	1,075	11,750	11,475	100	106	920	1,024
South Carolina	4,753	4,504	5.5%	59	74	3,264	3,161	0	0	1,429	1,268
Virginia	10,436	8,830	18.2%	3,393	3,206	5,427	4,098	365	402	1,251	1,123
West Virginia	2,196	2,099	4.7%	30	0	2,166	2,099	0	0	0	0
East South Central	10,100	8,347	21.0%	319	334	4,578	2,811	5	5	5,196	5,197
Alabama	4,522	4,371	3.5%	77	25	1,215	1,217	0	0	3,230	3,129
Kentucky	671	573	17.0%	129	124	244	119	2	1	296	329
Mississippi	3,319	1,972	68.3%	111	182	1,934	459	0	0	1,274	1,332
Tennessee	1,589	1,430	11.1%	2	3	1,185	1,016	4	3	398	407
West South Central	210,660	190,432	10.6%	9,977	7,481	197,057	179,194	50	46	3,576	3,711
Arkansas	3,121	1,511	106.6%	501	241	1,834	561	17	19	769	690
Louisiana	3,176	2,280	39.3%	28	40	1,248	335	0	0	1,900	1,904
Oklahoma	38,610	37,356	3.4%	6,911	6,743	31,384	30,365	-3	-7	317	256
Texas	165,753	149,285	11.0%	2,536	457	162,591	147,932	35	35	590	861
Mountain	99,112	83,476	18.7%	16,555	14,764	82,045	68,184	116	121	397	408
Arizona	13,546	9,365	44.6%	1,038	593	12,458	8,718	16	20	34	34
Colorado	22,629	19,840	14.1%	4,433	4,256	18,159	15,568	6	8	30	8
Idaho	4,531	3,706	22.3%	445	435	3,753	2,906	37	31	295	335
Montana	6,216	4,825	28.8%	1,747	959	4,449	3,846	0	0	21	20
Nevada	16,712	14,192	17.8%	418	177	16,236	13,955	47	47	10	12
New Mexico	19,474	17,576	10.8%	3,393	3,142	16,080	14,433	0	1	0	0
Utah	6,581	5,163	27.5%	306	255	6,259	4,894	9	14	7	0
Wyoming	9,425	8,810	7.0%	4,774	4,945	4,651	3,865	0	0	0	0
Pacific Contiguous	102,537	92,484	10.9%	8,087	6,996	91,081	82,145	934	991	2,434	2,352
California	79,350	71,348	11.2%	1,751	1,490	75,614	67,939	891	953	1,095	966
Oregon	12,776	11,955	6.9%	1,646	1,532	10,474	9,866	33	31	623	526
Washington	10,410	9,181	13.4%	4,691	3,974	4,993	4,340	10	7	716	860
Pacific Noncontiguous	2,020	1,918	5.3%	166	158	1,655	1,569	199	190	0	0
Alaska	174	150	15.8%	70	61	61	50	43	39	0	0
Hawaii	1,846	1,767	4.4%	96	97	1,594	1,519	156	151	0	0
U.S. Total	733,567	650,239	12.8%	123,555	106,543	582,350	516,694	4,441	4,545	23,220	22,456

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
 NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.16. Utility Scale Facility Net Generation from Hydroelectric (Pumped Storage) Power
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	-479	-375	27.7%	0	0	-479	-375	0	0	0	0
Connecticut	5	5	-0.2%	0	0	5	5	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	-483	-379	27.4%	0	0	-483	-379	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	-1,550	-1,442	7.5%	-410	-372	-1,141	-1,070	0	0	0	0
New Jersey	-232	-165	40.3%	0	0	-232	-165	0	0	0	0
New York	-410	-372	10.1%	-410	-372	0	0	0	0	0	0
Pennsylvania	-909	-905	0.4%	0	0	-909	-905	0	0	0	0
East North Central	-976	-810	20.5%	-976	-810	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	-976	-810	20.5%	-976	-810	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	147	-49	-400.6%	147	-49	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	147	-49	-400.6%	147	-49	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	-2,544	-2,573	-1.1%	-2,544	-2,573	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	-760	-664	14.5%	-760	-664	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	-251	-454	-44.8%	-251	-454	0	0	0	0	0	0
Virginia	-1,533	-1,455	5.3%	-1,533	-1,455	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	-571	-554	3.1%	-571	-554	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	-571	-554	3.1%	-571	-554	0	0	0	0	0	0
West South Central	29	47	-38.9%	29	47	0	0	0	0	0	0
Arkansas	77	101	-23.9%	77	101	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	-48	-53	-10.4%	-48	-53	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	136	161	-15.9%	136	161	0	0	0	0	0	0
Arizona	69	136	-49.6%	69	136	0	0	0	0	0	0
Colorado	67	25	167.6%	67	25	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	-44	-396	-88.9%	-44	-396	0	0	0	0	0	0
California	-46	-393	-88.4%	-46	-393	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	2	-3	-156.3%	2	-3	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	-5,852	-5,990	-2.3%	-4,232	-4,545	-1,619	-1,445	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.17. Utility Scale Facility Net Generation from Other Energy Sources
by State, by Sector, and 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	1,671	1,686	-0.9%	2	2	1,031	1,031	500	518	139	136
Connecticut	424	429	-1.2%	0	0	424	429	0	0	0	0
Maine	280	276	1.7%	0	0	136	131	5	9	139	136
Massachusetts	917	928	-1.2%	-1	-1	423	420	494	509	0	0
New Hampshire	50	51	-2.9%	0	0	50	51	0	0	0	0
Rhode Island	0	0	8.0%	0	0	0	0	0	0	0	0
Vermont	1	3	-63.7%	2	3	-1	0	0	0	0	0
Middle Atlantic	2,462	2,377	3.6%	-2	0	962	1,005	1,429	1,350	73	22
New Jersey	607	554	9.5%	0	0	120	127	414	405	73	22
New York	997	949	5.0%	-2	0	200	206	799	743	0	0
Pennsylvania	858	874	-1.8%	0	0	643	672	216	202	0	0
East North Central	782	977	-20.0%	19	95	30	76	54	51	679	755
Illinois	233	256	-8.8%	0	0	-5	-9	0	0	239	265
Indiana	432	482	-10.4%	-2	0	0	0	0	0	434	482
Michigan	94	138	-32.3%	0	0	40	87	54	51	0	0
Ohio	1	6	-77.8%	-1	0	-5	-2	0	0	6	8
Wisconsin	22	95	-76.9%	22	95	0	0	0	0	0	0
West North Central	353	344	2.4%	159	163	148	143	40	36	5	3
Iowa	-1	0	NM	-1	0	0	0	0	0	0	0
Kansas	5	3	60.0%	0	0	0	0	0	0	5	3
Minnesota	311	303	2.4%	122	125	148	143	40	36	0	0
Missouri	0	0	-	0	0	0	0	0	0	0	0
Nebraska	0	0	92.6%	0	0	0	0	0	0	0	0
North Dakota	38	38	-1.1%	38	38	0	0	0	0	0	0
South Dakota	0	0	-	0	0	0	0	0	0	0	0
South Atlantic	3,206	3,508	-8.6%	-38	-39	1,149	1,221	900	1,014	1,196	1,313
Delaware	0	0	-	0	0	0	0	0	0	0	0
District of Columbia	0	0	-	0	0	0	0	0	0	0	0
Florida	2,106	2,366	-11.0%	-26	-38	818	923	471	535	843	946
Georgia	83	86	-3.8%	-2	0	-4	-5	0	0	89	91
Maryland	338	312	8.2%	0	0	338	312	0	0	0	0
North Carolina	220	235	-6.7%	-5	-1	0	0	0	0	225	237
South Carolina	45	44	2.2%	0	0	7	5	0	0	39	40
Virginia	422	477	-11.6%	-4	0	-2	-2	428	478	0	0
West Virginia	-8	-14	-45.3%	0	0	-8	-14	0	0	0	0
East South Central	16	92	-82.8%	12	91	-4	0	0	0	8	0
Alabama	7	0	NM	0	0	0	0	0	0	7	0
Kentucky	12	91	-87.1%	12	91	0	0	0	0	0	0
Mississippi	-4	0	-	0	0	-4	0	0	0	0	0
Tennessee	0	0	-1.0%	0	0	0	0	0	0	0	0
West South Central	340	762	-55.4%	226	245	-343	-89	-4	-10	461	615
Arkansas	7	6	11.3%	0	0	0	0	-1	-1	8	7
Louisiana	452	501	-9.8%	201	219	0	0	0	0	251	282
Oklahoma	21	18	11.6%	26	28	-2	0	-3	-9	0	0
Texas	-140	236	-159.5%	-1	-1	-341	-89	0	0	202	326
Mountain	211	432	-51.1%	-26	66	-82	112	-3	0	322	254
Arizona	-224	-40	466.6%	-33	-6	-191	-33	0	0	0	0
Colorado	-4	25	-116.5%	-12	0	-37	-20	-3	0	48	45
Idaho	69	72	-4.8%	-1	0	0	0	0	0	70	72
Montana	256	224	14.4%	0	0	256	224	0	0	0	0
Nevada	-118	-13	805.1%	-17	28	-101	-41	0	0	0	0
New Mexico	-10	-19	-48.6%	-2	-1	-8	-18	0	0	0	0
Utah	153	98	55.2%	39	46	0	0	0	0	114	53
Wyoming	90	84	6.8%	0	0	0	0	0	0	90	84
Pacific Contiguous	-1,027	-390	163.5%	-62	-38	-1,240	-671	29	49	245	271
California	-1,113	-482	130.7%	-61	-39	-1,326	-763	29	49	245	271
Oregon	13	23	-42.6%	0	0	14	24	0	0	0	0
Washington	72	69	4.4%	0	1	73	69	0	0	0	0
Pacific Noncontiguous	156	170	-8.1%	-5	-4	-25	-4	186	178	0	0
Alaska	-5	-4	6.0%	-5	-4	0	0	0	0	0	0
Hawaii	161	174	-7.7%	0	0	-25	-4	186	178	0	0
U.S. Total	8,170	9,957	-17.9%	285	580	1,627	2,823	3,130	3,185	3,127	3,369

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.18. Utility Scale Facility Net Generation from Wind
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	3,604	3,450	4.5%	204	202	3,377	3,223	23	25	0	0
Connecticut	10	10	5.7%	0	0	10	10	0	0	0	0
Maine	2,446	2,339	4.6%	0	0	2,446	2,339	0	0	0	0
Massachusetts	169	182	-6.9%	32	37	119	125	17	19	0	0
New Hampshire	445	411	8.1%	0	0	445	411	0	0	0	0
Rhode Island	178	169	5.5%	0	0	172	163	6	6	0	0
Vermont	355	340	4.6%	171	165	184	175	0	0	0	0
Middle Atlantic	9,307	8,076	15.2%	0	232	9,303	7,840	3	3	2	1
New Jersey	19	18	5.2%	0	0	19	18	0	0	0	0
New York	6,031	4,800	25.7%	0	232	6,027	4,563	3	3	2	1
Pennsylvania	3,257	3,258	-0.1%	0	0	3,257	3,258	0	0	0	0
East North Central	49,877	43,502	14.7%	7,474	5,903	42,310	37,483	28	24	66	92
Illinois	24,910	21,808	14.2%	6	10	24,900	21,797	4	1	0	0
Indiana	10,312	8,844	16.6%	228	0	10,084	8,844	0	0	0	0
Michigan	9,839	8,292	18.6%	5,873	4,742	3,966	3,551	0	0	0	0
Ohio	2,822	169	0.1%	4	5	2,755	2,726	2	3	61	86
Wisconsin	1,994	1,738	14.7%	1,362	1,147	605	564	22	20	5	7
West North Central	134,372	125,583	7.0%	51,351	48,134	82,970	77,404	39	34	12	11
Iowa	44,277	41,439	6.8%	31,993	30,030	12,282	11,407	2	2	0	0
Kansas	29,795	27,273	9.2%	2,682	2,530	27,088	24,718	13	13	12	11
Minnesota	14,781	14,398	2.7%	6,397	6,160	8,360	8,220	24	19	0	0
Missouri	6,790	6,775	0.2%	2,676	2,777	4,114	3,998	0	0	0	0
Nebraska	11,891	11,845	0.4%	62	87	11,829	11,758	0	0	0	0
North Dakota	14,763	14,477	2.0%	5,114	5,155	9,648	9,321	0	0	0	0
South Dakota	12,074	9,376	28.8%	2,426	1,395	9,648	7,981	0	0	0	0
South Atlantic	3,144	3,151	-0.2%	50	47	3,091	3,100	3	4	0	0
Delaware	3	4	-36.8%	0	0	0	0	3	4	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	558	482	15.9%	0	0	558	482	0	0	0	0
North Carolina	530	529	0.2%	0	0	530	529	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	50	47	7.0%	50	47	0	0	0	0	0	0
West Virginia	2,003	2,089	-4.1%	0	0	2,003	2,089	0	0	0	0
East South Central	360	16	NM	0	0	360	16	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	347	0	--	0	0	347	0	0	0	0	0
Tennessee	13	16	-18.7%	0	0	13	16	0	0	0	0
West South Central	162,244	156,867	3.4%	9,151	6,861	153,061	149,975	33	32	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	37,967	37,012	2.6%	6,820	6,669	31,147	30,344	0	0	0	0
Texas	124,278	119,855	3.7%	2,331	193	121,914	119,631	33	32	0	0
Mountain	54,179	49,227	10.1%	14,029	12,980	40,147	36,243	0	1	3	2
Arizona	2,540	1,733	46.6%	0	0	2,540	1,733	0	0	0	0
Colorado	17,602	16,091	9.4%	4,415	4,243	13,184	11,846	0	0	3	2
Idaho	3,016	2,320	30.0%	167	149	2,849	2,170	0	0	0	0
Montana	5,815	4,557	27.6%	1,729	951	4,086	3,606	0	0	0	0
Nevada	319	291	9.6%	0	0	319	291	0	0	0	0
New Mexico	15,136	14,914	1.5%	2,943	2,691	12,193	12,222	0	1	0	0
Utah	748	683	9.5%	0	0	748	683	0	0	0	0
Wyoming	9,002	8,637	4.2%	4,774	4,945	4,227	3,691	0	0	0	0
Pacific Contiguous	34,031	30,522	11.5%	6,727	5,699	27,281	24,812	6	7	16	5
California	15,648	14,019	11.6%	755	579	14,871	13,428	6	7	16	5
Oregon	9,519	8,954	6.3%	1,580	1,462	7,939	7,491	0	0	0	0
Washington	8,863	7,550	17.4%	4,392	3,657	4,472	3,892	0	0	0	0
Pacific Noncontiguous	787	746	5.5%	70	61	717	684	0	0	0	0
Alaska	123	111	10.8%	70	61	53	50	0	0	0	0
Hawaii	663	634	4.6%	0	0	663	634	0	0	0	0
U.S. Total	451,904	421,141	7.3%	89,056	80,120	362,616	340,780	133	130	99	112

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NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.19. Utility Scale Facility Net Generation from Biomass
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	4,379	4,392	-0.3%	246	236	2,989	3,049	475	489	669	618
Connecticut	551	591	-6.7%	0	0	551	591	0	0	0	0
Maine	1,644	1,458	12.7%	0	0	970	833	4	7	669	618
Massachusetts	925	914	1.2%	0	0	493	471	432	443	0	0
New Hampshire	664	779	-14.7%	0	0	628	742	36	37	0	0
Rhode Island	197	247	-20.4%	0	0	197	247	0	0	0	0
Vermont	398	403	-1.4%	246	236	150	166	2	1	0	0
Middle Atlantic	3,739	3,830	-2.4%	0	0	2,088	2,215	1,214	1,149	436	465
New Jersey	657	671	-2.1%	0	0	312	335	345	335	0	0
New York	1,593	1,627	-2.1%	0	0	786	869	658	612	149	146
Pennsylvania	1,489	1,532	-2.8%	0	0	990	1,011	212	201	288	319
East North Central	3,721	3,873	-3.9%	631	640	1,949	2,137	84	96	1,057	1,000
Illinois	224	242	-7.4%	75	83	149	159	0	0	0	0
Indiana	183	254	-28.0%	94	154	42	57	0	0	47	43
Michigan	1,937	2,023	-4.2%	0	0	1,304	1,462	44	42	589	519
Ohio	292	324	-9.9%	0	0	137	154	8	8	147	162
Wisconsin	1,085	1,030	5.3%	461	403	317	305	32	46	275	276
West North Central	1,645	1,616	1.8%	239	249	479	490	152	147	775	729
Iowa	217	209	3.8%	28	31	103	101	7	6	80	71
Kansas	56	66	-15.3%	0	0	56	66	0	0	0	0
Minnesota	1,165	1,135	2.6%	118	129	289	285	85	83	673	638
Missouri	106	99	6.7%	23	17	31	39	48	40	3	3
Nebraska	82	90	-9.1%	69	72	0	0	13	18	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	20	17	19.2%	0	0	0	0	0	0	20	17
South Atlantic	15,438	15,325	0.7%	1,390	1,491	4,771	5,095	815	912	8,462	7,827
Delaware	42	66	-37.1%	0	0	27	53	0	0	15	13
District of Columbia	56	58	-3.6%	0	0	0	0	56	58	0	0
Florida	2,965	3,124	-5.1%	330	366	969	1,056	396	450	1,271	1,251
Georgia	5,366	4,951	8.4%	0	0	1,785	1,798	0	0	3,581	3,153
Maryland	333	322	3.3%	0	0	333	319	0	3	0	0
North Carolina	1,454	1,692	-14.1%	0	0	534	668	0	0	920	1,024
South Carolina	1,827	1,741	4.9%	52	67	351	412	0	0	1,424	1,263
Virginia	3,388	3,361	0.8%	1,009	1,058	764	779	364	401	1,251	1,123
West Virginia	8	9	-16.2%	0	0	8	9	0	0	0	0
East South Central	5,414	5,380	0.6%	86	81	135	107	0	0	5,193	5,192
Alabama	3,267	3,171	3.0%	0	0	37	41	0	0	3,230	3,129
Kentucky	394	418	-5.7%	86	81	12	8	0	0	296	329
Mississippi	1,281	1,339	-4.4%	0	0	7	8	0	0	1,274	1,332
Tennessee	471	452	4.3%	0	0	79	50	0	0	393	402
West South Central	4,018	4,247	-5.4%	190	250	258	305	-3	-7	3,572	3,700
Arkansas	792	713	11.0%	0	0	27	27	0	0	765	687
Louisiana	1,978	1,988	-0.5%	0	0	78	84	0	0	1,900	1,904
Oklahoma	332	265	25.2%	0	0	17	17	-3	-7	317	256
Texas	916	1,280	-28.4%	190	250	136	177	0	0	590	853
Mountain	860	957	-10.1%	38	25	466	536	46	44	310	352
Arizona	184	193	-4.5%	0	0	184	193	0	0	0	0
Colorado	88	134	-34.1%	0	0	88	134	0	0	0	0
Idaho	405	444	-8.7%	20	17	56	64	37	31	292	332
Montana	35	27	27.5%	18	8	0	0	0	0	17	20
Nevada	52	54	-2.8%	0	0	52	54	0	0	0	0
New Mexico	25	13	92.8%	0	0	25	13	0	0	0	0
Utah	70	92	-23.9%	0	0	61	79	9	14	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	6,947	7,253	-4.2%	401	420	3,682	3,911	763	787	2,101	2,135
California	4,750	5,062	-6.2%	48	47	3,220	3,518	720	749	761	749
Oregon	1,087	924	17.6%	60	65	370	303	33	31	623	526
Washington	1,110	1,267	-12.4%	292	309	92	90	10	7	716	860
Pacific Noncontiguous	262	327	-19.9%	19	19	48	124	195	184	0	0
Alaska	43	39	10.5%	0	0	0	0	43	39	0	0
Hawaii	219	288	-24.0%	19	19	48	124	152	145	0	0
U.S. Total	46,422	47,199	-1.6%	3,239	3,411	16,865	17,970	3,742	3,800	22,575	22,018

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.20. Utility Scale Facility Net Generation from Geothermal
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	0	0	--	0	0	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	4,455	4,733	-5.9%	272	248	4,182	4,485	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	92	89	3.9%	0	0	92	89	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	3,886	4,150	-6.4%	0	0	3,886	4,150	0	0	0	0
New Mexico	26	36	-27.2%	0	0	26	36	0	0	0	0
Utah	451	458	-1.5%	272	248	179	210	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	10,693	11,442	-6.5%	642	534	10,052	10,908	0	0	0	0
California	10,524	11,266	-6.6%	642	534	9,883	10,732	0	0	0	0
Oregon	169	176	-4.0%	0	0	169	176	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	259	193	34.5%	0	0	259	193	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	259	193	34.5%	0	0	259	193	0	0	0	0
U.S. Total	15,407	16,367	-5.9%	914	782	14,493	15,586	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.21. Net Generation from Solar Photovoltaic
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors																								Electric Power Sector								Commercial Sector								Industrial Sector								Residential Sector			
	Estimated Generation From Utility and Small Scale Facilities								Generation at Utility Scale Facilities				Estimated Small Scale Generation				Generation at Utility Scale Facilities				Independent Power Producers				Estimated Generation From Utility and Small Scale Facilities				Generation at Utility Scale Facilities				Estimated Small Scale Generation				Estimated Generation From Utility and Small Scale Facilities				Generation at Utility Scale Facilities				Estimated Small Scale Generation				Estimated Small Scale Generation			
	Year 2024		Year 2023		Percentage Change	Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023		Year 2024		Year 2023								
	Year 2024	Year 2023	Year 2024	Year 2023		Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023											
New England	11,789	10,294	14.5%	4,369	3,577	7,420	6,717	138	134	4,212	3,421	3,833	3,607	16	14	3,818	3,593	189	221	4	9	185	213	3,417	2,911																											
Connecticut	1,935	1,659	16.6%	476	421	1,458	1,238	2	0	469	412	433	396	6	5	427	391	61	58	0	5	61	54	970	793																											
Maine	1,960	1,152	70.2%	945	523	1,015	629	0	0	945	523	861	520	0	0	861	520	0	0	0	0	0	0	153	109																											
Massachusetts	6,185	5,724	8.1%	2,127	2,015	4,058	3,709	77	77	2,036	1,924	2,277	2,078	10	9	2,268	2,069	105	143	4	4	101	138	1,689	1,501																											
New Hampshire	365	302	20.6%	4	3	361	299	0	0	4	3	112	105	0	0	112	105	12	12	0	0	12	12	237	182																											
Rhode Island	882	1,027	-14.1%	600	423	282	603	0	0	600	423	55	413	0	0	55	413	9	7	0	0	9	7	217	183																											
Vermont	462	430	7.4%	217	192	245	239	58	56	158	135	94	95	0	0	94	95	2	2	0	0	2	2	150	142																											
Middle Atlantic	14,710	12,304	19.6%	5,819	4,141	8,892	8,163	127	126	5,528	3,948	4,280	3,913	143	146	4,137	3,768	315	324	21	22	295	302	4,480	3,921																											
New Jersey	4,992	4,710	6.0%	1,596	1,544	3,395	3,166	127	126	1,338	1,283	1,541	1,466	126	130	1,415	1,336	214	201	5	6	208	195	1,772	1,635																											
New York	7,650	6,205	23.3%	3,127	2,236	4,522	3,968	0	0	3,109	2,218	2,477	2,178	10	9	2,467	2,169	31	27	8	9	22	18	2,033	1,781																											
Pennsylvania	2,069	1,389	48.9%	1,095	361	974	1,029	0	0	1,081	347	262	269	7	7	255	262	71	96	7	7	64	89	565	678																											
East North Central	18,230	10,580	72.3%	14,890	7,694	3,340	2,887	4,520	2,023	10,347	5,658	1,422	1,431	17	11	1,405	1,420	132	97	6	2	126	95	1,810	1,372																											
Illinois	4,787	3,447	38.9%	3,057	1,911	1,730	1,536	7	2	3,046	1,907	702	824	2	2	699	822	19	4	5	2	NM	17	5	1,014	708																										
Indiana	3,478	2,203	57.9%	3,091	1,854	387	349	1,968	980	1,122	872	213	193	2	2	211	191	18	14	0	0	18	14	158	144																											
Michigan	2,205	1,566	40.8%	1,859	1,269	346	296	80	80	1,780	1,189	130	105	0	0	130	105	6	5	0	0	6	5	210	187																											
Ohio	4,510	1,800	150.6%	4,002	1,382	508	418	7	7	3,985	1,370	226	191	9	4	217	187	52	44	0	2	52	43	240	187																											
Wisconsin	3,250	1,564	107.7%	2,880	1,277	369	287	2,459	954	414	320	152	118	4	4	148	115	36	27	3	0	33	27	188	145																											
West North Central	5,670	4,586	23.6%	3,812	2,997	1,858	1,589	712	440	3,009	2,557	677	558	0	0	676	558	159	58	91	0	68	58	1,134	972																											
Iowa	1,142	911	25.3%	663	521	478	390	418	291	246	230	242	200	0	0	242	200	19	15	0	0	19	15	217	175																											
Kansas	288	210	37.1%	122	81	166	129	58	16	63	66	50	40	0	0	50	40	3	1	0	0	3	1	113	88																											
Minnesota	2,689	2,417	11.2%	2,285	2,094	403	323	149	65	2,045	2,029	113	88	0	0	113	88	115	23	91	0	23	23	267	211																											
Missouri	950	867	9.6%	208	174	742	692	68	61	140	113	256	218	0	0	255	218	19	15	0	0	19	15	408	455																											
Nebraska	254	129	97.2%	196	79	57	49	19	8	177	72	13	11	0	0	13	11	4	4	0	0	4	4	41	35																											
North Dakota	3	2	25.0%	0	0	3	2	0	0	0	0	1	1	0	0	1	1	0	0	0	0	0	0	2	1																											
South Dakota	346	50	588.4%	338	47	7	4	0	0	338	47	3	1	0	0	3	1	0	0	0	0	0	0	7	5																											
South Atlantic	60,789	50,516	20.3%	51,021	42,375	9,768	8,141	21,371	16,953	29,511	25,273	1,598	1,369	126	140	1,472	1,228	460	443	14	8	446	434	5,849	6,479																											
Delaware	369	344	7.2%	166	155	203	189	7	7	151	146	42	38	3	3	39	35	15	13	6	0	9	13	154	118																											
District of Columbia	289	231	25.0%	32	25	257	206	1	3	30	21	90	75	0	0	90	75	0	0	0	0	0	0	167	132																											
Florida	23,261	17,804	30.6%	18,649	14,059	4,611	3,745	17,422	13,112	1,216	938	351	286	7	7	343	279	76	67	3	3	73	64	4,195	3,401																											
Georgia	9,753	8,069	20.9%	9,185	7,550	568	519	503	640	8,880	6,908	95	78	2	2	93	77	260	260	0	0	260	260	215	183																											
Maryland	2,515	2,325	8.2%	1,036	943	1,479	1,382	7	8	1,017	914	318	317	13	21	306	296	31	31	0	0	31	31	1,142	1,055																											
North Carolina	12,752	12,216	4.4%	11,844	11,459	908	757	1,058	1,075	10,685	10,278	309	287	100	106	209	181	20	17	0	0	20	17	679	559																											
South Carolina	3,563	3,351	6.3%	2,926	2,762	637	589	8	8	2,913	2,749	121	113	0	0	121	113	48	46	5	5	43	41	473	435																											
Virginia	8,042	6,129	31.2%	6,998	5,421	1,044	708	2,334	2,101	4,662	3,319	259	164	1	1	258	162	7	6	0	0	7	6	780	539																											
West Virginia	247	47	421.8%	186	0	61	47	30	0	156	0	14	11	0	0	14	11	3	2	0	0	3	2	45	35																											
East South Central	4,632	3,199	44.8%	4,327	2,950	305	248	248	233	253	4,084	2,688	130	109	5	5	124	104	12	11	5	6	7	5																												
Alabama	1,282	1,223	4.9%	1,255	1,201	27	22	77	25	1,178	1,176	17	14	0	0	17	14	3	3	0	0	3	3	7	5																											
Kentucky	438	286	53.1%	277	155	161	131	43	43	232	111	41	34	2	1	40	32	3	2	0	0	3	2	119	96																											
Mississippi	1,721	656	162.3%	1,691	633	30	23	111	182	1,580	451	10	9	0	0	10	9	1	1	0	0	1	1	20	13																											
Tennessee	1,191	1,034	15.2%	1,104	961	96	72	2	3	1,093	950	62	52	4	3	58	49	5	6	5	6	0	0	28	24																											
West South Central	50,430	34,353	46.8%	44,398	29,317	6,032	5,036	636	370	43,738	28,914	749	699	20	22	728	667	99	55	4	11	95	43	5,208	4,325																											
Arkansas	2,840	1,194	137.9%	2,329	798	511	397	901	241	1,907	535	188	167	17	10	171	148	84	43	4	3	81	40	259	208																											
Louisiana	1,535	592	159.3%	1,199	292	336	300	28	40	1,170	251	26	24	0	0	26	24	0	0	0	0	0	0	310	275																											
Oklahoma	540	242	122.9%	311	79	229	164	92	74	220	4	28	28	0	0	28	28	4	3	0	0	4	3	196	132																											
Texas	45,515	32,325	40.8%	40,559	28,150	4,956	4,175	15	14	40,541	28,124	506	470	3	4	503	466	10	8	0	8	10	0	4,443	3,709																											
Mountain	50,280	37,823	32.9%	38,546	27,614	11,735	10,209	2,216	1,510	36,176	25,974	2,153	1,993	69	75	2,083	1,918	279	215	84	55	194	161	9,457	8,131																											
Arizona	15,438	11,535	33.8%	9,992	6,663	5,446	4,871	1,038	593	8,905	6,017	1,210	1,121	16	20	1,194	1,102	50	47	34	16	14	14	4,238	3,616																											
Colorado	6,974	5,319	31.1%	4,939	3,615	2,035	1,704	18	13	4,887	3,588	415	381	6	8	409	373																																			

Table 3.22. Utility Scale Facility Net Generation from Solar Thermal
by State, by Sector, 2024 and 2023 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	0	0	--	0	0	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	1,073	946	13.4%	0	0	1,073	946	0	0	0	0
Arizona	828	775	6.9%	0	0	828	775	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	245	172	42.8%	0	0	245	172	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	2,045	1,901	7.6%	0	0	2,045	1,901	0	0	0	0
California	2,045	1,901	7.6%	0	0	2,045	1,901	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	3,118	2,847	9.5%	0	0	3,118	2,847	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.23. Useful Thermal Output by Energy Source: Total Combined Heat and Power (All Sectors), 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	232,509	11,990	23,457	545,624	104,869	624,086	21,390	1,563,923
2015	211,030	11,796	21,748	591,749	98,910	626,887	19,729	1,581,849
2016	220,162	8,607	20,122	785,413	148,881	698,858	25,342	1,907,384
2017	193,164	7,922	17,322	789,485	151,579	674,248	23,685	1,857,405
2018	182,373	9,878	16,581	813,127	172,677	663,644	23,169	1,881,448
2019	162,108	7,992	14,278	802,153	142,229	643,548	22,429	1,794,736
2020	139,423	6,463	12,359	835,666	135,048	602,034	20,901	1,751,893
2021	149,948	7,603	12,390	818,647	135,509	609,495	19,596	1,753,188
2022	146,782	16,516	11,793	805,556	133,148	587,576	18,475	1,719,846
2023	121,382	12,155	9,979	810,007	143,075	541,688	19,090	1,657,377
2024	114,656	8,211	10,262	835,189	146,260	532,926	18,733	1,666,236
Year 2022								
January	13,842	1,523	941	74,850	11,832	52,132	1,668	156,788
February	12,010	951	988	65,806	10,693	47,280	1,470	139,200
March	12,937	1,371	1,029	68,372	11,541	49,787	1,401	146,438
April	11,623	1,387	928	62,340	10,702	49,043	1,450	137,473
May	11,936	1,243	1,100	63,862	11,755	50,125	1,389	141,411
June	11,579	1,442	921	65,044	10,959	48,845	1,617	140,406
July	12,492	1,439	864	70,619	11,501	50,440	1,734	149,089
August	12,458	934	1,056	70,833	11,502	49,912	1,586	148,279
September	11,532	1,270	883	64,472	10,485	45,872	1,562	136,075
October	11,966	1,319	1,026	63,798	10,902	46,754	1,504	137,270
November	11,637	1,323	1,085	65,580	10,519	48,226	1,605	139,975
December	12,768	2,314	974	69,981	10,757	49,159	1,489	147,443
Year 2023								
January	12,058	1,558	685	70,919	11,903	50,312	1,575	149,009
February	10,343	1,551	465	64,348	10,823	44,130	1,477	133,137
March	10,805	1,196	1,037	69,034	12,139	48,554	1,525	144,290
April	9,472	1,383	913	62,551	11,606	42,243	1,403	129,571
May	9,975	625	975	63,680	11,946	45,258	1,448	133,906
June	9,422	611	839	66,229	11,959	41,360	1,535	131,955
July	10,386	659	817	70,460	12,273	43,700	1,556	139,852
August	9,582	802	884	69,535	12,304	44,606	1,572	139,284
September	9,534	779	871	66,880	12,504	43,397	1,381	135,347
October	9,351	739	848	65,086	12,537	43,637	1,383	133,581
November	9,933	981	809	68,719	11,043	46,833	2,065	140,383
December	10,522	1,271	837	72,566	12,038	47,659	2,169	147,062
Year 2024								
January	11,761	1,164	997	77,746	12,817	46,520	1,718	152,722
February	9,653	584	795	68,086	11,908	44,034	1,577	136,636
March	10,546	566	775	69,222	12,500	45,611	1,614	140,834
April	8,659	814	779	63,287	11,798	44,450	1,695	131,481
May	8,677	604	867	65,800	12,713	43,372	1,279	133,312
June	8,626	626	879	67,413	12,338	42,263	1,435	133,580
July	9,595	757	954	72,773	12,724	43,392	2,045	142,240
August	9,225	523	899	73,417	12,805	43,863	1,560	142,293
September	8,914	412	822	68,490	11,558	44,213	1,270	135,679
October	9,053	564	777	66,940	11,698	41,692	1,367	132,092
November	9,620	550	788	68,215	11,196	45,580	1,458	137,406
December	10,326	1,048	932	73,801	12,205	47,935	1,713	147,960

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Table 3.24. Useful Thermal Output by Energy Source: Electric Power Sector Combined Heat and Power, 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	15,513	4,931	936	182,148	7,732	17,736	5,666	234,662
2015	16,036	4,894	1,143	178,167	7,161	16,999	5,180	229,580
2016	13,922	695	1,237	227,427	17,400	24,993	8,046	293,719
2017	11,269	627	1,267	192,299	17,798	24,279	7,422	254,961
2018	13,573	1,023	1,023	207,459	18,692	23,375	7,119	272,265
2019	12,759	655	1,019	197,106	19,684	26,057	7,544	264,823
2020	7,412	530	1,300	203,104	17,318	24,815	7,322	261,801
2021	6,793	891	1,180	191,119	16,931	22,963	5,547	245,424
2022	6,936	1,201	996	187,898	17,384	20,406	2,882	237,704
2023	4,653	982	1,208	188,431	17,627	19,046	3,244	235,191
2024	2,488	2,407	1,085	193,640	17,106	16,305	3,150	236,180
Year 2022								
January	674	213	89	17,433	1,426	2,155	278	22,268
February	637	55	109	15,602	1,380	1,874	224	19,881
March	742	104	99	16,051	1,420	1,863	210	20,489
April	611	77	87	13,952	1,648	1,563	235	18,171
May	533	78	85	14,840	1,825	1,323	229	18,913
June	475	83	68	15,765	1,497	1,492	248	19,628
July	488	69	14	17,425	1,467	1,601	285	21,350
August	568	71	85	16,961	1,407	1,603	264	20,959
September	541	81	85	15,310	1,403	1,546	215	19,182
October	539	92	88	14,489	1,350	1,529	229	18,317
November	582	99	89	14,166	1,161	1,865	200	18,162
December	546	179	98	15,903	1,399	1,993	265	20,384
Year 2023								
January	442	109	98	15,783	1,327	1,854	263	19,876
February	480	95	104	15,205	1,157	1,872	241	19,153
March	652	78	110	15,908	1,411	2,499	242	20,901
April	435	84	89	14,339	1,415	1,791	292	18,445
May	374	75	107	14,012	1,588	1,639	290	18,085
June	476	77	98	15,307	1,534	1,428	284	19,204
July	304	70	101	17,143	1,495	1,229	285	20,627
August	266	63	106	17,205	1,715	1,042	278	20,674
September	244	73	109	15,559	1,502	786	214	18,486
October	379	100	90	15,440	1,395	1,670	187	19,261
November	290	71	87	16,148	1,409	1,595	328	19,927
December	313	88	108	16,381	1,679	1,641	340	20,551
Year 2024								
January	290	239	100	17,376	1,477	1,786	349	21,616
February	258	77	87	15,881	1,167	1,532	287	19,289
March	317	79	99	16,072	1,576	1,470	296	19,910
April	193	319	72	13,883	1,435	1,330	260	17,492
May	231	196	79	15,182	1,189	1,144	242	18,264
June	189	138	108	16,097	1,516	1,000	235	19,283
July	166	401	107	17,927	1,386	1,183	249	21,420
August	144	211	125	18,422	1,495	1,194	272	21,863
September	146	77	84	16,736	1,375	1,172	206	19,795
October	162	111	8	15,860	1,596	1,201	213	19,151
November	144	126	85	14,604	1,356	1,568	183	18,067
December	247	432	130	15,601	1,538	1,725	358	20,030

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Table 3.25. Useful Thermal Output by Energy Source: Commercial Sector Combined Heat and Power, 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	11,081	820	327	26,876	0	7,610	5,123	51,837
2015	7,966	823	325	26,498	0	8,228	5,641	49,482
2016	8,313	924	140	57,356	0	11,017	5,381	83,131
2017	7,360	806	234	71,149	0	10,762	5,140	95,450
2018	6,943	1,020	165	58,312	0	10,902	4,918	82,260
2019	6,211	1,346	95	56,356	0	8,307	3,335	75,650
2020	5,446	692	50	55,508	0	6,929	2,863	71,489
2021	5,975	820	88	50,047	0	6,377	2,825	66,132
2022	5,996	1,165	212	52,264	0	9,263	6,333	75,235
2023	4,334	908	50	49,140	0	8,717	6,303	69,453
2024	4,668	1,022	81	57,762	0	8,711	6,342	78,586
Year 2022								
January	682	303	27	5,178	0	834	561	7,584
February	652	81	25	4,604	0	761	485	6,606
March	438	97	27	4,509	0	745	487	6,303
April	298	75	23	4,035	0	663	483	5,576
May	304	75	29	3,921	0	779	542	5,651
June	428	38	26	4,061	0	865	557	5,975
July	487	68	19	4,727	0	848	591	6,738
August	496	60	0	4,787	0	878	591	6,812
September	503	29	5	4,021	0	743	537	5,838
October	499	37	0	3,770	0	665	475	5,447
November	571	48	11	3,980	0	781	560	5,951
December	639	255	21	4,671	0	702	465	6,752
Year 2023								
January	557	133	22	4,468	0	755	493	6,429
February	483	99	5	4,079	0	661	492	5,819
March	439	65	3	4,170	0	748	526	5,952
April	382	26	0	3,616	0	672	502	5,197
May	287	29	0	3,656	0	668	570	5,209
June	263	43	0	3,848	0	739	498	5,390
July	280	40	0	4,419	0	691	543	5,973
August	295	36	0	4,203	0	787	579	5,900
September	296	42	0	4,063	0	770	520	5,691
October	268	40	0	3,941	0	660	430	5,338
November	359	74	0	4,276	0	731	547	5,987
December	425	282	20	4,400	0	836	604	6,567
Year 2024								
January	721	214	21	5,683	0	841	571	8,051
February	531	102	9	4,993	0	724	550	6,909
March	397	115	0	4,790	0	685	540	6,527
April	346	80	0	4,098	0	546	404	5,474
May	225	98	16	3,809	0	710	540	5,398
June	299	188	18	4,525	0	741	541	6,311
July	307	26	0	5,295	0	825	573	7,026
August	327	18	0	5,176	0	671	477	6,669
September	327	18	0	4,627	0	740	507	6,219
October	334	26	0	4,547	0	706	539	6,152
November	406	46	0	4,815	0	734	545	6,545
December	448	91	18	5,405	0	788	556	7,305

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Table 3.26. Useful Thermal Output by Energy Source: Industrial Sector Combined Heat and Power, 2014 - 2024
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Fossil Gas	Renewable Sources	Other	Total
Annual Totals								
2014	199,512	6,120	22,167	334,901	97,137	596,087	10,600	1,266,524
2015	180,501	5,965	20,203	384,369	91,749	598,890	8,899	1,290,576
2016	173,589	6,792	18,692	478,068	131,481	655,831	11,904	1,476,358
2017	151,780	6,289	15,721	503,614	133,781	631,768	11,112	1,454,066
2018	142,671	7,535	15,281	521,936	153,985	622,699	11,118	1,475,224
2019	127,411	5,787	13,012	523,919	122,544	607,138	11,535	1,411,347
2020	114,031	5,078	10,863	548,938	117,730	568,537	10,702	1,375,879
2021	120,335	5,658	10,933	547,717	118,578	578,150	11,208	1,392,579
2022	116,212	13,837	10,375	537,793	115,764	555,335	9,245	1,358,561
2023	100,884	10,076	8,645	545,036	125,448	511,656	9,521	1,311,266
2024	97,987	4,589	9,094	554,896	129,154	505,459	9,238	1,310,416
Year 2022								
January	10,800	927	810	49,490	10,406	48,935	827	122,194
February	9,296	774	779	43,261	9,313	44,432	760	108,616
March	10,346	1,153	891	45,486	10,121	46,936	702	115,636
April	9,433	1,223	816	42,760	9,054	46,595	732	110,614
May	9,975	1,076	975	43,143	9,930	47,876	618	113,592
June	9,260	1,307	817	42,871	9,462	46,320	811	110,848
July	9,778	1,285	822	45,738	10,033	47,805	857	116,319
August	9,761	792	963	46,573	10,095	47,228	730	116,142
September	8,923	1,146	786	42,961	9,082	43,356	807	107,061
October	9,632	1,176	931	43,722	9,552	44,432	798	110,243
November	9,130	1,162	932	45,012	9,359	45,296	844	111,734
December	9,877	1,815	853	46,774	9,358	46,125	758	115,561
Year 2023								
January	9,826	1,296	559	48,140	10,576	47,447	816	118,660
February	8,491	1,334	345	42,775	9,666	41,382	742	104,735
March	8,685	1,041	905	46,609	10,728	45,062	756	113,786
April	7,998	1,260	802	42,614	10,191	39,561	609	103,034
May	8,452	500	868	44,063	10,358	42,904	585	107,730
June	7,826	478	740	44,839	10,425	39,045	752	104,105
July	8,597	534	709	46,224	10,778	41,615	726	109,184
August	7,843	691	771	45,820	10,589	42,588	712	109,013
September	7,959	655	760	45,007	11,002	41,743	646	107,772
October	7,928	581	757	43,791	11,142	41,115	765	106,078
November	8,436	821	721	45,921	9,634	44,267	1,189	110,989
December	8,845	886	708	49,233	10,359	44,926	1,223	116,179
Year 2024								
January	9,548	654	874	52,132	11,340	43,634	797	118,979
February	8,025	394	698	44,847	10,741	41,537	739	106,983
March	9,058	360	676	45,816	10,924	43,193	778	110,804
April	7,395	398	707	43,312	10,363	42,335	1,031	105,541
May	7,549	299	771	44,624	11,524	41,384	497	106,649
June	7,446	285	754	44,418	10,821	40,325	659	104,709
July	8,284	318	847	46,753	11,338	41,162	1,224	109,926
August	7,819	281	774	47,087	11,310	41,808	811	109,891
September	7,705	308	737	44,588	10,184	42,102	557	106,181
October	7,943	412	770	44,427	10,102	39,689	616	103,959
November	8,433	365	702	46,684	9,840	43,082	730	109,836
December	8,783	513	784	50,207	10,666	45,208	800	116,960

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, Other Fossil Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Table 3.27 Gross/Net Generation by Energy Storage Technology: Total (All Sectors), 2014 - 2024
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities									
	Gross Generation					Net Generation				
	Battery	Compressed Air	Flywheels	Hydroelectric Pumped Storage	Total	Battery	Compressed Air	Flywheels	Hydroelectric Pumped Storage	Total
Annual Totals										
2014	24	9	47	20,054	20,133	-14	-2	-21	-6,174	-6,210
2015	76	8	49	20,111	20,244	-20	-7	-24	-5,091	-5,142
2016	142	17	43	22,443	22,645	-170	-8	-22	-6,686	-6,886
2017	383	12	62	22,752	23,209	-69	-8	-26	-6,495	-6,597
2018	358	6	67	21,503	21,934	-88	-6	-28	-5,905	-6,026
2019	456	6	59	20,772	21,293	-97	-7	-26	-5,261	-5,391
2020	557	6	53	21,073	21,689	-131	-5	-24	-5,321	-5,482
2021	1,507	23	46	20,618	22,194	-264	-6	-23	-5,112	-5,404
2022	3,808	26	49	22,466	26,349	-689	-6	-23	-6,028	-6,746
2023	6,696	2	42	22,132	28,872	-1,281	-4	-20	-5,990	-7,294
2024	14,936	1	22	23,151	38,109	-2,399	-2	-16	-5,852	-8,269
Year 2022										
January	201	1	4	1,626	1,832	-33	0	-2	-493	-528
February	224	0	3	1,375	1,602	-40	0	-2	-412	-453
March	225	0	4	1,566	1,795	-39	0	-2	-318	-359
April	248	1	4	1,216	1,468	-40	0	-2	-265	-307
May	287	2	4	1,874	2,167	-53	-1	-2	-467	-522
June	322	4	4	2,461	2,791	-57	-1	-2	-589	-649
July	345	4	4	2,726	3,081	-66	-1	-2	-768	-838
August	348	5	4	2,812	3,169	-67	-1	-2	-640	-710
September	349	3	4	2,191	2,546	-68	-1	-2	-598	-668
October	423	3	4	1,442	1,872	-78	-1	-2	-434	-515
November	416	1	4	1,524	1,946	-75	0	-2	-495	-572
December	421	2	4	1,653	2,081	-72	-1	-2	-548	-623
Year 2023										
January	474	0	4	1,574	2,051	-76	0	-2	-620	-698
February	403	0	4	1,482	1,889	-98	0	-2	-456	-556
March	484	0	4	1,579	2,067	-118	0	-2	-519	-639
April	497	0	4	1,465	1,965	-85	0	-2	-290	-377
May	477	0	4	1,880	2,360	-82	0	-2	-459	-543
June	510	0	4	2,299	2,813	-94	-1	-2	-551	-647
July	576	0	3	2,707	3,287	-121	-1	-2	-656	-779
August	606	0	3	2,678	3,287	-116	-1	-2	-653	-771
September	599	0	3	2,213	2,815	-123	0	-2	-553	-677
October	703	0	3	1,496	2,202	-123	0	-2	-372	-497
November	687	0	3	1,378	2,068	-118	0	-1	-347	-466
December	680	0	3	1,383	2,066	-128	0	-2	-514	-643
Year 2024										
January	744	0	2	1,642	2,388	-129	0	-1	-414	-545
February	827	0	2	1,557	2,386	-126	0	-1	-404	-532
March	969	0	2	1,276	2,247	-148	0	-1	-349	-498
April	1,078	0	2	1,526	2,606	-158	0	-1	-338	-498
May	1,114	0	2	2,166	3,282	-177	0	-1	-284	-462
June	1,186	0	2	2,605	3,793	-209	0	-2	-579	-789
July	1,370	0	2	2,902	4,275	-224	0	-1	-639	-865
August	1,448	0	2	2,822	4,272	-239	0	-2	-798	-1,039
September	1,371	0	1	2,169	3,541	-228	0	-1	-637	-867
October	1,565	0	2	1,429	2,997	-261	0	-2	-439	-702
November	1,553	0	2	1,443	2,999	-237	0	-1	-490	-728
December	1,710	0	2	1,614	3,325	-261	0	-1	-481	-744

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Chapter 4

Generation Capacity

Table 4.1. Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within Plant, 2014 through 2024

Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Other Renewables	Hydroelectric Pumped Storage	Other Energy Sources
Total (All Sectors)									
2014	491	1,082	1,749	43	62	1,441	2,674	41	94
2015	427	1,082	1,779	45	62	1,440	3,043	41	83
2016	381	1,076	1,801	45	61	1,451	3,624	40	117
2017	359	1,080	1,820	44	61	1,458	4,174	40	148
2018	336	1,087	1,854	46	60	1,458	4,667	40	171
2019	308	1,090	1,899	43	58	1,452	5,244	40	212
2020	284	1,091	1,926	42	56	1,446	5,918	40	267
2021	269	1,104	2,020	37	55	1,449	6,579	40	372
2022	242	1,084	2,073	33	54	1,445	7,084	40	483
2023	227	1,075	2,084	35	54	1,441	7,684	40	617
2024	219	1,065	2,078	34	56	1,433	8,503	39	791
Electric Utilities									
2014	286	780	803	1	32	889	272	35	20
2015	256	782	816	1	32	890	318	35	15
2016	230	771	819	1	31	893	375	35	36
2017	219	765	820	1	31	894	417	35	53
2018	206	751	819	1	31	896	462	35	60
2019	194	743	818	1	31	898	512	35	71
2020	181	743	820	1	31	892	586	35	78
2021	169	739	813	1	31	879	649	34	86
2022	157	726	835	1	31	875	709	34	104
2023	148	721	837	1	31	873	782	34	132
2024	145	717	844	1	31	867	899	33	175
Independent Power Producers, Non-Combined Heat and Power Plants									
2014	87	148	395	1	30	499	2,006	5	18
2015	80	143	397	--	30	497	2,309	5	21
2016	75	142	406	--	30	500	2,826	5	34
2017	71	145	415	--	30	505	3,320	5	43
2018	65	140	450	--	29	514	3,749	5	59
2019	59	141	476	--	27	506	4,251	5	74
2020	56	135	491	--	25	506	4,847	5	119
2021	56	150	521	--	24	521	5,429	6	214
2022	46	139	548	--	23	521	5,833	6	306
2023	43	135	562	--	23	520	6,359	6	409
2024	42	131	551	--	25	519	7,060	6	539
Independent Power Producers, Combined Heat and Power Plants									
2014	30	9	145	2	--	--	54	--	7
2015	27	8	143	3	--	--	58	--	3
2016	24	7	143	3	--	--	57	--	2
2017	22	7	138	3	--	--	56	--	3
2018	19	8	133	3	--	--	56	--	3
2019	14	6	128	3	--	--	56	--	3
2020	12	7	121	3	--	--	56	--	4
2021	11	8	122	3	--	--	52	--	4
2022	8	7	119	3	--	--	54	--	3
2023	8	7	118	3	--	--	52	--	3
2024	7	7	117	3	--	1	49	--	3
Commercial Sector									
2014	17	93	169	--	--	10	178	1	6
2015	12	94	176	--	--	10	186	1	3
2016	9	101	181	--	--	14	195	--	3
2017	9	112	189	--	--	15	203	--	4
2018	7	139	192	--	--	15	220	--	5
2019	6	152	203	--	--	15	242	--	20
2020	4	156	220	--	--	15	240	--	21
2021	4	160	281	--	--	16	255	--	24
2022	3	161	287	--	--	17	277	--	26
2023	3	163	285	--	--	17	278	--	28
2024	3	162	285	--	--	16	270	--	29
Industrial Sector									
2014	71	52	237	39	--	43	164	--	43
2015	52	55	247	41	--	43	172	--	41
2016	43	55	252	41	--	44	171	--	42
2017	38	51	258	40	--	44	178	--	45
2018	39	49	260	42	--	33	180	--	44
2019	35	48	274	39	--	33	183	--	44
2020	31	50	274	38	--	33	189	--	45
2021	29	47	283	33	--	33	194	--	44
2022	28	51	284	29	--	32	211	--	44
2023	25	49	282	31	--	31	213	--	45
2024	22	48	281	30	--	30	225	--	45

Notes: The number of power plants for each energy source is the number of sites for which the respective energy source was reported as the most predominant energy source for at least one of its generators. If all generators for a site have the same energy source reported as the most predominant, that site will be counted once under that energy source. However, if the most predominant energy source is not the same for all generators within a site, the site is counted more than once, based on the number of most predominant energy sources for generators at a site. In general, this table translates the number of generators by energy source into the number of sites represented by the generators for an energy source. Therefore, the count for Total (All Sectors) above is the sum of the counts for each sector by energy source and does not necessarily represent unique sites. In addition, changes to predominant energy sources and status codes from year to year may result in changes to previously-posted data.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.2.A. Existing Net Summer Capacity by Energy Source and Producer Type, 2014 through 2024 (Megawatts)

	Utility Scale Capacity										Small Scale Capacity
Year	Coal	Petroleum	Natural Gas	Other Fossil Gas	Nuclear	Hydroelectric Conventional	Other Renewable Sources	Hydroelectric Pumped Storage	Other Energy Sources	Utility Total	Estimated Photovoltaic
Total (All Sectors)											
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	90,603.7	22,485.1	2,792.6	1,068,422.2	7,326.6
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	102,871.6	22,575.1	1,795.6	1,064,054.5	9,778.5
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	119,778.9	22,778.7	2,015.1	1,074,332.8	12,765.1
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	131,008.1	22,810.4	2,886.3	1,084,369.6	16,147.8
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	142,473.6	22,830.2	2,346.7	1,094,739.8	19,547.1
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	156,708.2	22,778.3	2,606.4	1,099,109.3	23,213.6
2020	215,554.2	27,569.3	485,807.2	2,275.2	96,500.6	79,924.3	181,954.5	23,016.2	3,079.3	1,115,680.8	27,584.8
2021	209,825.7	28,204.5	491,870.2	1,888.0	95,546.4	79,909.7	209,292.6	23,007.7	6,311.3	1,145,856.1	33,081.0
2022	189,316.3	30,775.3	502,396.9	1,728.2	94,658.9	80,067.6	229,039.1	23,043.9	10,405.6	1,161,431.8	39,828.0
2023	178,441.7	29,440.7	507,535.8	1,866.8	95,712.2	79,985.3	253,964.6	23,147.4	17,450.9	1,187,545.4	47,774.7
2024	174,177.6	28,649.7	506,371.0	1,678.1	98,391.2	79,896.5	289,658.2	23,156.6	28,436.4	1,230,415.2	53,228.1
Electric Utilities											
2014	219,837.9	24,045.0	215,690.8	12.0	52,390.9	73,725.4	10,893.7	19,121.3	914.5	616,631.5	--
2015	202,922.4	22,269.7	223,215.6	12.0	52,457.2	73,713.0	12,654.3	19,211.3	87.5	606,543.0	--
2016	193,122.6	20,285.5	229,677.1	12.0	53,274.1	73,879.3	14,236.4	19,398.3	236.1	604,121.4	--
2017	186,623.1	19,999.9	236,557.8	12.0	53,343.6	73,739.5	15,281.3	19,430.0	519.3	605,506.5	--
2018	179,047.8	18,642.6	241,477.0	12.0	53,725.6	73,818.2	18,155.9	19,449.8	341.8	604,670.7	--
2019	171,088.7	18,219.8	247,018.9	12.0	53,880.6	73,719.7	20,745.8	19,428.9	418.3	604,532.7	--
2020	163,886.7	14,723.5	252,902.3	12.0	54,002.7	73,855.3	27,910.6	19,668.8	438.3	607,398.2	--
2021	157,681.0	15,660.6	257,969.4	12.0	53,917.1	73,316.9	33,028.9	19,235.3	958.5	611,779.7	--
2022	146,127.6	16,411.3	266,709.4	12.0	53,862.9	73,482.6	35,629.0	19,279.1	1,298.5	612,812.4	--
2023	139,158.0	15,291.5	270,951.7	12.0	54,917.4	73,467.1	41,569.6	19,377.1	1,917.6	616,662.0	--
2024	135,786.0	14,931.4	273,739.3	12.0	55,949.3	73,378.7	48,099.6	19,385.6	2,861.5	624,143.3	--
Independent Power Producers, Non-Combined Heat and Power Plants											
2014	71,994.6	15,724.4	172,224.5	47.0	46,178.4	5,651.2	72,144.4	3,358.4	238.7	387,561.6	--
2015	70,217.8	13,102.9	172,519.2	--	46,214.8	5,650.5	82,014.6	3,358.4	354.3	393,432.5	--
2016	67,667.7	12,587.4	173,455.8	--	46,290.7	5,676.9	97,408.4	3,380.4	487.5	406,954.8	--
2017	64,419.3	11,777.0	176,029.0	--	46,285.3	5,697.9	107,618.0	3,380.4	989.3	416,196.2	--
2018	58,716.2	11,733.2	186,542.1	--	45,707.3	5,770.0	116,197.3	3,380.4	670.1	428,716.6	--
2019	53,646.5	11,514.8	187,715.6	--	44,238.4	5,764.3	127,964.3	3,349.4	760.7	434,954.0	--
2020	48,069.4	11,007.6	190,621.4	--	42,497.9	5,780.6	145,809.5	3,349.4	1,204.4	448,340.2	--
2021	48,742.4	10,672.5	190,877.6	--	41,629.3	6,293.8	168,330.4	3,772.4	3,891.7	474,210.1	--
2022	40,460.6	12,386.6	192,400.0	--	40,796.0	6,288.7	185,017.6	3,764.8	7,811.0	488,925.3	--
2023	36,615.5	12,249.2	193,777.0	--	40,794.8	6,224.0	204,050.1	3,770.3	14,192.5	511,673.4	--
2024	36,051.2	11,795.8	190,783.5	--	42,441.9	6,228.4	233,407.1	3,771.0	24,234.5	548,713.3	--
Independent Power Producers, Combined Heat and Power Plants											
2014	4,073.0	308.2	27,676.7	83.0	--	--	885.9	--	335.8	33,362.6	--
2015	3,843.6	307.2	27,284.1	350.0	--	--	970.5	--	126.0	32,881.4	--
2016	3,552.4	301.2	27,222.4	350.0	--	--	1,068.3	--	19.0	32,513.3	--
2017	3,338.0	301.2	26,922.1	350.0	--	--	969.8	--	21.0	31,902.1	--
2018	2,922.0	458.0	25,658.1	350.0	--	--	884.2	--	21.0	30,293.3	--
2019	2,074.1	298.8	24,782.0	350.0	--	--	944.9	--	112.0	28,561.8	--
2020	1,994.2	450.8	24,635.8	350.0	--	--	952.0	--	113.0	28,495.8	--
2021	1,902.6	452.2	24,611.8	350.0	--	--	888.1	--	113.0	28,317.7	--
2022	1,283.9	449.9	24,506.3	350.0	--	--	856.8	--	17.0	27,462.9	--
2023	1,245.0	451.1	24,172.2	350.0	--	--	770.0	--	31.0	27,019.3	--
2024	939.2	451.1	23,371.7	322.0	--	7.2	750.6	--	31.0	25,872.8	--
Commercial Sector											
2014	290.1	463.5	1,832.6	--	--	21.4	1,066.8	5.4	15.6	3,695.4	3,279.7
2015	226.6	466.1	1,932.5	--	--	21.4	1,126.5	5.4	6.7	3,785.2	3,706.7
2016	202.4	511.0	1,982.6	--	--	74.5	1,132.0	--	6.7	3,909.2	4,022.8
2017	202.4	596.5	2,018.7	--	--	74.9	1,162.0	--	11.6	4,066.1	5,155.8
2018	144.2	823.6	2,157.6	--	--	74.7	1,241.5	--	13.0	4,454.6	6,271.4
2019	123.2	856.7	2,247.5	--	--	74.9	1,218.6	--	49.1	4,570.0	7,167.9
2020	77.6	875.1	2,345.0	--	--	74.2	1,217.9	--	51.8	4,641.6	8,376.1
2021	77.6	912.5	2,272.7	--	--	84.8	1,373.0	--	51.1	4,771.7	9,752.0
2022	47.9	958.1	2,378.2	--	--	87.5	1,925.2	--	53.1	5,450.0	11,212.3
2023	47.9	960.5	2,347.4	--	--	87.5	1,927.1	--	55.1	5,425.5	12,605.1
2024	47.9	985.8	2,408.3	--	--	81.3	1,848.0	--	55.6	5,427.0	14,014.0
Industrial Sector											
2014	2,898.6	594.3	14,725.7	1,772.3	--	279.3	5,612.9	--	1,288.0	27,171.1	700.6
2015	2,509.5	684.4	14,474.0	2,138.4	--	279.3	6,105.7	--	1,221.1	27,412.4	880.3
2016	2,074.8	697.3	14,485.3	2,094.9	--	282.2	5,933.8	--	1,265.8	26,834.1	1,215.3
2017	1,964.5	632.1	14,484.0	2,013.8	--	282.2	5,977.0	--	1,345.1	26,698.7	1,365.1
2018	1,955.4	560.8	14,402.1	2,181.9	--	208.9	5,994.7	--	1,300.8	26,604.6	1,555.4
2019	1,724.9	510.2	14,803.4	2,137.2	--	214.2	5,834.6	--	1,266.3	26,490.8	1,796.6
2020	1,526.3	512.3	15,302.7	1,913.2	--	214.2	6,064.5	--	1,271.8	26,805.0	2,045.3
2021	1,422.1	506.7	16,138.7	1,526.0	--	214.2	5,672.2	--	1,297.0	26,776.9	2,212.7
2022	1,396.3	569.4	16,404.0	1,366.2	--	208.8	5,610.5	--	1,226.0	26,781.2	2,321.7
2023	1,375.3	488.4	16,287.5	1,504.8	--	206.7	5,647.8	--	1,254.7	26,765.2	2,558.3
2024	1,353.3	485.6	16,068.4	1,344.1	--	200.9	5,552.9	--	1,253.8	26,258.9	2,712.2
Residential Sector											
2014	--	--	--	--	--	--	--	--	--	--	3,346.3
2015	--	--	--	--	--	--	--	--	--	--	5,191.5
2016	--	--	--	--	--	--	--	--	--	--	7,527.0
2017	--	--	--	--	--	--	--	--	--	--	9,626.8
2018	--	--	--	--	--	--	--	--	--	--	11,720.4
2019	--	--	--	--	--	--	--	--	--	--	14,249.0
2020	--	--	--	--	--	--	--	--	--	--	17,163.3
2021	--	--	--	--	--	--	--	--	--	--	21,116.2
2022	--	--	--	--	--	--	--	--	--	--	26,294.0
2023	--	--	--	--	--	--	--	--	--	--	32,611.3
2024	--	--	--	--	--	--	--	--	--	--	36,501.8

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal syrefuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Renewable Sources include wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

Source: U.S. Energy Information Administration, Form EIA-860, Annual Electric Generator Report.

Estimated small scale solar photovoltaic generation and capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type,
2014 through 2024 (Megawatts) (Page 1)

Utility Scale Capacity								Utility and Small Scale Capacity		
Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Total (All Sectors)										
2014	64,231.5	8,656.6	1,666.7	8,368.1	2,514.3	5,166.5	90,603.7	7,326.6	15,983.2	17,649.9
2015	72,573.4	11,905.4	1,757.9	8,968.9	2,541.5	5,124.5	102,871.6	9,778.5	21,683.9	23,441.8
2016	81,286.6	20,192.9	1,757.9	8,936.1	2,516.6	5,088.8	119,778.9	12,765.1	32,958.0	34,715.9
2017	87,597.5	25,209.0	1,757.9	8,830.9	2,483.3	5,129.5	131,008.1	16,147.8	41,356.8	43,114.7
2018	94,417.7	30,120.5	1,757.9	8,694.6	2,444.3	5,038.6	142,473.6	19,547.1	49,667.6	51,425.5
2019	103,571.2	35,710.2	1,758.1	8,374.5	2,555.4	4,738.8	156,708.2	23,213.6	58,923.8	60,681.9
2020	118,378.7	46,306.2	1,747.9	8,326.5	2,571.9	4,623.3	181,954.5	27,584.8	73,891.0	75,638.9
2021	132,753.4	60,070.1	1,480.0	7,923.2	2,596.7	4,469.2	209,292.6	33,081.0	93,151.1	94,631.1
2022	141,402.2	71,381.5	1,480.0	7,804.5	2,648.6	4,322.3	229,039.1	39,828.0	111,209.5	112,689.5
2023	147,444.7	90,517.8	1,480.0	7,693.1	2,695.8	4,133.2	253,964.6	47,774.7	138,292.5	139,772.5
2024	152,097.3	122,061.8	1,392.0	7,414.8	2,695.5	3,996.9	289,658.2	53,228.1	175,289.9	176,681.9
Electric Utilities										
2014	9,022.6	568.5	--	654.8	164.1	483.7	10,893.7	--	568.5	568.5
2015	10,580.9	842.9	--	623.8	165.9	440.8	12,654.3	--	842.9	842.9
2016	11,552.6	1,388.4	--	708.8	167.9	418.7	14,236.4	--	1,388.4	1,388.4
2017	12,150.8	1,724.5	--	811.3	161.9	432.8	15,281.3	--	1,724.5	1,724.5
2018	14,031.7	2,683.5	--	807.0	148.8	484.9	18,155.9	--	2,683.5	2,683.5
2019	15,715.0	3,851.4	--	696.2	146.5	336.7	20,745.8	--	3,851.4	3,851.4
2020	20,788.5	5,965.4	--	670.8	149.5	336.4	27,910.6	--	5,965.4	5,965.4
2021	23,991.7	7,979.1	--	627.7	149.5	280.9	33,028.9	--	7,979.1	7,979.1
2022	24,445.7	10,141.2	--	628.6	149.5	264.0	35,629.0	--	10,141.2	10,141.2
2023	26,855.3	13,691.6	--	628.6	158.5	235.6	41,569.6	--	13,691.6	13,691.6
2024	27,574.3	19,502.8	--	612.6	158.5	251.5	48,099.6	--	19,502.8	19,502.8
Independent Power Producers, Non-Combined Heat and Power Plants										
2014	55,133.0	7,857.0	1,666.7	1,816.6	2,308.8	3,362.3	72,144.4	--	7,857.0	9,523.7
2015	61,905.4	10,768.2	1,757.9	1,873.3	2,375.6	3,334.2	82,014.6	--	10,768.2	12,526.1
2016	69,645.4	18,483.3	1,757.9	1,789.6	2,348.7	3,383.5	97,408.4	--	18,483.3	20,241.2
2017	75,346.6	23,127.0	1,757.9	1,649.1	2,321.4	3,416.0	107,618.0	--	23,127.0	24,884.9
2018	80,267.6	27,055.8	1,757.9	1,576.2	2,246.1	3,293.7	116,197.3	--	27,055.8	28,813.7
2019	87,737.8	31,416.4	1,758.1	1,475.7	2,359.5	3,216.8	127,964.3	--	31,416.4	33,174.5
2020	97,242.6	39,868.8	1,747.9	1,463.3	2,373.0	3,113.9	145,809.5	--	39,868.8	41,616.7
2021	108,637.2	51,546.2	1,480.0	1,339.8	2,373.0	2,954.2	168,330.4	--	51,546.2	53,026.2
2022	116,829.6	60,617.7	1,480.0	1,318.3	2,499.1	2,272.9	185,017.6	--	60,617.7	62,097.7
2023	120,466.5	76,128.3	1,480.0	1,320.0	2,537.3	2,118.0	204,050.1	--	76,128.3	77,608.3
2024	124,376.6	101,819.0	1,392.0	1,198.8	2,537.0	2,083.6	233,407.1	--	101,819.0	103,211.0

Notes: Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass includes municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

* = Value is less than half of the smallest unit of measure.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type,
2014 through 2024 (Megawatts) (Page 2)

Utility Scale Capacity	Utility and Small Scale Capacity
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Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Independent Power Producers, Combined Heat and Power Plants										
2014	--	--	--	465.5	41.4	379.0	885.9	--	--	--
2015	--	--	--	568.2	--	402.3	970.5	--	--	--
2016	--	1.0	--	667.2	--	400.1	1,068.3	--	1.0	1.0
2017	--	2.5	--	582.0	--	385.3	969.8	--	2.5	2.5
2018	--	3.3	--	492.7	--	388.2	884.2	--	3.3	3.3
2019	--	3.3	--	554.7	--	386.9	944.9	--	3.3	3.3
2020	--	3.9	--	563.2	--	384.9	952.0	--	3.9	3.9
2021	--	3.9	--	467.2	--	417.0	888.1	--	3.9	3.9
2022	--	4.1	--	467.2	--	385.5	856.8	--	4.1	4.1
2023	--	3.9	--	382.2	--	383.9	770.0	--	3.9	3.9
2024	--	3.9	--	396.1	--	350.6	750.6	--	3.9	3.9
Commercial Sector										
2014	51.6	223.4	--	65.4	--	726.4	1,066.8	3,279.7	3,503.1	3,503.1
2015	55.3	282.1	--	65.3	--	723.8	1,126.5	3,706.7	3,988.8	3,988.8
2016	56.8	300.8	--	67.1	--	707.3	1,132.0	4,022.8	4,323.6	4,323.6
2017	60.8	311.6	--	63.1	--	726.5	1,162.0	5,155.8	5,467.4	5,467.4
2018	73.4	330.6	--	63.1	49.4	725.0	1,241.5	6,271.4	6,602.0	6,602.0
2019	73.4	381.1	--	63.1	49.4	651.6	1,218.6	7,167.9	7,549.0	7,549.0
2020	67.6	385.1	--	63.3	49.4	652.5	1,217.9	8,376.1	8,761.2	8,761.2
2021	67.8	412.9	--	137.3	74.2	680.8	1,373.0	9,752.0	10,164.9	10,164.9
2022	70.2	444.3	--	137.3	--	1,273.4	1,925.2	11,212.3	11,656.6	11,656.6
2023	69.2	448.6	--	137.3	--	1,272.0	1,927.1	12,605.1	13,053.7	13,053.7
2024	69.2	435.8	--	136.0	--	1,207.0	1,848.0	14,014.0	14,449.9	14,449.9
Industrial Sector										
2014	24.3	7.7	--	5,365.8	--	215.1	5,612.9	700.6	708.3	708.3
2015	31.8	12.2	--	5,838.3	--	223.4	6,105.7	880.3	892.5	892.5
2016	31.8	19.4	--	5,703.4	--	179.2	5,933.8	1,215.3	1,234.7	1,234.7
2017	39.3	43.4	--	5,725.4	--	168.9	5,977.0	1,365.1	1,408.5	1,408.5
2018	45.0	47.3	--	5,755.6	--	146.8	5,994.7	1,555.4	1,602.7	1,602.7
2019	45.0	58.0	--	5,584.8	--	146.8	5,834.6	1,796.6	1,854.6	1,854.6
2020	280.0	83.0	--	5,565.9	--	135.6	6,064.5	2,045.3	2,128.3	2,128.3
2021	56.7	128.0	--	5,351.2	--	136.3	5,672.2	2,212.7	2,340.7	2,340.7
2022	56.7	174.2	--	5,253.1	--	126.5	5,610.5	2,321.7	2,495.9	2,495.9
2023	53.7	245.4	--	5,225.0	--	123.7	5,647.8	2,558.3	2,803.7	2,803.7
2024	77.2	300.2	--	5,071.3	--	104.2	5,552.9	2,712.2	3,012.4	3,012.4
Residential Sector										
2014	--	--	--	--	--	--	--	3,346.3	3,346.3	3,346.3
2015	--	--	--	--	--	--	--	5,191.5	5,191.5	5,191.5
2016	--	--	--	--	--	--	--	7,527.0	7,527.0	7,527.0
2017	--	--	--	--	--	--	--	9,626.8	9,626.8	9,626.8
2018	--	--	--	--	--	--	--	11,720.4	11,720.4	11,720.4
2019	--	--	--	--	--	--	--	14,249.0	14,249.0	14,249.0
2020	--	--	--	--	--	--	--	17,163.3	17,163.3	17,163.3
2021	--	--	--	--	--	--	--	21,116.2	21,116.2	21,116.2
2022	--	--	--	--	--	--	--	26,294.0	26,294.0	26,294.0
2023	--	--	--	--	--	--	--	32,611.3	32,611.3	32,611.3
2024	--	--	--	--	--	--	--	36,501.8	36,501.8	36,501.8

Notes: Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass includes municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

* = Value is less than half of the smallest unit of measure.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.3. Existing Capacity by Energy Source, 2024 (Megawatts)

Energy Source	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	Utility Scale	462	188,951.9	174,177.6	175,340.0
Petroleum	Utility Scale	3,884	33,324.0	28,649.7	31,934.5
Natural Gas	Utility Scale	6,693	571,226.5	506,371.0	542,188.3
Other Fossil Gas	Utility Scale	70	1,871.1	1,678.1	1,692.4
Nuclear	Utility Scale	96	103,581.2	98,391.2	100,774.4
Hydroelectric Conventional	Utility Scale	3,978	79,982.5	79,896.5	79,346.3
Wind	Utility Scale	1,563	153,489.1	152,097.3	152,188.0
Solar Photovoltaic	Utility Scale	7,141	122,907.1	122,061.8	121,433.9
Solar Thermal	Utility Scale	12	1,405.0	1,392.0	1,288.5
Wood and Wood-Derived Fuels	Utility Scale	288	8,369.9	7,414.8	7,529.9
Geothermal	Utility Scale	163	4,002.1	2,695.5	3,162.2
Other Biomass	Utility Scale	1,493	4,549.8	3,996.9	4,050.5
Hydroelectric Pumped Storage	Utility Scale	150	22,224.1	23,156.6	23,180.5
Other Energy Sources	Utility Scale	861	28,856.2	28,436.4	28,474.6
Total	Utility Scale	26,854	1,324,740.5	1,230,415.2	1,272,583.9
Small Scale Photovoltaic	Small Scale	--	--	53,228.1	--
Estimated Total Photovoltaic	Utility and Small Scale	--	--	175,289.9	--
Estimated Total Solar	Utility and Small Scale	--	--	176,681.9	--

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Fossil Gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Fossil Gas.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen. Prior to 2011, waste heat was included in Natural Gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.4. Existing Capacity by Producer Type, 2024 (Megawatts)

Producer Type	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector					
Electric Utilities	Utility Scale	9,814	678,231.8	624,143.3	647,698.3
Independent Power Producers, Non-Combined Heat and Power Plants	Utility Scale	13,224	581,128.7	548,713.3	563,474.0
Independent Power Producers, Combined Heat and Power Plants	Utility Scale	438	29,222.8	25,872.8	27,868.1
Total	Utility Scale	23,476	1,288,583.3	1,198,729.3	1,239,040.4
Commercial and Industrial Sectors					
Commercial Sector	Utility Scale	1,888	5,911.4	5,427.0	5,524.1
Industrial Sector	Utility Scale	1,490	30,245.8	26,258.9	28,019.3
Total	Utility Scale	3,378	36,157.2	31,685.9	33,543.4
All Sectors					
Total	Utility Scale	26,854	1,324,740.5	1,230,415.2	1,272,583.9
Small Scale					
Estimated Solar Photovoltaic	Small Scale	--	--	53,228.1	--

Notes:

See Glossary reference for definitions.

Totals may not equal sum of components because of independent rounding.

In the case of some wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count. Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.5. Planned Utility-Scale Generating Capacity Changes, by Energy Source, 2025-2029 (Page 1)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2025						
U.S. Total	953	64,330.8	107	8,745.8	846	55,585.0
Coal	--	--	15	6,163.1	-15	-6,163.1
Petroleum	9	29.1	37	763.2	-28	-734.1
Natural Gas	94	4,725.8	26	1,635.7	68	3,090.1
Other Fossil Gas	--	--	3	62.2	-3	-62.2
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	10	14.4	1	0.5	9	13.9
Wind	39	7,445.1	2	6.6	37	7,438.5
Solar Thermal and Photovoltaic	580	32,689.2	3	1.8	577	32,687.4
Wood and Wood-Derived Fuels	1	3.0	2	90.0	-1	-87.0
Geothermal	--	--	--	--	--	--
Other Biomass	7	10.4	15	14.7	-8	-4.3
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	213	19,413.8	3	8.0	210	19,405.8
Year 2026						
U.S. Total	623	72,360.7	81	7,884.4	542	64,476.4
Coal	--	--	8	3,449.9	-8	-3,449.9
Petroleum	3	22.8	3	19.7	--	3.1
Natural Gas	55	5,960.3	41	4,386.9	14	1,573.4
Other Fossil Gas	--	--	1	0.8	-1	-0.8
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	5	11.8	--	--	5	11.8
Wind	35	10,369.1	9	1.5	26	10,367.6
Solar Thermal and Photovoltaic	345	36,389.3	6	9.6	339	36,379.7
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	6	47.5	--	--	6	47.5
Other Biomass	7	59.2	12	11.0	-5	48.2
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	167	19,500.7	1	5.0	166	19,495.7
Year 2027						
U.S. Total	460	73,389.7	69	11,321.9	391	62,067.8
Coal	--	--	19	6,751.0	-19	-6,751.0
Petroleum	5	17.0	4	8.0	1	9.0
Natural Gas	45	5,676.6	20	4,418.8	25	1,257.8
Other Fossil Gas	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	21	63.2	11	18.6	10	44.6
Wind	25	7,552.5	1	80.0	24	7,472.5
Solar Thermal and Photovoltaic	240	40,110.7	4	3.8	236	40,106.9
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	3	56.7	--	--	3	56.7
Other Biomass	12	106.4	9	40.7	3	65.7
Hydroelectric Pumped Storage	3	600.0	--	--	3	600.0
Other Energy Sources	106	19,206.6	1	1.0	105	19,205.6

Notes: These data reflect plans as of December 31, 2024

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, synthetic gas, and propane.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In the case of wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.5. Planned Generating Capacity Changes, by Energy Source, 2025-2029 (Page 2)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2028						
U.S. Total	270	48,509.1	50	12,789.5	220	35,719.6
Coal	--	--	17	11,420.0	-17	-11,420.0
Petroleum	3	10.9	7	38.4	-4	-27.5
Natural Gas	66	12,259.2	15	1,232.9	51	11,026.3
Other Fossil Gas	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	33	134.8	2	3.4	31	131.4
Wind	8	2,380.1	2	87.0	6	2,293.1
Solar Thermal and Photovoltaic	92	18,958.6	7	7.8	85	18,950.8
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	1	1.8	--	--	1	1.8
Other Biomass	--	--	--	--	--	--
Hydroelectric Pumped Storage	8	2,000.0	--	--	8	2,000.0
Other Energy Sources	59	12,763.7	--	--	59	12,763.7
Year 2029						
U.S. Total	68	17,029.5	18	5,752.9	50	11,276.6
Coal	--	--	7	3,327.9	-7	-3,327.9
Petroleum	--	--	3	704.0	-3	-704.0
Natural Gas	17	5,590.8	7	1,682.0	10	3,908.8
Other Fossil Gas	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	7	6.3	--	--	7	6.3
Wind	10	3,170.2	--	--	10	3,170.2
Solar Thermal and Photovoltaic	22	5,514.2	--	--	22	5,514.2
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	--	--	--	--	--	--
Other Biomass	--	--	1	39.0	-1	-39.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	12	2,748.0	--	--	12	2,748.0
Years 2025-2029						
U.S. Total	2,374	275,619.8	325	46,494.5	2,049	229,125.3
Coal	--	--	66	31,111.9	-66	-31,111.9
Petroleum	20	79.8	54	1,533.3	-34	-1,453.5
Natural Gas	277	34,212.8	109	13,356.3	168	20,856.5
Other Fossil Gas	--	--	4	63.0	-4	-63.0
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	76	230.5	14	22.5	62	208.0
Wind	117	30,917.0	14	175.1	103	30,741.9
Solar Thermal and Photovoltaic	1,279	133,662.0	20	23.0	1,259	133,639.0
Wood and Wood-Derived Fuels	1	3.0	2	90.0	-1	-87.0
Geothermal	10	106.0	--	--	10	106.0

Other Biomass	26	176.0	37	105.4	-11	70.6
Hydroelectric Pumped Storage	11	2,600.0	--	--	11	2,600.0
Other Energy Sources	557	73,632.8	5	14.0	552	73,618.8

Notes: These data reflect plans as of December 31, 2024

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, synthetic gas, and propane.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In the case of wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.6. Utility-Scale Capacity Additions, Retirements and Changes by Energy Source, 2024 (Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements			
	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	--	--	--	--	12	4,460.0	3,958.6	4,021.7
Petroleum	22	33.1	32.3	32.3	64	299.6	233.8	264.5
Natural Gas	99	2,535.5	2,113.1	2,256.4	73	5,246.3	4,269.2	4,682.1
Other Fossil Gas	--	--	--	--	--	--	--	--
Nuclear	1	1,114.0	1,114.0	1,114.0	--	--	--	--
Hydroelectric Conventional	1	1.0	1.0	1.0	20	148.6	156.2	156.2
Wind	31	5,155.9	5,154.3	5,154.3	5	34.4	34.6	34.6
Solar Thermal and Photovoltaic	693	31,102.3	30,915.9	30,867.0	3	4.5	4.5	4.5
Wood and Wood-Derived Fuels	1	40.0	40.0	40.0	5	201.3	165.6	173.2
Geothermal	2	29.2	20.0	29.2	2	20.6	14.1	15.1
Other Biomass	5	8.0	7.9	7.9	97	180.0	117.6	115.6
Hydroelectric Pumped Storage	--	--	--	--	2	42.0	42.0	42.0
Other Energy Sources	188	11,157.3	11,055.4	11,055.2	8	39.5	31.2	32.7
Total	1,043	51,176.3	50,454.0	50,557.4	291	10,676.8	9,027.4	9,542.2

Energy Source	Other Changes to Existing Capacity			
		Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal		-512.7	-759.9	-722.8
Petroleum		-4,542.8	-4,431.6	-4,237.0
Natural Gas		59.7	-509.8	40.7
Other Fossil Gas		-160.2	-188.7	-179.1
Nuclear		1,792.6	1,565.0	1,597.2
Hydroelectric Conventional		63.9	-24.5	24.9
Wind		226.0	-542.7	-474.7
Solar Thermal and Photovoltaic		338.4	390.5	996.8
Wood and Wood-Derived Fuels		-146.8	-152.7	-148.6
Geothermal		-16.0	-6.2	-6.9
Other Biomass		19.0	-31.5	-30.9
Hydroelectric Pumped Storage		96.0	51.2	35.8
Other Energy Sources		-34.0	-71.2	-71.2
Total		-2,816.9	-4,712.1	-3,175.8

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, synthetic gas, and propane.

Other Fossil Gas includes gaseous propane, blast furnace gas, other manufactured and waste gases derived from fossil fuels other than hydrogen.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Other Energy Sources include hydrogen, non-biogenic municipal solid waste, batteries, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In the case of some wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count.

Other Changes to Existing Capacity reflect updates, derates, repowerings, and changes to previously reported generator capacity.

* = Value is less than half of the smallest unit of measure.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.7.A. Net Summer Capacity of Utility Scale Units by Technology and by State, 2024 and 2023 (Megawatts)

Census Division and State	Renewable Sources		Fossil Fuels		Hydroelectric Pumped Storage		Other Energy Storage		Nuclear		All Other Sources		All Sources	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	7,932.9	7,418.1	21,161.1	22,647.6	1,863.4	1,863.4	407.7	369.9	3,354.2	3,326.9	22.0	22.0	34,741.3	35,647.9
Connecticut	586.1	551.2	7,272.8	7,272.5	29.4	29.4	1.6	1.6	2,104.2	2,081.2	0.0	0.0	9,994.1	9,935.9
Maine	3,073.1	2,724.9	2,428.9	2,442.4	0.0	0.0	62.3	62.3	0.0	0.0	22.0	22.0	5,586.3	5,251.6
Massachusetts	2,072.6	1,981.2	7,292.9	8,766.2	1,834.0	1,834.0	305.9	268.1	0.0	0.0	0.0	0.0	11,505.4	12,849.5
New Hampshire	945.9	946.6	2,260.4	2,260.4	0.0	0.0	14.0	14.0	1,250.0	1,245.7	0.0	0.0	4,470.3	4,466.7
Rhode Island	538.6	505.4	1,780.1	1,780.1	0.0	0.0	3.0	3.0	0.0	0.0	0.0	0.0	2,321.7	2,288.5
Vermont	716.6	708.8	126.0	126.0	0.0	0.0	20.9	20.9	0.0	0.0	0.0	0.0	863.5	855.7
Middle Atlantic	15,678.1	14,452.9	70,655.0	71,613.0	3,317.4	3,312.0	402.4	350.5	16,683.1	15,854.5	11.2	11.2	106,747.2	105,594.1
New Jersey	1,388.3	1,376.1	11,223.8	11,509.1	416.1	415.4	109.7	69.7	3,456.7	3,456.7	11.2	11.2	16,605.8	16,838.2
New York	10,502.0	9,482.0	25,805.4	25,811.9	1,409.8	1,405.1	238.1	226.2	3,330.4	3,304.6	0.0	0.0	41,285.7	40,229.8
Pennsylvania	3,787.8	3,594.8	33,625.8	34,292.0	1,491.5	1,491.5	54.6	54.6	9,896.0	9,093.2	0.0	0.0	48,855.7	48,526.1
East North Central	30,970.7	25,670.1	101,639.1	103,395.4	2,179.8	2,185.6	223.1	173.9	18,997.4	18,206.2	166.0	169.8	154,176.1	149,801.0
Illinois	10,920.5	9,210.5	23,588.8	24,467.0	0.0	0.0	100.3	96.1	11,591.6	11,567.6	78.0	78.0	46,279.2	45,419.2
Indiana	6,249.3	4,849.3	21,418.3	21,605.0	0.0	0.0	81.0	36.0	0.0	0.0	88.0	88.0	27,836.6	26,578.3
Michigan	5,674.1	5,304.5	20,197.7	20,306.7	2,179.8	2,185.6	1.3	1.3	4,086.5	3,318.0	0.0	3.8	32,139.4	31,119.9
Ohio	4,504.5	3,089.8	23,817.4	23,845.1	0.0	0.0	34.8	34.8	2,134.0	2,134.0	0.0	0.0	30,490.7	29,103.7
Wisconsin	3,622.3	3,216.0	12,616.9	13,171.6	0.0	0.0	5.7	5.7	1,185.3	1,186.6	0.0	0.0	17,430.2	17,579.9
West North Central	47,635.7	45,724.5	55,856.5	56,682.2	657.0	657.0	38.0	31.6	4,792.2	4,792.2	12.2	12.2	108,991.6	107,899.7
Iowa	13,771.6	13,295.8	9,444.4	9,401.7	0.0	0.0	10.3	8.9	0.0	0.0	0.0	0.0	23,226.3	22,706.4
Kansas	9,124.5	9,098.8	9,053.9	8,921.1	0.0	0.0	0.0	0.0	1,176.7	1,176.7	0.8	0.8	19,355.9	19,197.4
Minnesota	7,071.7	6,748.7	9,456.8	9,413.8	0.0	0.0	21.0	16.0	1,657.0	1,657.0	6.1	6.1	18,212.6	17,841.6
Missouri	3,425.2	3,038.2	15,145.8	16,286.1	657.0	657.0	1.0	1.0	1,190.0	1,190.0	0.0	0.0	20,419.0	21,172.3
Nebraska	3,946.2	3,854.1	6,148.6	6,153.4	0.0	0.0	4.9	4.9	768.5	768.5	0.0	0.0	10,868.2	10,780.9
North Dakota	5,033.8	4,839.9	4,644.5	4,556.9	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	9,683.6	9,402.1
South Dakota	5,262.7	4,849.0	1,962.5	1,949.2	0.0	0.0	0.8	0.8	0.0	0.0	0.0	0.0	7,226.0	6,799.0
South Atlantic	42,310.5	36,635.5	153,112.6	153,342.1	8,272.5	8,192.5	1,077.1	847.9	27,018.1	25,904.1	366.9	366.9	232,157.7	225,289.0
Delaware	113.1	105.6	3,189.9	3,189.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,303.0	3,295.5
District of Columbia	41.2	31.6	20.6	20.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.8	52.2
Florida	11,986.3	8,847.4	55,471.0	55,335.9	0.0	0.0	575.7	560.7	3,666.0	3,666.0	312.9	312.9	72,011.9	68,722.9
Georgia	8,054.8	7,175.1	23,358.5	23,457.0	1,897.4	1,897.4	146.2	81.2	6,289.0	5,175.0	0.0	0.0	39,746.0	37,785.7
Maryland	1,514.9	1,429.2	8,448.4	8,742.0	0.0	0.0	9.4	7.7	1,745.2	1,745.2	0.0	0.0	11,717.9	11,924.1
North Carolina	9,603.0	9,197.4	21,304.2	21,318.2	86.0	86.0	139.8	58.3	5,149.6	5,149.6	54.0	54.0	36,336.6	35,863.5
South Carolina	3,403.2	3,317.2	11,578.1	11,526.3	3,036.0	2,956.0	88.0	22.0	6,600.3	6,600.3	0.0	0.0	24,705.6	24,421.8
Virginia	6,270.3	5,332.8	15,984.6	15,993.8	3,253.1	3,253.1	70.5	70.5	3,568.0	3,568.0	0.0	0.0	29,146.5	28,218.2
West Virginia	1,323.6	1,199.2	13,757.3	13,758.4	0.0	0.0	47.5	47.5	0.0	0.0	0.0	0.0	15,128.4	15,005.1
East South Central	11,207.0	9,893.9	61,699.5	62,317.4	1,616.3	1,616.3	52.5	2.5	11,365.7	11,358.4	1.4	1.4	85,942.4	85,189.9
Alabama	4,568.0	4,509.6	20,974.0	21,134.0	0.0	0.0	1.0	1.0	5,452.7	5,452.7	0.0	0.0	30,995.7	31,097.3
Kentucky	1,634.0	1,290.2	16,746.4	17,045.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18,380.4	18,335.7
Mississippi	1,706.6	728.0	12,811.3	12,719.1	0.0	0.0	51.5	1.5	1,390.3	1,383.0	1.4	1.4	15,961.1	14,833.0
Tennessee	3,298.4	3,366.1	11,167.8	11,418.8	1,616.3	1,616.3	0.0	0.0	4,522.7	4,522.7	0.0	0.0	20,605.2	20,923.9
West South Central	84,169.8	72,879.6	139,018.8	140,206.5	271.5	288.0	7,948.2	3,830.6	8,852.5	8,941.9	575.8	578.1	240,836.6	226,724.7
Arkansas	3,274.7	2,309.9	10,752.9	10,875.0	30.0	30.0	28.2	22.0	1,821.0	1,825.0	0.0	0.0	15,906.8	15,061.9
Louisiana	1,664.7	958.6	20,633.7	21,508.7	0.0	0.0	0.0	0.0	2,051.5	2,136.9	356.8	359.1	24,706.7	24,963.3
Oklahoma	13,830.3	13,209.5	17,824.8	18,212.3	241.5	258.0	10.0	10.0	0.0	0.0	0.0	0.0	31,906.6	31,689.8
Texas	65,400.1	56,401.6	89,807.4	89,610.5	0.0	0.0	7,910.0	3,798.6	4,980.0	4,980.0	219.0	219.0	168,316.5	155,009.7
Mountain	47,329.9	41,576.5	58,669.1	58,237.6	794.8	806.7	4,306.1	1,955.8	3,937.0	3,937.0	121.6	124.6	115,158.5	106,638.2
Arizona	9,033.8	7,251.8	17,568.4	17,548.5	216.3	216.3	2,121.0	931.0	3,937.0	3,937.0	0.0	0.0	32,876.5	29,884.6
Colorado	8,425.3	8,228.5	10,460.4	10,472.4	578.5	590.4	346.3	241.0	0.0	0.0	6.1	9.1	19,816.6	19,541.4
Idaho	4,381.3	4,095.5	1,111.5	1,242.3	0.0	0.0	40.0	0.0	0.0	0.0	14.8	14.8	5,547.6	5,352.6
Montana	4,908.9	4,589.9	2,233.6	2,068.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	7,182.5	6,697.9
Nevada	7,080.9	5,903.3	8,529.0	8,082.3	0.0	0.0	1,108.8	543.8	0.0	0.0	6.5	6.5	16,725.2	14,535.9
New Mexico	6,416.6	5,635.4	4,781.1	4,849.1	0.0	0.0	689.0	239.0	0.0	0.0	0.7	0.7	11,887.4	10,724.2
Utah	2,930.1	2,367.0	7,305.9	7,301.6	0.0	0.0	1.0	1.0	0.0	0.0	40.2	40.2	10,277.2	9,709.8
Wyoming	4,153.0	3,505.1	6,679.2	6,673.4	0.0	0.0	0.0	0.0	0.0	0.0	13.3	13.3	10,845.5	10,191.8
Pacific Contiguous	80,841.0	78,304.1	44,887.8	44,686.6	4,183.9	4,225.9	12,045.3	8,025.6	3,391.0	3,391.0	91.2	94.4	145,440.2	138,727.6
California	41,814.0	39,289.0	37,040.8	36,855.0	3,869.9	3,911.9	11,717.3	7,984.6	2,240.0	2,240.0	91.2	94.4	96,773.2	90,374.9
Oregon	13,600.7	13,664.8	3,769.0	3,769.0	0.0	0.0	322.0	35.0	0.0	0.0	0.0	0.0	17,691.7	17,468.8
Washington	25,426.3	25,350.3	4,078.0	4,062.6	314.0	314.0	6.0	6.0	1,151.0	1,151.0	0.0	0.0	30,975.3	30,883.9
Pacific Noncontiguous	1,478.0	1,404.6	4,177.0	4,156.4	0.0	0.0	566.6	453.6	0.0	0.0	1.1	28.4	6,222.7	6,043.0
Alaska	550.0	549.9	2,168.6	2,176.5	0.0	0.0	133.7	93.7	0.0	0.0	1.1	0.9	2,853.4	2,821.0
Hawaii	928.0	854.7	2,008.4	1,979.9	0.0	0.0	432.9	359.9	0.0	0.0	0.0	27.5	3,369.3	3,222.0
U.S. Total	369,553.6	333,959.8	710,876.5	717,284.8	23,156.6	23,147.4	27,067.0	16,041.9	98,391.2	95,712.2	1,369.4	1,409.0	1,230,414.3	1,187,555.1

NM = Not meaningful due to large relative standard error.

Values are final.

NOTES:

Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of capacity for some technologies such as solar photovoltaic generation. Concentrated Solar Power Energy Storage is included in 'Renewable sources'; it is not included in 'Other Energy Storage'

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.7.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, 2024 and 2023 (Megawatts)

Census Division and State	Summer Capacity at Utility Scale Facilities														Small Scale Capacity				Capacity From Utility and Small Scale Facilities			
	Wind		Solar Photovoltaic		Solar Thermal		Conventional Hydroelectric		Biomass Sources		Geothermal		Total Renewable Sources		Estimated Solar Photovoltaic		Estimated Total Solar Photovoltaic		Estimated Total Solar		Estimated Total Solar	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	1,575.7	1,575.7	3,158.1	2,641.4	0.0	0.0	1,951.7	1,953.6	1,247.4	1,247.4	0.0	0.0	7,932.9	7,418.1	5,628.8	5,033.3	8,786.9	7,674.7	8,786.9	7,674.7	8,786.9	7,674.7
Connecticut	5.0	5.0	322.3	287.4	0.0	0.0	119.2	119.2	139.6	139.6	0.0	0.0	586.1	551.2	1,132.3	978.6	1,454.6	1,266.0	1,454.6	1,266.0	1,454.6	1,266.0
Maine	1,029.5	1,029.5	829.2	481.0	0.0	0.0	725.8	725.8	488.6	488.6	0.0	0.0	3,073.1	2,724.9	849.4	532.9	1,678.6	1,013.9	1,678.6	1,013.9	1,678.6	1,013.9
Massachusetts	101.8	101.8	1,430.5	1,339.1	0.0	0.0	267.2	267.2	273.1	273.1	0.0	0.0	2,072.6	1,981.2	2,966.5	2,661.3	4,397.0	4,000.4	4,397.0	4,000.4	4,397.0	4,000.4
New Hampshire	211.9	211.9	2.4	2.4	0.0	0.0	505.8	506.5	225.8	225.8	0.0	0.0	945.9	946.6	270.4	232.8	272.8	235.2	272.8	235.2	272.8	235.2
Rhode Island	77.3	77.3	418.5	385.3	0.0	0.0	2.7	2.7	40.1	40.1	0.0	0.0	538.6	505.4	224.4	453.2	642.9	838.5	642.9	838.5	642.9	838.5
Vermont	150.2	150.2	155.2	146.2	0.0	0.0	331.0	332.2	80.2	80.2	0.0	0.0	716.6	708.8	185.7	174.4	340.9	320.6	340.9	320.6	340.9	320.6
Middle Atlantic	4,429.9	4,306.5	4,722.2	3,576.6	0.0	0.0	5,505.2	5,502.6	1,020.8	1,067.2	0.0	0.0	15,678.1	14,452.9	6,867.6	6,104.4	11,589.8	9,681.0	11,589.8	9,681.0	11,589.8	9,681.0
New Jersey	7.6	7.6	1,179.7	1,167.5	0.0	0.0	12.3	12.3	188.7	188.7	0.0	0.0	1,388.3	1,376.1	2,489.6	2,297.4	3,669.3	3,464.9	3,669.3	3,464.9	3,669.3	3,464.9
New York	2,869.7	2,746.3	2,688.6	1,719.6	0.0	0.0	4,563.4	4,560.8	400.3	455.3	0.0	0.0	10,502.0	9,482.0	3,394.0	2,995.2	6,062.6	4,714.8	6,062.6	4,714.8	6,062.6	4,714.8
Pennsylvania	1,552.6	1,552.6	873.9	689.5	0.0	0.0	929.5	929.5	431.8	423.2	0.0	0.0	3,767.8	3,594.8	984.0	811.8	1,857.9	1,501.3	1,857.9	1,501.3	1,857.9	1,501.3
East North Central	17,215.1	16,816.1	11,949.2	6,969.1	0.0	0.0	880.5	880.2	925.9	1,004.7	0.0	0.0	30,970.7	25,670.1	2,596.2	2,185.1	14,545.4	9,154.2	14,545.4	9,154.2	14,545.4	9,154.2
Illinois	7,873.7	7,873.7	2,958.7	1,248.7	0.0	0.0	32.9	32.9	55.2	55.2	0.0	0.0	10,920.5	9,210.5	1,372.4	1,164.1	4,331.1	2,412.8	4,331.1	2,412.8	4,331.1	2,412.8
Indiana	3,639.1	3,439.1	2,490.0	1,288.9	0.0	0.0	71.6	71.6	48.6	49.7	0.0	0.0	6,249.3	4,849.3	270.3	238.1	2,760.3	1,527.0	2,760.3	1,527.0	2,760.3	1,527.0
Michigan	3,774.3	3,575.3	1,158.0	975.0	0.0	0.0	263.5	263.8	478.3	490.4	0.0	0.0	5,674.1	5,304.5	270.0	226.4	1,428.0	1,201.4	1,428.0	1,201.4	1,428.0	1,201.4
Ohio	1,101.8	1,101.8	3,236.5	1,808.3	0.0	0.0	101.9	101.9	64.3	77.8	0.0	0.0	4,504.5	3,089.8	411.9	341.2	3,648.4	2,149.5	3,648.4	2,149.5	3,648.4	2,149.5
Wisconsin	826.2	826.2	2,106.0	1,648.2	0.0	0.0	410.6	410.0	279.5	331.6	0.0	0.0	3,622.3	3,216.0	271.7	215.2	2,377.7	1,863.4	2,377.7	1,863.4	2,377.7	1,863.4
West North Central	40,683.7	40,153.1	3,198.9	1,815.9	0.0	0.0	3,363.7	3,364.6	389.4	390.9	0.0	0.0	47,635.7	45,724.5	1,220.9	1,059.7	4,419.8	2,875.6	4,419.8	2,875.6	4,419.8	2,875.6
Iowa	12,865.5	12,803.8	678.1	262.0	0.0	0.0	209.4	209.4	20.6	20.6	0.0	0.0	13,771.6	13,295.8	332.8	286.4	1,008.9	548.4	1,008.9	548.4	1,008.9	548.4
Kansas	9,042.7	9,042.7	65.8	40.1	0.0	0.0	7.0	7.0	9.0	9.0	0.0	0.0	9,124.5	9,098.8	108.6	87.8	174.4	127.9	174.4	127.9	174.4	127.9
Minnesota	4,901.4	4,928.7	1,641.7	1,291.4	0.0	0.0	212.0	212.0	316.6	316.6	0.0	0.0	7,071.7	6,748.7	296.1	243.2	1,937.8	1,534.6	1,937.8	1,534.6	1,937.8	1,534.6
Missouri	2,392.9	2,374.9	469.8	100.8	0.0	0.0	548.5	548.5	14.0	14.0	0.0	0.0	3,425.2	3,038.2	439.8	403.2	909.6	504.0	909.6	504.0	909.6	504.0
Nebraska	3,516.9	3,518.3	136.5	40.6	0.0	0.0	278.8	279.7	14.0	15.5	0.0	0.0	3,946.2	3,854.1	36.0	33.0	172.5	73.6	172.5	73.6	172.5	73.6
North Dakota	4,514.0	4,320.1	0.0	0.0	0.0	0.0	510.0	510.0	9.8	9.8	0.0	0.0	5,033.8	4,839.9	2.2	2.2	8.9	2.2	8.9	2.2	8.9	2.2
South Dakota	3,450.3	3,164.6	209.0	81.0	0.0	0.0	1,598.0	1,598.0	5.4	5.4	0.0	0.0	5,262.7	4,849.0	5.4	3.8	214.4	84.8	214.4	84.8	214.4	84.8
South Atlantic	1,456.2	1,267.2	29,987.3	24,432.6	0.0	0.0	7,054.2	7,055.3	3,812.8	3,880.4	0.0	0.0	42,310.5	36,635.5	6,328.6	5,717.6	36,315.9	30,150.2	36,315.9	30,150.2	36,315.9	30,150.2
Delaware	2.0	2.0	96.9	89.4	0.0	0.0	0.0	0.0	14.2	14.2	0.0	0.0	113.1	105.6	143.5	130.1	240.4	219.5	240.4	219.5	240.4	219.5
District of Columbia	0.0	0.0	29.2	19.6	0.0	0.0	0.0	0.0	12.0	12.0	0.0	0.0	41.2	31.6	176.1	142.2	205.3	161.8	205.3	161.8	205.3	161.8
Florida	0.0	0.0	10,950.8	7,802.3	0.0	0.0	43.5	43.5	992.0	1,001.6	0.0	0.0	11,986.3	8,847.4	2,819.9	2,582.3	13,770.7	10,384.6	13,770.7	10,384.6	13,770.7	10,384.6
Georgia	0.0	0.0	5,002.8	4,123.0	0.0	0.0	1,985.0	1,985.0	1,067.1	1,067.1	0.0	0.0	8,054.9	7,175.1	342.4	320.2	5,345.2	4,443.2	5,345.2	4,443.2	5,345.2	4,443.2
Maryland	190.0	190.0	671.4	584.4	0.0	0.0	514.9	514.9	138.6	139.9	0.0	0.0	1,514.9	1,429.2	1,132.4	1,038.0	1,803.8	1,622.4	1,803.8	1,622.4	1,803.8	1,622.4
North Carolina	397.0	208.0	6,786.7	6,597.8	0.0	0.0	2,009.4	2,010.5	409.9	381.1	0.0	0.0	9,603.0	9,197.4	579.2	498.1	7,365.9	7,095.9	7,365.9	7,095.9	7,365.9	7,095.9
South Carolina	0.0	0.0	1,646.7	1,557.5	0.0	0.0	1,294.0	1,294.0	462.5	465.7	0.0	0.0	3,403.2	3,317.2	400.2	378.1	2,046.9	1,935.6	2,046.9	1,935.6	2,046.9	1,935.6
Virginia	12.0	12.0	4,678.4	3,658.6	0.0	0.0	866.6	866.6	713.3	795.6	0.0	0.0	6,270.3	5,332.8	690.1	592.8	5,368.5	4,251.4	5,368.5	4,251.4	5,368.5	4,251.4
West Virginia	855.2	855.2	124.4	0.0	0.0	0.0	340.8	340.8	3.2	3.2	0.0	0.0	1,323.6	1,199.2	44.8	35.7	169.2	35.7	169.2	35.7	169.2	35.7
East South Central	186.6	29.1	2,910.3	1,692.3	0.0	0.0	7,036.6	7,037.8	1,073.5	1,134.5	0.0	0.0	11,207.0	9,893.9	204.4	177.2	3,114.7	1,889.7	3,114.7	1,889.7	3,114.7	1,889.7
Alabama	0.0	0.0	663.5	601.1	0.0	0.0	3,290.6	3,291.8	613.9	616.7	0.0	0.0	4,568.0	4,509.6	17.0	15.8	680.5	618.9	680.5	618.9	680.5	618.9
Kentucky	0.0	0.0	426.1	82.3	0.0	0.0	1,137.4	1,137.4	70.5	70.5	0.0	0.0	1,634.0	1,290.2	110.4	93.5	536.5	175.8	536.5	175.8	536.5	175.8
Mississippi	184.5	0.0	1,219.7	425.6	0.0	0.0	0.0	0.0	302.4	302.4	0.0	0.0	1,706.6	728.0	18.4	14.4	1,238.1	440.0	1,238.1	440.0	1,238.1	440.0
Tennessee	2.1	29.1	601.0	583.5	0.0	0.0	2,608.6	2,608.6	86.7	144.9	0.0	0.0	3,298.4	3,366.1	58.6	53.5	659.6	637.0	659.6	637.0	659.6	637.0
West South Central	54,726.1	52,572.3	25,383.8	16,219.1	0.0	0.0	3,002.3	3,013.0	1,057.6	1,075.2	0.0	0.0	84,169.8	72,879.6	3,753.6	3,349.5	29,137.4	19,568.6	29,137.4	19,568.6	29,137.4	19,568.6
Arkansas	0.0	0.0	1,784.5	820.9	0.0	0.0	1,264.5	1,265.2	225.7	223.8	0.0	0.0	3,274.7	2,309.9	333.9	250.5	2,118.4	1,071.4	2,118.4	1,071.4	2,118.4	1,071.4
Louisiana	0.0	0.0	1,052.6	344.5	0.0	0.0	192.0	192.0	420.1	422.1	0.0	0.0	1,664.7	958.6	202.6	185.1	1,255.2	529.6	1,255.2	529.6	1,255.2	529.6
Oklahoma	12,748.2	12,245.2	173.5	47.5	0.0	0.0	832.4	840.6	76.2	76.2	0.0	0.0	13,830.3	13,209.5	145.1	110.9	318.6	158.4	318.6	158.4	318.6	158.4
Texas	41,977.9	40,327.1	22,373.2	15,006.2	0.0	0.0	713.4	715.2	335.6	353.1	0.0	0.0	65,400.1	56,401.6	3,072.0	2,803.0	25,445.2	17,809.2	25,445.2	17,809.2	25,445.2	17,809.2
Mountain	17,729.7	16,796.9	17,591.9	12,812.3	474.2	474.2	10,602.9	10,568.6	179.4	176.2	751.8	748.3	47,329.9	41,576.5	6,500.9	5,850.9	24,092.8	18,663.2	24,092.8	18,663.2	24,092.8	18,663.2
Arizona	1,234.5	855.5	4,755.2	3,350.9	295.6	295.6	2,720.6	2,721.9	27.9	27.9	0.0	0.0	9,033.8	7,251.8	2,896.3	2,679.6	7,651.5	6,030.5	7,651.5	6,030.5	7,651.5	6

Table 4.7.C. Net Summer Capacity of Utility Scale Units Using Primarily Fossil Fuels and by State, 2024 and 2023 (Megawatts)

Census Division and State	Natural Gas Fired Combined Cycle		Natural Gas Fired Combustion Turbine		Other Natural Gas		Coal		Petroleum Coke		Petroleum Liquids		Other Fossil Gas		Total Fossil Fuels	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	12,524.2	14,115.3	1,456.3	1,368.4	1,089.5	672.5	533.9	533.9	0.0	0.0	5,557.2	5,957.5	0.0	0.0	21,161.1	22,647.6
Connecticut	3,901.0	3,923.0	591.8	584.0	570.5	556.8	0.0	0.0	0.0	0.0	2,209.5	2,208.7	0.0	0.0	7,272.8	7,272.5
Maine	1,272.2	1,285.7	312.0	312.0	0.0	0.0	0.0	0.0	0.0	0.0	844.7	844.7	0.0	0.0	2,428.9	2,442.4
Massachusetts	4,387.3	5,942.9	536.3	456.2	93.4	90.3	0.0	0.0	0.0	0.0	2,275.9	2,276.8	0.0	0.0	7,292.9	8,766.2
New Hampshire	1,228.5	1,228.5	3.8	3.8	400.2	0.0	533.9	533.9	0.0	0.0	94.0	494.2	0.0	0.0	2,260.4	2,260.4
Rhode Island	1,735.2	1,735.2	12.4	12.4	25.4	25.4	0.0	0.0	0.0	0.0	7.1	7.1	0.0	0.0	1,780.1	1,780.1
Vermont	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.0	126.0	0.0	0.0	126.0	126.0
Middle Atlantic	37,150.1	37,337.0	6,914.8	7,092.0	15,931.5	15,936.8	5,362.6	6,008.7	11.6	11.6	5,149.5	5,112.0	114.9	114.9	70,655.0	71,613.0
New Jersey	8,222.0	8,374.0	2,604.2	2,734.5	66.9	69.9	0.0	0.0	11.6	11.6	290.1	290.1	29.0	29.0	11,222.8	11,509.1
New York	9,927.1	9,908.2	2,989.1	2,459.2	9,954.9	9,962.7	0.0	0.0	0.0	0.0	3,525.3	3,481.8	0.0	0.0	25,805.4	25,911.9
Pennsylvania	19,001.0	19,054.8	1,912.5	1,898.3	5,909.7	5,904.2	5,382.6	6,008.7	0.0	0.0	1,334.1	1,340.1	85.9	85.9	33,625.8	34,292.0
East North Central	31,065.4	31,442.5	26,165.6	26,550.4	4,643.6	4,503.0	36,512.1	37,336.3	25.1	25.1	2,147.3	2,269.1	854.0	1,043.0	101,639.1	103,395.4
Illinois	5,452.9	5,823.1	10,367.0	10,721.0	373.0	373.0	6,694.5	6,853.5	0.0	0.0	664.9	659.9	36.5	36.5	23,588.8	24,467.0
Indiana	3,892.3	3,899.6	3,343.0	3,365.9	992.2	851.4	12,721.4	12,847.2	0.0	0.0	85.3	95.8	384.1	545.1	21,418.3	21,605.0
Michigan	7,688.9	7,691.6	3,555.0	3,570.0	2,536.5	2,513.5	5,732.3	5,801.9	47.2	47.2	387.8	432.5	250.0	250.0	20,197.7	20,306.7
Ohio	10,552.6	10,554.2	5,721.0	5,721.3	91.4	102.2	6,620.5	6,607.5	145.5	145.5	503.0	503.0	183.4	211.4	23,817.4	23,845.1
Wisconsin	3,478.7	3,474.0	3,179.6	3,172.2	650.5	662.9	4,743.4	5,226.2	58.4	58.4	506.3	577.9	0.0	0.0	12,616.9	13,171.6
West North Central	7,051.7	7,047.3	11,873.7	11,620.1	3,729.5	3,755.9	29,329.7	30,374.7	32.0	32.0	3,831.5	3,843.8	8.4	8.4	55,856.5	56,682.2
Iowa	1,748.7	1,741.9	1,248.9	1,210.6	781.7	751.2	4,832.9	4,860.8	32.0	32.0	800.2	805.2	0.0	0.0	9,444.4	9,401.7
Kansas	247.0	247.0	2,173.6	2,208.4	1,398.2	1,396.3	4,695.0	4,524.7	0.0	0.0	540.1	544.7	0.0	0.0	9,053.9	8,921.1
Minnesota	2,532.9	2,532.9	2,570.4	2,545.0	428.1	421.9	3,135.5	3,141.7	0.0	0.0	789.9	772.3	0.0	0.0	9,456.8	9,413.8
Missouri	1,869.2	1,892.5	3,323.9	3,200.0	333.1	362.8	8,539.2	9,714.2	0.0	0.0	1,060.4	1,085.8	0.0	0.0	15,145.8	16,286.1
Nebraska	338.9	338.0	1,104.8	1,107.6	513.3	518.4	3,817.9	3,825.8	0.0	0.0	373.7	383.6	0.0	0.0	6,148.6	6,153.4
North Dakota	0.0	0.0	542.4	454.0	203.7	203.9	3,831.9	3,832.5	0.0	0.0	58.1	58.1	8.4	8.4	4,644.5	4,556.9
South Dakota	295.0	295.0	909.7	893.7	71.4	71.4	477.3	475.0	0.0	0.0	209.1	214.1	0.0	0.0	1,962.5	1,949.2
South Atlantic	65,888.7	65,781.6	32,491.9	32,264.9	13,248.8	14,129.5	35,415.3	35,006.2	83.8	83.8	5,849.1	5,941.1	135.0	135.0	153,112.6	153,342.1
Delaware	1,496.0	1,496.0	314.0	314.0	723.8	723.8	41.0	41.0	0.0	0.0	111.1	111.1	135.0	135.0	3,189.9	3,189.9
District of Columbia	0.0	0.0	20.6	20.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6	20.6
Florida	35,819.7	35,743.0	8,791.4	8,791.0	5,698.3	5,201.3	3,564.7	3,989.7	0.0	0.0	1,596.9	1,610.9	0.0	0.0	55,471.0	55,335.9
Georgia	8,090.8	8,067.0	7,446.1	7,569.1	850.1	850.1	5,780.0	5,780.0	83.8	83.8	1,107.7	1,107.0	0.0	0.0	23,358.5	23,457.0
Maryland	2,741.1	2,745.8	1,675.4	1,675.6	1,212.6	1,211.3	1,273.0	1,453.0	0.0	0.0	1,546.3	1,656.3	0.0	0.0	8,448.4	8,742.0
North Carolina	5,579.0	5,579.0	6,395.5	6,030.5	3,277.7	4,665.7	5,561.0	4,552.0	0.0	0.0	491.0	491.0	0.0	0.0	21,304.2	21,318.2
South Carolina	3,252.0	3,252.0	2,548.6	2,528.7	780.0	780.0	4,754.0	4,749.0	0.0	0.0	243.5	216.6	0.0	0.0	11,578.1	11,526.3
Virginia	8,910.1	8,988.8	4,212.0	4,245.9	590.9	581.8	1,530.1	1,530.1	0.0	0.0	741.8	737.2	0.0	0.0	15,984.6	15,993.8
West Virginia	0.0	0.0	1,088.2	1,089.5	115.5	115.5	12,542.5	12,542.4	0.0	0.0	11.0	11.0	0.0	0.0	13,757.3	13,758.4
East South Central	23,835.1	23,800.8	13,685.0	13,682.0	4,136.3	4,012.2	19,506.5	20,288.5	0.0	0.0	532.8	533.9	3.8	0.0	61,699.5	62,317.4
Alabama	11,138.3	11,172.2	3,284.8	3,307.8	1,776.5	1,883.4	4,728.0	4,728.0	0.0	0.0	42.6	42.6	3.8	0.0	20,974.0	21,134.0
Kentucky	1,791.0	1,789.0	5,599.6	5,599.6	714.0	483.0	8,631.0	9,162.0	0.0	0.0	10.8	11.9	0.0	0.0	16,746.4	17,045.5
Mississippi	8,450.7	8,384.5	1,395.3	1,369.3	1,512.3	1,512.3	1,444.0	1,444.0	0.0	0.0	9.0	9.0	0.0	0.0	12,811.3	12,719.1
Tennessee	2,455.1	2,455.1	3,405.3	3,405.3	133.5	133.5	4,703.5	4,954.5	0.0	0.0	470.4	470.4	0.0	0.0	11,167.8	11,418.8
West South Central	64,443.9	64,856.8	17,447.4	16,899.8	28,788.3	29,761.0	26,393.7	26,698.6	856.7	891.4	744.1	754.2	344.7	344.7	139,018.8	140,206.5
Arkansas	4,608.2	4,605.2	702.8	703.3	824.0	703.4	4,734.0	4,734.0	0.0	0.0	9.0	9.0	0.0	0.0	10,752.9	10,875.0
Louisiana	9,404.2	9,688.0	2,845.0	2,834.2	5,252.7	5,872.1	2,121.6	2,069.5	792.9	827.6	49.7	49.7	167.6	167.6	20,633.7	21,508.7
Oklahoma	7,299.7	7,327.6	1,653.2	1,649.2	5,567.8	5,909.1	3,258.9	3,272.5	0.0	0.0	45.2	53.9	0.0	0.0	17,824.8	18,212.3
Texas	43,131.8	43,236.0	12,246.4	11,713.6	17,264.5	17,155.8	16,283.6	16,622.6	63.8	63.8	640.2	641.6	177.1	177.1	89,807.4	89,610.5
Mountain	23,015.7	23,087.2	10,014.1	9,570.6	5,045.7	3,683.1	20,208.9	21,299.9	52.0	52.0	327.9	537.0	4.8	7.8	58,669.1	58,237.6
Arizona	10,138.6	10,181.6	3,129.0	3,061.8	1,278.6	1,097.6	2,936.0	2,939.0	0.0	0.0	86.2	268.5	0.0	0.0	17,568.4	17,548.5
Colorado	3,250.5	3,193.5	2,637.2	2,661.0	636.2	633.4	3,786.0	3,804.0	0.0	0.0	150.5	177.5	0.0	3.0	10,460.4	10,472.4
Idaho	515.5	601.0	573.7	619.2	16.7	16.7	0.0	0.0	0.0	0.0	5.6	5.4	0.0	0.0	1,111.5	1,242.3
Montana	0.0	0.0	315.8	315.8	237.8	72.2	1,626.5	1,626.5	52.0	52.0	0.0	0.0	1.5	1.5	2,233.6	2,068.0
Nevada	5,703.0	5,703.0	1,629.6	1,185.6	450.0	447.3	740.4	740.4	0.0	0.0	6.0	6.0	0.0	0.0	8,529.0	8,082.3
New Mexico	1,484.1	1,484.1	943.3	945.3	767.7	833.7	1,540.0	1,540.0	0.0	0.0	46.0	46.0	0.0	0.0	4,781.1	4,849.1
Utah	1,830.0	1,830.0	534.6	534.6	332.5	328.2	4,581.0	4,581.0	0.0	0.0	27.8	27.8	0.0	0.0	7,305.9	7,301.6
Wyoming	94.0	94.0	250.9	247.3	1,326.2	254.0	4,999.0	6,069.0	0.0	0.0	5.8	5.8	3.3	3.3	6,670.2	6,673.4
Pacific Contiguous	26,458.4	26,426.9	12,349.5	12,312.6	4,669.0	4,568.1	727.0	727.0	0.0	0.0	471.4	439.0	212.5	213.0	44,887.8	44,686.6
California	20,412.6	20,391.1	11,506.3	11,469.4	4,410.2	4,309.3	57.0	57.0	0.0	0.0	442.2	415.2	212.5	213.0	37,040.8	36,855.0
Oregon	3,409.2	3,409.2	124.0	124.0	229.2	229.2	0.0	0.0	0.0	0.0	6.6	6.6	0.0	0.0	3,769.0	3,769.0
Washington	2,636.6	2,626.6	719.2	719.2	29.6	29.6	670.0	670.0	0.0	0.0	22.6	17.2	0.0	0.0	4,076.0	4,062.6
Pacific Noncontiguous	374.6	374.6	708.5	708.5	174.4	174.4	167.9	167.9	0.0	0.0	2,751.8	2,731.0	0.0	0.0	4,177.0	4,156.4
Alaska	374.6	374.6	708.5	708.5	174.4	174.4	167.9	167.9	0.0	0.0	743.2	751.1	0.0	0.0	2,168.6	2,176.5
Hawaii	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,008.4	1,979.9	0.0	0.0	2,008.4	1,979.9
U.S. Total	291,807.8	294,270.0	133,106.8	132,069.3	81,456.6	81,196.5	174,177.6	178,441.7	1,287.2	1,321.9	27,362.4	28,118.6	1,678.1	1,866.8	710,876.5	717,284.8

NM = Not meaningful due to large relative standard error.
Values are final.

NOTES:
Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of existing or planned capacity for some technologies such as solar photovoltaic generation.

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels

Year/Month	Coal		Natural Gas								Petroleum					
	Combined Cycle		Gas Turbine		Steam Turbine		Internal Combustion		Steam Turbine		Gas Turbine		Internal Combustion			
	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor
Annual Data																
2014	299,064.7	60.5%	224,183.2	48.6%	124,736.9	8.3%	75,049.1	10.3%	3,026.7	10.8%	18,057.0	13.0%	16,791.5	1.2%	5,011.3	2.1%
2015	286,082.7	54.3%	231,467.5	55.8%	123,444.3	9.8%	80,348.0	11.3%	3,507.8	11.9%	14,965.4	14.0%	16,122.8	1.3%	5,075.2	2.1%
2016	269,477.1	52.8%	236,442.8	55.4%	125,148.4	11.0%	81,225.1	12.3%	3,684.3	11.5%	13,993.7	12.2%	15,114.0	1.3%	5,082.8	2.3%
2017	259,930.2	53.1%	242,839.1	51.2%	125,806.6	9.6%	79,149.4	10.7%	4,225.5	11.6%	13,290.9	13.7%	14,275.3	1.0%	5,153.3	2.1%
2018	246,866.8	53.6%	254,403.3	55.1%	126,763.4	11.9%	76,177.8	12.6%	4,446.6	13.0%	13,300.1	14.2%	14,234.9	1.3%	5,289.7	1.9%
2019	235,089.3	47.5%	266,846.5	57.4%	128,832.5	11.4%	72,797.3	14.1%	4,848.3	15.3%	11,214.7	12.8%	14,009.7	1.0%	5,287.8	2.0%
2020	220,623.2	40.5%	274,300.4	57.1%	129,085.6	11.6%	75,462.3	14.2%	5,123.0	15.1%	8,443.3	13.9%	13,875.8	1.2%	5,300.7	1.8%
2021	212,587.0	49.1%	277,618.5	55.0%	130,103.4	11.7%	74,003.4	12.5%	5,171.8	18.2%	8,385.5	14.2%	13,729.8	1.6%	5,522.7	1.8%
2022	196,396.3	48.4%	286,467.1	56.6%	130,170.6	12.9%	77,518.8	15.6%	5,526.9	18.1%	9,839.0	13.2%	15,005.7	1.6%	5,407.0	1.8%
2023	182,767.5	42.4%	291,134.7	59.7%	130,736.5	12.9%	76,908.1	17.4%	5,802.9	20.1%	8,743.2	10.1%	14,386.8	1.3%	5,418.9	1.8%
2024	176,028.6	42.6%	292,189.2	60.5%	132,099.1	13.9%	75,196.7	19.9%	6,044.6	18.0%	8,122.7	8.9%	14,167.2	1.9%	5,461.8	1.8%
Year 2022																
January	202,043.3	57.4%	284,236.2	55.6%	129,881.8	11.3%	78,088.0	14.8%	5,454.3	16.0%	9,839.0	19.6%	15,279.8	1.4%	5,401.4	2.2%
February	202,013.8	52.2%	284,236.2	52.4%	129,967.8	9.6%	78,088.0	11.7%	5,454.3	14.8%	9,839.0	15.3%	15,279.8	0.9%	5,402.0	1.8%
March	200,821.8	41.0%	284,247.2	46.6%	130,009.3	8.2%	77,514.0	8.5%	5,484.9	13.6%	9,839.0	9.8%	15,245.8	1.0%	5,392.6	1.7%
April	200,376.8	38.5%	284,450.3	44.2%	130,070.8	9.6%	77,514.0	9.6%	5,486.4	13.5%	9,839.0	10.1%	15,119.1	0.9%	5,395.3	1.7%
May	198,851.8	42.1%	283,899.1	49.6%	130,070.8	12.5%	77,514.0	14.6%	5,544.4	14.7%	9,839.0	12.0%	15,119.1	1.4%	5,399.7	1.8%
June	195,863.8	52.5%	286,389.0	61.2%	130,127.6	16.9%	77,510.0	20.2%	5,546.0	18.8%	9,839.0	12.2%	14,947.1	1.8%	5,407.0	1.9%
July	195,881.8	59.6%	287,485.0	70.5%	130,274.1	20.1%	77,510.0	28.1%	5,549.7	23.0%	9,839.0	10.3%	14,947.1	2.5%	5,410.4	1.7%
August	194,856.8	59.2%	288,566.5	72.4%	130,035.1	18.5%	77,379.0	22.4%	5,563.9	25.1%	9,839.0	11.8%	14,947.1	2.2%	5,410.7	1.7%
September	192,425.8	47.3%	288,493.5	63.9%	130,259.8	13.8%	77,374.0	16.3%	5,559.0	21.7%	9,839.0	13.1%	14,858.1	1.7%	5,409.2	1.8%
October	192,425.8	38.7%	288,458.5	53.0%	130,348.7	10.2%	77,374.0	13.3%	5,558.0	17.9%	9,839.0	12.3%	14,817.2	1.4%	5,413.1	1.8%
November	192,271.3	40.9%	288,485.6	52.0%	130,380.6	11.2%	77,379.8	13.7%	5,555.9	17.9%	9,839.0	13.6%	14,789.6	1.0%	5,420.9	1.6%
December	189,316.3	51.4%	288,504.6	56.8%	130,606.5	12.5%	77,026.8	14.1%	5,560.7	19.3%	9,839.0	18.2%	14,735.6	2.8%	5,421.2	2.2%
Year 2023																
January	186,822.6	44.6%	287,456.6	57.4%	130,416.1	9.3%	78,868.8	9.6%	5,738.6	18.7%	8,743.2	9.1%	14,494.8	1.0%	5,428.8	1.9%
February	186,812.0	37.3%	287,688.6	57.1%	130,416.1	9.2%	78,868.8	10.3%	5,742.7	18.0%	8,743.2	11.7%	14,494.8	1.4%	5,426.8	1.8%
March	186,007.1	36.2%	288,941.6	53.6%	130,356.1	10.5%	78,303.3	11.5%	5,744.2	19.5%	8,743.2	8.9%	14,494.8	1.1%	5,422.2	1.8%
April	186,007.1	30.6%	289,463.1	47.9%	130,356.1	11.2%	77,868.3	13.4%	5,746.9	16.2%	8,743.2	8.4%	14,494.8	1.2%	5,422.2	2.0%
May	184,515.1	32.6%	291,190.1	53.0%	130,248.2	12.4%	77,038.3	15.4%	5,745.0	16.0%	8,743.2	7.9%	14,463.5	1.2%	5,413.4	1.8%
June	182,361.9	44.5%	291,270.1	63.7%	130,403.5	15.0%	76,724.3	22.1%	5,752.6	21.4%	8,743.2	10.2%	14,315.1	1.3%	5,399.1	1.8%
July	181,713.0	58.3%	292,441.8	74.0%	130,558.5	19.4%	76,724.3	31.7%	5,752.6	26.0%	8,743.2	14.3%	14,315.1	1.6%	5,414.9	1.6%
August	181,099.7	58.0%	292,441.8	74.1%	131,221.5	19.0%	76,724.3	31.0%	5,884.2	26.7%	8,743.2	13.3%	14,315.1	1.9%	5,416.6	1.6%
September	180,234.7	46.4%	292,441.8	66.2%	131,221.5	13.6%	75,688.3	22.4%	5,878.3	22.0%	8,743.2	14.5%	14,315.1	1.3%	5,425.7	1.5%
October	179,749.7	38.6%	293,100.7	53.8%	131,221.5	12.6%	75,687.9	16.3%	5,879.5	18.9%	8,743.2	8.7%	14,315.1	1.3%	5,429.6	1.7%
November	179,749.7	39.7%	293,100.7	54.8%	131,217.5	11.5%	75,681.6	14.1%	5,880.7	18.8%	8,743.2	6.8%	14,315.1	1.0%	5,414.6	2.1%
December	178,441.7	42.3%	293,802.5	60.0%	131,178.5	10.1%	74,854.6	10.8%	5,885.5	18.6%	8,743.2	7.7%	14,315.1	1.2%	5,413.5	1.8%
Year 2024																
January	177,497.2	56.8%	293,471.8	64.1%	131,958.7	12.9%	75,752.5	15.9%	5,899.4	18.5%	8,122.7	10.8%	14,230.3	2.0%	5,471.1	1.8%
February	177,497.2	36.2%	293,471.8	56.6%	131,611.5	10.0%	75,745.5	10.4%	5,901.6	16.4%	8,122.7	8.2%	14,230.3	1.3%	5,471.3	1.6%
March	177,323.7	29.8%	293,471.8	51.1%	131,662.7	10.6%	75,334.8	13.0%	5,898.6	16.1%	8,122.7	8.0%	14,230.3	1.3%	5,472.2	1.8%
April	176,697.6	29.9%	292,884.3	46.9%	131,662.7	13.1%	75,334.8	15.9%	5,901.7	14.8%	8,122.7	8.0%	14,230.3	1.6%	5,474.9	2.2%
May	176,201.6	35.6%	292,984.3	53.9%	131,655.7	13.4%	75,334.8	20.4%	5,951.9	16.0%	8,122.7	8.5%	14,230.3	1.8%	5,466.3	1.7%
June	176,021.6	49.0%	291,603.0	65.7%	131,565.2	15.1%	75,084.8	26.3%	6,000.8	19.5%	8,122.7	8.6%	14,122.3	2.0%	5,457.1	1.9%
July	176,021.6	55.0%	291,603.0	75.8%	131,960.2	20.9%	75,084.8	32.0%	6,007.2	22.5%	8,122.7	10.2%	14,122.3	3.3%	5,470.8	1.7%
August	176,021.6	53.2%	291,064.9	75.3%	132,555.6	19.2%	75,084.8	32.4%	6,181.5	22.3%	8,122.7	9.5%	14,122.3	2.7%	5,465.5	1.9%
September	175,762.6	43.7%	291,601.2	67.6%	132,555.6	14.7%	75,084.8	21.6%	6,182.0	19.0%	8,122.7	7.8%	14,122.3	1.7%	5,454.9	1.6%
October	174,584.6	37.0%	291,454.9	55.6%	132,524.6	13.1%	74,879.0	19.5%	6,183.8	16.3%	8,122.7	8.2%	14,122.3	1.8%	5,455.3	1.8%
November	174,597.6	35.9%	291,464.9	54.9%	132,706.8	12.3%	74,875.6	16.4%	6,183.8	18.0%	8,122.7	8.3%	14,122.3	1.7%	5,448.1	1.7%
December	174,177.6	48.7%	291,238.9	58.5%	132,741.8	11.0%	74,786.7	14.2%	6,236.6	16.7%	8,122.7	10.5%	14,122.3	1.5%	5,434.3	1.9%

Values are final.
Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.
Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.
Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels

Year/Month	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Fossil Gas		Solar				Wind		Wood	
	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor	Time Adjusted Capacity (MW)	Capacity Factor
Annual Data																		
2014	2,513.3	72.0%	79,582.8	37.2%	98,569.3	91.7%	5,114.6	62.7%	1,994.0	54.0%	6,555.6	25.6%	1,445.3	18.3%	60,587.8	34.0%	8,319.7	60.0%
2015	2,523.0	71.9%	79,650.8	35.7%	98,614.6	92.3%	5,104.5	62.6%	2,527.7	60.8%	9,521.6	25.5%	1,697.3	21.7%	67,106.2	32.2%	9,024.5	59.3%
2016	2,516.6	71.6%	79,806.0	38.2%	99,364.8	92.3%	5,099.5	62.7%	2,458.8	64.8%	14,161.4	25.0%	1,757.9	22.1%	74,162.7	34.5%	8,979.8	58.3%
2017	2,460.4	73.2%	79,696.8	43.0%	99,619.5	92.3%	5,125.6	61.8%	2,375.8	62.8%	21,940.9	25.6%	1,757.9	21.8%	83,355.6	34.6%	8,807.5	60.2%
2018	2,391.5	76.0%	79,771.9	41.9%	99,605.2	92.5%	5,059.0	61.8%	2,543.9	65.4%	27,143.3	25.1%	1,757.9	23.6%	89,228.5	34.6%	8,760.2	60.6%
2019	2,535.2	69.6%	79,838.0	41.2%	98,836.7	93.4%	4,786.5	62.5%	2,504.1	67.4%	31,840.8	24.3%	1,758.1	21.2%	97,564.8	34.4%	8,485.0	59.0%
2020	2,561.5	69.1%	79,810.4	40.7%	97,238.3	92.4%	4,653.8	62.5%	2,275.2	64.6%	39,458.1	24.2%	1,747.9	20.6%	107,387.7	35.3%	8,327.2	57.8%
2021	2,588.5	69.8%	79,878.4	36.0%	95,802.7	92.8%	4,490.4	63.2%	1,902.5	60.9%	51,219.7	24.4%	1,629.0	20.5%	123,757.1	34.4%	7,959.0	59.9%
2022	2,616.0	69.0%	80,054.5	36.3%	94,969.9	92.7%	4,402.5	60.2%	1,716.0	61.6%	64,501.0	24.4%	1,480.0	23.1%	136,669.4	35.9%	7,817.6	57.9%
2023	2,670.6	69.4%	79,982.5	35.0%	95,065.2	93.0%	4,162.6	60.4%	1,871.6	53.8%	77,130.8	23.2%	1,480.0	22.1%	143,443.5	33.2%	7,830.2	53.5%
2024	2,690.2	64.6%	79,883.9	34.6%	98,022.9	90.8%	4,054.5	59.5%	1,685.1	49.0%	102,319.5	23.2%	1,392.0	25.0%	149,299.0	34.3%	7,476.0	55.8%
Year 2022																		
January	2,592.8	75.1%	80,036.5	40.6%	95,406.4	99.4%	4,460.5	60.7%	1,664.2	64.2%	60,335.2	16.8%	1,480.0	11.3%	132,415.6	37.5%	7,829.0	60.8%
February	2,592.8	70.3%	80,040.6	39.6%	95,406.4	96.5%	4,459.1	60.6%	1,664.2	62.8%	61,350.2	21.2%	1,480.0	15.9%	133,711.4	41.6%	7,829.0	62.6%
March	2,592.8	65.7%	80,050.6	41.0%	95,406.4	89.0%	4,444.5	59.8%	1,664.2	63.4%	61,673.4	24.4%	1,480.0	23.1%	133,969.5	42.7%	7,829.0	57.4%
April	2,592.8	67.1%	80,054.7	34.8%	95,406.4	80.5%	4,437.0	60.0%	1,733.5	56.2%	62,666.8	28.5%	1,480.0	30.1%	135,080.4	46.6%	7,829.0	54.9%
May	2,609.8	67.4%	80,054.7	39.2%	95,427.4	89.3%	4,434.2	59.2%	1,733.5	59.9%	63,122.2	30.9%	1,480.0	33.5%	137,384.2	41.1%	7,811.3	55.4%
June	2,609.8	67.0%	80,057.2	45.1%	94,658.9	96.4%	4,434.2	61.7%	1,733.5	63.6%	63,890.6	33.2%	1,480.0	34.9%	137,594.2	33.9%	7,805.5	59.5%
July	2,609.8	67.1%	80,057.2	41.2%	94,658.9	97.8%	4,374.4	61.7%	1,733.5	63.7%	65,118.6	31.2%	1,480.0	26.2%	137,993.8	28.6%	7,805.5	61.5%
August	2,639.4	67.9%	80,057.2	35.5%	94,658.9	97.8%	4,378.3	60.7%	1,733.5	59.5%	65,707.2	28.4%	1,480.0	25.3%	137,999.4	24.0%	7,817.5	60.3%
September	2,661.3	68.6%	80,058.7	29.5%	94,658.9	93.5%	4,369.7	59.5%	1,733.5	61.6%	66,419.3	26.5%	1,480.0	26.7%	138,005.0	27.3%	7,817.5	56.4%
October	2,620.5	65.3%	80,059.2	24.1%	94,658.9	83.7%	4,366.5	59.2%	1,733.5	59.5%	67,201.8	22.9%	1,480.0	26.4%	138,005.0	31.6%	7,817.5	50.9%
November	2,620.5	72.6%	80,059.2	31.0%	94,658.9	91.0%	4,354.3	59.6%	1,733.5	63.2%	67,739.4	16.5%	1,480.0	14.1%	138,025.0	40.8%	7,817.5	56.7%
December	2,648.6	74.1%	80,067.7	34.3%	94,658.9	98.1%	4,322.3	60.1%	1,728.2	62.3%	68,569.5	12.5%	1,480.0	9.0%	139,628.0	36.8%	7,804.5	58.8%
Year 2023																		
January	2,657.6	71.2%	79,971.6	38.2%	94,598.2	100.7%	4,259.7	60.6%	1,896.8	48.4%	71,639.2	14.2%	1,480.0	7.7%	140,883.2	36.3%	7,933.1	57.5%
February	2,657.6	72.4%	79,989.6	37.1%	94,598.2	95.7%	4,158.1	59.7%	1,896.8	54.3%	72,849.9	18.6%	1,480.0	10.9%	141,532.3	43.1%	7,933.1	56.2%
March	2,623.3	73.2%	79,989.6	35.9%	94,598.2	89.3%	4,158.1	58.3%	1,866.8	54.7%	73,402.2	21.5%	1,480.0	14.0%	142,245.7	40.6%	7,933.1	53.5%
April	2,623.3	70.6%	80,007.4	34.4%	94,598.2	83.2%	4,158.1	55.6%	1,866.8	54.7%	73,948.2	26.8%	1,480.0	27.8%	142,659.5	41.2%	7,933.1	48.6%
May	2,684.3	66.9%	79,978.4	46.5%	94,598.2	86.9%	4,158.1	61.1%	1,866.8	51.1%	74,880.6	29.5%	1,480.0	27.4%	142,976.1	30.0%	7,888.1	51.9%
June	2,684.3	66.5%	79,979.8	37.5%	94,598.2	95.2%	4,158.1	62.4%	1,866.8	54.1%	75,981.9	30.9%	1,480.0	34.6%	143,730.8	26.4%	7,873.5	52.2%
July	2,684.3	64.6%	79,979.8	36.9%	94,598.2	99.1%	4,159.4	61.9%	1,866.8	57.0%	77,601.9	30.9%	1,480.0	35.0%	143,730.8	25.9%	7,788.5	54.0%
August	2,671.8	63.1%	79,979.8	35.8%	95,712.2	97.9%	4,155.4	61.4%	1,866.8	56.4%	78,928.8	28.7%	1,480.0	28.3%	144,230.3	26.2%	7,788.5	56.3%
September	2,671.8	67.4%	79,977.0	29.4%	95,712.2	95.1%	4,155.4	58.1%	1,866.8	52.9%	79,648.0	25.6%	1,480.0	27.7%	144,334.3	27.1%	7,756.3	52.6%
October	2,695.8	70.4%	79,974.9	26.3%	95,712.2	86.3%	4,147.2	59.4%	1,866.8	51.2%	80,606.0	22.0%	1,480.0	26.1%	144,417.5	33.1%	7,756.3	47.4%
November	2,695.8	73.7%	79,979.5	29.6%	95,712.2	90.3%	4,148.8	61.8%	1,866.8	54.0%	82,386.8	16.7%	1,480.0	15.7%	145,235.0	34.6%	7,693.1	54.5%
December	2,695.8	72.9%	79,983.6	32.1%	95,712.2	96.7%	4,133.2	63.8%	1,866.8	56.4%	83,392.8	13.5%	1,480.0	9.9%	145,232.0	34.6%	7,693.1	56.7%
Year 2024																		
January	2,689.6	69.3%	79,886.6	36.3%	97,277.2	95.6%	4,097.7	60.8%	1,706.1	53.7%	91,150.6	13.4%	1,392.0	7.5%	146,957.0	31.6%	7,540.4	60.2%
February	2,689.6	69.0%	79,886.6	37.4%	97,277.2	95.4%	4,099.2	59.2%	1,706.1	50.2%	93,683.5	18.6%	1,392.0	12.4%	147,815.2	39.6%	7,540.4	58.3%
March	2,689.6	67.4%	79,887.1	39.3%	97,277.2	87.5%	4,098.2	56.5%	1,706.1	46.7%	94,296.2	21.8%	1,392.0	21.0%	148,016.7	40.7%	7,540.4	55.6%
April	2,689.6	65.5%	79,887.1	36.4%	97,277.2	81.8%	4,073.4	55.8%	1,678.1	48.2%	97,257.0	26.3%	1,392.0	32.2%	148,176.7	43.7%	7,493.4	52.5%
May	2,675.5	61.9%	79,887.1	41.2%	98,391.2	88.8%	4,056.4	60.8%	1,678.1	49.3%	98,677.7	29.0%	1,392.0	38.8%	149,305.6	35.2%	7,493.4	53.6%
June	2,675.5	61.5%	79,878.6	38.9%	98,391.2	96.3%	4,052.8	59.6%	1,678.1	48.1%	101,220.5	31.6%	1,392.0	40.1%	149,391.1	35.7%	7,493.4	56.4%
July	2,695.5	60.4%	79,878.6	36.0%	98,391.2	95.4%	4,034.3	60.9%	1,678.1	48.5%	103,886.6	30.3%	1,392.0	33.7%	149,419.7	25.2%	7,481.9	57.4%
August	2,695.5	60.8%	79,884.2	34.5%	98,391.2	95.3%	4,034.3	62.1%	1,678.1	49.9%	104,868.2	29.7%	1,392.0	33.1%	150,120.2	26.1%	7,481.9	58.2%
September	2,695.5	61.5%	79,884.2	27.7%	98,391.2	88.5%	4,037.5	59.9%	1,678.1	49.4%	106,071.6	25.4%	1,392.0	32.7%	150,470.4	26.9%	7,481.9	54.5%
October	2,695.5	62.4%	79,874.9	25.8%	98,391.2	80.3%	4,037.5	58.7%	1,678.1	45.7%	108,568.7	23.1%	1,392.0	22.8%	150,623.5	35.3%	7,417.2	47.8%
November	2,695.5	67.3%	79,874.9	29.1%	98,391.2	87.4%	4,037.5	60.4%	1,678.1	48.7%	111,404.8	16.2%	1,392.0	13.8%	150,623.5	36.9%	7,374.8	55.9%
December	2,695.5	68.8%	79,897.0	32.9%	98,391.2	97.3%	3,997.0	60.0%	1,678.1	49.6%	116,407.3	13.8%	1,392.0	11.7%	150,620.0	35.0%	7,374.8	58.7%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.C. Usage Factors for Utility Scale Storage Generators

Year/Month	Battery		Pumped Storage	
	Time Adjusted Capacity (MW)	Usage Factor	Time Adjusted Capacity (MW)	Usage Factor
Annual Data				
2014	155.1	1.7%	22,477.9	10.2%
2015	206.8	3.6%	22,568.9	10.2%
2016	423.0	3.8%	22,752.7	11.2%
2017	632.8	6.8%	22,791.7	11.4%
2018	713.6	5.2%	22,815.4	10.8%
2019	949.8	5.4%	22,754.7	10.4%
2020	1,210.3	5.2%	22,938.6	10.5%
2021	2,627.6	6.1%	23,007.7	10.2%
2022	6,566.1	6.4%	23,033.9	11.1%
2023	11,225.7	6.6%	23,132.1	10.9%
2024	19,945.1	8.3%	23,178.5	11.4%
Year 2022				
January	4,926.4	5.5%	23,013.4	9.5%
February	4,996.7	6.6%	23,013.4	8.9%
March	5,069.2	5.7%	23,013.4	9.1%
April	5,316.2	6.0%	23,013.4	7.3%
May	6,055.5	6.4%	23,043.9	10.9%
June	6,064.5	7.1%	23,043.9	14.8%
July	6,555.2	6.9%	23,043.9	15.9%
August	6,941.6	6.6%	23,043.9	16.4%
September	7,489.9	6.1%	23,043.9	13.2%
October	7,958.4	6.7%	23,043.9	8.4%
November	8,630.7	6.7%	23,043.9	9.2%
December	8,696.4	6.5%	23,043.9	9.6%
Year 2023				
January	9,168.7	6.9%	23,057.8	9.2%
February	9,236.4	6.5%	23,057.8	9.6%
March	9,318.4	7.0%	23,137.8	9.2%
April	9,621.5	7.2%	23,147.4	8.8%
May	9,791.5	6.5%	23,147.4	10.9%
June	9,943.1	6.4%	23,147.4	13.8%
July	10,846.6	6.5%	23,147.4	15.7%
August	12,332.2	6.4%	23,147.4	15.5%
September	12,815.4	6.3%	23,147.4	13.3%
October	13,515.9	7.0%	23,147.4	8.7%
November	13,768.3	6.7%	23,147.4	8.3%
December	14,197.5	6.3%	23,147.4	8.0%
Year 2024				
January	15,989.6	6.2%	23,118.6	9.5%
February	16,276.4	7.3%	23,118.6	9.7%
March	16,312.3	7.9%	23,198.6	7.4%
April	17,352.7	8.4%	23,198.6	9.1%
May	18,040.6	8.0%	23,198.6	12.5%
June	19,187.2	8.1%	23,198.6	15.6%
July	20,434.9	8.8%	23,198.6	16.8%
August	21,174.1	9.0%	23,198.6	16.3%
September	22,411.1	8.3%	23,198.6	13.0%
October	23,219.6	9.0%	23,198.6	8.3%
November	23,961.5	8.8%	23,156.6	8.7%
December	24,826.7	8.6%	23,156.6	9.4%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Usage factors are a comparison of gross generation with available capacity. See the technical note for an explanation of how usage factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.9 Total Capacity of Non Net Metered Distributed Generators by Technology Type and Sector, 2014 through 2024

Generators by Technology and Sector						
Year	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
Photovoltaic						
2014	-	-	-	-	-	692,034
2015	-	-	-	-	-	825,354
2016	80,577	988,811	132,970	-	112,927	715,385
2017	189,910	513,251	177,192	-	120,946	998,299
2018	289,151	584,977	189,874	-	124,793	1,198,895
2019	437,911	688,050	202,992	-	151,393	1,480,353
2020	656,125	872,946	211,173	-	139,251	1,877,495
2021	891,399	1,205,598	254,733	-	144,532	2,292,262
2022	1,534,849	1,506,717	185,959	-	150,015	2,758,533
2023	1,613,746	1,114,113	221,723	-	156,700	3,106,283
2024	2,032,152	1,664,858	233,024	-	157,285	3,478,259
Battery						
2014	-	-	-	-	-	7,227
2015	-	-	-	-	-	34,443
2016	0,070	32,678	8,714	-	1,240	42,702
2017	3,918	42,884	12,271	-	1,444	60,515
2018	4,926	79,643	10,874	-	2,275	101,551
2019	14,308	113,708	15,519	-	15,929	159,544
2020	26,048	136,448	16,876	-	17,243	196,617
2021	109,876	166,043	16,733	-	20,719	313,371
2022	171,343	221,150	16,084	-	20,535	429,622
2023	229,419	242,722	16,999	-	3,110	501,990
2024	343,046	287,214	16,780	-	3,535	630,575
Battery Energy (MWh)						
2014	-	-	-	-	-	-
2015	-	-	-	-	-	-
2016	-	-	-	-	-	-
2017	-	-	-	-	-	-
2018	-	-	-	-	-	-
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	607,049	561,387	0,086	-	22,134	1,189,636
2024	423,115	629,892	2,398	-	4,035	1,057,512
Wind						
2014	-	-	-	-	-	33,727
2015	-	-	-	-	-	26,686
2016	2,616	15,742	1,366	-	8,628	28,552
2017	2,632	18,452	1,044	-	8,988	29,117
2018	2,579	13,527	1,441	-	9,977	28,525
2019	2,437	15,797	1,452	-	9,918	29,514
2020	3,184	13,547	1,549	-	9,523	28,803
2021	2,091	15,338	1,433	-	9,971	27,832
2022	1,884	13,393	1,171	-	9,572	25,920
2023	1,961	15,547	0,771	-	9,573	27,753
2024	2,451	15,339	1,909	-	10,452	29,851
Hydroelectric						
2014	-	-	-	-	-	108,793
2015	-	-	-	-	-	113,234
2016	6,140	39,330	8,933	-	101,146	155,749
2017	9,315	30,243	8,933	-	103,057	149,334
2018	5,452	35,648	5,901	-	113,193	160,194
2019	7,482	37,818	5,901	-	113,912	164,713
2020	2,827	39,339	2,730	-	124,253	169,449
2021	2,529	43,226	6,083	-	102,913	154,751
2022	2,529	45,880	4,893	-	99,542	152,854
2023	2,529	44,698	4,493	-	109,544	160,094
2024	2,524	44,234	2,430	-	87,973	147,159
Fuel Cell						
2014	-	-	-	-	-	-
2015	-	-	-	-	-	-
2016	0,161	6,229	3,700	-	0,225	10,315
2017	0,167	7,953	6,136	-	0,620	14,883
2018	0,150	12,730	3,969	-	0,620	17,527
2019	0,150	19,943	3,901	-	0,620	24,319
2020	1,123	18,699	4,499	-	0,620	24,941
2021	0,133	20,609	5,164	-	0,620	26,526
2022	0,134	23,207	5,310	-	0,620	29,271
2023	0,144	23,393	5,310	-	0,620	29,467
2024	0,117	26,600	3,285	-	0,640	30,647
Internal Combustion						
2014	-	-	-	-	-	813,841
2015	-	-	-	-	-	797,594
2016	46,974	679,238	223,937	-	69,217	1,019,467
2017	86,784	651,943	386,355	-	1,527,614	1,562,696
2018	69,428	609,278	336,970	-	81,159	1,496,835
2019	76,934	955,455	263,507	0,275	111,993	1,408,152
2020	66,475	662,210	299,856	-	61,832	1,390,751
2021	70,081	606,179	345,146	-	78,941	1,400,347
2022	85,208	644,505	295,954	-	77,522	1,443,244
2023	78,988	1,040,711	321,368	-	74,499	1,525,566
2024	78,772	1,095,684	300,771	-	69,395	1,534,108
Gas Turbine						
2014	-	-	-	-	-	81,321
2015	-	-	-	-	-	49,338
2016	0,230	62,127	24,415	-	2,728	89,503
2017	11,792	56,187	29,999	-	3,893	101,869
2018	0,070	75,151	24,568	-	3,488	103,277
2019	0,077	76,096	22,128	-	4,488	102,389
2020	0,077	84,936	21,658	-	4,488	110,209
2021	0,197	102,084	22,383	-	1,253	125,867
2022	0,213	109,087	21,598	-	1,253	132,151
2023	0,213	96,421	37,178	-	1,253	135,071
2024	0,588	95,359	49,287	-	1,013	141,197
Steam Turbine						
2014	-	-	-	-	-	12,921
2015	-	-	-	-	-	10,521
2016	-	2,995	0,524	-	0,431	3,950
2017	1,250	1,900	1,264	-	0,431	4,845
2018	4,626	0,039	0,039	-	2,581	7,740
2019	-	8,499	0,039	-	2,581	11,059
2020	-	7,444	0,039	-	1,981	10,504
2021	-	7,589	0,039	-	2,581	10,700
2022	-	9,259	0,019	-	2,581	11,869
2023	-	7,779	0,019	-	2,581	10,379
2024	-	7,779	0,074	-	2,581	11,034
Geothermal						
2014	-	-	-	-	-	100,991
2015	-	-	-	-	-	88,423
2016	0,750	24,080	20,389	-	0,290	45,249
2017	1,139	33,090	15,729	-	4,950	51,911
2018	0,629	36,452	16,309	-	3,310	56,600
2019	0,644	37,238	14,864	-	1,571	56,305
2020	0,117	38,842	16,349	-	2,979	58,187
2021	0,841	48,090	15,964	-	2,018	64,474
2022	0,951	48,094	15,984	-	2,018	68,046
2023	1,233	47,136	7,134	-	1,101	56,732
2024	1,582	37,898	9,789	-	1,115	50,384
Total						
2014	-	-	-	-	-	1,859,451
2015	-	-	-	-	-	1,994,564
2016	137,524	1,261,861	413,648	-	302,793	2,115,826
2017	306,445	1,553,887	560,243	-	305,064	2,725,639
2018	374,968	1,763,292	588,737	-	367,895	3,094,792
2019	529,763	1,852,751	530,102	0,275	384,482	3,418,292
2020	744,304	2,064,924	575,111	-	360,820	3,765,154
2021	1,165,938	2,341,954	627,616	-	366,751	4,502,257
2022	1,507,061	2,551,175	580,578	-	363,662	5,002,473
2023	1,636,103	2,632,812	614,666	-	362,662	5,246,274
2024	2,451,708	2,892,217	589,949	-	333,779	6,026,650
Total Number of Generators						
2014	-	-	-	-	-	203,090
2015	-	-	-	-	-	215,525
2016	-	-	-	-	-	176,751
2017	-	-	-	-	-	215,889
2018	-	-	-	-	-	231,220
2019	-	-	-	-	-	251,867
2020	-	-	-	-	-	279,730
2021	-	-	-	-	-	322,085
2022	-	-	-	-	-	389,187
2023	-	-	-	-	-	433,096
2024	-	-	-	-	-	461,159

Starting in 2023, capacity and energy capacity is now collected for batteries. Prior to 2023, the battery historical data was listed as storage.

Starting in 2019, PV Capacities have been converted to AC.

Starting in 2016, Capacity is now collected by technology and sector.

Starting in 2013, the residential sector is now included and at net metering units are excluded.

Distributed generators are generation which are connected to the grid. They may be installed at or near a customer's site or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-881, "Annual Electric Power Industry Report."

Table 4.10. Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2014 through 2024

Year	Capacity (MW)					Customers				
	Residential	Commercial	Industrial	Transportation	Total	Residential	Commercial	Industrial	Transportation	Total
Photovoltaic										
2014	3,452.987	2,933.122	710.719	--	7,096.828	642,276	43,335	3,131	--	688,742
2015	5,357.358	3,455.124	884.664	--	9,697.146	958,850	51,501	3,624	--	1,013,975
2016	7,487.643	3,975.813	1,078.607	--	12,542.064	1,321,277	60,456	4,391	--	1,386,124
2017	9,486.987	5,119.870	1,197.785	--	15,804.641	1,626,283	69,538	5,267	--	1,701,088
2018	11,356.711	6,173.324	1,378.863	--	18,908.896	1,911,892	78,912	5,844	--	1,996,648
2019	13,863.288	7,181.594	1,613.248	--	22,658.129	2,283,702	86,552	6,499	--	2,376,753
2020	16,432.611	8,223.285	1,853.604	--	26,509.501	2,661,029	95,037	7,330	--	2,763,396
2021	19,929.222	9,462.694	2,036.963	--	31,428.877	3,157,429	104,645	8,108	--	3,270,182
2022	24,668.240	11,091.920	2,194.394	--	37,954.553	3,788,427	112,054	8,670	--	3,909,151
2023	30,490.572	12,303.454	2,409.643	--	45,203.667	4,549,601	123,679	9,977	--	4,683,257
2024	34,226.260	13,801.814	2,566.347	--	50,594.412	5,077,543	138,495	10,586	--	5,226,624
Battery										
2016	4.489	7.575	11.698	--	23.762	793	79	31	--	903
2017	13.276	15.356	12.328	--	40.960	2,316	137	34	--	2,487
2018	65.199	40.141	24.526	--	129.866	10,633	303	61	--	10,997
2019	153.282	48.397	40.441	--	242.120	24,007	427	93	--	24,527
2020	309.866	67.428	56.081	--	433.375	45,042	552	126	--	45,720
2021	631.087	88.178	61.909	--	781.174	86,124	807	150	--	87,081
2022	922.394	129.782	65.323	--	1,117.499	128,360	1,011	168	--	129,539
2023	1,346.459	370.969	88.261	--	1,805.686	191,493	1,580	205	--	193,278
2024	2,271.932	456.687	93.705	--	2,822.320	299,998	2,012	213	--	302,223
Virtual PV										
2016	42.653	267.434	3.168	--	313.255	13,898	1,828	11	--	15,737
2017	53.120	416.987	7.136	--	477.244	14,948	2,907	19	--	17,874
2018	68.951	523.977	8.069	--	600.997	19,116	4,996	33	--	24,145
2019	77.492	624.588	10.684	--	712.763	20,753	5,908	40	--	26,701
2020	108.466	818.499	11.845	--	938.810	23,411	6,517	46	--	29,974
2021	156.792	1,081.457	12.242	--	1,250.492	28,880	11,215	49	--	40,144
2022	160.309	1,493.413	15.880	--	1,669.604	29,401	24,761	54	--	54,216
2023	286.277	2,346.135	19.165	--	2,651.579	59,901	55,194	63	--	115,158
2024	327.357	3,850.457	27.579	--	4,205.396	91,705	90,628	65	--	182,398
Wind										
2014	37.918	101.622	25.426	--	164.966	5,379	1,351	94	--	6,824
2015	34.893	103.086	29.137	--	167.116	5,387	1,434	109	--	6,930
2016	37.030	108.726	41.454	--	187.210	5,759	1,470	113	--	7,342
2017	35.005	119.651	49.507	--	204.163	5,258	1,429	111	--	6,798
2018	33.625	133.856	52.386	--	219.867	5,368	1,452	110	--	6,930
2019	33.668	148.594	52.580	--	234.842	5,218	1,438	107	--	6,763
2020	29.858	151.950	76.209	--	258.017	4,825	1,378	105	--	6,308
2021	28.103	152.021	76.253	--	256.377	4,711	1,350	106	--	6,167
2022	27.616	146.647	82.158	--	256.421	4,648	1,303	97	--	6,048
2023	27.566	146.114	72.127	--	245.807	4,696	1,296	102	--	6,094
2024	26.593	164.626	72.222	--	263.441	4,476	1,298	98	--	5,872
Other										
2014	7.633	102.797	98.277	--	208.707	857	397	201	--	1,455
2015	7.873	116.382	116.780	--	241.035	821	445	249	--	1,515
2016	7.952	155.889	149.608	--	313.449	862	592	325	--	1,779
2017	9.064	208.639	199.398	--	417.101	915	693	330	--	1,938
2018	6.351	258.601	241.416	--	506.368	692	826	347	--	1,865
2019	23.364	254.281	263.966	--	541.611	2,226	842	381	--	3,449
2020	12.983	281.848	282.195	--	577.026	850	814	385	--	2,049
2021	9.338	337.186	298.198	--	644.722	962	937	403	--	2,302
2022	12.129	364.602	317.492	--	694.223	1,256	972	402	--	2,630
2023	22.263	418.597	383.953	--	824.813	2,961	969	610	--	4,540
2024	22.610	426.952	295.952	--	745.514	2,301	955	403	--	3,659
All Technologies										
2014	3,498.538	3,137.541	834.422	--	7,470.501	648,512	45,083	3,426	--	697,021
2015	5,400.124	3,674.592	1,030.581	--	10,105.297	965,058	53,380	3,982	--	1,022,420
2016	7,715.715	4,576.384	1,289.946	--	13,582.045	1,341,796	64,346	4,840	--	1,410,982
2017	9,584.177	5,865.147	1,453.826	--	16,903.148	1,647,404	74,567	5,727	--	1,727,698
2018	11,465.638	7,089.758	1,680.734	--	20,236.128	1,937,068	86,186	6,334	--	2,029,588
2019	13,997.811	8,209.056	1,940.478	--	24,147.345	2,311,899	94,740	7,027	--	2,413,666
2020	16,583.921	9,475.582	2,223.853	--	28,283.355	2,690,115	103,746	7,866	--	2,801,727
2021	20,123.453	11,033.357	2,423.656	--	33,580.468	3,191,982	118,147	8,666	--	3,318,795
2022	24,868.296	13,096.584	2,609.924	--	40,574.800	3,823,732	139,090	9,223	--	3,972,045
2023	30,826.677	15,214.297	2,884.888	--	48,925.862	4,617,159	181,138	10,752	--	4,809,049
2024	34,602.819	18,243.845	2,962.100	--	55,808.760	5,176,025	231,376	11,152	--	5,418,553

Starting in 2023, capacity and customers are now collected for batteries. Prior to 2023, the battery historical data was listed as storage.

N/A = Not Available.

Total customer count for the years 2007, 2009, and 2010 were revised based on requests from respondents.

Capacity and customer count was not collected by technology type before 2010.

Starting in 2013, there is no maximum capacity on installed units.

Starting in 2016, utilities have the option to report photovoltaic in DC or AC. Values have been converted to AC.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 4.11. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2024
(Megawatts, Percent)

Producer Type	Fuel-Switchable Part of Total				
	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Electric Utilities	273,739.3	82,320.4	30.1%	77,918.4	19,091.0
Independent Power Producers, Non-Combined Heat and Power Plants	190,783.5	42,820.7	22.4%	39,475.6	7,386.8
Independent Power Producers, Combined Heat and Power Plants	23,371.7	3,543.3	15.2%	3,521.4	298.1
Electric Power Sector Subtotal	487,894.4	128,684.4	26.4%	120,915.5	26,775.9
Commercial Sector	2,408.3	965.9	40.1%	924.1	148.1
Industrial Sector	16,068.4	903.9	5.6%	880.9	66.8
All Sectors	506,371.0	130,554.2	25.8%	122,720.4	26,990.7

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

**Table 4.12. Fuel-Switching Capacity of Operable Generators Reporting Petroleum Liquids as the Primary Fuel,
by Producer Type, 2024 (Megawatts, Percent)**

Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum Liquids as the Primary Fuel	Fuel-Switchable Part of Total		
		Net Summer Capacity of Petroleum Liquids-Fired Generators Reporting the Ability to Switch to Natural Gas	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Natural Gas
Electric Utilities	14,080.1	1,345.3	9.6%	1,330.6
Independent Power Producers, Non-Combined Heat and Power Plants	11,795.8	3,530.0	29.9%	2,406.8
Independent Power Producers, Combined Heat and Power Plants	259.6	--	0.0%	--
Electric Power Sector Subtotal	26,135.5	4,875.3	18.7%	3,737.4
Commercial Sector	985.8	--	0.0%	--
Industrial Sector	241.2	29.0	12.0%	25.0
All Sectors	27,362.5	4,904.3	17.9%	3,762.4

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.13. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Type of Prime Mover, 2024 (Megawatts, Percent)

Prime Mover Type	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Steam Generator	158	23,611.9	9,356.6
Combined Cycle	364	49,509.6	5,658.1
Internal Combustion	303	1,192.7	344.7
Gas Turbine	806	56,239.9	11,631.4
All Fuel Switchable Prime Movers	1,631	130,554.2	26,990.7

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.14. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel,

by Year of Initial Commercial Operation, 2024 (Megawatts, Percent)

Year of Initial Commercial Operation	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Pre-1970	230	9,461.1	3,497.8
1970-1974	203	11,085.5	4,182.5
1975-1979	84	10,009.2	3,960.4
1980-1984	39	844.6	205.6
1985-1989	72	2,144.4	184.8
1990-1994	175	10,849.3	1,301.6
1995-1999	119	8,765.6	946.0
2000-2004	393	37,351.6	5,639.1
2005-2009	120	15,929.1	1,970.8
2010-2014	99	11,461.6	243.3
2015-2019	68	9,417.9	2,678.1
2020-2024	29	3,234.3	2,180.8
Total	1,631	130,554.2	26,990.7

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Chapter 5

Consumption of Fossil Fuels

Table 5.1.A. Coal: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	853,634	624,235	224,568	202	4,629
2015	739,594	539,506	195,927	163	3,999
2016	677,371	496,192	178,047	111	3,021
2017	663,911	484,389	176,643	95	2,783
2018	636,213	473,617	159,976	87	2,534
2019	537,620	399,545	135,838	76	2,161
2020	435,351	325,352	108,125	72	1,802
2021	500,367	372,694	125,920	87	1,666
2022	471,576	349,320	120,514	87	1,655
2023	386,626	291,034	94,063	69	1,460
2024	372,931	284,849	86,586	65	1,431
Year 2022					
January	48,671	35,515	13,004	8	145
February	39,951	28,588	11,219	7	137
March	34,396	24,194	10,045	5	151
April	30,904	22,073	8,704	4	124
May	35,210	26,438	8,621	3	148
June	41,748	31,926	9,666	9	147
July	49,433	37,902	11,380	8	143
August	48,356	36,307	11,897	9	142
September	37,302	28,179	8,983	9	130
October	31,458	23,343	7,980	8	126
November	32,398	23,313	8,953	8	122
December	41,750	31,540	10,062	9	139
Year 2023					
January	35,506	27,360	7,998	9	138
February	26,854	19,980	6,749	8	118
March	28,671	21,207	7,345	6	114
April	22,889	16,155	6,616	7	111
May	25,484	18,557	6,799	6	122
June	33,541	26,111	7,308	3	120
July	44,412	34,525	9,752	4	131
August	43,887	34,029	9,730	4	123
September	34,223	26,184	7,913	5	121
October	29,580	21,997	7,460	6	117
November	29,549	21,115	8,310	6	117
December	32,031	23,814	8,083	7	127
Year 2024					
January	42,393	32,434	9,820	10	128
February	25,982	20,147	5,708	7	120
March	22,380	17,494	4,753	6	127
April	21,240	15,721	5,417	5	97
May	26,178	19,956	6,105	2	115
June	34,428	26,875	7,435	3	115
July	40,450	31,245	9,073	5	126
August	39,364	30,096	9,138	5	124
September	31,493	24,019	7,351	5	118
October	27,312	20,283	6,906	5	119
November	26,333	19,691	6,522	5	115
December	35,378	26,887	8,358	6	128

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.B. Coal: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	18,107	978	1,821	861	14,448
2015	16,632	1,032	1,980	635	12,985
2016	16,586	2,979	1,336	572	11,700
2017	14,667	2,802	1,158	515	10,192
2018	13,813	2,268	1,356	490	9,700
2019	12,397	2,062	1,161	443	8,731
2020	10,402	1,635	715	401	7,651
2021	11,301	2,153	667	447	8,034
2022	11,356	2,269	731	448	7,908
2023	9,363	1,580	527	331	6,925
2024	8,883	1,485	338	356	6,703
Year 2022					
January	1,071	221	66	48	736
February	930	189	67	49	625
March	985	181	78	32	694
April	898	163	72	22	641
May	904	149	56	24	676
June	892	173	52	33	634
July	954	219	55	36	643
August	963	203	62	37	661
September	905	190	57	38	621
October	933	174	56	38	664
November	904	181	56	43	624
December	1,018	227	55	48	688
Year 2023					
January	922	157	53	43	669
February	787	127	47	37	576
March	839	142	65	33	600
April	710	88	40	29	553
May	744	119	33	22	569
June	731	117	43	20	552
July	811	167	36	21	586
August	771	157	38	22	553
September	753	146	34	22	551
October	734	114	47	22	551
November	760	115	43	28	574
December	802	131	48	33	591
Year 2024					
January	926	167	41	53	665
February	753	131	31	40	552
March	813	129	46	31	607
April	667	114	29	26	498
May	672	107	31	17	518
June	668	112	25	23	507
July	733	130	23	23	558
August	728	144	19	25	540
September	691	115	16	25	534
October	690	99	20	27	545
November	733	104	19	32	578
December	809	134	38	34	603

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.C. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	871,741	625,212	226,389	1,063	19,076
2015	756,226	540,538	197,906	798	16,984
2016	693,958	499,172	179,383	683	14,720
2017	678,578	487,192	177,801	610	12,975
2018	650,027	475,885	161,332	577	12,233
2019	550,017	401,607	136,998	519	10,892
2020	445,753	326,987	108,840	473	9,453
2021	511,669	374,848	126,587	534	9,700
2022	482,931	351,589	121,245	535	9,563
2023	395,989	292,615	94,591	400	8,384
2024	381,814	286,334	86,924	422	8,134
Year 2022					
January	49,742	35,736	13,069	56	881
February	40,880	28,777	11,286	55	762
March	35,381	24,375	10,123	37	845
April	31,802	22,236	8,776	25	765
May	36,114	26,587	8,677	27	824
June	42,640	32,099	9,718	42	781
July	50,387	38,121	11,435	44	787
August	49,318	36,510	11,959	46	803
September	38,207	28,369	9,040	47	751
October	32,391	23,518	8,036	46	791
November	33,301	23,494	9,009	52	746
December	42,768	31,766	10,117	57	828
Year 2023					
January	36,428	27,518	8,051	51	808
February	27,641	20,107	6,796	44	694
March	29,511	21,349	7,409	39	714
April	23,599	16,243	6,656	36	664
May	26,227	18,677	6,832	28	691
June	34,273	26,228	7,351	22	672
July	45,223	34,692	9,788	26	718
August	44,658	34,186	9,768	26	677
September	34,975	26,329	7,948	27	671
October	30,313	22,111	7,507	27	668
November	30,308	21,231	8,353	34	691
December	32,833	23,945	8,131	39	718
Year 2024					
January	43,320	32,601	9,861	63	794
February	26,736	20,278	5,739	47	671
March	23,193	17,623	4,800	37	733
April	21,907	15,835	5,446	31	595
May	26,850	20,063	6,135	19	632
June	35,096	26,987	7,460	26	622
July	41,183	31,375	9,096	28	684
August	40,091	30,240	9,157	31	664
September	32,184	24,134	7,367	31	652
October	28,002	20,382	6,926	31	663
November	27,066	19,795	6,541	37	692
December	36,188	27,021	8,396	41	731

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.D. Coal: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Billion Btus)**

by Sector, 2014 - 2024 (Simon Data)		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	16,472,004	12,217,628	4,154,134	4,344	95,898
2015	14,167,878	10,456,910	3,624,869	3,443	82,656
2016	12,979,911	9,641,625	3,274,103	2,293	61,889
2017	12,606,527	9,328,961	3,219,833	1,914	55,820
2018	12,037,444	9,041,357	2,944,321	1,736	50,029
2019	10,166,309	7,623,281	2,498,944	1,509	42,575
2020	8,224,162	6,206,153	1,980,662	1,330	36,018
2021	9,482,946	7,124,244	2,323,722	1,577	33,403
2022	8,868,315	6,636,816	2,197,088	1,629	32,781
2023	7,240,596	5,556,006	1,655,101	1,182	28,307
2024	7,013,266	5,455,735	1,528,334	1,116	28,081
Year 2022					
January	932,465	681,662	247,758	162	2,884
February	755,759	541,928	210,989	131	2,711
March	648,077	457,992	186,983	100	3,002
April	586,192	425,501	158,133	68	2,491
May	664,220	508,370	152,870	58	2,922
June	782,819	606,620	173,150	154	2,895
July	929,477	719,031	207,472	145	2,828
August	907,079	685,213	218,881	166	2,820
September	695,932	531,013	162,189	170	2,561
October	575,870	435,090	138,144	153	2,484
November	601,968	442,289	157,075	154	2,450
December	788,457	602,109	183,445	169	2,733
Year 2023					
January	659,607	513,389	143,312	160	2,746
February	500,285	376,970	120,835	140	2,339
March	540,007	405,614	132,031	113	2,249
April	432,462	314,052	116,149	112	2,150
May	474,300	353,561	118,277	92	2,369
June	623,856	499,160	122,404	44	2,248
July	840,127	664,788	172,782	64	2,493
August	829,792	653,077	174,273	66	2,376
September	642,442	498,804	141,204	78	2,357
October	547,246	416,202	128,691	96	2,257
November	549,358	402,536	144,457	95	2,270
December	601,115	457,856	140,685	121	2,454
Year 2024					
January	800,706	618,577	179,448	188	2,494
February	480,064	379,572	98,009	130	2,354
March	417,432	335,607	79,205	104	2,516
April	399,867	303,921	93,958	81	1,907
May	495,782	385,244	108,257	34	2,247
June	658,338	520,787	135,242	56	2,254
July	768,748	602,294	163,872	81	2,501
August	743,448	578,541	162,374	88	2,445
September	586,255	457,869	126,009	89	2,287
October	506,627	384,006	120,233	74	2,314
November	489,182	374,337	112,516	89	2,240
December	666,817	514,980	149,212	103	2,522

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.E. Coal: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Billion Btus)**

by Sector, 2014 - 2024 (Simon Dzus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	391,550	18,332	37,139	18,805	317,274
2015	356,895	18,640	37,815	13,483	286,956
2016	342,370	51,590	29,330	11,736	249,714
2017	297,521	48,745	24,682	10,284	213,810
2018	278,277	38,513	28,829	9,719	201,217
2019	247,251	33,559	25,686	8,571	179,436
2020	208,052	26,952	15,375	7,424	158,300
2021	224,841	35,397	14,246	8,211	166,986
2022	222,498	37,337	14,441	8,270	162,450
2023	181,221	25,906	10,216	5,839	139,259
2024	171,692	23,799	6,413	6,226	135,255
Year 2022					
January	21,216	3,619	1,375	942	15,279
February	18,306	3,109	1,362	895	12,939
March	19,606	2,963	1,560	592	14,491
April	17,720	2,720	1,303	384	13,314
May	17,823	2,433	1,097	407	13,886
June	17,248	2,787	967	605	12,889
July	18,598	3,623	1,062	684	13,229
August	18,804	3,331	1,213	699	13,561
September	17,542	3,149	1,155	701	12,537
October	18,133	2,905	1,112	687	13,429
November	17,783	2,985	1,157	780	12,861
December	19,719	3,713	1,078	893	14,035
Year 2023					
January	18,141	2,595	951	794	13,800
February	15,528	2,083	937	672	11,836
March	16,361	2,339	1,339	589	12,095
April	13,897	1,475	865	508	11,049
May	14,545	1,969	704	380	11,493
June	13,843	1,860	958	340	10,685
July	15,546	2,795	738	365	11,648
August	14,582	2,623	702	387	10,871
September	14,472	2,360	651	391	11,069
October	14,100	1,848	829	366	11,058
November	14,698	1,853	732	475	11,638
December	15,507	2,106	809	573	12,018
Year 2024					
January	17,751	2,649	751	1,000	13,351
February	14,619	2,113	626	723	11,158
March	15,856	2,021	788	527	12,520
April	12,908	1,866	529	453	10,061
May	12,991	1,715	582	282	10,413
June	12,904	1,798	509	397	10,200
July	14,368	2,098	445	410	11,415
August	14,120	2,403	364	435	10,918
September	13,278	1,894	333	435	10,617
October	13,417	1,554	423	439	11,002
November	14,017	1,606	384	537	11,490
December	15,463	2,082	679	591	12,111

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.F. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

			Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2014	16,863,554	12,235,960	4,191,273	23,149	413,173	
2015	14,524,773	10,475,551	3,662,685	16,926	369,612	
2016	13,322,281	9,693,215	3,303,433	14,029	311,604	
2017	12,904,048	9,377,705	3,244,514	12,198	269,630	
2018	12,315,720	9,079,870	2,973,150	11,455	251,245	
2019	10,413,560	7,656,840	2,524,630	10,080	222,011	
2020	8,432,214	6,233,105	1,996,036	8,754	194,318	
2021	9,707,787	7,159,642	2,337,968	9,788	200,389	
2022	9,090,813	6,674,153	2,211,529	9,900	195,231	
2023	7,421,817	5,581,912	1,665,316	7,022	167,567	
2024	7,184,959	5,479,534	1,534,747	7,342	163,336	
Year 2022						
January	953,681	685,281	249,133	1,104	18,163	
February	774,064	545,038	212,351	1,026	15,650	
March	667,683	460,955	188,543	692	17,494	
April	603,912	428,220	159,436	452	15,804	
May	682,042	510,802	153,967	465	16,808	
June	800,067	609,407	174,117	759	15,784	
July	948,074	722,654	208,534	830	16,057	
August	925,883	688,544	220,093	864	16,381	
September	713,474	534,161	163,344	871	15,097	
October	594,004	437,995	139,256	839	15,913	
November	619,751	445,273	158,232	934	15,311	
December	808,176	605,822	184,523	1,063	16,768	
Year 2023						
January	677,748	515,984	144,264	954	16,546	
February	515,813	379,053	121,772	812	14,176	
March	556,368	407,953	133,370	702	14,343	
April	446,359	315,527	117,014	620	13,198	
May	488,845	355,530	118,981	472	13,862	
June	637,699	501,020	123,362	385	12,932	
July	855,673	667,583	173,520	429	14,141	
August	844,374	655,700	174,975	452	13,247	
September	656,915	501,164	141,855	470	13,426	
October	561,346	418,049	129,520	462	13,315	
November	564,056	404,389	145,189	570	13,908	
December	616,622	459,962	141,494	694	14,472	
Year 2024						
January	818,457	621,226	180,198	1,189	15,844	
February	494,683	381,685	98,634	852	13,512	
March	433,288	337,628	79,993	631	15,036	
April	412,775	305,787	94,487	533	11,967	
May	508,773	386,958	108,839	315	12,660	
June	671,243	522,585	135,751	452	12,454	
July	783,116	604,392	164,317	490	13,916	
August	757,567	580,944	162,738	522	13,363	
September	599,533	459,763	126,342	524	12,904	
October	520,044	385,560	120,656	513	13,316	
November	503,199	375,943	112,900	626	13,730	
December	682,280	517,063	149,890	693	14,633	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.A. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	31,531	19,652	10,689	451	739
2015	28,925	18,562	9,473	249	641
2016	22,405	16,137	5,624	108	536
2017	21,696	15,567	5,461	191	476
2018	28,614	18,345	9,467	269	534
2019	20,836	15,677	4,464	251	444
2020	18,008	13,913	3,447	238	410
2021	21,633	16,850	4,102	250	432
2022	28,760	18,375	9,474	254	657
2023	21,335	16,366	4,253	200	517
2024	20,787	16,058	4,137	179	414
Year 2022					
January	5,217	2,325	2,794	44	54
February	2,067	1,239	768	16	43
March	1,732	1,304	365	14	48
April	1,408	1,098	250	17	43
May	1,588	1,275	252	20	42
June	1,704	1,286	351	20	46
July	2,020	1,375	576	21	48
August	1,896	1,301	537	19	39
September	1,738	1,341	335	12	49
October	1,814	1,370	387	14	43
November	1,700	1,339	304	15	42
December	5,876	3,121	2,553	42	160
Year 2023					
January	1,821	1,453	283	24	61
February	2,432	1,558	791	36	47
March	1,677	1,305	303	16	53
April	1,605	1,262	292	11	40
May	1,689	1,348	290	15	36
June	1,680	1,370	256	11	43
July	1,778	1,318	405	13	41
August	1,789	1,445	289	13	41
September	1,666	1,277	339	12	38
October	1,825	1,351	423	13	37
November	1,671	1,313	304	15	38
December	1,704	1,366	277	21	41
Year 2024					
January	2,757	1,991	690	30	47
February	1,385	1,142	183	14	46
March	1,419	1,154	214	18	34
April	1,592	1,229	311	17	35
May	1,576	1,253	274	18	32
June	1,614	1,224	334	23	32
July	1,832	1,324	468	8	33
August	1,813	1,448	326	9	30
September	1,485	1,232	217	7	28
October	1,651	1,364	247	7	33
November	1,535	1,242	252	10	31
December	2,128	1,455	620	18	35

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.B. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	3,099	64	1,170	216	1,650
2015	3,142	62	1,155	282	1,643
2016	2,277	68	245	245	1,719
2017	2,012	72	220	238	1,482
2018	2,614	103	354	350	1,807
2019	2,162	71	226	419	1,446
2020	1,730	59	179	269	1,223
2021	2,072	80	278	330	1,384
2022	4,181	106	403	495	3,177
2023	3,133	65	330	363	2,374
2024	2,238	66	612	440	1,120
Year 2022					
January	425	28	68	114	214
February	239	14	18	30	177
March	336	6	35	33	263
April	335	4	27	26	277
May	310	5	27	34	244
June	345	5	28	18	294
July	360	5	25	38	292
August	243	3	27	30	183
September	302	4	28	10	259
October	317	5	32	14	266
November	310	4	33	16	257
December	659	21	55	131	451
Year 2023					
January	406	6	35	62	303
February	373	9	29	30	305
March	326	4	26	25	271
April	329	5	29	8	288
May	163	7	26	10	120
June	166	5	26	16	120
July	174	5	25	16	129
August	204	5	23	16	161
September	207	3	25	20	158
October	193	6	32	17	137
November	247	5	25	37	181
December	344	5	29	107	203
Year 2024					
January	324	18	59	87	160
February	170	3	23	45	98
March	189	4	26	63	96
April	215	6	75	41	94
May	191	4	51	59	77
June	199	5	38	86	69
July	182	4	93	6	79
August	128	5	52	5	67
September	104	3	24	5	72
October	144	5	34	7	98
November	142	5	37	12	89
December	251	4	101	24	122

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.C. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	34,630	19,716	11,859	667	2,389
2015	32,067	18,624	10,629	531	2,283
2016	24,682	16,205	5,869	352	2,255
2017	23,708	15,640	5,681	429	1,958
2018	31,228	18,448	9,820	619	2,341
2019	22,998	15,748	4,690	670	1,890
2020	19,738	13,972	3,626	507	1,633
2021	23,705	16,929	4,379	580	1,816
2022	32,940	18,480	9,877	749	3,835
2023	24,468	16,431	4,583	563	2,891
2024	23,025	16,124	4,748	619	1,534
Year 2022					
January	5,642	2,353	2,863	158	268
February	2,306	1,253	786	47	220
March	2,068	1,310	400	47	311
April	1,742	1,102	277	43	320
May	1,898	1,280	279	54	285
June	2,049	1,291	379	38	341
July	2,380	1,380	601	59	340
August	2,139	1,305	564	48	222
September	2,040	1,345	364	23	308
October	2,131	1,375	419	28	310
November	2,011	1,344	337	31	299
December	6,534	3,142	2,608	173	611
Year 2023					
January	2,227	1,460	318	86	363
February	2,805	1,566	820	66	352
March	2,003	1,309	329	41	324
April	1,934	1,267	321	18	328
May	1,852	1,355	317	25	155
June	1,846	1,374	281	27	163
July	1,952	1,323	430	29	170
August	1,993	1,450	312	29	202
September	1,872	1,280	364	32	197
October	2,018	1,357	456	30	174
November	1,918	1,319	329	52	219
December	2,049	1,371	306	127	245
Year 2024					
January	3,081	2,009	749	117	207
February	1,555	1,146	206	60	144
March	1,609	1,158	239	81	130
April	1,807	1,235	386	58	129
May	1,767	1,256	325	77	109
June	1,812	1,230	373	109	101
July	2,014	1,328	561	14	111
August	1,941	1,452	378	14	97
September	1,589	1,235	242	11	100
October	1,795	1,369	282	14	130
November	1,677	1,246	289	22	119
December	2,379	1,459	721	42	157

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.D. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

Period		Electric Power Sector		Commercial Sector		Industrial Sector	
Total (all sectors)		Electric Utilities		Independent Power Producers			
Annual Totals							
2014	188,814	118,226	63,488	2,765	4,335		
2015	172,884	111,808	55,979	1,482	3,616		
2016	133,457	96,967	32,922	639	2,928		
2017	128,649	92,975	31,895	1,125	2,654		
2018	169,663	109,734	55,433	1,579	2,916		
2019	122,591	93,088	25,678	1,466	2,359		
2020	105,735	82,276	19,821	1,396	2,241		
2021	126,799	99,374	23,648	1,466	2,312		
2022	169,716	108,473	56,212	1,482	3,548		
2023	126,106	96,840	25,293	1,162	2,810		
2024	123,273	95,103	24,872	1,038	2,259		
Year 2022							
January	31,071	13,759	16,747	260	306		
February	12,135	7,285	4,511	96	243		
March	10,220	7,691	2,173	84	272		
April	8,301	6,485	1,483	97	235		
May	9,410	7,568	1,498	115	228		
June	9,991	7,555	2,064	116	255		
July	11,966	8,119	3,456	123	267		
August	11,188	7,674	3,192	108	214		
September	10,277	7,960	1,981	71	265		
October	10,721	8,139	2,258	79	245		
November	10,022	7,902	1,795	86	239		
December	34,416	18,335	15,055	247	779		
Year 2023							
January	10,680	8,575	1,639	143	322		
February	14,494	9,267	4,754	208	266		
March	9,884	7,698	1,797	90	298		
April	9,464	7,453	1,727	61	223		
May	9,973	7,977	1,717	89	191		
June	9,913	8,120	1,501	64	228		
July	10,546	7,801	2,454	76	215		
August	10,580	8,554	1,731	75	220		
September	9,901	7,598	2,023	71	209		
October	10,793	8,015	2,501	77	201		
November	9,851	7,754	1,800	88	209		
December	10,027	8,029	1,648	121	229		
Year 2024							
January	16,257	11,733	4,090	173	261		
February	8,181	6,774	1,086	82	239		
March	8,383	6,799	1,290	103	191		
April	9,362	7,230	1,841	99	192		
May	9,391	7,463	1,656	102	170		
June	9,560	7,223	2,029	136	172		
July	10,864	7,830	2,811	46	177		
August	10,805	8,614	1,972	53	166		
September	8,872	7,346	1,332	39	155		
October	9,842	8,116	1,507	42	177		
November	9,107	7,354	1,529	59	166		
December	12,648	8,622	3,729	104	193		

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.E. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	18,181	395	6,802	1,311	9,672
2015	18,449	379	6,748	1,755	9,568
2016	13,164	395	1,391	1,496	9,882
2017	11,825	405	1,253	1,432	8,736
2018	15,163	598	1,951	2,082	10,533
2019	12,383	403	1,319	2,472	8,189
2020	9,962	317	1,056	1,595	6,994
2021	11,989	453	1,624	1,964	7,948
2022	24,130	613	2,452	2,920	18,145
2023	18,007	370	2,027	2,160	13,450
2024	12,990	374	3,583	2,602	6,431
Year 2022					
January	2,487	166	397	665	1,260
February	1,414	79	108	181	1,045
March	1,958	34	215	192	1,517
April	1,916	23	167	155	1,570
May	1,781	29	169	199	1,384
June	1,977	27	174	108	1,667
July	2,072	31	157	225	1,660
August	1,397	20	168	174	1,035
September	1,749	25	176	63	1,485
October	1,843	29	195	84	1,535
November	1,835	26	198	99	1,512
December	3,702	125	327	775	2,474
Year 2023					
January	2,322	37	211	369	1,705
February	2,154	50	176	185	1,743
March	1,883	25	162	149	1,547
April	1,895	26	180	48	1,641
May	940	40	164	62	675
June	942	26	159	95	662
July	987	28	155	93	711
August	1,159	26	141	94	898
September	1,181	18	155	118	890
October	1,109	35	198	102	774
November	1,452	29	150	218	1,055
December	1,984	30	177	627	1,150
Year 2024					
January	1,890	101	340	514	935
February	972	19	135	270	549
March	1,107	24	156	374	553
April	1,238	32	429	240	538
May	1,103	20	298	347	438
June	1,152	31	229	501	391
July	1,039	23	532	39	445
August	740	26	303	29	382
September	612	18	148	28	419
October	849	30	211	42	566
November	827	26	221	72	509
December	1,461	24	582	145	709

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.F. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

			Electric Power Sector			
Period	Total (all sectors)		Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals						
2014	206,995		118,621	70,291	4,076	14,008
2015	191,333		112,186	62,727	3,236	13,184
2016	146,621		97,363	34,313	2,135	12,810
2017	140,474		93,380	33,148	2,557	11,389
2018	184,826		110,332	57,383	3,661	13,449
2019	134,974		93,491	26,998	3,937	10,548
2020	115,697		82,594	20,877	2,991	9,235
2021	138,788		99,827	25,271	3,430	10,259
2022	193,845		109,086	58,664	4,402	21,693
2023	144,113		97,210	27,320	3,323	16,260
2024	136,263		95,477	28,455	3,641	8,690
Year 2022						
January	33,558		13,924	17,144	924	1,566
February	13,549		7,365	4,619	277	1,288
March	12,178		7,725	2,388	276	1,789
April	10,216		6,509	1,651	252	1,805
May	11,190		7,597	1,666	314	1,613
June	11,968		7,582	2,239	225	1,923
July	14,037		8,150	3,613	348	1,927
August	12,585		7,694	3,359	282	1,249
September	12,026		7,985	2,157	134	1,750
October	12,564		8,169	2,453	163	1,780
November	11,857		7,928	1,993	184	1,751
December	38,117		18,460	15,382	1,022	3,253
Year 2023						
January	13,002		8,612	1,850	513	2,028
February	16,648		9,317	4,929	393	2,009
March	11,767		7,723	1,959	239	1,845
April	11,359		7,479	1,907	109	1,864
May	10,913		8,017	1,881	151	865
June	10,855		8,146	1,661	159	889
July	11,533		7,829	2,609	170	926
August	11,739		8,580	1,873	169	1,118
September	11,082		7,617	2,178	189	1,098
October	11,902		8,050	2,699	179	974
November	11,302		7,783	1,950	306	1,264
December	12,011		8,058	1,825	747	1,380
Year 2024						
January	18,146		11,834	4,430	687	1,195
February	9,153		6,794	1,221	351	788
March	9,489		6,822	1,446	477	743
April	10,600		7,262	2,270	338	730
May	10,494		7,483	1,953	449	608
June	10,712		7,253	2,258	637	563
July	11,903		7,853	3,343	85	621
August	11,546		8,640	2,275	82	548
September	9,484		7,363	1,480	68	573
October	10,691		8,146	1,717	85	743
November	9,935		7,380	1,749	131	674
December	14,109		8,646	4,311	249	902

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.3.A. Petroleum Coke: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	4,412	3,440	599	2	371
2015	4,044	3,120	669	2	253
2016	4,253	3,427	591	2	233
2017	3,490	2,731	542	3	214
2018	3,623	2,740	704	2	177
2019	2,724	2,067	478	1	177
2020	3,077	2,260	658	1	158
2021	3,070	2,323	618	1	127
2022	2,985	2,271	578	3	132
2023	2,028	1,328	594	1	105
2024	1,662	960	596	1	104
Year 2022					
January	240	166	63	0	11
February	248	180	55	0	13
March	216	143	62	0	10
April	225	156	59	0	10
May	248	212	22	0	12
June	281	224	46	0	10
July	219	177	31	0	11
August	241	178	52	0	11
September	280	210	60	0	10
October	263	192	60	0	11
November	227	178	36	0	13
December	296	254	31	0	10
Year 2023					
January	179	116	52	0	11
February	163	107	47	0	9
March	135	73	49	0	12
April	124	74	43	0	7
May	144	76	60	0	8
June	162	107	48	0	7
July	266	196	59	0	10
August	265	197	59	0	9
September	238	175	55	0	8
October	125	76	41	0	8
November	80	49	24	0	8
December	147	81	57	0	8
Year 2024					
January	163	95	59	0	9
February	120	69	42	0	8
March	89	22	58	0	9
April	125	66	51	0	8
May	140	76	56	0	8
June	171	115	47	0	9
July	199	131	58	0	10
August	193	128	57	0	9
September	109	70	32	0	7
October	113	72	33	0	8
November	102	44	49	0	9
December	137	72	55	0	10

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

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**Table 5.3.B. Petroleum Coke: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,283	3	90	16	1,174
2015	1,144	9	109	16	1,010
2016	1,099	6	113	9	971
2017	977	11	115	15	836
2018	929	12	93	10	814
2019	839	17	93	6	724
2020	780	16	124	3	637
2021	760	21	113	6	621
2022	718	23	92	13	589
2023	622	8	115	3	495
2024	608	0	103	5	499
Year 2022					
January	55	2	8	2	44
February	67	8	11	2	46
March	60	1	9	2	48
April	56	0	8	1	47
May	68	1	8	2	57
June	52	1	6	2	44
July	51	1	1	1	47
August	69	1	8	0	60
September	49	1	8	0	40
October	62	1	8	0	53
November	71	6	8	1	56
December	58	0	9	1	48
Year 2023					
January	49	1	9	1	37
February	38	1	10	0	26
March	60	2	10	0	47
April	52	2	8	0	41
May	56	0	10	0	46
June	51	0	10	0	41
July	52	1	10	0	41
August	56	1	10	0	45
September	53	0	11	0	41
October	53	0	8	0	45
November	49	0	8	0	41
December	53	0	10	1	41
Year 2024					
January	57	0	9	1	46
February	43	0	8	1	35
March	45	0	9	0	36
April	49	0	7	0	42
May	47	0	7	1	39
June	52	0	10	1	41
July	57	0	10	0	47
August	56	0	12	0	44
September	47	0	8	0	39
October	43	0	1	0	42
November	51	0	9	0	42
December	62	0	13	1	48

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.C. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	5,695	3,443	689	18	1,545
2015	5,188	3,128	779	18	1,263
2016	5,352	3,433	705	10	1,204
2017	4,467	2,742	657	17	1,050
2018	4,552	2,752	797	12	991
2019	3,563	2,083	571	7	900
2020	3,856	2,276	782	4	795
2021	3,830	2,344	731	7	748
2022	3,702	2,294	671	16	721
2023	2,649	1,336	709	4	600
2024	2,270	960	699	6	604
Year 2022					
January	295	168	71	2	54
February	315	188	66	2	59
March	275	144	71	2	58
April	282	156	67	2	57
May	315	214	30	2	69
June	333	225	53	2	53
July	270	178	33	1	58
August	310	179	59	0	72
September	330	211	68	0	51
October	325	193	68	0	64
November	298	184	44	1	69
December	355	255	40	2	58
Year 2023					
January	228	116	62	2	48
February	201	108	57	0	35
March	195	75	60	0	59
April	175	77	51	0	48
May	200	76	70	0	54
June	213	107	57	0	49
July	318	197	69	0	52
August	321	197	69	0	54
September	290	175	66	0	49
October	178	76	49	0	53
November	129	49	32	0	49
December	200	81	67	1	50
Year 2024					
January	220	95	68	2	55
February	163	69	50	1	43
March	134	22	67	0	45
April	174	66	58	0	50
May	187	76	63	1	46
June	223	115	57	1	50
July	256	131	68	0	57
August	248	128	68	0	52
September	156	70	40	0	46
October	156	72	33	0	50
November	153	44	58	0	50
December	199	72	68	1	58

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.D. Petroleum Coke: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	123,736	95,642	17,032	59	11,003
2015	113,568	87,210	18,889	58	7,411
2016	118,303	94,892	16,591	47	6,774
2017	94,136	72,919	15,100	72	6,045
2018	100,362	73,895	21,327	57	5,083
2019	74,970	56,411	13,472	37	5,050
2020	84,427	61,343	18,446	18	4,619
2021	83,779	62,714	17,234	32	3,799
2022	79,689	59,461	16,174	81	3,973
2023	53,489	33,329	16,961	16	3,183
2024	41,450	21,300	16,984	28	3,137
Year 2022					
January	6,687	4,613	1,750	10	314
February	6,925	5,013	1,523	10	380
March	5,799	3,783	1,702	10	304
April	5,978	4,010	1,660	9	299
May	6,475	5,449	643	11	372
June	7,360	5,737	1,321	10	293
July	5,639	4,423	886	6	324
August	6,432	4,643	1,452	0	337
September	7,444	5,440	1,689	2	313
October	6,735	4,743	1,647	0	345
November	6,147	4,750	1,005	4	388
December	8,067	6,858	897	8	304
Year 2023					
January	4,615	2,789	1,484	8	334
February	4,475	2,860	1,349	2	264
March	3,677	1,909	1,402	1	365
April	3,282	1,854	1,222	0	206
May	3,714	1,754	1,713	0	247
June	4,382	2,763	1,399	0	220
July	7,156	5,123	1,715	0	318
August	7,008	5,049	1,682	0	277
September	6,291	4,496	1,563	0	232
October	3,107	1,710	1,154	0	242
November	2,046	1,130	688	0	228
December	3,736	1,892	1,588	5	251
Year 2024					
January	4,055	2,135	1,637	6	276
February	2,840	1,400	1,183	3	253
March	2,403	450	1,674	0	279
April	3,164	1,454	1,459	0	251
May	3,491	1,667	1,585	6	232
June	4,287	2,653	1,364	6	265
July	5,001	3,034	1,666	0	301
August	4,926	3,043	1,627	0	256
September	2,655	1,523	916	0	216
October	2,602	1,431	921	0	250
November	2,649	979	1,408	0	261
December	3,377	1,530	1,543	7	297

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas. See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.E. Petroleum Coke: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	36,602	90	2,597	449	33,467
2015	33,138	255	3,167	446	29,269
2016	32,473	159	3,255	241	28,817
2017	28,680	297	3,335	403	24,645
2018	27,398	332	2,693	284	24,088
2019	24,348	470	2,681	164	21,032
2020	22,623	453	3,563	87	18,521
2021	22,772	594	3,182	152	18,844
2022	21,600	665	2,646	366	17,924
2023	18,788	241	3,297	87	15,163
2024	18,416	6	2,976	140	15,294
Year 2022					
January	1,642	46	233	47	1,317
February	1,998	246	305	43	1,404
March	1,809	34	261	46	1,468
April	1,679	5	229	39	1,406
May	2,045	35	224	50	1,736
June	1,593	29	179	45	1,340
July	1,546	27	36	32	1,450
August	2,088	23	224	0	1,841
September	1,502	18	225	9	1,250
October	1,856	20	232	0	1,604
November	2,117	175	238	19	1,686
December	1,726	7	261	36	1,422
Year 2023					
January	1,392	14	265	39	1,075
February	1,112	35	292	8	777
March	1,808	63	299	6	1,440
April	1,574	72	235	0	1,267
May	1,710	0	293	0	1,418
June	1,571	2	276	0	1,293
July	1,577	22	277	0	1,279
August	1,708	20	286	0	1,402
September	1,604	8	310	0	1,286
October	1,623	3	238	0	1,382
November	1,496	0	230	0	1,266
December	1,612	3	295	35	1,279
Year 2024					
January	1,699	6	270	36	1,387
February	1,300	0	232	15	1,052
March	1,364	0	270	0	1,094
April	1,482	0	200	0	1,282
May	1,444	0	212	28	1,205
June	1,586	0	295	30	1,261
July	1,713	0	290	0	1,423
August	1,689	0	344	0	1,346
September	1,445	0	227	0	1,218
October	1,323	0	21	0	1,302
November	1,523	0	251	0	1,272
December	1,847	0	365	31	1,452

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Fossil Gas.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.3.F. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	160,338	95,731	19,629	508	44,470
2015	146,706	87,465	22,056	505	36,680
2016	150,776	95,051	19,846	288	35,591
2017	122,816	73,216	18,435	475	30,690
2018	127,760	74,227	24,020	341	29,171
2019	99,318	56,881	16,153	201	26,083
2020	107,050	61,796	22,009	105	23,140
2021	106,551	63,308	20,416	184	22,644
2022	101,289	60,125	18,820	446	21,897
2023	72,276	33,570	20,257	103	18,347
2024	59,865	21,306	19,960	168	18,431
Year 2022					
January	8,330	4,659	1,983	57	1,631
February	8,923	5,259	1,828	52	1,784
March	7,608	3,817	1,963	57	1,772
April	7,657	4,015	1,889	48	1,705
May	8,520	5,484	867	61	2,108
June	8,953	5,766	1,499	54	1,633
July	7,185	4,450	922	38	1,774
August	8,520	4,666	1,676	0	2,178
September	8,946	5,459	1,914	11	1,563
October	8,591	4,763	1,879	0	1,949
November	8,263	4,924	1,242	23	2,074
December	9,793	6,865	1,158	44	1,726
Year 2023					
January	6,007	2,803	1,749	46	1,408
February	5,588	2,895	1,641	10	1,041
March	5,485	1,973	1,700	7	1,805
April	4,856	1,926	1,457	0	1,472
May	5,425	1,754	2,006	0	1,665
June	5,953	2,765	1,675	0	1,513
July	8,733	5,145	1,992	0	1,596
August	8,715	5,068	1,969	0	1,679
September	7,895	4,504	1,874	0	1,518
October	4,730	1,713	1,393	0	1,624
November	3,542	1,130	918	0	1,494
December	5,347	1,895	1,883	39	1,530
Year 2024					
January	5,754	2,141	1,907	42	1,663
February	4,140	1,400	1,416	19	1,306
March	3,767	450	1,945	0	1,372
April	4,646	1,454	1,659	0	1,532
May	4,935	1,667	1,796	34	1,437
June	5,874	2,653	1,659	36	1,526
July	6,714	3,034	1,956	0	1,724
August	6,616	3,043	1,971	0	1,602
September	4,100	1,523	1,143	0	1,434
October	3,925	1,431	942	0	1,552
November	4,172	979	1,659	0	1,534
December	5,225	1,530	1,908	37	1,749

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.A. Natural Gas: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	8,544,387	3,895,008	3,954,032	71,957	623,390
2015	10,016,576	4,745,255	4,576,683	70,092	624,545
2016	10,170,110	5,018,894	4,571,375	46,304	533,537
2017	9,508,062	4,754,893	4,161,984	50,060	541,126
2018	10,842,129	5,560,267	4,663,935	52,650	565,276
2019	11,612,858	5,980,679	4,958,798	55,575	617,805
2020	11,928,104	6,196,152	5,061,569	51,827	618,556
2021	11,502,569	5,876,442	4,995,247	45,537	585,343
2022	12,384,086	6,376,041	5,364,050	48,658	595,337
2023	13,245,495	6,821,490	5,766,810	49,069	608,127
2024	13,754,749	7,282,518	5,831,864	47,993	592,373
Year 2022					
January	972,571	499,668	416,488	3,980	52,436
February	823,713	414,497	360,403	3,525	45,288
March	800,152	407,227	339,907	3,791	49,227
April	767,572	391,895	325,930	3,536	46,211
May	947,250	488,790	406,341	3,767	48,352
June	1,168,712	623,023	491,993	4,050	49,645
July	1,430,805	752,312	619,375	4,873	54,246
August	1,407,824	722,888	625,436	5,064	54,436
September	1,149,683	579,459	517,292	4,325	48,606
October	971,750	491,554	428,251	3,632	48,313
November	928,162	480,119	394,845	3,849	49,349
December	1,015,891	524,610	437,787	4,265	49,229
Year 2023					
January	987,973	509,721	424,167	4,015	50,070
February	887,314	452,645	385,437	3,707	45,525
March	960,860	498,746	408,397	3,937	49,780
April	883,667	460,878	375,346	3,608	43,836
May	1,016,179	541,909	421,533	3,794	48,943
June	1,205,103	629,369	519,772	4,171	51,790
July	1,502,219	772,992	669,249	4,980	54,998
August	1,499,764	785,760	653,790	4,761	55,453
September	1,226,450	620,224	549,340	4,449	52,437
October	1,041,989	527,917	459,521	3,948	50,603
November	987,442	487,374	445,387	3,784	50,897
December	1,046,536	533,955	454,871	3,915	53,796
Year 2024					
January	1,162,832	599,189	505,458	4,128	54,057
February	934,713	485,159	397,568	3,745	48,241
March	941,501	495,352	393,681	3,746	48,722
April	905,025	476,354	377,984	3,512	47,174
May	1,070,779	580,971	438,725	3,519	47,565
June	1,260,404	676,543	531,767	4,168	47,925
July	1,551,563	834,670	659,202	4,998	52,693
August	1,521,577	822,175	639,987	4,741	54,674
September	1,244,270	662,026	529,221	3,974	49,050
October	1,089,749	575,812	465,530	3,720	44,687
November	1,009,898	531,088	428,789	3,798	46,223
December	1,062,440	543,180	463,952	3,945	51,363

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

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Table 5.4.B. Natural Gas: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	865,146	4,926	292,016	46,635	521,569
2015	935,098	8,060	283,372	46,287	597,379
2016	1,151,866	38,096	356,905	80,943	675,922
2017	1,168,544	38,740	309,949	104,324	715,532
2018	1,205,962	43,156	331,952	81,856	748,997
2019	1,196,025	42,645	317,231	79,734	756,415
2020	1,292,624	47,025	326,976	78,844	839,778
2021	1,221,841	49,103	307,795	71,094	793,849
2022	1,206,250	46,329	305,125	74,683	780,113
2023	1,210,187	46,531	306,058	69,832	787,767
2024	1,246,683	48,851	313,214	80,431	804,187
Year 2022					
January	111,979	4,635	28,424	7,331	71,588
February	98,435	3,929	25,170	6,465	62,872
March	102,253	3,852	25,861	6,384	66,156
April	92,922	2,748	22,502	5,734	61,937
May	95,766	3,356	24,200	5,623	62,587
June	97,703	3,887	25,622	5,855	62,339
July	106,539	4,604	28,679	6,816	66,440
August	106,095	4,242	27,578	6,894	67,381
September	96,584	3,583	24,804	5,816	62,381
October	95,266	3,073	23,556	5,412	63,225
November	98,143	4,017	23,125	5,694	65,307
December	104,564	4,401	25,603	6,659	67,900
Year 2023					
January	105,723	4,357	25,508	6,329	69,529
February	96,304	3,879	24,676	5,808	61,940
March	103,019	3,925	25,733	5,947	67,415
April	93,580	3,302	23,341	5,165	61,771
May	94,810	3,414	22,583	5,196	63,617
June	98,931	3,707	24,782	5,484	64,959
July	105,392	4,560	27,941	6,314	66,578
August	104,094	4,161	27,825	5,996	66,113
September	99,792	3,791	25,380	5,797	64,824
October	97,361	3,239	25,276	5,602	63,245
November	102,875	3,964	26,458	6,009	66,444
December	108,306	4,232	26,556	6,186	71,332
Year 2024					
January	115,493	4,354	27,991	7,908	75,239
February	101,815	3,991	25,995	6,931	64,898
March	103,186	4,285	25,888	6,646	66,368
April	94,071	3,262	22,280	5,730	62,799
May	98,002	3,599	24,380	5,331	64,691
June	100,201	4,040	26,090	6,319	63,752
July	109,041	4,795	28,982	7,424	67,841
August	109,971	4,683	29,645	7,236	68,407
September	102,699	4,298	27,052	6,464	64,886
October	99,916	3,508	25,663	6,278	64,469
November	102,011	3,645	23,961	6,680	67,725
December	110,274	4,390	25,287	7,484	73,112

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Table 5.4.C. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	9,409,532	3,899,934	4,246,048	118,591	1,144,959
2015	10,951,674	4,753,315	4,860,055	116,380	1,221,924
2016	11,321,975	5,056,990	4,928,280	127,246	1,209,459
2017	10,676,606	4,793,632	4,471,933	154,383	1,256,658
2018	12,048,091	5,603,423	4,995,888	134,507	1,314,273
2019	12,808,883	6,023,324	5,276,029	135,310	1,374,220
2020	13,220,728	6,243,178	5,388,546	130,671	1,458,334
2021	12,724,410	5,925,545	5,303,041	116,631	1,379,193
2022	13,590,336	6,422,369	5,669,175	123,342	1,375,449
2023	14,455,682	6,868,021	6,072,868	118,901	1,395,893
2024	15,001,432	7,331,369	6,145,078	128,424	1,396,561
Year 2022					
January	1,084,549	504,303	444,912	11,311	124,023
February	922,149	418,426	385,573	9,989	108,160
March	902,405	411,079	365,768	10,175	115,382
April	860,494	394,643	348,432	9,270	108,148
May	1,043,016	492,145	430,541	9,390	110,939
June	1,266,415	626,911	517,616	9,905	111,984
July	1,537,345	756,916	648,054	11,689	120,685
August	1,513,919	727,130	653,015	11,958	121,816
September	1,246,267	583,042	542,096	10,141	110,987
October	1,067,017	494,626	451,807	9,044	111,539
November	1,026,306	484,136	417,970	9,543	114,656
December	1,120,455	529,011	463,390	10,924	117,129
Year 2023					
January	1,093,696	514,078	449,675	10,344	119,599
February	983,618	456,525	410,113	9,514	107,465
March	1,063,879	502,671	434,129	9,884	117,195
April	977,247	464,180	398,687	8,774	105,607
May	1,110,989	545,322	444,116	8,990	112,560
June	1,304,034	633,076	544,554	9,655	116,748
July	1,607,611	777,552	697,190	11,294	121,576
August	1,603,858	789,921	681,615	10,757	121,565
September	1,326,241	624,014	574,721	10,246	117,261
October	1,139,351	531,156	484,797	9,550	113,848
November	1,090,317	491,338	471,844	9,793	117,342
December	1,154,842	538,187	481,427	10,101	125,127
Year 2024					
January	1,278,325	603,544	533,449	12,036	129,296
February	1,036,528	489,150	423,563	10,676	113,139
March	1,044,687	499,637	419,569	10,392	115,089
April	999,096	479,616	400,264	9,242	109,973
May	1,168,782	584,570	463,105	8,850	112,256
June	1,360,605	680,584	557,858	10,487	111,677
July	1,660,604	839,464	688,184	12,422	120,534
August	1,631,548	826,858	669,632	11,976	123,081
September	1,346,969	666,324	556,272	10,438	113,936
October	1,189,665	579,319	491,192	9,998	109,156
November	1,111,910	534,733	452,750	10,478	113,948
December	1,172,713	547,570	489,239	11,429	124,475

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.D. Natural Gas: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	8,795,303	4,001,826	4,076,787	74,194	642,495
2015	10,360,990	4,905,009	4,739,438	71,929	644,615
2016	10,515,826	5,189,543	4,728,444	47,550	550,288
2017	9,827,794	4,911,629	4,308,241	51,592	556,331
2018	11,200,796	5,739,753	4,825,957	54,390	580,696
2019	12,008,434	6,178,186	5,137,826	57,028	635,394
2020	12,324,847	6,398,560	5,239,106	53,175	634,006
2021	11,892,547	6,071,668	5,172,999	46,896	600,984
2022	12,792,589	6,580,269	5,550,639	50,198	611,483
2023	13,684,878	7,041,713	5,967,921	50,769	624,475
2024	14,226,488	7,528,352	6,040,206	49,538	608,392
Year 2022					
January	1,005,525	516,084	431,435	4,104	53,901
February	851,167	427,737	373,226	3,640	46,563
March	825,945	419,799	351,669	3,910	50,566
April	791,873	403,696	337,071	3,637	47,469
May	976,896	503,588	419,789	3,875	49,643
June	1,205,401	642,072	508,210	4,180	50,938
July	1,476,117	775,494	640,021	5,013	55,590
August	1,455,041	746,891	647,073	5,212	55,865
September	1,189,365	599,087	535,910	4,476	49,894
October	1,003,933	507,308	443,201	3,758	49,666
November	958,728	495,304	408,724	3,979	50,722
December	1,052,598	543,210	454,311	4,413	50,664
Year 2023					
January	1,023,822	528,227	439,936	4,156	51,503
February	917,770	468,004	399,184	3,842	46,740
March	993,060	515,120	422,752	4,081	51,106
April	911,874	474,690	388,440	3,729	45,014
May	1,048,194	558,303	435,700	3,922	50,269
June	1,244,180	649,299	537,412	4,315	53,155
July	1,551,623	797,788	692,277	5,146	56,412
August	1,548,587	810,543	676,215	4,925	56,904
September	1,265,777	639,723	567,639	4,602	53,813
October	1,075,631	544,341	475,223	4,088	51,978
November	1,020,346	502,764	461,393	3,912	52,278
December	1,084,013	552,910	471,749	4,051	55,304
Year 2024					
January	1,205,058	621,082	524,115	4,262	55,598
February	968,732	502,543	412,709	3,869	49,611
March	974,061	511,931	408,216	3,869	50,045
April	934,104	490,734	391,304	3,624	48,441
May	1,104,003	598,023	453,505	3,626	48,848
June	1,301,428	697,766	550,162	4,300	49,200
July	1,606,334	864,343	682,739	5,155	54,098
August	1,575,288	851,390	662,885	4,892	56,121
September	1,286,659	684,448	547,770	4,101	50,340
October	1,126,414	594,946	481,782	3,846	45,839
November	1,044,383	548,971	444,017	3,921	47,473
December	1,100,025	562,174	481,001	4,071	52,779

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.4.E. Natural Gas: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	891,994	5,033	300,870	47,579	538,514
2015	965,573	8,254	292,629	47,573	617,118
2016	1,188,399	39,123	367,919	83,938	697,418
2017	1,204,582	39,828	318,611	107,987	738,156
2018	1,242,771	44,393	341,707	85,108	771,563
2019	1,232,925	43,862	327,203	82,455	779,405
2020	1,330,225	48,377	337,024	81,490	863,334
2021	1,258,705	50,514	316,694	73,588	817,909
2022	1,241,812	47,619	313,753	77,225	803,214
2023	1,245,459	47,866	314,352	72,281	810,961
2024	1,283,047	50,258	321,517	83,211	828,062
Year 2022					
January	115,425	4,763	29,244	7,589	73,829
February	101,428	4,030	25,905	6,706	64,787
March	105,152	3,945	26,566	6,606	68,035
April	95,492	2,808	23,111	5,921	63,651
May	98,439	3,439	24,825	5,804	64,370
June	100,539	3,996	26,351	6,061	64,131
July	109,613	4,736	29,480	7,039	68,358
August	109,239	4,375	28,378	7,127	69,360
September	99,549	3,697	25,602	6,017	64,232
October	98,163	3,163	24,207	5,599	65,194
November	101,006	4,130	23,735	5,878	67,263
December	107,768	4,538	26,349	6,877	70,004
Year 2023					
January	108,883	4,492	26,208	6,550	71,633
February	99,105	3,990	25,368	6,007	63,740
March	105,904	4,034	26,442	6,149	69,279
April	96,246	3,387	23,983	5,324	63,552
May	97,552	3,502	23,200	5,368	65,482
June	101,827	3,807	25,465	5,671	66,884
July	108,416	4,694	28,686	6,530	68,506
August	107,213	4,289	28,645	6,211	68,068
September	102,648	3,905	26,025	6,004	66,714
October	100,203	3,331	25,929	5,799	65,144
November	105,925	4,079	27,145	6,241	68,460
December	111,537	4,357	27,254	6,427	73,499
Year 2024					
January	119,009	4,487	28,786	8,185	77,551
February	104,900	4,103	26,740	7,181	66,877
March	106,209	4,399	26,598	6,879	68,332
April	96,649	3,339	22,832	5,924	64,554
May	100,760	3,696	24,987	5,509	66,568
June	103,083	4,148	26,755	6,531	65,649
July	112,169	4,947	29,732	7,673	69,818
August	113,213	4,835	30,475	7,485	70,418
September	105,660	4,431	27,720	6,683	66,827
October	102,836	3,604	26,312	6,509	66,411
November	104,992	3,750	24,583	6,912	69,747
December	113,568	4,520	25,997	7,740	75,310

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.F. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	9,687,297	4,006,859	4,377,657	121,773	1,181,009
2015	11,326,564	4,913,263	5,032,066	119,502	1,261,732
2016	11,704,224	5,228,667	5,096,363	131,489	1,247,706
2017	11,032,375	4,951,457	4,626,852	159,580	1,294,487
2018	12,443,568	5,784,146	5,167,665	139,498	1,352,259
2019	13,241,359	6,222,048	5,465,029	139,483	1,414,799
2020	13,655,071	6,446,937	5,576,130	134,665	1,497,340
2021	13,151,252	6,122,182	5,489,692	120,485	1,418,893
2022	14,034,401	6,627,889	5,864,392	127,423	1,414,697
2023	14,930,337	7,089,579	6,282,273	123,050	1,435,435
2024	15,509,535	7,578,610	6,361,723	132,749	1,436,454
Year 2022					
January	1,120,949	520,847	460,679	11,693	127,730
February	952,594	431,767	399,131	10,346	111,350
March	931,097	423,744	378,235	10,516	118,601
April	887,365	406,504	360,181	9,559	111,120
May	1,075,335	507,028	444,615	9,679	114,014
June	1,305,940	646,069	534,561	10,241	115,069
July	1,585,730	780,229	669,501	12,052	123,948
August	1,564,279	751,266	675,450	12,339	125,225
September	1,288,914	602,784	561,511	10,493	114,126
October	1,102,096	510,470	467,408	9,358	114,860
November	1,059,735	499,433	432,459	9,857	117,985
December	1,160,366	547,747	480,661	11,290	120,668
Year 2023					
January	1,132,704	532,719	466,145	10,706	123,135
February	1,016,876	471,994	424,553	9,848	110,480
March	1,098,964	519,154	449,195	10,230	120,385
April	1,008,120	478,077	412,424	9,054	108,566
May	1,145,746	561,805	458,900	9,290	115,751
June	1,346,007	653,106	562,877	9,986	120,039
July	1,660,039	802,482	720,962	11,676	124,918
August	1,655,800	814,832	704,860	11,136	124,972
September	1,368,425	643,628	593,665	10,606	120,526
October	1,175,834	547,672	501,153	9,887	117,121
November	1,126,271	506,842	488,538	10,153	120,738
December	1,195,550	557,267	499,003	10,478	128,802
Year 2024					
January	1,324,066	625,568	552,902	12,447	133,149
February	1,073,631	506,646	439,449	11,049	116,488
March	1,080,270	516,331	434,813	10,748	118,377
April	1,030,753	494,073	414,136	9,548	112,996
May	1,204,763	601,720	478,492	9,135	115,415
June	1,404,511	701,914	576,917	10,832	114,849
July	1,718,503	869,289	712,471	12,827	123,916
August	1,688,501	856,226	693,360	12,377	126,539
September	1,392,319	688,878	575,489	10,784	117,167
October	1,229,250	598,550	508,095	10,355	112,250
November	1,149,375	552,721	468,600	10,833	117,220
December	1,213,593	566,694	506,999	11,812	128,088

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.5.D. Wood / Wood Waste Biomass: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	431,285	45,643	174,513	961	210,167
2015	406,650	43,919	171,387	504	190,840
2016	359,983	41,036	149,516	473	168,959
2017	363,646	42,806	151,877	460	168,503
2018	361,703	45,856	143,288	520	172,039
2019	338,317	42,240	128,980	583	166,514
2020	318,381	31,606	125,695	608	160,472
2021	328,253	41,868	129,554	998	155,833
2022	323,820	46,357	125,125	1,140	151,198
2023	289,996	38,914	110,338	732	140,012
2024	279,132	35,766	104,307	709	138,350
Year 2022					
January	28,590	4,116	11,148	102	13,225
February	27,354	4,072	10,966	94	12,223
March	26,834	3,220	10,911	69	12,633
April	24,378	2,638	9,297	73	12,370
May	26,094	3,542	9,711	110	12,731
June	27,667	4,060	10,713	129	12,766
July	30,189	4,960	11,506	119	13,604
August	29,708	5,264	11,129	171	13,144
September	26,117	3,722	10,273	81	12,041
October	23,854	3,181	9,295	42	11,335
November	25,533	3,117	9,864	72	12,481
December	27,502	4,466	10,313	77	12,647
Year 2023					
January	26,972	3,947	10,564	76	12,384
February	23,316	3,531	8,879	47	10,859
March	24,472	2,504	9,943	55	11,971
April	21,340	1,966	8,038	46	11,290
May	24,408	2,836	9,447	24	12,101
June	24,292	3,798	9,164	68	11,262
July	26,080	4,560	9,783	58	11,678
August	27,025	4,473	10,163	85	12,304
September	23,669	3,310	8,832	82	11,446
October	20,337	2,193	7,284	61	10,800
November	22,798	2,521	8,717	56	11,503
December	25,286	3,276	9,522	74	12,414
Year 2024					
January	26,093	4,339	9,893	99	11,762
February	23,434	3,273	9,003	37	11,121
March	23,476	1,944	9,739	24	11,770
April	20,826	2,962	6,634	9	11,221
May	22,584	2,707	8,149	33	11,696
June	24,318	3,708	8,842	66	11,702
July	25,152	3,598	9,419	111	12,025
August	25,625	4,069	9,488	60	12,008
September	22,153	2,006	9,021	83	11,044
October	19,018	1,403	6,868	45	10,702
November	21,812	2,012	8,127	76	11,596
December	24,640	3,744	9,124	68	11,704

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.5.E. Wood / Wood Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	946,344	8,835	22,262	3,766	911,481
2015	943,962	9,351	19,200	3,714	911,697
2016	969,841	10,950	22,905	4,520	931,465
2017	939,633	11,656	22,986	4,522	900,469
2018	929,365	10,297	21,623	4,806	892,639
2019	907,420	3,564	25,740	4,969	873,147
2020	860,062	3,051	25,022	3,595	828,394
2021	870,986	3,520	21,804	2,958	842,704
2022	819,538	4,629	21,579	3,158	790,172
2023	754,615	4,076	20,744	2,343	727,452
2024	740,218	4,445	17,219	2,295	716,259
Year 2022					
January	72,157	390	2,158	282	69,327
February	65,478	385	1,740	281	63,071
March	68,069	443	1,613	228	65,785
April	68,138	403	1,617	171	65,947
May	70,011	269	1,639	274	67,828
June	68,973	296	1,688	367	66,623
July	71,267	330	1,709	327	68,901
August	70,484	360	1,819	375	67,931
September	64,897	408	1,977	199	62,313
October	65,076	230	1,763	149	62,935
November	66,976	513	1,895	250	64,318
December	68,011	603	1,960	256	65,192
Year 2023					
January	69,277	456	1,721	249	66,851
February	60,917	377	1,949	163	58,427
March	66,831	438	2,692	223	63,478
April	59,109	391	1,725	162	56,830
May	63,132	91	1,803	81	61,157
June	58,285	266	1,869	254	55,897
July	61,598	295	1,451	129	59,723
August	62,979	339	1,215	221	61,204
September	60,896	182	866	256	59,592
October	61,213	344	2,393	185	58,292
November	64,741	433	1,506	179	62,623
December	65,636	464	1,555	241	63,377
Year 2024					
January	63,467	474	1,688	285	61,020
February	60,551	431	1,485	138	58,497
March	62,314	473	1,366	75	60,401
April	61,443	433	1,324	65	59,621
May	60,090	252	1,392	147	58,299
June	60,041	365	1,310	223	58,143
July	61,068	410	1,461	318	58,879
August	62,242	346	1,483	185	60,227
September	62,115	364	1,566	233	59,953
October	58,196	169	1,301	150	56,576
November	62,481	343	1,262	218	60,659
December	66,211	387	1,582	259	63,983

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.5.F. Wood / Wood Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,377,629	54,478	196,775	4,727	1,121,648
2015	1,350,612	53,269	190,587	4,219	1,102,537
2016	1,329,824	51,986	172,421	4,993	1,100,424
2017	1,303,279	54,462	174,862	4,982	1,068,972
2018	1,291,068	56,153	164,911	5,326	1,064,678
2019	1,245,737	45,804	154,720	5,552	1,039,661
2020	1,178,443	34,657	150,717	4,203	988,866
2021	1,199,240	45,387	151,359	3,957	998,537
2022	1,143,358	50,986	146,704	4,297	941,370
2023	1,044,610	42,990	131,082	3,075	867,464
2024	1,019,350	40,211	121,526	3,004	854,608
Year 2022					
January	100,746	4,505	13,306	384	82,552
February	92,833	4,457	12,706	376	75,294
March	94,902	3,663	12,524	297	78,418
April	92,516	3,041	10,914	244	78,317
May	96,104	3,810	11,350	384	80,559
June	96,641	4,356	12,401	495	79,388
July	101,457	5,290	13,216	446	82,505
August	100,192	5,624	12,948	545	81,075
September	91,014	4,131	12,251	280	74,354
October	88,930	3,412	11,058	191	74,270
November	92,510	3,630	11,759	322	76,800
December	95,513	5,068	12,273	334	77,839
Year 2023					
January	96,249	4,403	12,285	325	79,236
February	84,233	3,908	10,828	210	69,287
March	91,304	2,942	12,635	278	75,449
April	80,449	2,357	9,763	209	68,121
May	87,540	2,927	11,250	105	73,258
June	82,577	4,064	11,032	322	67,159
July	87,677	4,855	11,234	187	71,401
August	90,005	4,812	11,378	306	73,508
September	84,565	3,492	9,698	338	71,037
October	81,550	2,537	9,677	246	69,091
November	87,538	2,954	10,223	235	74,126
December	90,923	3,740	11,078	315	75,791
Year 2024					
January	89,560	4,813	11,581	384	72,782
February	83,985	3,704	10,488	175	69,618
March	85,790	2,416	11,105	98	72,171
April	82,268	3,394	7,958	74	70,842
May	82,674	2,959	9,540	180	69,995
June	84,359	4,073	10,152	289	69,845
July	86,220	4,008	10,880	429	70,903
August	87,867	4,415	10,972	245	72,236
September	84,269	2,370	10,586	315	70,997
October	77,215	1,573	8,169	195	67,278
November	84,293	2,355	9,389	294	72,255
December	90,851	4,131	10,707	326	75,687

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.A. Landfill Gas: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Million Cubic Feet)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	285,982	25,819	228,447	27,038	4,678
2015	282,530	25,257	227,381	25,250	4,642
2016	273,557	24,280	224,993	20,445	3,839
2017	278,112	25,074	229,050	20,121	3,866
2018	270,235	23,580	223,513	19,790	3,352
2019	257,494	22,726	214,819	16,874	3,075
2020	252,501	23,571	208,196	18,136	2,597
2021	231,876	22,831	190,031	16,472	2,542
2022	211,866	18,486	176,160	14,898	2,323
2023	194,292	15,815	162,861	13,392	2,224
2024	181,646	14,369	152,452	12,687	2,137
Year 2022					
January	18,515	1,725	15,257	1,343	190
February	17,347	1,602	14,349	1,216	180
March	19,127	1,751	15,882	1,301	192
April	17,226	1,547	14,618	900	161
May	17,953	1,594	14,955	1,209	195
June	17,609	1,531	14,651	1,225	202
July	17,975	1,543	14,919	1,314	198
August	17,540	1,487	14,533	1,315	207
September	17,102	1,461	14,174	1,275	192
October	17,877	1,480	14,857	1,337	202
November	16,933	1,419	14,149	1,177	188
December	16,663	1,347	13,815	1,285	216
Year 2023					
January	16,986	1,407	14,217	1,180	182
February	15,093	1,220	12,583	1,094	196
March	16,449	1,392	13,673	1,145	238
April	15,225	1,273	12,683	1,075	193
May	17,019	1,411	14,329	1,104	175
June	16,409	1,356	13,731	1,113	208
July	16,595	1,332	13,925	1,162	176
August	16,660	1,320	13,972	1,207	162
September	15,396	1,188	12,927	1,133	149
October	15,747	1,271	13,387	930	160
November	15,859	1,284	13,301	1,100	174
December	16,855	1,360	14,133	1,150	212
Year 2024					
January	15,763	1,189	13,278	1,108	189
February	14,939	1,216	12,519	1,002	203
March	15,785	1,228	13,266	1,081	211
April	14,426	1,123	12,149	981	172
May	15,722	1,216	13,318	1,060	128
June	14,687	1,148	12,406	993	139
July	15,423	1,218	12,945	1,074	187
August	15,793	1,290	13,244	1,074	184
September	14,907	1,205	12,489	1,040	172
October	15,054	1,201	12,582	1,046	224
November	14,542	1,188	12,077	1,105	172
December	14,604	1,146	12,179	1,124	155

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.B. Landfill Gas: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

by Sector, 2014 - 2024 (million cubic feet)					
		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,710	176	525	674	335
2015	1,522	2	644	515	362
2016	4,163	3	2,339	1,034	788
2017	3,940	2	1,948	1,099	891
2018	3,621	0	1,867	911	843
2019	3,570	5	1,933	820	812
2020	4,011	3	2,187	820	1,000
2021	4,030	6	2,155	741	1,129
2022	4,280	15	1,996	817	1,451
2023	3,411	10	1,722	705	973
2024	3,228	33	1,709	523	964
Year 2022					
January	401	1	197	81	121
February	374	1	186	69	118
March	436	1	218	78	138
April	330	1	157	70	102
May	293	1	116	51	125
June	344	1	163	65	115
July	362	1	170	66	125
August	362	1	164	74	122
September	355	1	160	76	117
October	355	1	163	69	122
November	315	1	130	64	120
December	354	1	173	55	124
Year 2023					
January	298	1	153	64	80
February	267	1	135	52	79
March	282	1	144	49	88
April	297	1	142	65	89
May	221	1	103	40	78
June	294	1	152	53	88
July	310	1	161	65	83
August	309	1	160	70	78
September	279	1	155	61	63
October	293	1	147	72	73
November	247	1	104	60	83
December	314	1	166	54	93
Year 2024					
January	295	3	166	46	80
February	281	2	144	51	84
March	291	3	151	52	85
April	304	2	132	38	131
May	218	3	120	32	63
June	226	3	133	18	72
July	266	3	148	26	88
August	305	3	156	50	95
September	284	3	143	52	86
October	284	3	147	55	79
November	221	3	112	53	53
December	254	3	155	48	48

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.C. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	287,692	25,995	228,971	27,713	5,013
2015	284,052	25,259	228,024	25,765	5,004
2016	277,720	24,283	227,332	21,479	4,626
2017	282,051	25,076	230,998	21,220	4,757
2018	273,856	23,580	225,380	20,701	4,196
2019	261,064	22,731	216,753	17,694	3,887
2020	256,512	23,575	210,383	18,956	3,598
2021	235,906	22,836	192,186	17,212	3,671
2022	216,146	18,501	178,155	15,715	3,774
2023	197,703	15,825	164,584	14,097	3,197
2024	184,874	14,402	154,161	13,210	3,100
Year 2022					
January	18,916	1,726	15,454	1,424	311
February	17,721	1,603	14,535	1,285	298
March	19,562	1,753	16,100	1,379	330
April	17,556	1,548	14,775	971	263
May	18,246	1,595	15,070	1,260	321
June	17,953	1,532	14,813	1,290	318
July	18,337	1,545	15,089	1,380	323
August	17,902	1,488	14,696	1,389	329
September	17,456	1,462	14,334	1,350	309
October	18,232	1,482	15,020	1,406	324
November	17,247	1,420	14,279	1,241	308
December	17,017	1,348	13,988	1,340	340
Year 2023					
January	17,284	1,408	14,370	1,244	262
February	15,360	1,221	12,719	1,146	275
March	16,731	1,393	13,817	1,194	326
April	15,522	1,274	12,826	1,140	282
May	17,240	1,412	14,432	1,144	253
June	16,702	1,357	13,884	1,166	295
July	16,905	1,333	14,085	1,227	259
August	16,969	1,321	14,132	1,277	239
September	15,675	1,189	13,082	1,193	211
October	16,040	1,272	13,534	1,001	233
November	16,106	1,285	13,405	1,159	257
December	17,169	1,361	14,299	1,204	305
Year 2024					
January	16,058	1,192	13,444	1,154	268
February	15,220	1,218	12,662	1,053	286
March	16,076	1,231	13,417	1,133	295
April	14,730	1,126	12,282	1,019	303
May	15,940	1,219	13,438	1,092	191
June	14,913	1,151	12,540	1,012	211
July	15,689	1,221	13,093	1,100	275
August	16,097	1,293	13,400	1,125	280
September	15,191	1,208	12,632	1,092	258
October	15,338	1,204	12,729	1,102	303
November	14,763	1,191	12,189	1,158	225
December	14,858	1,149	12,334	1,172	204

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.D. Landfill Gas: Consumption for Electricity Generation,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	140,779	13,132	114,333	10,937	2,377
2015	138,085	12,846	112,911	10,023	2,304
2016	135,365	12,294	112,770	8,374	1,927
2017	137,635	13,071	114,131	8,508	1,926
2018	133,957	12,395	111,769	8,104	1,689
2019	127,540	11,794	107,100	7,086	1,560
2020	124,647	12,337	103,453	7,510	1,348
2021	113,839	11,897	93,819	6,826	1,297
2022	103,630	9,661	86,766	6,007	1,197
2023	95,684	8,251	80,667	5,640	1,126
2024	89,564	7,341	75,604	5,533	1,086
Year 2022					
January	9,050	900	7,506	546	98
February	8,482	837	7,060	492	93
March	9,339	916	7,813	511	99
April	8,482	812	7,202	385	83
May	8,781	836	7,372	473	100
June	8,624	800	7,221	498	105
July	8,813	806	7,376	529	102
August	8,603	776	7,187	534	106
September	8,359	763	6,979	518	98
October	8,707	773	7,298	531	104
November	8,282	741	6,968	476	96
December	8,108	700	6,784	513	111
Year 2023					
January	8,356	735	7,049	481	91
February	7,401	636	6,224	442	99
March	8,098	728	6,780	470	120
April	7,498	667	6,276	458	98
May	8,365	739	7,070	469	88
June	8,078	708	6,798	468	104
July	8,190	696	6,910	495	89
August	8,221	688	6,937	514	83
September	7,572	617	6,404	475	76
October	7,805	661	6,650	412	82
November	7,809	668	6,587	465	88
December	8,290	707	6,984	490	109
Year 2024					
January	7,775	607	6,587	485	95
February	7,388	623	6,220	442	103
March	7,799	629	6,584	478	109
April	7,135	575	6,031	440	89
May	7,787	620	6,625	474	67
June	7,260	585	6,170	432	72
July	7,607	621	6,425	466	95
August	7,807	659	6,587	466	95
September	7,351	616	6,200	447	89
October	7,396	614	6,229	449	104
November	7,116	608	5,951	470	87
December	7,144	584	5,996	484	81

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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**Table 5.6.E. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2014 - 2024 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	852	88	266	326	173
2015	756	1	326	250	179
2016	2,236	1	1,266	589	380
2017	2,196	1	1,066	698	431
2018	1,964	0	966	594	403
2019	1,960	2	1,034	531	394
2020	2,225	1	1,168	535	521
2021	2,210	2	1,151	504	553
2022	2,363	5	1,081	547	729
2023	1,876	3	944	464	465
2024	1,772	10	938	362	462
Year 2022					
January	224	0	107	55	61
February	207	0	101	47	60
March	240	0	117	53	70
April	186	0	86	48	51
May	159	0	64	32	63
June	193	0	89	45	59
July	199	0	93	43	63
August	201	0	89	50	61
September	196	0	87	50	58
October	196	0	88	46	61
November	174	0	71	43	60
December	189	0	89	37	62
Year 2023					
January	163	0	83	42	38
February	145	0	74	34	38
March	156	0	79	34	42
April	163	0	78	43	43
May	121	0	59	25	37
June	160	0	83	34	42
July	171	0	88	43	39
August	172	0	87	47	37
September	155	0	84	40	30
October	163	0	81	47	35
November	134	0	58	37	39
December	174	0	91	37	45
Year 2024					
January	162	1	90	33	38
February	154	1	79	34	40
March	159	1	83	35	41
April	166	1	74	27	65
May	119	1	67	21	30
June	121	1	73	13	34
July	142	1	81	18	42
August	168	1	85	36	46
September	157	1	78	37	41
October	155	1	80	38	36
November	125	1	62	37	25
December	144	1	85	34	24

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Table 5.6.F. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	141,632	13,220	114,599	11,263	2,550
2015	138,841	12,847	113,238	10,273	2,483
2016	137,600	12,295	114,036	8,963	2,307
2017	139,831	13,072	115,197	9,206	2,357
2018	135,921	12,395	112,736	8,698	2,092
2019	129,500	11,795	108,134	7,617	1,954
2020	126,872	12,338	104,621	8,045	1,868
2021	116,049	11,899	94,971	7,330	1,850
2022	105,993	9,666	87,846	6,554	1,926
2023	97,560	8,254	81,611	6,104	1,591
2024	91,336	7,351	76,542	5,895	1,548
Year 2022					
January	9,274	901	7,612	601	160
February	8,689	838	7,160	538	153
March	9,579	917	7,930	564	169
April	8,668	812	7,288	433	135
May	8,939	836	7,436	505	163
June	8,817	800	7,310	543	163
July	9,012	806	7,468	572	166
August	8,804	776	7,277	584	168
September	8,554	764	7,066	568	156
October	8,903	774	7,386	577	166
November	8,456	742	7,039	519	156
December	8,297	700	6,873	550	173
Year 2023					
January	8,519	735	7,132	523	129
February	7,547	637	6,298	476	136
March	8,254	729	6,859	504	162
April	7,661	667	6,353	500	140
May	8,486	739	7,128	494	125
June	8,238	709	6,881	503	146
July	8,361	697	6,997	539	128
August	8,393	688	7,024	561	120
September	7,727	617	6,488	515	106
October	7,969	662	6,732	459	117
November	7,943	669	6,645	502	128
December	8,464	707	7,075	527	154
Year 2024					
January	7,937	608	6,678	518	133
February	7,543	624	6,299	477	143
March	7,959	630	6,667	513	150
April	7,300	576	6,104	467	154
May	7,906	621	6,692	495	97
June	7,380	586	6,244	444	106
July	7,749	622	6,506	484	137
August	7,975	660	6,672	502	141
September	7,508	616	6,278	484	130
October	7,552	615	6,309	487	140
November	7,241	609	6,013	507	112
December	7,287	585	6,081	517	105

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.A. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	16,706	444	13,809	2,447	6
2015	16,631	452	13,797	2,375	8
2016	16,994	464	13,953	2,566	11
2017	16,348	422	13,381	2,537	8
2018	16,783	467	13,859	2,448	9
2019	15,559	297	12,941	2,310	10
2020	15,516	280	12,975	2,251	10
2021	15,223	252	12,442	2,521	7
2022	14,589	274	7,346	6,969	0
2023	13,916	283	6,960	6,674	0
2024	13,636	283	6,721	6,632	0
Year 2022					
January	1,214	22	645	547	0
February	1,117	20	567	530	0
March	1,215	17	638	560	0
April	1,207	23	592	591	0
May	1,225	28	607	589	0
June	1,248	25	622	601	0
July	1,272	25	634	612	0
August	1,246	28	623	595	0
September	1,199	18	604	577	0
October	1,211	24	592	595	0
November	1,212	23	593	595	0
December	1,224	21	626	577	0
Year 2023					
January	1,205	24	616	564	0
February	1,048	15	539	494	0
March	1,112	21	575	516	0
April	1,065	21	533	512	0
May	1,170	21	591	558	0
June	1,180	26	582	572	0
July	1,248	24	620	604	0
August	1,235	28	614	592	0
September	1,140	24	572	544	0
October	1,156	27	564	565	0
November	1,131	26	546	559	0
December	1,226	24	607	595	0
Year 2024					
January	1,182	21	582	578	0
February	1,065	17	531	516	0
March	1,105	13	565	527	0
April	1,070	20	504	546	0
May	1,172	29	567	575	0
June	1,137	27	555	555	0
July	1,201	28	595	578	0
August	1,228	27	604	597	0
September	1,117	24	560	533	0
October	1,118	27	544	547	0
November	1,113	24	554	535	0
December	1,129	25	558	546	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.B. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	1,955	0	650	1,104	200
2015	1,986	0	655	1,127	203
2016	2,232	0	885	1,134	213
2017	2,124	0	814	1,102	208
2018	2,050	0	752	1,109	189
2019	1,667	0	743	737	187
2020	1,650	0	757	705	188
2021	1,712	0	873	666	173
2022	1,647	0	401	1,246	0
2023	1,667	0	449	1,218	0
2024	1,611	0	417	1,194	0
Year 2022					
January	148	0	38	110	0
February	130	0	31	99	0
March	129	0	30	100	0
April	125	0	29	96	0
May	143	0	34	109	0
June	141	0	32	108	0
July	148	0	37	111	0
August	151	0	34	117	0
September	137	0	32	104	0
October	127	0	32	95	0
November	139	0	34	106	0
December	129	0	38	91	0
Year 2023					
January	135	0	38	97	0
February	129	0	33	96	0
March	137	0	34	103	0
April	129	0	32	97	0
May	141	0	33	108	0
June	128	0	33	95	0
July	148	0	41	107	0
August	153	0	40	113	0
September	140	0	40	101	0
October	122	0	37	85	0
November	145	0	44	102	0
December	159	0	43	115	0
Year 2024					
January	153	0	43	110	0
February	141	0	35	106	0
March	137	0	33	103	0
April	121	0	35	85	0
May	146	0	36	109	0
June	137	0	31	106	0
July	141	0	35	106	0
August	124	0	36	87	0
September	124	0	33	91	0
October	126	0	30	96	0
November	126	0	31	95	0
December	136	0	37	99	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.C. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	18,661	444	14,459	3,551	206
2015	18,617	452	14,452	3,502	211
2016	19,226	464	14,838	3,700	224
2017	18,473	422	14,195	3,639	216
2018	18,833	467	14,611	3,557	197
2019	17,225	297	13,684	3,047	197
2020	17,166	280	13,732	2,956	198
2021	16,934	252	13,315	3,187	180
2022	16,236	274	7,747	8,215	0
2023	15,584	283	7,408	7,892	0
2024	15,247	283	7,138	7,827	0
Year 2022					
January	1,362	22	683	657	0
February	1,248	20	598	629	0
March	1,344	17	668	660	0
April	1,332	23	621	687	0
May	1,368	28	642	697	0
June	1,389	25	655	709	0
July	1,420	25	671	723	0
August	1,397	28	657	712	0
September	1,336	18	636	682	0
October	1,338	24	624	690	0
November	1,351	23	627	701	0
December	1,353	21	664	668	0
Year 2023					
January	1,340	24	654	662	0
February	1,177	15	571	591	0
March	1,250	21	609	619	0
April	1,194	21	564	609	0
May	1,311	21	625	665	0
June	1,309	26	615	668	0
July	1,396	24	661	711	0
August	1,388	28	654	705	0
September	1,281	24	612	644	0
October	1,278	27	601	649	0
November	1,276	26	590	660	0
December	1,385	24	650	710	0
Year 2024					
January	1,335	21	626	688	0
February	1,206	17	566	623	0
March	1,242	13	599	630	0
April	1,191	20	539	631	0
May	1,317	29	604	684	0
June	1,274	27	586	661	0
July	1,342	28	630	684	0
August	1,352	27	641	684	0
September	1,241	24	593	624	0
October	1,244	27	575	642	0
November	1,239	24	585	630	0
December	1,265	25	595	645	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.D. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	134,408	4,429	110,569	19,366	45,054
2015	133,117	4,295	109,691	19,068	63,063
2016	135,957	4,434	111,003	20,431	89,093
2017	130,942	4,172	106,382	20,320	67,050
2018	134,465	4,568	110,452	19,374	72,071
2019	115,114	2,454	95,638	16,946	76,076
2020	114,814	2,284	95,941	16,511	77,078
2021	113,173	2,029	92,144	18,944	56,056
2022	108,508	2,212	54,250	52,046	0
2023	103,306	2,275	51,190	49,841	0
2024	100,831	2,273	49,294	49,263	0
Year 2022					
January	9,109	172	4,796	4,141	0
February	8,332	161	4,204	3,967	0
March	9,091	134	4,797	4,160	0
April	9,014	186	4,404	4,424	0
May	9,156	227	4,528	4,401	0
June	9,285	203	4,602	4,480	0
July	9,451	205	4,699	4,547	0
August	9,222	227	4,574	4,420	0
September	8,817	143	4,423	4,251	0
October	8,960	192	4,319	4,449	0
November	8,977	188	4,321	4,468	0
December	9,095	174	4,584	4,338	0
Year 2023					
January	8,952	198	4,517	4,237	0
February	7,833	124	3,984	3,725	0
March	8,285	174	4,245	3,866	0
April	7,938	169	3,923	3,846	0
May	8,740	173	4,378	4,188	0
June	8,746	208	4,274	4,264	0
July	9,244	195	4,584	4,465	0
August	9,066	227	4,465	4,373	0
September	8,403	194	4,194	4,015	0
October	8,593	215	4,161	4,217	0
November	8,403	204	4,003	4,196	0
December	9,104	193	4,462	4,449	0
Year 2024					
January	8,780	167	4,308	4,305	0
February	7,906	137	3,911	3,857	0
March	8,207	106	4,164	3,937	0
April	7,900	156	3,723	4,021	0
May	8,714	237	4,182	4,294	0
June	8,334	211	4,059	4,063	0
July	8,825	219	4,333	4,273	0
August	8,959	225	4,354	4,380	0
September	8,199	192	4,090	3,918	0
October	8,281	225	3,994	4,062	0
November	8,305	198	4,064	4,043	0
December	8,420	200	4,112	4,108	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.E. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	15,783	0	5,140	9,046	1,597
2015	16,623	0	5,195	9,752	1,676
2016	18,259	0	6,877	9,665	1,717
2017	17,720	0	6,475	9,474	1,772
2018	16,724	0	5,887	9,312	1,524
2019	12,308	0	5,362	5,527	1,419
2020	11,939	0	5,420	5,117	1,401
2021	12,721	0	6,371	5,050	1,300
2022	12,244	0	2,966	9,278	0
2023	12,535	0	3,367	9,168	0
2024	12,179	0	3,101	9,079	0
Year 2022					
January	1,125	0	281	845	0
February	959	0	231	728	0
March	949	0	220	729	0
April	912	0	211	701	0
May	1,051	0	254	797	0
June	1,042	0	238	803	0
July	1,125	0	274	851	0
August	1,117	0	254	862	0
September	1,020	0	237	783	0
October	929	0	232	696	0
November	1,063	0	253	810	0
December	952	0	279	673	0
Year 2023					
January	995	0	282	713	0
February	955	0	245	710	0
March	1,024	0	254	770	0
April	965	0	237	728	0
May	1,064	0	251	813	0
June	975	0	249	726	0
July	1,102	0	307	795	0
August	1,121	0	292	829	0
September	1,051	0	297	754	0
October	942	0	291	650	0
November	1,129	0	334	795	0
December	1,211	0	327	884	0
Year 2024					
January	1,170	0	329	840	0
February	1,064	0	259	805	0
March	1,042	0	250	792	0
April	900	0	259	640	0
May	1,064	0	260	804	0
June	1,025	0	231	794	0
July	1,052	0	262	790	0
August	921	0	269	652	0
September	951	0	250	701	0
October	972	0	228	745	0
November	981	0	232	749	0
December	1,039	0	273	766	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.F. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	150,191	4,429	115,709	28,411	1,643
2015	149,740	4,295	114,886	28,821	1,739
2016	154,216	4,434	117,880	30,095	1,806
2017	148,662	4,172	112,857	29,794	1,839
2018	151,188	4,568	116,339	28,686	1,596
2019	127,422	2,454	101,000	22,473	1,495
2020	126,752	2,284	101,362	21,629	1,478
2021	125,894	2,029	98,516	23,994	1,355
2022	120,753	2,212	57,217	61,324	0
2023	115,841	2,275	54,557	59,009	0
2024	113,010	2,273	52,395	58,341	0
Year 2022					
January	10,234	172	5,077	4,986	0
February	9,291	161	4,435	4,696	0
March	10,040	134	5,018	4,889	0
April	9,926	186	4,615	5,125	0
May	10,207	227	4,782	5,198	0
June	10,327	203	4,841	5,283	0
July	10,576	205	4,973	5,398	0
August	10,338	227	4,829	5,283	0
September	9,837	143	4,660	5,033	0
October	9,889	192	4,551	5,146	0
November	10,040	188	4,575	5,277	0
December	10,047	174	4,863	5,010	0
Year 2023					
January	9,947	198	4,799	4,950	0
February	8,788	124	4,229	4,436	0
March	9,310	174	4,499	4,637	0
April	8,903	169	4,160	4,573	0
May	9,804	173	4,630	5,001	0
June	9,721	208	4,523	4,989	0
July	10,346	195	4,891	5,260	0
August	10,187	227	4,757	5,202	0
September	9,455	194	4,491	4,769	0
October	9,534	215	4,452	4,867	0
November	9,532	204	4,337	4,991	0
December	10,316	193	4,789	5,333	0
Year 2024					
January	9,950	167	4,637	5,146	0
February	8,970	137	4,170	4,662	0
March	9,249	106	4,414	4,729	0
April	8,800	156	3,982	4,662	0
May	9,778	237	4,442	5,098	0
June	9,358	211	4,290	4,857	0
July	9,877	219	4,595	5,063	0
August	9,880	225	4,623	5,032	0
September	9,150	192	4,339	4,619	0
October	9,254	225	4,222	4,807	0
November	9,286	198	4,297	4,792	0
December	9,458	200	4,385	4,874	0

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.D. Other Waste Biomass: Consumption for Electricity Generation, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	38,361	2,360	21,628	5,745	8,627
2015	41,785	2,853	25,058	5,935	7,939
2016	33,786	2,553	18,194	5,504	7,536
2017	35,755	1,845	22,517	5,288	6,105
2018	29,407	1,343	16,874	5,867	5,324
2019	23,947	1,133	12,606	5,668	4,540
2020	22,234	1,024	11,195	5,014	5,001
2021	22,623	1,007	11,536	5,075	5,005
2022	19,910	638	9,809	4,548	4,915
2023	20,807	865	11,019	4,700	4,224
2024	21,130	842	10,266	5,320	4,702
Year 2022					
January	1,896	57	934	436	470
February	1,712	40	904	351	417
March	1,800	45	851	414	490
April	1,502	34	665	356	447
May	1,427	64	566	355	442
June	1,610	55	858	365	331
July	1,648	63	883	373	329
August	1,701	48	903	378	372
September	1,593	70	840	375	307
October	1,709	44	848	398	419
November	1,535	59	675	373	428
December	1,777	59	882	374	462
Year 2023					
January	1,708	78	882	335	412
February	1,932	80	1,138	354	360
March	1,614	60	784	388	383
April	1,540	85	759	337	360
May	1,727	66	844	439	379
June	1,604	47	840	420	298
July	1,655	61	895	402	297
August	1,716	60	966	390	300
September	1,642	73	943	374	252
October	1,783	105	879	419	380
November	1,773	66	889	408	409
December	2,112	84	1,200	435	393
Year 2024					
January	1,875	47	924	458	446
February	1,745	45	852	429	418
March	1,763	68	729	500	466
April	1,545	62	631	447	406
May	1,742	84	741	478	439
June	1,715	92	876	449	299
July	1,654	99	792	436	327
August	1,784	105	946	382	350
September	1,765	63	970	396	337
October	1,829	64	936	440	389
November	1,795	53	875	443	424
December	1,917	61	994	461	400

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.E. Other Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	65,201	15	6,930	1,543	56,712
2015	67,512	1	7,845	2,000	57,666
2016	57,123	18	11,252	3,569	42,284
2017	50,518	15	10,543	3,218	36,742
2018	50,338	14	10,753	3,673	35,898
2019	41,084	39	10,452	3,282	27,312
2020	43,383	18	9,358	3,166	30,841
2021	45,209	9	9,499	2,907	32,793
2022	45,181	13	9,088	2,633	33,446
2023	39,471	15	9,646	2,666	27,144
2024	40,916	12	8,722	2,601	29,581
Year 2022					
January	4,959	0	1,143	247	3,568
February	4,327	0	1,079	237	3,010
March	5,115	0	1,158	244	3,712
April	4,088	0	672	196	3,219
May	3,785	0	364	221	3,199
June	2,664	0	515	222	1,927
July	2,521	0	612	197	1,712
August	2,727	0	558	197	1,972
September	2,339	2	440	228	1,671
October	3,637	3	536	231	2,867
November	4,198	3	953	198	3,044
December	4,821	2	1,058	214	3,546
Year 2023					
January	4,601	4	1,199	257	3,141
February	3,837	4	1,010	215	2,607
March	4,177	0	1,186	234	2,757
April	3,713	4	1,004	210	2,495
May	3,571	0	705	214	2,652
June	2,156	0	348	211	1,596
July	2,108	0	467	202	1,439
August	2,082	0	486	206	1,390
September	1,922	0	410	230	1,281
October	3,457	0	813	243	2,401
November	3,638	0	978	212	2,448
December	4,211	0	1,042	232	2,937
Year 2024					
January	4,557	1	1,111	248	3,196
February	4,093	1	911	233	2,948
March	4,057	1	959	251	2,846
April	3,876	1	752	225	2,898
May	3,672	1	437	234	3,000
June	2,089	1	343	214	1,531
July	2,241	1	437	211	1,592
August	2,312	1	456	186	1,669
September	2,272	1	368	214	1,689
October	3,388	1	634	210	2,543
November	4,180	1	1,180	177	2,822
December	4,179	1	1,132	198	2,848

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.F. Other Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2014 - 2024 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2014	103,561	2,375	28,558	7,289	65,339
2015	109,297	2,854	32,903	7,935	65,605
2016	90,909	2,571	29,446	9,073	49,820
2017	86,274	1,860	33,060	8,506	42,848
2018	79,745	1,357	27,627	9,540	41,221
2019	65,031	1,172	23,057	8,950	31,852
2020	65,617	1,043	20,552	8,180	35,842
2021	67,832	1,017	21,035	7,982	37,798
2022	65,090	652	18,897	7,181	38,361
2023	60,278	879	20,665	7,366	31,368
2024	62,046	854	18,988	7,921	34,283
Year 2022					
January	6,855	57	2,077	683	4,038
February	6,039	40	1,983	588	3,428
March	6,915	46	2,009	658	4,202
April	5,590	35	1,338	552	3,666
May	5,211	64	930	577	3,641
June	4,273	56	1,373	587	2,258
July	4,169	63	1,495	570	2,041
August	4,428	49	1,461	574	2,344
September	3,932	72	1,280	603	1,978
October	5,346	47	1,385	629	3,285
November	5,733	62	1,628	571	3,472
December	6,598	61	1,940	589	4,008
Year 2023					
January	6,309	82	2,081	593	3,553
February	5,769	84	2,148	570	2,967
March	5,791	60	1,969	622	3,140
April	5,253	89	1,762	547	2,855
May	5,298	66	1,548	653	3,030
June	3,760	47	1,188	631	1,894
July	3,763	61	1,363	603	1,736
August	3,799	60	1,452	596	1,690
September	3,563	73	1,353	604	1,534
October	5,240	106	1,692	662	2,781
November	5,411	67	1,867	620	2,858
December	6,324	85	2,242	668	3,330
Year 2024					
January	6,432	48	2,035	706	3,642
February	5,838	46	1,764	663	3,366
March	5,820	69	1,688	750	3,312
April	5,422	63	1,383	673	3,304
May	5,414	85	1,178	712	3,439
June	3,804	93	1,219	663	1,830
July	3,896	100	1,229	647	1,920
August	4,096	106	1,402	568	2,019
September	4,038	64	1,338	610	2,025
October	5,217	65	1,571	650	2,931
November	5,974	54	2,055	620	3,246
December	6,096	62	2,127	659	3,248

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.9. Consumption of Coal for Electricity Generation by State by Sector, 2024 and 2023 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	106	82	29.0%	0	0	106	82	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	8	12	-39.0%	0	0	8	12	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	98	70	41.0%	0	0	98	70	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	9,432	9,769	-3.5%	0	0	9,413	9,749	0	0	19	20
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	9,432	9,769	-3.5%	0	0	9,413	9,749	0	0	19	20
East North Central	75,333	74,465	1.2%	47,788	46,314	27,304	27,808	6	11	234	332
Illinois	16,293	16,078	1.3%	731	768	15,349	15,033	3	5	210	272
Indiana	20,579	20,998	-2.0%	18,956	19,025	1,621	1,966	3	6	0	0
Michigan	14,405	12,777	13.0%	14,328	12,684	76	92	0	0	1	0
Ohio	12,369	12,788	-3.3%	2,110	2,071	10,259	10,717	0	0	0	0
Wisconsin	11,686	11,825	-1.2%	11,663	11,765	0	0	0	0	23	60
West North Central	76,664	81,912	-6.4%	75,844	81,126	0	0	5	5	815	780
Iowa	8,424	9,380	-10.0%	7,937	8,935	0	0	2	3	485	443
Kansas	8,480	10,482	-19.0%	8,480	10,482	0	0	0	0	0	0
Minnesota	6,618	7,425	-11.0%	6,574	7,380	0	0	2	2	42	43
Missouri	22,880	24,046	-4.8%	22,879	24,046	0	0	1	1	0	0
Nebraska	10,021	10,954	-8.5%	9,772	10,702	0	0	0	0	249	252
North Dakota	19,261	18,646	3.3%	19,222	18,604	0	0	0	0	39	41
South Dakota	981	978	0.3%	981	978	0	0	0	0	0	0
South Atlantic	47,950	46,873	2.3%	43,937	42,046	3,915	4,735	6	3	92	89
Delaware	107	13	706.0%	0	0	107	13	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,818	5,456	-30.0%	3,814	5,451	0	0	0	0	4	5
Georgia	9,295	8,641	7.6%	9,267	8,616	0	0	0	0	27	25
Maryland	1,130	815	39.0%	0	0	1,130	815	0	0	0	0
North Carolina	7,135	5,913	21.0%	7,123	5,897	0	0	6	3	6	13
South Carolina	7,356	6,452	14.0%	7,353	6,432	0	15	0	0	2	4
Virginia	1,138	816	39.0%	1,085	775	0	0	0	0	53	41
West Virginia	17,972	18,766	-4.2%	15,294	14,875	2,678	3,892	0	0	0	0
East South Central	45,511	43,869	3.7%	43,329	40,859	2,082	2,926	0	0	100	85
Alabama	11,880	10,966	8.3%	11,880	10,966	0	0	0	0	0	0
Kentucky	21,546	20,594	4.6%	21,546	20,594	0	0	0	0	0	0
Mississippi	3,045	3,888	-22.0%	964	962	2,082	2,926	0	0	0	0
Tennessee	9,039	8,421	7.3%	8,939	8,336	0	0	0	0	100	85
West South Central	63,051	67,421	-6.5%	29,106	30,377	33,916	37,029	0	0	29	15
Arkansas	9,459	10,095	-6.3%	7,629	8,159	1,824	1,929	0	0	6	6
Louisiana	2,556	3,096	-17.0%	1,974	2,133	582	963	0	0	0	0
Oklahoma	4,177	3,525	19.0%	4,154	3,516	0	0	0	0	23	9
Texas	46,860	50,706	-7.6%	15,349	16,569	31,510	34,137	0	0	0	0
Mountain	52,289	58,839	-11.0%	44,417	49,930	7,794	8,822	0	0	79	87
Arizona	5,956	7,301	-18.0%	5,956	7,301	0	0	0	0	0	0
Colorado	9,599	10,964	-12.0%	9,599	10,964	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	6,304	7,371	-14.0%	0	0	6,301	7,368	0	0	3	3
Nevada	1,459	1,300	12.0%	799	675	660	625	0	0	0	0
New Mexico	4,630	4,033	15.0%	4,630	4,033	0	0	0	0	0	0
Utah	8,122	7,867	3.2%	7,714	7,533	408	334	0	0	0	0
Wyoming	16,220	20,002	-19.0%	15,719	19,423	425	495	0	0	76	84
Pacific Contiguous	2,016	2,848	-29.0%	0	0	1,954	2,795	0	0	62	53
California	56	47	20.0%	0	0	0	0	0	0	56	47
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	1,960	2,802	-30.0%	0	0	1,954	2,795	0	0	6	7
Pacific Noncontiguous	580	549	5.6%	429	381	102	118	49	50	0	0
Alaska	580	549	5.6%	429	381	102	118	49	50	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	372,931	386,626	-3.5%	284,849	291,034	86,586	94,063	65	69	1,431	1,460

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.10. Consumption of Petroleum Liquids for Electricity Generation by State, by Sector, 2024 and 2023 (Thousand Barrels)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	645	737	-12.0%	83	66	522	633	28	25	12	14
Connecticut	172	265	-35.0%	7	8	163	253	1	1	2	2
Maine	91	110	-17.0%	0	0	82	99	0	0	10	11
Massachusetts	292	195	50.0%	64	49	211	135	16	10	1	0
New Hampshire	68	115	-41.0%	0	0	57	103	10	11	0	0
Rhode Island	11	45	-75.0%	0	0	10	43	NM	2	0	0
Vermont	12	8	39.0%	12	8	0	0	0	0	0	0
Middle Atlantic	864	1,034	-16.0%	329	262	463	679	30	50	43	43
New Jersey	49	60	-19.0%	0	0	47	58	2	2	0	0
New York	579	795	-27.0%	324	260	230	490	19	33	6	12
Pennsylvania	236	178	32.0%	4	2	185	132	10	15	36	30
East North Central	845	853	-0.9%	596	588	238	253	2	4	9	8
Illinois	53	64	-17.0%	16	14	37	50	0	0	0	0
Indiana	191	205	-7.0%	189	188	0	16	1	0	0	1
Michigan	179	177	1.5%	177	173	0	0	0	0	2	3
Ohio	255	217	17.0%	51	27	201	186	1	1	3	3
Wisconsin	167	190	-12.0%	162	185	0	1	1	2	4	1
West North Central	1,117	1,059	5.5%	1,107	1,050	5	4	3	2	3	3
Iowa	132	147	-10.0%	127	143	4	3	0	NM	0	0
Kansas	248	156	59.0%	248	156	0	0	0	0	0	0
Minnesota	51	160	-68.0%	46	155	1	1	2	2	3	2
Missouri	416	340	22.0%	416	340	0	0	0	0	0	0
Nebraska	128	96	33.0%	128	96	0	0	0	0	0	0
North Dakota	89	107	-17.0%	89	107	0	0	0	0	0	0
South Dakota	53	53	-0.6%	53	53	0	0	NM	NM	0	0
South Atlantic	2,288	1,772	29.0%	1,377	1,188	765	355	65	78	81	151
Delaware	62	36	75.0%	0	2	62	33	0	0	0	0
District of Columbia	0	0	-36.0%	0	0	0	0	0	0	0	0
Florida	327	396	-17.0%	306	366	17	24	0	0	4	6
Georgia	226	191	18.0%	109	67	64	10	2	1	51	112
Maryland	484	183	164.0%	3	2	480	181	NM	1	0	NM
North Carolina	314	187	68.0%	263	159	39	11	6	3	6	14
South Carolina	196	172	15.0%	183	160	4	4	1	0	9	7
Virginia	449	307	47.0%	283	133	99	88	56	73	10	12
West Virginia	229	301	-24.0%	229	297	0	4	0	0	0	0
East South Central	413	419	-1.4%	393	397	1	NM	0	0	19	21
Alabama	35	49	-29.0%	18	29	1	NM	0	0	15	19
Kentucky	126	122	3.1%	126	122	0	0	0	0	0	0
Mississippi	13	11	12.0%	10	10	0	0	0	0	3	1
Tennessee	240	236	1.4%	240	236	NM	0	0	0	0	0
West South Central	511	623	-18.0%	281	358	222	260	0	0	8	5
Arkansas	94	81	17.0%	82	62	12	18	0	0	0	0
Louisiana	18	18	1.5%	18	18	0	0	0	0	0	0
Oklahoma	53	40	32.0%	49	38	0	0	0	0	5	3
Texas	346	485	-29.0%	132	240	210	242	0	0	3	2
Mountain	359	905	-60.0%	322	878	36	26	0	0	0	1
Arizona	60	62	-3.4%	60	62	0	0	0	0	0	0
Colorado	96	508	-81.0%	89	506	7	1	0	0	0	1
Idaho	0	0	-52.0%	0	0	0	0	0	0	0	0
Montana	37	18	103.0%	13	0	24	18	0	0	0	0
Nevada	13	18	-30.0%	10	15	3	3	0	0	0	0
New Mexico	2	151	-99.0%	2	151	0	0	0	0	0	0
Utah	61	56	9.5%	59	51	2	5	0	0	0	0
Wyoming	90	91	-1.9%	90	91	0	0	0	0	0	0
Pacific Contiguous	254	190	34.0%	173	95	33	25	34	23	15	47
California	130	142	-8.6%	65	64	18	14	33	21	13	42
Oregon	24	0	NM	24	0	0	0	0	0	0	0
Washington	101	48	112.0%	84	30	15	11	0	1	1	5
Pacific Noncontiguous	13,490	13,744	-1.8%	11,398	11,486	1,851	2,016	16	18	225	224
Alaska	1,688	1,626	3.8%	1,616	1,556	0	0	3	2	69	68
Hawaii	11,803	12,118	-2.6%	9,782	9,930	1,851	2,016	13	16	157	156
U.S. Total	20,787	21,335	-2.6%	16,058	16,366	4,137	4,253	179	200	414	517

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.11. Consumption of Petroleum Coke for Electricity Generation by State, by Sector,
2024 and 2023 (Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	1,202	1,028	17.0%	686	548	457	416	0	0	59	64
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	744	594	25.0%	685	530	0	0	0	0	59	64
Ohio	457	416	9.8%	0	0	457	416	0	0	0	0
Wisconsin	1	18	-93.0%	1	18	0	0	0	0	0	0
West North Central	1	1	99.0%	0	0	0	0	1	1	0	0
Iowa	1	1	99.0%	0	0	0	0	1	1	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	279	399	-30.0%	259	383	0	0	0	0	21	16
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	259	383	-33.0%	259	383	0	0	0	0	0	0
Georgia	21	16	30.0%	0	0	0	0	0	0	21	16
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	40	421	-91.0%	15	396	0	0	0	0	24	25
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	15	396	-96.0%	15	396	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	24	25	-1.9%	0	0	0	0	0	0	24	25
Mountain	139	178	-22.0%	0	0	139	178	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	139	178	-22.0%	0	0	139	178	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,662	2,028	-18.0%	960	1,328	596	594	1	1	104	105

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.12. Consumption of Nautral Gas for Electricity Generation by State, by Sector, 2024 and 2023 (Million Cubic Feet)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	439,569	409,759	7.3%	2,579	1,681	423,397	394,951	6,843	5,743	6,749	7,384
Connecticut	179,512	172,421	4.1%	770	794	173,297	166,191	1,755	1,706	3,690	3,730
Maine	43,463	27,059	61.0%	0	0	42,652	25,875	153	150	658	1,034
Massachusetts	118,088	106,935	10.0%	1,802	884	110,768	101,528	4,706	3,610	812	914
New Hampshire	31,961	31,076	2.8%	0	0	31,758	30,849	54	55	149	172
Rhode Island	66,535	72,259	-7.9%	0	0	64,922	70,507	172	218	1,441	1,534
Vermont	10	8	24.0%	8	3	0	0	3	5	0	0
Middle Atlantic	1,712,403	1,657,419	3.3%	116,650	104,837	1,562,121	1,515,554	7,841	8,003	25,791	29,025
New Jersey	208,860	232,173	-10.0%	1,366	1,543	203,469	226,561	1,883	1,816	2,142	2,253
New York	494,919	459,614	7.7%	115,053	103,135	370,658	347,478	5,261	5,399	3,946	3,601
Pennsylvania	1,008,624	965,633	4.5%	231	159	987,994	941,515	696	788	19,703	23,170
East North Central	1,698,855	1,596,860	6.4%	690,581	634,104	965,309	919,184	8,100	8,408	34,864	35,164
Illinois	214,217	206,544	3.7%	23,822	20,805	181,856	177,320	2,138	2,465	6,401	5,954
Indiana	297,409	271,610	9.5%	163,255	139,670	116,369	113,133	1,053	1,048	16,733	17,760
Michigan	402,532	386,488	4.2%	238,814	227,125	156,514	152,889	3,085	3,114	4,119	3,360
Ohio	595,059	546,691	8.8%	81,180	67,796	510,570	475,843	1,381	1,302	1,927	1,751
Wisconsin	189,638	185,526	2.2%	183,511	178,708	0	0	443	479	5,684	6,339
West North Central	368,146	353,576	4.1%	302,971	287,973	52,180	54,245	2,060	2,034	10,935	9,325
Iowa	66,374	70,472	-5.8%	61,924	66,557	0	1	845	829	3,604	3,085
Kansas	53,937	43,392	24.0%	51,272	40,877	0	0	0	0	2,665	2,514
Minnesota	114,753	100,974	14.0%	74,847	63,753	35,822	33,824	446	466	3,638	2,932
Missouri	77,227	79,501	-2.9%	60,024	58,210	16,358	20,420	707	722	137	149
Nebraska	14,018	14,311	-2.0%	13,742	14,226	0	0	61	17	215	68
North Dakota	22,672	26,949	-16.0%	22,493	26,836	0	0	0	0	179	114
South Dakota	19,165	17,977	6.6%	18,669	17,514	0	0	0	0	496	463
South Atlantic	3,083,361	2,968,871	3.9%	2,575,550	2,479,796	473,275	453,816	7,053	7,014	27,483	28,245
Delaware	31,948	32,510	-1.7%	723	187	26,501	26,787	0	0	4,724	5,536
District of Columbia	1,036	929	12.0%	0	0	0	0	1,036	929	0	0
Florida	1,461,029	1,411,685	3.5%	1,380,249	1,334,485	73,002	69,181	733	611	7,044	7,408
Georgia	409,570	432,544	-5.3%	339,623	351,745	64,680	75,916	0	0	5,267	4,883
Maryland	103,528	113,908	-9.1%	20,415	29,849	79,201	79,968	3,615	3,804	297	287
North Carolina	432,828	402,323	7.6%	372,923	341,537	57,880	58,451	1,373	1,506	652	829
South Carolina	171,963	181,285	-5.1%	160,623	176,155	10,479	4,138	0	0	861	993
Virginia	437,577	359,769	22.0%	295,279	239,745	136,004	114,036	295	163	5,998	5,825
West Virginia	33,882	33,917	-0.1%	5,716	6,094	25,527	25,339	0	0	2,640	2,484
East South Central	1,159,126	1,070,452	8.3%	907,887	796,214	227,201	252,010	970	930	23,069	21,298
Alabama	457,530	440,871	3.8%	226,527	185,032	220,316	246,231	0	0	10,687	9,608
Kentucky	140,930	111,679	26.0%	133,280	105,150	6,792	5,692	0	0	858	837
Mississippi	433,715	404,776	7.1%	430,590	401,631	NM	87	0	0	3,032	3,058
Tennessee	126,952	113,126	12.0%	117,490	104,401	0	0	970	930	8,492	7,795
West South Central	3,291,213	3,174,679	3.7%	1,416,933	1,294,209	1,488,843	1,475,232	3,633	4,364	381,805	400,874
Arkansas	181,207	188,232	-3.7%	173,722	180,167	6,050	6,709	380	426	1,056	930
Louisiana	541,815	527,984	2.6%	366,776	336,771	32,496	37,130	258	408	142,285	153,677
Oklahoma	385,146	361,639	6.5%	272,505	252,811	108,984	104,869	3	1	3,654	3,957
Texas	2,183,045	2,096,823	4.1%	603,930	524,460	1,341,313	1,326,524	2,992	3,529	234,810	242,309
Mountain	1,055,921	1,003,818	5.2%	853,253	796,598	186,897	192,413	2,362	2,270	13,409	12,536
Arizona	419,403	401,841	4.4%	296,100	282,480	122,700	118,779	603	582	0	0
Colorado	143,210	134,799	6.2%	118,100	113,708	23,884	19,907	26	14	1,200	1,170
Idaho	53,862	47,138	14.0%	43,740	34,166	9,217	12,190	171	170	734	611
Montana	9,941	10,315	-3.6%	8,262	9,265	1,671	1,043	0	0	8	7
Nevada	185,103	180,100	2.8%	173,263	167,450	7,700	8,331	257	267	3,883	4,053
New Mexico	101,168	121,525	-17.0%	79,264	89,193	20,533	31,014	542	518	829	800
Utah	90,034	89,405	0.7%	85,936	86,091	1,181	1,140	763	719	2,154	1,455
Wyoming	53,200	18,694	185.0%	48,587	14,245	12	9	0	0	4,600	4,440
Pacific Contiguous	919,250	982,282	-6.4%	389,374	398,570	452,640	509,403	9,131	10,302	68,105	64,007
California	618,772	680,050	-9.0%	205,190	209,418	342,082	402,638	8,889	9,126	62,610	58,868
Oregon	174,275	162,894	7.0%	93,414	92,367	79,929	69,745	212	165	720	617
Washington	126,204	139,338	-9.4%	90,770	96,784	30,630	37,019	29	1,012	4,776	4,522
Pacific Noncontiguous	26,906	27,780	-3.1%	26,742	27,509	0	0	2	1	162	270
Alaska	26,906	27,780	-3.1%	26,742	27,509	0	0	2	1	162	270
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	13,754,749	13,245,495	3.8%	7,282,518	6,821,490	5,831,864	5,766,810	47,993	49,069	592,373	608,127

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.13. Consumption of Landfill Gas for Electricity Generation by State, by Sector, 2024 and 2023 (Million Cubic Feet)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	10,127	11,098	-8.7%	1,259	1,154	8,657	9,729	211	216	0	0
Connecticut	130	144	-9.6%	0	0	130	144	0	0	0	0
Maine	408	412	-1.0%	0	0	408	412	0	0	0	0
Massachusetts	1,961	2,163	-9.3%	0	0	1,961	2,163	0	0	0	0
New Hampshire	2,186	2,123	3.0%	0	0	1,975	1,907	211	216	0	0
Rhode Island	4,183	4,907	-15.0%	0	0	4,183	4,907	0	0	0	0
Vermont	1,259	1,350	-6.8%	1,259	1,154	0	196	0	0	0	0
Middle Atlantic	30,882	31,878	-3.1%	0	0	29,372	30,367	290	351	1,220	1,160
New Jersey	3,550	3,929	-9.7%	0	0	3,478	3,905	71	24	0	0
New York	14,373	14,421	-0.3%	0	0	14,373	14,421	0	0	0	0
Pennsylvania	12,960	13,528	-4.2%	0	0	11,521	12,041	219	327	1,220	1,160
East North Central	38,928	42,136	-7.6%	4,243	5,868	34,405	35,814	93	243	188	211
Illinois	7,033	7,218	-2.6%	2,448	2,428	4,585	4,790	0	0	0	0
Indiana	2,864	4,744	-40.0%	1,795	3,440	1,069	1,304	0	0	0	0
Michigan	17,046	18,055	-5.6%	0	0	17,046	18,055	0	0	0	0
Ohio	2,933	3,342	-12.0%	0	0	2,933	3,342	0	0	0	0
Wisconsin	9,052	8,777	3.1%	0	0	8,772	8,324	93	243	188	211
West North Central	6,830	7,223	-5.4%	2,160	2,211	4,654	4,999	0	0	17	13
Iowa	2,242	2,221	0.9%	0	0	2,242	2,221	0	0	0	0
Kansas	1,200	1,453	-17.0%	0	0	1,200	1,453	0	0	0	0
Minnesota	507	484	4.8%	7	31	499	453	0	0	0	0
Missouri	1,274	1,360	-6.3%	562	488	713	872	0	0	0	0
Nebraska	1,591	1,692	-6.0%	1,591	1,692	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	17	13	30.0%	0	0	0	0	0	0	17	13
South Atlantic	35,243	39,744	-11.0%	2,301	2,421	32,294	36,606	291	205	357	512
Delaware	757	1,284	-41.0%	0	0	617	1,160	0	0	140	124
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	8,417	8,133	3.5%	1,053	723	7,363	7,410	0	0	0	0
Georgia	6,455	6,577	-1.8%	0	0	6,450	6,558	0	0	5	19
Maryland	1,341	1,501	-11.0%	0	0	1,339	1,499	2	2	0	0
North Carolina	6,239	7,945	-21.0%	0	0	6,239	7,945	0	0	0	0
South Carolina	1,459	2,083	-30.0%	1,247	1,699	0	15	0	0	212	369
Virginia	10,486	12,115	-13.0%	0	0	10,198	11,912	289	203	0	0
West Virginia	89	107	-18.0%	0	0	89	107	0	0	0	0
East South Central	5,211	4,288	22.0%	2,080	1,955	3,131	2,333	0	0	0	0
Alabama	943	875	7.8%	0	0	943	875	0	0	0	0
Kentucky	2,438	2,216	10.0%	2,080	1,955	358	261	0	0	0	0
Mississippi	144	150	-4.4%	0	0	144	150	0	0	0	0
Tennessee	1,686	1,047	61.0%	0	0	1,686	1,047	0	0	0	0
West South Central	4,098	5,046	-19.0%	0	0	4,098	5,046	0	0	0	0
Arkansas	625	614	1.8%	0	0	625	614	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	528	378	40.0%	0	0	528	378	0	0	0	0
Texas	2,945	4,054	-27.0%	0	0	2,945	4,054	0	0	0	0
Mountain	7,093	6,974	1.7%	830	547	5,330	5,581	932	846	0	0
Arizona	406	427	-4.8%	0	0	406	427	0	0	0	0
Colorado	1,019	891	14.0%	0	0	1,019	891	0	0	0	0
Idaho	1,555	1,617	-3.9%	419	397	382	630	754	590	0	0
Montana	411	150	175.0%	411	150	0	0	0	0	0	0
Nevada	1,714	1,718	-0.2%	0	0	1,714	1,718	0	0	0	0
New Mexico	417	0	--	0	0	417	0	0	0	0	0
Utah	1,571	2,171	-28.0%	0	0	1,392	1,915	179	256	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	42,414	45,143	-6.0%	1,497	1,659	30,510	32,386	10,051	10,769	356	329
California	36,559	38,921	-6.1%	85	104	26,549	28,062	9,570	10,426	356	329
Oregon	5,043	5,248	-3.9%	1,412	1,555	3,150	3,350	482	343	0	0
Washington	811	974	-17.0%	0	0	811	974	0	0	0	0
Pacific Noncontiguous	818	762	7.4%	0	0	0	0	818	762	0	0
Alaska	818	762	7.4%	0	0	0	0	818	762	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	181,646	194,292	-6.5%	14,369	15,815	152,452	162,861	12,687	13,392	2,137	2,224

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.14. Consumption of Biogenic Municipal Solid Waste for Electricity Generation by State, by Sector, 2024 and 2023 (Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	2,941,593	2,980,013	-1.3%	0	0	1,885,646	1,908,674	1,055,947	1,071,339	0	0
Connecticut	855,203	860,460	-0.6%	0	0	855,203	860,460	0	0	0	0
Maine	131,430	153,208	-14.0%	0	0	93,772	106,137	37,658	47,071	0	0
Massachusetts	1,845,975	1,856,682	-0.6%	0	0	827,686	832,414	1,018,289	1,024,268	0	0
New Hampshire	108,985	109,663	-0.6%	0	0	108,985	109,663	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	4,872,619	4,841,993	0.6%	0	0	1,976,231	2,031,713	2,896,388	2,810,280	0	0
New Jersey	1,271,226	1,266,075	0.4%	0	0	348,364	346,491	922,862	919,584	0	0
New York	1,790,301	1,737,122	3.1%	0	0	303,760	303,946	1,486,541	1,433,176	0	0
Pennsylvania	1,811,092	1,838,796	-1.5%	0	0	1,324,107	1,381,276	486,985	457,520	0	0
East North Central	167,088	162,756	2.7%	38,580	35,569	0	0	128,508	127,187	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	15,058	16,411	-8.2%	0	0	0	0	15,058	16,411	0	0
Michigan	113,450	110,776	2.4%	0	0	0	0	113,450	110,776	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	38,580	35,569	8.5%	38,580	35,569	0	0	0	0	0	0
West North Central	482,382	474,670	1.6%	244,164	247,635	222,651	213,909	15,567	13,126	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	482,382	474,670	1.6%	244,164	247,635	222,651	213,909	15,567	13,126	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	4,456,333	4,615,485	-3.4%	0	0	2,397,035	2,465,758	2,059,298	2,149,727	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	2,935,805	3,113,542	-5.7%	0	0	1,822,867	1,957,695	1,112,938	1,155,847	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	574,168	508,063	13.0%	0	0	574,168	508,063	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	946,360	993,880	-4.8%	0	0	0	0	946,360	993,880	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	4,839	1,150	321.0%	0	0	0	0	4,839	1,150	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	4,839	1,150	321.0%	0	0	0	0	4,839	1,150	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	324,958	465,926	-30.0%	0	0	239,399	339,670	85,559	126,256	0	0
California	95,180	248,135	-62.0%	0	0	9,621	121,879	85,559	126,256	0	0
Oregon	75,894	71,939	5.5%	0	0	75,894	71,939	0	0	0	0
Washington	153,884	145,852	5.5%	0	0	153,884	145,852	0	0	0	0
Pacific Noncontiguous	386,197	374,493	3.1%	0	0	0	0	386,197	374,493	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	386,197	374,493	3.1%	0	0	0	0	386,197	374,493	0	0
U.S. Total	13,636,009	13,916,486	-2.0%	282,744	283,204	6,720,962	6,959,724	6,632,303	6,673,558	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Chapter 6

Fossil Fuel Stocks for Electricity Generation

Table 6.1. Stocks of Coal, Petroleum Liquids, and Petroleum Coke: Electric Power Sector, 2014 - 2024

Period	Electric Power Sector			Electric Utilities			Independent Power Producers		
	Coal (Thousand Tons)	Petroleum Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroleum Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroleum Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)
End of Year Stocks									
2014	151,548	32,322	827	116,684	21,304	686	34,864	11,018	142
2015	195,548	31,694	1,340	153,226	20,253	1,163	42,322	11,441	177
2016	162,009	30,593	845	130,885	19,767	603	31,124	10,827	241
2017	137,687	28,089	864	114,782	19,047	692	22,905	9,041	171
2018	102,793	25,977	539	84,728	16,553	521	18,065	9,423	19
2019	128,102	25,960	471	104,265	16,435	428	23,837	9,525	43
2020	131,431	26,063	298	107,965	15,941	273	23,466	10,123	25
2021	91,884	26,002	302	75,231	15,634	290	16,653	10,368	12
2022	88,861	22,812	318	74,917	14,204	297	13,943	8,608	21
2023	133,028	24,402	427	111,524	15,353	421	21,504	9,050	7
2024	127,826	23,014	438	105,219	14,659	431	22,607	8,355	7
Year 2022, End of Month Stocks									
January	84,541	24,166	336	70,468	14,938	324	14,073	9,228	12
February	81,034	24,252	299	68,800	15,159	287	12,234	9,092	12
March	86,143	23,755	350	73,271	15,156	340	12,872	8,599	10
April	90,746	23,758	424	76,913	15,311	416	13,833	8,446	8
May	92,692	24,025	454	78,852	15,053	425	13,840	8,972	29
June	86,869	24,078	423	73,119	15,309	408	13,750	8,769	16
July	79,172	25,707	474	66,434	15,384	459	12,738	10,323	15
August	75,570	22,794	490	64,278	14,882	479	11,292	7,912	11
September	79,354	22,484	405	67,442	14,704	397	11,912	7,780	8
October	87,342	22,771	351	73,276	14,779	344	14,066	7,992	7
November	93,203	23,678	408	78,597	14,925	393	14,605	8,753	15
December	88,861	22,812	318	74,917	14,204	297	13,943	8,608	21
Year 2023, End of Month Stocks									
January	92,714	24,410	385	77,005	15,167	360	15,709	9,243	25
February	99,760	24,622	380	82,205	15,413	355	17,554	9,209	24
March	109,041	24,059	534	89,836	15,370	505	19,205	8,689	29
April	119,460	24,068	644	98,558	15,363	598	20,902	8,704	46
May	127,788	23,882	600	105,620	15,175	591	22,168	8,708	9
June	129,191	24,066	533	106,412	15,299	525	22,778	8,767	8
July	122,916	24,065	440	101,603	15,422	434	21,313	8,643	6
August	117,898	23,416	356	97,758	15,018	348	20,140	8,398	8
September	118,054	23,469	279	98,026	15,117	273	20,027	8,352	6
October	123,046	23,257	284	102,453	14,998	279	20,593	8,258	5
November	130,985	23,335	369	109,555	14,910	356	21,430	8,425	13
December	133,028	24,402	427	111,524	15,353	421	21,504	9,050	7
Year 2024, End of Month Stocks									
January	123,854	24,275	312	104,292	15,319	306	19,562	8,956	6
February	129,170	24,355	308	108,070	15,307	300	21,100	9,047	8
March	135,537	24,275	333	112,576	15,275	328	22,961	9,000	5
April	138,839	24,011	309	115,173	15,191	302	23,666	8,820	7
May	139,893	23,834	311	116,439	15,072	305	23,454	8,762	6
June	135,229	23,974	332	112,260	15,154	317	22,970	8,820	15
July	127,378	23,442	410	105,766	14,843	379	21,611	8,600	31
August	121,756	22,743	399	100,925	14,416	384	20,831	8,327	15
September	122,555	22,927	470	101,105	14,630	439	21,450	8,298	31
October	127,747	22,567	428	105,127	14,270	421	22,620	8,297	7
November	131,091	22,697	404	107,639	14,251	400	23,452	8,446	4
December	127,826	23,014	438	105,219	14,659	431	22,607	8,355	7

Notes: See Glossary for definitions. Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms. Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423,

Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 6.2 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by State, 2024 and 2023

Census Division and State	Coal (Thousand Tons)			Petroleum Liquids (Thousand Barrels)			Petroleum Coke (Thousand Tons)		
	December 2024	December 2023	Percentage Change	December 2024	December 2023	Percentage Change	December 2024	December 2023	Percentage Change
New England	W	W	W	1,952	2,315	-15.7%	0	0	--
Connecticut	0	0	--	496	644	-23.0%	0	0	--
Maine	W	0	W	252	294	-14.4%	0	0	--
Massachusetts	0	0	--	804	986	-18.5%	0	0	--
New Hampshire	W	W	W	242	235	3.1%	0	0	--
Rhode Island	0	0	--	130	126	2.9%	0	0	--
Vermont	0	0	--	29	29	-2.4%	0	0	--
Middle Atlantic	1,971	2,627	-25.0%	4,647	5,047	-7.9%	0	0	--
New Jersey	0	0	--	500	520	-3.9%	0	0	--
New York	0	0	--	2,874	3,165	-9.2%	0	0	--
Pennsylvania	1,971	2,627	-25.0%	1,273	1,361	-6.5%	0	0	--
East North Central	26,580	27,100	-1.9%	1,066	1,040	2.4%	W	W	W
Illinois	6,776	5,591	21.2%	134	102	31.0%	0	0	--
Indiana	9,294	9,574	-2.9%	98	110	-10.9%	0	0	--
Michigan	3,297	3,730	-11.6%	164	190	-13.9%	W	W	W
Ohio	4,173	4,122	1.2%	452	428	5.7%	0	0	--
Wisconsin	3,041	4,083	-25.5%	218	210	3.7%	W	W	W
West North Central	25,740	27,153	-5.2%	1,241	1,178	5.4%	0	0	--
Iowa	4,669	5,094	-8.3%	84	94	-10.4%	0	0	--
Kansas	5,753	5,151	11.7%	210	206	1.9%	0	0	--
Minnesota	2,356	2,879	-18.1%	95	117	-18.9%	0	0	--
Missouri	8,047	8,458	-4.9%	588	569	3.4%	0	0	--
Nebraska	3,015	3,556	-15.2%	159	91	73.6%	0	0	--
North Dakota	1,483	1,561	-5.0%	36	36	-0.9%	0	0	--
South Dakota	W	W	W	70	64	8.2%	0	0	--
South Atlantic	18,942	21,166	-10.5%	9,360	9,578	-2.3%	W	W	W
Delaware	W	W	W	416	518	-19.7%	0	0	--
District of Columbia	0	0	--	0	0	--	0	0	--
Florida	1,838	1,996	-7.9%	3,815	3,846	-0.8%	W	W	W
Georgia	W	W	W	1,221	1,211	0.8%	0	0	--
Maryland	W	799	W	637	641	-0.7%	0	0	--
North Carolina	3,973	3,654	8.7%	1,099	1,144	-3.9%	0	0	--
South Carolina	1,759	2,353	-25.2%	567	574	-1.2%	0	0	--
Virginia	W	W	W	1,457	1,491	-2.3%	0	0	--
West Virginia	6,380	6,852	-6.9%	149	153	-2.6%	W	W	W
East South Central	11,175	13,032	-14.2%	1,067	1,099	-2.9%	0	0	--
Alabama	3,220	4,180	-23.0%	254	258	-1.4%	0	0	--
Kentucky	5,570	6,731	-17.2%	285	278	2.6%	0	0	--
Mississippi	W	W	W	18	4	295.2%	0	0	--
Tennessee	1,748	1,573	11.1%	510	559	-8.7%	0	0	--
West South Central	24,985	26,728	-6.5%	2,099	2,164	-3.0%	W	W	W
Arkansas	4,071	4,679	-13.0%	170	165	3.0%	0	0	--
Louisiana	4,279	3,563	20.1%	181	185	-1.9%	W	W	W
Oklahoma	4,240	5,042	-15.9%	18	38	-51.6%	0	0	--
Texas	12,395	13,444	-7.8%	1,729	1,776	-2.6%	0	0	--
Mountain	17,702	14,249	24.2%	350	330	6.0%	W	W	W
Arizona	3,886	3,585	8.4%	148	126	17.7%	0	0	--
Colorado	3,563	3,566	-0.1%	116	117	-1.6%	0	0	--
Idaho	0	0	--	0	0	141.9%	0	0	--
Montana	W	W	W	14	12	13.6%	W	W	W
Nevada	W	W	W	2	3	-24.9%	0	0	--
New Mexico	0	0	--	4	5	-10.5%	0	0	--
Utah	3,743	2,438	53.5%	37	28	33.2%	0	0	--
Wyoming	5,102	3,530	44.5%	28	39	-27.3%	0	0	--
Pacific Contiguous	W	W	W	337	351	-3.9%	0	0	--
California	0	0	--	165	173	-4.6%	0	0	--
Oregon	0	0	--	51	72	-29.4%	0	0	--
Washington	W	W	W	122	107	14.3%	0	0	--
Pacific Noncontiguous	W	W	W	896	1,301	-31.2%	0	0	--
Alaska	W	W	W	38	62	-38.6%	0	0	--
Hawaii	0	0	--	858	1,240	-30.8%	0	0	--
U.S. Total	127,826	133,028	-3.9%	23,014	24,402	-5.7%	438	427	2.5%

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

**Table 6.3 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by Census Divison, 2024 and 2023**

Census Division	Electric Power Sector			Electric Utilities		Independent Power Producers	
	December 2024	December 2023	Percentage Change	December 2024	December 2023	December 2024	December 2023
Coal (Thousand Tons)							
New England	W	W	W	0	0	W	W
Middle Atlantic	1,971	2,627	-25.0%	W	W	1,711	2,366
East North Central	26,580	27,100	-1.9%	17,185	18,108	9,396	8,992
West North Central	25,740	27,153	-5.2%	25,740	27,153	0	0
South Atlantic	18,942	21,166	-10.5%	18,180	19,855	761	1,311
East South Central	11,175	13,032	-14.2%	11,175	13,032	0	0
West South Central	24,985	26,728	-6.5%	15,642	19,496	9,342	7,232
Mountain	17,702	14,249	24.2%	16,971	13,558	W	W
Pacific Contiguous	W	W	W	0	0	W	W
Pacific Noncontiguous	W	W	W	W	W	W	W
U.S. Total	127,826	133,028	-3.9%	105,219	111,524	22,607	21,504
Petroleum Liquids (Thousand Barrels)							
New England	1,952	2,315	-15.7%	253	255	1,699	2,060
Middle Atlantic	4,647	5,047	-7.9%	1,947	2,085	2,700	2,962
East North Central	1,066	1,040	2.4%	672	687	393	353
West North Central	1,241	1,178	5.4%	1,215	1,150	26	27
South Atlantic	9,360	9,578	-2.3%	7,225	7,348	2,135	2,230
East South Central	1,067	1,099	-2.9%	1,029	1,060	38	39
West South Central	2,099	2,164	-3.0%	883	919	1,216	1,244
Mountain	350	330	6.0%	323	305	26	24
Pacific Contiguous	337	351	-3.9%	255	270	82	81
Pacific Noncontiguous	896	1,301	-31.2%	858	1,273	38	29
U.S. Total	23,014	24,402	-5.7%	14,659	15,353	8,355	9,050
Petroleum Coke (Thousand Tons)							
New England	0	0	--	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0
East North Central	W	W	W	W	W	0	0
West North Central	0	0	--	0	0	0	0
South Atlantic	W	W	W	W	W	W	W
East South Central	0	0	--	0	0	0	0
West South Central	W	W	W	W	W	0	0
Mountain	W	W	W	0	0	W	W
Pacific Contiguous	0	0	--	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0
U.S. Total	438	427	2.5%	431	421	7	7

W = Withheld to avoid disclosure of individual company data.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form-923, 'Power Plant Operations Report.'

Table 6.4. Stocks of Coal by Coal Rank: Electric Power Sector, 2014 - 2024
(Thousand Tons)

Period	Electric Power Sector			
	Bituminous Coal	Subbituminous Coal	Lignite Coal	Total
End of Year Stocks				
2014	72,771	72,552	6,225	151,548
2015	82,004	108,614	4,931	195,548
2016	67,241	90,376	4,393	162,009
2017	56,140	77,875	3,672	137,687
2018	41,507	58,247	3,039	102,793
2019	54,769	69,942	3,124	128,102
2020	50,649	77,033	3,556	131,431
2021	34,560	54,726	2,598	91,884
2022	35,194	50,704	2,956	88,861
2023	46,574	83,013	3,439	133,028
2024	43,844	80,772	3,198	127,826
Year 2022, End of Month Stocks				
January	30,697	51,157	2,686	84,541
February	29,288	49,029	2,717	81,034
March	31,687	51,304	3,152	86,143
April	33,868	53,609	3,269	90,746
May	33,202	56,289	3,191	92,692
June	30,392	53,338	3,129	86,869
July	28,769	47,358	3,040	79,172
August	28,730	44,005	2,826	75,570
September	30,766	45,802	2,776	79,354
October	34,061	50,366	2,905	87,342
November	35,998	54,329	2,867	93,203
December	35,194	50,704	2,956	88,861
Year 2023, End of Month Stocks				
January	37,880	51,812	3,014	92,714
February	40,066	56,667	3,022	99,760
March	41,614	64,432	2,991	109,041
April	43,352	72,772	3,330	119,460
May	46,598	77,685	3,500	127,788
June	47,911	77,671	3,601	129,191
July	44,256	75,155	3,499	122,916
August	42,345	72,129	3,424	117,898
September	42,659	72,147	3,247	118,054
October	44,914	74,948	3,184	123,046
November	46,999	80,588	3,393	130,985
December	46,574	83,013	3,439	133,028
Year 2024, End of Month Stocks				
January	42,859	77,766	3,220	123,854
February	44,581	81,459	3,124	129,170
March	47,285	85,012	3,232	135,537
April	48,624	86,824	3,388	138,839
May	49,199	87,376	3,311	139,893
June	46,915	84,931	3,374	135,229
July	43,890	80,227	3,251	127,378
August	42,163	76,310	3,273	121,756
September	42,608	76,769	3,171	122,555
October	44,603	79,892	3,245	127,747
November	46,116	81,733	3,231	131,091
December	43,844	80,772	3,198	127,826

Notes: See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923, and predecessor forms. Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms. Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following:

Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Chapter 7

Receipts, Cost, and Quality of Fossil Fuels

Table 7.1. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 2014 through 2024

Period	Coal				Petroleum				Natural Gas		All Fossil Fuels
	Receipts (Thousand Tons)		Average Cost		Receipts (Thousand Barrels)		Average Cost		Receipts (Thousand Mcf)	Average Cost	Average Cost
			Average Sulfur Percent by Weight	(Dollars per MMBtu)			Average Sulfur Percent by Weight	(Dollars per MMBtu)		(Dollars per MMBtu)	(Dollars per MMBtu)
				(Dollars per Ton)				(Dollars per Barrel)			
2014	854,560	1.32	2.37	45.96	54,488	3.56	11.60	68.12	8,431,423	5.00	3.31
2015	782,929	1.29	2.22	42.86	48,804	3.38	6.74	39.51	9,842,581	3.23	2.65
2016	650,770	1.34	2.11	40.64	37,637	3.69	5.24	30.46	10,271,180	2.87	2.47
2017	642,364	1.28	2.06	39.27	32,672	3.59	7.10	41.23	9,628,733	3.37	2.65
2018	596,215	1.31	2.06	39.25	37,341	3.31	9.68	56.82	10,894,849	3.55	2.83
2019	560,153	1.31	2.02	38.70	24,556	3.03	9.07	53.55	11,704,743	2.88	2.50
2020	439,636	1.28	1.92	36.36	24,846	3.45	5.98	34.92	11,981,552	2.40	2.22
2021	461,477	1.30	1.98	37.48	27,783	3.11	10.08	58.93	11,578,254	5.20	3.82
2022	469,718	1.28	2.36	44.69	30,792	2.91	16.53	97.42	12,436,074	7.21	5.22
2023	431,375	1.23	2.51	47.23	25,590	2.44	15.98	94.80	13,237,380	3.36	3.12
2024	369,134	1.27	2.47	46.66	19,275	2.14	14.70	87.70	13,741,165	2.76	2.73

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.

- See Glossary for definitions.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.2. Receipts and Quality of Coal Delivered for the Electric Power Industry, 2014 through 2024

Period	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
2014	334,082	2.34	10.3	440,013	0.31	5.8	71,534	0.90	14.1
2015	289,093	2.40	10.4	421,127	0.32	5.8	65,826	0.89	14.1
2016	245,141	2.43	10.3	333,241	0.31	5.8	64,426	0.91	14.0
2017	224,500	2.45	10.3	350,580	0.31	5.6	59,665	0.96	14.0
2018	205,783	2.55	10.1	329,974	0.31	5.7	52,438	0.91	13.4
2019	198,016	2.52	10.0	309,029	0.32	5.7	46,781	0.90	13.3
2020	144,966	2.57	10.3	245,158	0.32	5.8	43,862	0.86	13.1
2021	149,031	2.66	10.3	262,770	0.31	5.6	43,018	0.86	13.3
2022	148,785	2.64	10.2	271,258	0.32	5.8	41,887	0.89	13.5
2023	133,921	2.59	10.4	253,550	0.30	5.4	37,150	0.84	12.7
2024	120,985	2.57	10.6	206,952	0.30	5.4	34,677	0.87	13.0

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W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

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- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.3. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 2014 through 2024

Period	Coal			Petroleum			Natural Gas
	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Cubic Foot
2014	9,710	1.32	8.6	139,713	3.56	0.5	1,029
2015	9,634	1.29	8.6	139,681	3.38	0.5	1,034
2016	9,617	1.34	8.7	138,384	3.69	0.5	1,034
2017	9,544	1.28	8.4	138,324	3.59	0.4	1,034
2018	9,536	1.31	8.3	139,762	3.31	0.3	1,033
2019	9,592	1.31	8.3	140,549	3.03	0.3	1,034
2020	9,473	1.28	8.4	138,976	3.45	0.3	1,033
2021	9,485	1.30	8.3	139,137	3.11	0.3	1,034
2022	9,448	1.28	8.4	140,441	2.91	0.4	1,033
2023	9,403	1.23	8.1	141,246	2.44	0.4	1,033
2024	9,435	1.27	8.4	142,048	2.14	0.4	1,034

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W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.4. Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 2014 through 2024

	Coal								Petroleum		Natural Gas		Total Fossil	
	Bituminous		Subbituminous		Lignite		All Coal Ranks							
Period	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)
2014	7,883	2.74	7,681	2.06	934	1.77	16,595	2.37	320	11.60	8,679	5.00	25,594	3.31
2015	6,797	2.58	7,353	1.94	855	1.92	15,086	2.22	286	6.74	10,174	3.23	25,546	2.65
2016	5,770	2.40	5,818	1.89	840	1.74	12,516	2.11	219	5.24	10,619	2.87	23,354	2.47
2017	5,279	2.31	6,123	1.90	773	1.66	12,261	2.06	190	7.10	9,952	3.37	22,403	2.65
2018	4,838	2.31	5,765	1.90	677	1.71	11,371	2.06	219	9.68	11,254	3.55	22,844	2.83
2019	4,670	2.26	5,401	1.86	601	1.68	10,746	2.02	145	9.07	12,105	2.89	22,996	2.50
2020	3,399	2.11	4,300	1.78	566	1.90	8,329	1.92	145	5.98	12,381	2.40	20,855	2.22
2021	3,513	2.13	4,610	1.85	553	2.09	8,754	1.98	162	10.08	11,967	5.20	20,883	3.82
2022	3,499	2.74	4,748	2.17	538	1.78	8,876	2.36	182	16.53	12,840	7.21	21,898	5.22
2023	3,130	3.15	4,428	2.15	481	1.79	8,112	2.51	152	15.98	13,669	3.36	21,934	3.12
2024	2,813	3.08	3,628	2.08	451	1.94	6,965	2.47	115	14.70	14,206	2.76	21,286	2.73

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NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - All coal ranks subtotal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

Bituminous coal includes anthracite coal and beginning in 2011, coal-derived synthesis gas.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.5. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2014 - 2024

Table 7.5. Receipts, Average Cost, and Quantity of Fossil Fuels: Electric Utilities, 2014 - 2024													
	Coal						Petroleum Liquids						
	Receipts		Average Cost				Receipts		Average Cost				
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption	
Period													
Annual Totals													
2014	12,064,810	614,728	2.39	46.95	1.21	98.3	98,357	16,161	19.90	121.14	0.44	82.0	
2015	11,088,631	571,707	2.25	43.71	1.17	105.8	90,041	14,747	11.32	69.13	0.46	79.2	
2016	9,256,878	476,207	2.16	42.01	1.21	95.4	73,294	11,985	9.16	56.02	0.45	74.0	
2017	9,011,629	467,595	2.12	40.81	1.16	96.0	70,422	11,640	11.60	70.19	0.47	74.4	
2018	8,351,036	435,964	2.11	40.35	1.18	91.6	84,050	13,896	14.39	87.09	0.37	75.3	
2019	7,970,069	413,915	2.08	39.99	1.18	103.1	66,789	11,010	13.40	81.29	0.46	69.9	
2020	6,256,811	327,488	1.96	37.49	1.15	100.2	56,530	9,371	9.84	59.37	0.47	67.1	
2021	6,448,846	338,205	2.03	38.68	1.14	90.2	69,111	11,468	14.53	87.56	0.47	67.7	
2022	6,594,794	346,120	2.41	45.96	1.15	98.4	73,400	12,131	24.43	147.80	0.48	65.6	
2023	6,224,613	326,208	2.56	48.88	1.15	111.5	78,893	13,023	20.48	124.06	0.46	79.3	
2024	5,332,739	277,592	2.55	48.93	1.20	97.0	63,680	10,480	18.22	110.71	0.43	65.0	
Year 2022													
January	546,113	29,056	2.24	42.12	1.06	81.3	6,596	1,103	17.23	103.03	0.46	46.9	
February	500,644	26,344	2.19	41.69	1.05	91.5	6,361	1,045	18.65	113.52	0.48	83.4	
March	537,576	28,123	2.18	41.71	1.14	115.4	5,580	926	22.53	135.80	0.49	70.7	
April	486,354	25,278	2.24	43.02	1.17	113.7	5,684	934	26.28	159.85	0.48	84.8	
May	552,474	28,904	2.29	43.87	1.16	108.7	4,509	747	28.14	169.81	0.48	58.4	
June	537,295	28,300	2.35	44.64	1.14	88.2	7,089	1,166	28.58	173.77	0.48	90.3	
July	557,748	29,313	2.47	47.07	1.18	76.9	6,739	1,115	28.96	175.11	0.48	80.8	
August	627,619	32,918	2.53	48.27	1.19	90.2	5,736	947	26.06	157.81	0.47	72.6	
September	599,306	31,443	2.60	49.50	1.17	110.8	5,857	966	24.83	150.60	0.48	71.8	
October	579,715	30,502	2.53	48.08	1.16	129.7	6,272	1,028	23.81	145.25	0.48	74.8	
November	542,727	28,448	2.55	48.63	1.14	121.1	5,760	953	26.15	158.05	0.46	70.9	
December	527,223	27,491	2.69	51.67	1.22	86.5	7,217	1,202	23.01	138.22	0.48	38.2	
Year 2023													
January	559,118	29,346	2.65	50.44	1.13	106.6	11,620	1,944	22.15	132.38	0.47	133.2	
February	477,280	25,125	2.67	50.72	1.17	125.0	6,931	1,155	22.13	132.74	0.48	73.8	
March	549,894	28,881	2.53	48.18	1.19	135.3	5,960	986	20.64	124.72	0.48	75.3	
April	481,181	25,153	2.51	47.98	1.16	154.9	5,523	905	19.34	117.99	0.47	71.5	
May	486,120	25,332	2.54	48.84	1.14	135.6	6,074	1,006	18.86	113.90	0.48	74.2	
June	504,353	26,328	2.50	47.98	1.16	100.4	6,134	1,010	17.52	106.44	0.47	73.5	
July	552,719	29,116	2.53	48.00	1.13	83.9	7,002	1,138	17.18	105.70	0.44	86.0	
August	583,320	30,491	2.55	48.69	1.14	89.2	4,863	797	19.97	121.81	0.47	55.0	
September	517,934	27,065	2.59	49.49	1.12	102.8	6,073	992	22.75	139.30	0.43	77.5	
October	504,437	26,340	2.58	49.51	1.14	119.1	5,203	855	22.31	135.80	0.40	63.0	
November	509,063	26,715	2.57	48.89	1.14	125.8	5,628	932	21.72	131.14	0.43	70.7	
December	499,194	26,316	2.52	47.89	1.17	109.9	7,883	1,303	20.21	122.26	0.45	95.1	
Year 2024													
January	466,667	24,584	2.54	48.26	1.17	75.4	8,252	1,370	18.93	114.00	0.45	68.2	
February	447,767	23,505	2.57	48.91	1.13	115.9	5,312	874	19.54	118.80	0.46	76.3	
March	427,408	21,930	2.59	50.39	1.29	124.4	4,824	788	19.77	121.10	0.46	68.0	
April	365,902	18,583	2.67	52.51	1.33	117.4	4,798	785	19.55	119.45	0.43	63.6	
May	405,066	20,695	2.65	51.86	1.33	103.2	4,762	789	19.00	114.67	0.38	62.8	
June	431,887	22,308	2.58	50.00	1.28	82.7	4,898	808	18.10	109.70	0.41	65.7	
July	479,544	25,008	2.56	49.01	1.21	79.7	4,041	664	18.56	112.97	0.36	50.0	
August	490,835	25,647	2.50	47.79	1.18	84.8	5,085	835	18.26	111.11	0.46	57.5	
September	460,696	24,152	2.47	47.11	1.09	100.1	4,706	771	17.20	104.95	0.36	62.4	
October	455,323	23,814	2.56	48.96	1.12	116.8	6,392	1,051	16.29	99.08	0.41	76.7	
November	434,798	22,677	2.48	47.64	1.17	114.6	4,408	725	17.02	103.55	0.45	58.1	
December	466,846	24,692	2.45	46.28	1.10	91.4	6,202	1,020	16.76	101.96	0.47	69.9	

Displayed values of zero may represent small values that round to zero.

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Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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- See Glossary for definitions.

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Table 7.6. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2014 - 2024 (continued)

Table 7.0: Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2014 - 2024 (Continued)													
	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Period													
Annual Totals													
2014	123,793	4,349	1.89	53.77	5.56	126.3	3,876,549	3,772,596	5.17	5.31	96.7	3.16	
2015	115,929	4,069	1.77	50.44	5.23	130.1	4,717,748	4,565,040	3.52	3.64	96.0	2.67	
2016	99,706	3,538	1.52	42.85	5.38	103.1	5,075,337	4,907,538	3.15	3.26	97.0	2.54	
2017	90,481	3,224	2.15	60.31	5.55	117.6	4,794,383	4,640,827	3.62	3.74	96.8	2.68	
2018	83,211	2,940	2.56	72.34	5.74	106.8	5,562,903	5,388,544	3.68	3.80	96.2	2.80	
2019	54,266	1,896	1.92	54.88	5.50	91.0	6,038,432	5,842,392	3.03	3.13	97.0	2.53	
2020	65,684	2,317	1.70	48.07	5.39	101.8	6,207,039	6,011,244	2.63	2.72	96.3	2.32	
2021	64,891	2,296	3.16	89.27	5.24	98.0	5,901,472	5,713,855	5.21	5.39	96.4	3.60	
2022	64,607	2,283	4.35	122.99	5.52	99.5	6,393,812	6,200,191	7.49	7.73	96.5	5.01	
2023	40,716	1,450	4.05	113.73	5.61	108.5	6,803,788	6,596,937	3.81	3.92	96.1	3.32	
2024	26,786	953	2.96	83.22	5.60	99.2	7,249,583	7,018,235	3.03	3.13	95.7	2.90	
Year 2022													
January	5,343	189	4.32	122.16	5.11	112.6	503,615	487,628	7.15	7.39	96.7	4.67	
February	4,050	141	4.24	121.53	5.80	75.1	414,806	402,121	6.13	6.32	96.1	4.08	
March	5,791	205	4.84	136.40	5.31	142.5	408,255	396,288	5.28	5.43	96.4	3.63	
April	6,637	235	4.80	135.31	5.57	150.6	395,234	383,835	6.25	6.44	97.3	4.17	
May	5,992	212	4.97	140.62	5.48	99.1	494,026	479,966	7.53	7.75	97.5	4.86	
June	4,887	173	4.50	126.93	5.51	76.9	621,160	603,483	8.29	8.53	96.3	5.66	
July	5,781	205	4.65	131.34	5.54	115.1	749,263	727,668	7.75	7.98	96.1	5.61	
August	6,465	228	5.02	142.06	5.62	127.5	723,303	700,993	9.35	9.65	96.4	6.25	
September	3,818	134	2.32	66.08	5.74	63.7	579,405	560,966	8.53	8.81	96.2	5.58	
October	4,060	144	3.35	94.31	5.74	74.8	493,094	478,019	6.19	6.38	96.6	4.31	
November	6,485	229	3.84	108.96	5.53	124.4	482,176	467,566	6.05	6.24	96.6	4.31	
December	5,298	187	4.19	118.73	5.50	73.4	529,475	511,657	9.05	9.36	96.7	5.97	
Year 2023													
January	4,871	176	4.54	126.02	5.67	151.3	509,603	492,284	8.55	8.85	95.8	5.62	
February	3,886	136	4.80	136.95	5.62	125.8	447,571	433,509	4.89	5.05	95.0	3.88	
March	4,905	172	4.66	132.76	5.71	228.6	493,900	478,430	3.76	3.88	95.2	3.22	
April	4,768	168	4.70	133.61	5.72	218.3	460,793	447,538	3.05	3.14	96.4	2.88	
May	1,985	72	3.14	86.86	5.76	94.2	543,700	528,159	2.86	2.94	96.9	2.81	
June	1,853	66	3.48	98.25	5.77	61.3	627,911	609,220	2.92	3.01	96.2	2.81	
July	2,787	100	3.62	101.16	5.45	50.5	767,356	743,822	3.26	3.36	95.7	3.03	
August	2,311	84	3.39	93.79	5.73	42.4	781,288	757,734	3.30	3.40	95.9	3.04	
September	3,289	118	3.76	104.81	5.48	67.3	618,399	600,954	3.28	3.38	96.3	3.07	
October	2,404	86	3.84	107.56	5.50	112.5	528,905	513,656	3.32	3.41	96.7	3.06	
November	3,097	111	3.60	100.64	5.35	228.6	488,206	473,567	3.79	3.91	96.4	3.27	
December	4,559	163	3.39	94.99	5.53	199.5	536,155	518,063	3.73	3.86	96.3	3.27	
Year 2024													
January	909	33	2.65	73.16	5.53	34.6	592,967	572,724	4.98	5.16	94.9	4.02	
February	1,385	50	2.63	73.05	5.56	72.1	487,202	470,741	3.35	3.47	96.2	3.07	
March	1,054	38	2.63	73.51	5.49	173.2	498,041	482,291	2.48	2.56	96.5	2.62	
April	1,078	38	2.62	73.50	5.51	57.9	469,587	455,940	2.32	2.39	95.1	2.57	
May	2,177	78	2.86	80.18	5.46	101.9	575,740	559,701	2.57	2.64	95.8	2.68	
June	3,620	127	3.11	88.55	5.54	110.7	676,666	656,292	2.99	3.08	96.4	2.90	
July	5,356	189	3.23	91.69	5.52	144.2	828,531	801,114	2.78	2.88	95.4	2.75	
August	3,756	134	3.08	86.70	5.70	104.8	808,451	781,275	2.51	2.60	94.5	2.57	
September	3,518	125	3.09	87.22	5.49	178.0	662,215	640,859	2.60	2.69	96.2	2.61	
October	1,008	37	2.63	72.20	6.78	50.7	581,102	562,732	2.94	3.04	97.1	2.86	
November	1,280	46	2.64	72.99	5.91	104.8	534,520	517,612	2.93	3.03	96.8	2.79	
December	1,645	59	2.66	74.04	5.43	82.1	534,561	516,955	4.11	4.25	94.4	3.42	

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NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal receipts remained at 50 megawatts. The following caveats for each fuel type should be noted:

PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.7 Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2014 - 2024

Table 7.7 Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2014 - 2024												
	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2014	4,243,949	226,600	2.25	42.20	1.61	100.1	71,774	11,980	19.90	119.36	0.45	101.0
2015	3,731,508	198,982	2.10	39.39	1.66	100.5	55,248	9,189	11.69	70.36	0.46	86.5
2016	3,047,358	164,648	1.93	35.69	1.73	91.8	25,975	4,410	9.93	58.56	0.48	75.1
2017	3,056,215	165,567	1.85	34.19	1.64	93.1	24,704	4,190	12.67	74.73	0.46	73.8
2018	2,849,062	152,015	1.89	35.41	1.70	94.2	47,699	8,022	14.52	86.39	0.44	81.7
2019	2,629,405	139,141	1.81	34.16	1.74	101.6	20,188	3,425	14.40	84.89	0.50	73.0
2020	1,937,714	105,627	1.74	31.92	1.72	97.1	18,954	3,216	9.44	55.61	0.49	88.7
2021	2,163,331	116,480	1.79	33.35	1.79	92.0	25,972	4,447	15.38	89.84	0.47	101.6
2022	2,142,472	116,864	2.19	40.16	1.69	96.4	41,066	6,827	22.83	137.45	0.39	69.1
2023	1,763,719	98,990	2.28	40.63	1.52	104.7	29,337	4,849	20.59	124.91	0.36	105.8
2024	1,513,856	85,656	2.17	38.37	1.54	98.5	22,399	3,685	18.64	113.35	0.38	77.6
Year 2022												
January	190,059	10,391	2.06	37.66	1.62	79.5	8,892	1,482	18.48	111.05	0.39	51.8
February	169,787	9,274	2.07	37.95	1.56	82.2	4,566	762	18.20	109.02	0.36	96.9
March	191,644	10,240	2.04	38.27	1.72	101.2	1,540	252	22.72	138.89	0.45	63.0
April	175,332	9,448	1.99	37.03	1.86	107.7	1,498	247	27.01	163.98	0.48	89.1
May	170,813	9,355	2.01	36.76	1.87	107.8	1,250	205	28.43	173.23	0.48	73.6
June	170,764	9,296	2.20	40.47	1.83	95.7	1,651	275	30.73	185.03	0.41	72.6
July	188,956	10,384	2.45	44.55	1.71	90.8	1,756	293	30.58	183.42	0.47	48.7
August	189,136	10,350	2.41	44.15	1.63	86.5	2,286	381	27.18	162.89	0.47	67.6
September	175,484	9,589	2.16	39.62	1.72	106.1	2,185	358	23.44	143.49	0.41	98.3
October	185,852	10,141	2.18	40.02	1.67	126.2	2,848	471	23.30	140.86	0.35	112.5
November	164,764	9,127	2.20	39.71	1.49	101.3	3,910	654	26.55	158.67	0.37	194.2
December	169,882	9,269	2.47	45.38	1.65	91.6	8,682	1,447	19.92	119.50	0.33	55.5
Year 2023												
January	160,350	8,640	2.36	43.91	1.70	107.3	3,706	618	22.40	134.71	0.41	194.5
February	150,824	8,308	2.25	40.84	1.63	122.3	3,914	637	17.39	107.13	0.37	77.7
March	156,569	8,706	2.31	41.52	1.54	117.5	1,599	261	21.45	131.58	0.47	79.2
April	143,467	8,154	2.27	39.94	1.50	122.5	1,844	305	20.51	124.08	0.37	95.0
May	145,409	8,086	2.32	41.86	1.59	118.4	1,720	282	19.41	118.27	0.43	89.2
June	136,863	7,723	2.28	40.48	1.52	105.1	1,623	269	18.98	114.73	0.46	95.4
July	142,931	8,208	2.24	38.98	1.44	83.9	2,180	361	18.91	114.20	0.35	83.9
August	148,108	8,433	2.23	39.31	1.46	86.3	2,952	490	21.29	129.36	0.26	157.0
September	135,357	7,629	2.24	39.75	1.41	96.0	1,974	327	23.62	143.13	0.30	89.9
October	138,346	7,862	2.28	40.14	1.50	104.7	2,214	362	22.47	137.36	0.33	79.5
November	153,037	8,666	2.27	40.16	1.46	103.8	2,920	484	20.22	121.98	0.38	147.1
December	152,457	8,573	2.27	40.45	1.52	105.4	2,692	453	21.47	128.27	0.29	148.0
Year 2024												
January	136,350	7,689	2.25	39.91	1.54	78.0	2,732	457	19.22	114.73	0.35	61.1
February	125,437	7,169	2.12	37.19	1.56	124.9	1,128	186	20.22	122.40	0.42	90.7
March	111,385	6,300	2.10	37.16	1.63	131.3	1,259	206	21.01	128.52	0.45	86.0
April	97,606	5,729	2.02	34.36	1.45	105.2	1,632	269	20.39	123.79	0.44	69.7
May	104,074	5,887	2.20	38.90	1.59	96.0	2,004	329	19.41	118.21	0.38	101.2
June	120,305	6,732	2.20	39.37	1.65	90.3	2,044	335	18.17	110.82	0.46	89.9
July	137,833	7,806	2.15	37.95	1.60	85.8	1,836	301	19.09	116.28	0.29	53.8
August	147,122	8,293	2.23	39.55	1.49	90.6	1,705	280	18.63	113.61	0.40	74.0
September	133,554	7,466	2.20	39.42	1.47	101.3	1,454	236	17.80	109.92	0.39	97.5
October	141,888	7,921	2.15	38.56	1.54	114.4	1,923	313	16.68	102.39	0.32	111.3
November	128,787	7,226	2.17	38.75	1.59	110.5	2,482	408	17.54	106.75	0.37	141.1
December	129,516	7,437	2.19	38.19	1.44	88.6	2,202	365	17.27	104.34	0.39	50.6

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W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.8. Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2014 - 2024 (continued)

	Petroleum Coke						Natural Gas					All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)
Annual Totals												
2014	13,781	488	2.48	70.31	5.33	70.9	4,054,540	3,934,672	4.90	5.05	92.7	3.52
2015	14,550	524	2.45	68.22	5.26	67.3	4,683,291	4,530,195	2.94	3.04	93.2	2.57
2016	13,573	492	2.50	68.88	5.44	69.9	4,791,729	4,634,518	2.54	2.63	94.0	2.29
2017	0	0	--	--	--	0.0	4,346,156	4,201,573	3.08	3.19	94.0	2.54
2018	0	0	--	--	--	0.0	4,889,212	4,727,692	3.40	3.52	94.6	2.84
2019	0	0	--	--	--	0.0	5,242,547	5,062,877	2.70	2.80	96.0	2.40
2020	0	0	--	--	--	0.0	5,359,545	5,178,938	2.10	2.17	96.1	2.01
2021	0	0	--	--	--	0.0	5,255,390	5,077,009	5.29	5.48	95.7	4.16
2022	0	0	--	--	--	--	5,602,375	5,414,698	6.95	7.20	95.5	5.50
2023	0	0	--	--	--	--	6,038,310	5,836,072	2.82	2.92	96.1	2.75
2024	0	0	--	--	--	--	6,133,734	5,923,429	2.41	2.50	96.4	2.41
Year 2022												
January	0	0	--	--	--	--	440,567	425,442	6.15	6.38	95.6	4.92
February	0	0	--	--	--	--	375,891	363,057	5.88	6.09	94.2	4.62
March	0	0	--	--	--	--	359,407	347,490	4.96	5.14	95.0	3.87
April	0	0	--	--	--	--	344,208	332,882	6.22	6.44	95.5	4.66
May	0	0	--	--	--	--	428,890	414,929	7.60	7.86	96.4	5.80
June	0	0	--	--	--	--	513,920	497,609	7.55	7.81	96.1	6.03
July	0	0	--	--	--	--	644,066	623,293	7.29	7.54	96.2	6.04
August	0	0	--	--	--	--	645,276	623,863	8.56	8.86	95.5	6.95
September	0	0	--	--	--	--	538,145	519,483	7.58	7.86	95.8	6.04
October	0	0	--	--	--	--	446,464	431,379	5.29	5.48	95.5	4.32
November	0	0	--	--	--	--	407,043	393,319	5.35	5.54	94.1	4.44
December	0	0	--	--	--	--	458,497	441,951	9.26	9.61	95.4	7.27
Year 2023												
January	0	0	--	--	--	--	446,640	430,815	5.37	5.57	95.8	4.57
February	0	0	--	--	--	--	407,924	394,009	3.92	4.06	96.1	3.50
March	0	0	--	--	--	--	428,537	414,070	2.95	3.06	95.4	2.81
April	0	0	--	--	--	--	393,827	380,548	2.28	2.36	95.5	2.35
May	0	0	--	--	--	--	444,722	430,350	2.12	2.19	96.9	2.23
June	0	0	--	--	--	--	542,599	524,807	2.17	2.24	96.4	2.24
July	0	0	--	--	--	--	691,161	668,245	2.67	2.76	95.9	2.63
August	0	0	--	--	--	--	677,647	655,199	2.46	2.55	96.1	2.48
September	0	0	--	--	--	--	571,702	553,460	2.35	2.43	96.3	2.39
October	0	0	--	--	--	--	483,231	467,338	2.42	2.51	96.4	2.47
November	0	0	--	--	--	--	469,276	453,150	2.94	3.05	96.0	2.85
December	0	0	--	--	--	--	481,043	464,082	2.76	2.86	96.4	2.70
Year 2024												
January	0	0	--	--	--	--	535,112	516,165	4.90	5.08	96.8	4.33
February	0	0	--	--	--	--	422,449	407,092	2.34	2.42	96.1	2.32
March	0	0	--	--	--	--	417,748	402,983	1.85	1.92	96.1	1.96
April	0	0	--	--	--	--	398,022	384,553	1.69	1.75	96.1	1.83
May	0	0	--	--	--	--	462,442	447,391	1.92	1.99	96.6	2.05
June	0	0	--	--	--	--	554,335	535,943	2.25	2.33	96.1	2.30
July	0	0	--	--	--	--	687,681	664,168	2.10	2.18	96.5	2.16
August	0	0	--	--	--	--	666,449	643,563	1.88	1.95	96.1	2.00
September	0	0	--	--	--	--	557,352	538,490	2.04	2.11	96.8	2.11
October	0	0	--	--	--	--	485,365	469,303	2.14	2.21	95.5	2.19
November	0	0	--	--	--	--	455,042	439,462	2.27	2.35	97.1	2.32
December	0	0	--	--	--	--	491,738	474,316	3.60	3.73	97.0	3.31

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Table 7.9. Receipts, Average Cost, and Quality of Fossil Fuels: Commercial Sector, 2014 - 2024

Table 7.9. Receipts, Average Cost, and Quantity of Fossil Fuels: Commercial Sector, 2014 - 2024												
	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2014	4,096	182	3.12	70.30	2.50	17.1	0	0	--	--	--	0.0
2015	2,439	109	2.85	63.90	2.55	13.6	0	0	--	--	--	0.0
2016	1,288	57	2.69	60.89	3.03	8.3	0	0	--	--	--	0.0
2017	548	24	2.78	63.31	2.99	3.9	0	0	--	--	--	0.0
2018	290	13	2.94	66.52	3.04	2.2	0	0	--	--	--	0.0
2019	193	8	2.92	66.55	3.01	1.6	0	0	--	--	--	0.0
2020	132	6	2.96	67.66	2.93	1.2	0	0	--	--	--	0.0
2021	262	11	3.03	69.50	2.94	2.1	0	0	--	--	--	0.0
2022	268	12	4.17	94.87	3.08	2.2	0	0	--	--	--	--
2023	66	3	4.28	96.92	3.22	0.7	0	0	--	--	--	--
2024	128	6	4.28	96.74	3.06	1.3	0	0	--	--	--	--
Year 2022												
January	74	3	3.95	90.18	3.03	5.8	0	0	--	--	--	--
February	19	1	3.95	90.65	3.00	1.5	0	0	--	--	--	--
March	0	0	--	--	--	0.0	0	0	--	--	--	--
April	0	0	--	--	--	0.0	0	0	--	--	--	--
May	0	0	--	--	--	0.0	0	0	--	--	--	--
June	0	0	--	--	--	--	0	0	--	--	--	--
July	0	0	--	--	--	--	0	0	--	--	--	--
August	0	0	--	--	--	--	0	0	--	--	--	--
September	106	5	4.28	97.46	3.05	10.0	0	0	--	--	--	--
October	54	2	4.28	97.11	3.24	5.2	0	0	--	--	--	--
November	0	0	--	--	--	0.0	0	0	--	--	--	--
December	15	1	4.28	96.94	3.02	1.1	0	0	--	--	--	--
Year 2023												
January	21	1	4.28	96.60	3.06	1.8	0	0	--	--	--	--
February	22	1	4.28	97.20	3.12	2.1	0	0	--	--	--	--
March	0	0	--	--	--	--	0	0	--	--	--	--
April	0	0	--	--	--	--	0	0	--	--	--	--
May	0	0	--	--	--	--	0	0	--	--	--	--
June	0	0	--	--	--	--	0	0	--	--	--	--
July	0	0	--	--	--	--	0	0	--	--	--	--
August	0	0	--	--	--	--	0	0	--	--	--	--
September	0	0	--	--	--	--	0	0	--	--	--	--
October	0	0	--	--	--	--	0	0	--	--	--	--
November	0	0	--	--	--	--	0	0	--	--	--	--
December	24	1	4.28	96.94	3.46	2.6	0	0	--	--	--	--
Year 2024												
January	85	4	4.28	96.86	3.06	5.9	0	0	--	--	--	--
February	43	2	4.28	96.51	3.06	4.1	0	0	--	--	--	--
March	0	0	--	--	--	0.0	0	0	--	--	--	--
April	0	0	--	--	--	--	0	0	--	--	--	--
May	0	0	--	--	--	--	0	0	--	--	--	--
June	0	0	--	--	--	--	0	0	--	--	--	--
July	0	0	--	--	--	--	0	0	--	--	--	--
August	0	0	--	--	--	0.0	0	0	--	--	--	--
September	0	0	--	--	--	0.0	0	0	--	--	--	--
October	0	0	--	--	--	0.0	0	0	--	--	--	--
November	0	0	--	--	--	0.0	0	0	--	--	--	--
December	0	0	--	--	--	0.0	0	0	--	--	--	--

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

- Values are final.

- See Glossary for definitions.

- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.

- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commerical Sector, 2014 - 2024 (continued)

Table 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commercial Sector, 2014 - 2024 (continued)													
	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2014	0	0	--	--	--	0.0	5,849	5,795	5.42	5.47	4.9	4.47	
2015	0	0	--	--	--	0.0	6,499	6,371	4.11	4.19	5.5	3.76	
2016	0	0	--	--	--	0.0	8,005	7,766	3.85	3.97	6.1	3.69	
2017	0	0	--	--	--	0.0	7,841	7,593	3.82	3.95	4.9	3.75	
2018	0	0	--	--	--	0.0	9,090	8,823	3.49	3.59	6.6	3.47	
2019	0	0	--	--	--	0.0	9,429	9,087	3.26	3.39	6.7	3.26	
2020	0	0	--	--	--	0.0	8,532	8,188	3.07	3.20	6.3	3.07	
2021	0	0	--	--	--	0.0	8,869	8,528	3.42	3.56	7.3	3.41	
2022	0	0	--	--	--	--	8,636	8,322	3.88	4.02	6.8	3.89	
2023	0	0	--	--	--	--	8,130	7,861	3.04	3.15	6.6	3.05	
2024	0	0	--	--	--	--	7,834	7,544	3.28	3.41	5.9	3.30	
Year 2022													
January	0	0	--	--	--	--	759	731	3.29	3.42	6.5	3.35	
February	0	0	--	--	--	--	711	683	3.32	3.45	6.8	3.33	
March	0	0	--	--	--	--	712	687	3.30	3.42	6.8	3.30	
April	0	0	--	--	--	--	786	758	4.35	4.51	8.2	4.35	
May	0	0	--	--	--	--	686	661	4.13	4.29	7.0	4.13	
June	0	0	--	--	--	--	628	603	3.89	4.05	6.1	3.89	
July	0	0	--	--	--	--	693	668	3.86	4.00	5.7	3.86	
August	0	0	--	--	--	--	732	703	4.86	5.06	5.9	4.86	
September	0	0	--	--	--	--	766	738	4.56	4.73	7.3	4.53	
October	0	0	--	--	--	--	657	634	3.98	4.12	7.0	4.00	
November	0	0	--	--	--	--	656	636	3.18	3.28	6.7	3.18	
December	0	0	--	--	--	--	850	821	3.73	3.86	7.5	3.74	
Year 2023													
January	0	0	--	--	--	--	707	682	3.11	3.22	6.6	3.14	
February	0	0	--	--	--	--	707	683	3.01	3.11	7.2	3.05	
March	0	0	--	--	--	--	680	655	3.05	3.17	6.6	3.05	
April	0	0	--	--	--	--	720	700	2.89	2.97	8.0	2.89	
May	0	0	--	--	--	--	748	726	2.84	2.92	8.1	2.84	
June	0	0	--	--	--	--	617	598	2.89	2.99	6.2	2.89	
July	0	0	--	--	--	--	629	607	3.07	3.18	5.4	3.07	
August	0	0	--	--	--	--	670	646	3.09	3.21	6.0	3.09	
September	0	0	--	--	--	--	619	597	3.10	3.21	5.8	3.10	
October	0	0	--	--	--	--	685	664	3.03	3.13	7.0	3.03	
November	0	0	--	--	--	--	687	664	3.19	3.31	6.8	3.19	
December	0	0	--	--	--	--	661	638	3.27	3.38	6.3	3.30	
Year 2024													
January	0	0	--	--	--	--	715	686	3.29	3.43	5.7	3.40	
February	0	0	--	--	--	--	666	641	3.29	3.42	6.0	3.35	
March	0	0	--	--	--	--	572	552	3.18	3.29	5.3	3.18	
April	0	0	--	--	--	--	648	629	3.14	3.24	6.8	3.14	
May	0	0	--	--	--	--	577	554	3.18	3.31	6.3	3.18	
June	0	0	--	--	--	--	486	469	3.10	3.21	4.5	3.10	
July	0	0	--	--	--	--	652	629	3.31	3.42	5.1	3.31	
August	0	0	--	--	--	--	764	733	3.26	3.40	6.1	3.26	
September	0	0	--	--	--	--	618	595	3.42	3.56	5.7	3.42	
October	0	0	--	--	--	--	642	620	3.38	3.50	6.2	3.38	
November	0	0	--	--	--	--	772	740	3.30	3.44	7.1	3.30	
December	0	0	--	--	--	--	722	695	3.43	3.56	6.1	3.43	

Displayed values of zero may represent small values that round to zero.

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W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.11. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2014 - 2024

Period	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2014	281,867	13,050	2.97	64.15	1.33	68.4	2,290	373	17.91	109.99	1.43	15.6
2015	263,630	12,132	2.72	59.17	1.35	71.4	2,359	385	13.45	82.47	1.42	16.9
2016	210,749	9,859	2.67	57.01	1.30	67.0	2,541	412	10.51	64.79	1.27	18.3
2017	192,637	9,178	2.49	52.29	1.35	70.7	1,850	297	11.18	69.57	1.42	15.2
2018	170,730	8,224	2.47	51.38	1.30	67.2	2,319	372	13.46	83.97	1.35	15.9
2019	146,324	7,088	2.55	52.69	1.19	65.1	1,684	275	13.19	80.82	1.47	14.5
2020	134,523	6,515	2.49	51.38	1.27	68.9	1,700	277	10.52	64.54	1.20	17.0
2021	141,492	6,781	2.33	48.60	1.33	69.9	2,380	387	12.90	79.39	1.46	21.3
2022	138,708	6,721	2.78	57.30	1.27	70.3	2,475	404	18.35	112.54	1.26	10.5
2023	123,941	6,174	3.26	65.45	1.02	73.6	2,862	468	17.32	105.80	1.35	16.2
2024	118,599	5,880	2.94	59.35	1.03	72.3	2,130	346	16.58	102.07	1.57	22.6
Year 2022												
January	12,244	593	2.58	53.22	1.35	67.4	301	49	14.12	86.62	1.46	18.3
February	10,697	520	2.65	54.46	1.17	68.2	229	37	15.76	97.63	1.27	16.8
March	12,941	626	2.53	52.28	1.39	74.0	219	36	15.78	97.43	1.06	11.4
April	10,674	504	2.78	58.94	1.37	65.8	112	18	19.33	118.47	1.55	5.7
May	12,282	597	2.49	51.10	1.38	72.5	175	29	19.13	117.32	0.90	10.0
June	11,491	564	2.36	48.06	1.45	72.2	144	23	21.21	129.90	1.07	6.9
July	12,246	595	2.65	54.47	1.30	75.6	156	26	19.35	118.47	1.57	7.5
August	10,874	533	2.67	54.52	1.21	66.4	157	25	20.21	124.53	1.54	11.4
September	11,393	556	3.10	63.58	1.06	74.0	202	33	18.30	112.79	1.13	10.7
October	11,143	541	3.52	72.50	0.91	68.4	223	36	17.89	109.96	1.15	11.7
November	10,179	488	3.21	66.97	1.29	65.4	219	36	23.10	140.27	1.11	12.1
December	12,543	605	2.91	60.37	1.36	73.2	337	56	19.51	118.50	1.38	9.1
Year 2023												
January	11,082	548	2.99	60.56	1.21	67.8	336	55	17.76	108.25	1.35	15.2
February	10,894	523	3.79	78.83	1.06	75.4	332	55	17.22	104.12	1.55	15.6
March	10,570	525	3.64	73.24	0.78	73.6	440	73	16.48	99.40	1.62	22.5
April	11,351	563	3.48	70.15	0.97	84.9	300	50	17.07	103.34	1.55	15.1
May	10,576	520	3.41	69.33	1.16	75.3	309	51	15.64	95.51	1.12	32.7
June	10,155	532	2.82	53.77	0.82	79.2	93	15	16.41	103.52	1.09	9.0
July	9,652	499	2.86	55.29	0.73	69.5	141	23	16.54	102.83	1.00	13.4
August	10,109	515	3.10	60.84	0.91	76.1	136	22	17.84	111.00	1.20	10.9
September	8,716	431	3.73	75.33	1.07	64.2	154	25	16.85	104.23	1.13	12.6
October	10,465	521	3.22	64.67	1.08	77.9	232	38	20.00	122.63	1.47	21.7
November	9,969	489	3.04	62.05	1.15	70.7	198	32	19.26	117.80	1.37	14.8
December	10,403	508	3.04	62.22	1.25	70.8	191	31	17.47	108.06	1.32	12.6
Year 2024												
January	9,556	480	2.78	55.44	0.87	60.5	313	51	16.91	104.56	1.20	24.5
February	11,198	553	3.08	62.42	1.01	82.4	195	32	18.01	108.28	1.65	22.5
March	10,962	527	3.18	66.06	0.99	71.9	148	24	15.74	95.28	1.53	18.8
April	8,753	436	2.86	57.41	1.03	73.3	132	21	17.82	109.90	1.57	16.7
May	9,654	481	2.86	57.39	0.85	76.0	128	21	16.69	103.83	1.60	18.9
June	9,675	483	3.00	60.11	0.97	77.7	142	23	16.94	104.50	1.23	22.8
July	10,223	503	2.93	59.57	1.21	73.5	183	30	16.48	101.78	1.58	26.7
August	9,931	491	2.94	59.46	1.16	73.9	162	26	15.32	95.00	1.65	27.1
September	9,443	478	2.86	56.60	0.90	73.3	181	29	16.22	100.75	1.63	29.0
October	9,747	476	3.11	63.70	1.11	71.8	160	26	15.84	96.88	1.76	20.0
November	9,621	485	2.77	54.98	1.02	70.1	144	23	15.94	98.83	1.80	19.4
December	9,836	488	2.87	57.79	1.25	66.7	243	39	16.63	102.58	1.83	25.2

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W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.12. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2014 - 2024 (continued)

Table 7.12. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2014 - 2024 (continued)													
	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2014	9,736	358	2.56	69.67	5.83	23.2	742,347	718,360	4.54	4.69	62.7	4.12	
2015	8,189	304	1.73	46.72	5.50	24.1	765,964	740,975	2.83	2.93	60.6	2.82	
2016	3,664	135	2.00	54.12	5.84	11.2	744,034	721,358	2.65	2.74	59.6	2.68	
2017	2,356	85	1.59	44.08	5.84	8.1	803,435	778,741	3.18	3.28	62.0	3.06	
2018	1,911	71	1.75	47.47	5.74	7.1	792,297	769,790	3.39	3.49	58.6	3.25	
2019	2,028	73	1.69	46.99	5.81	8.1	814,483	790,388	2.82	2.91	57.5	2.80	
2020	2,157	80	1.73	46.84	5.89	10.0	805,785	783,182	2.28	2.34	53.7	2.32	
2021	0	0	--	--	--	0.0	801,054	778,861	4.65	4.79	56.5	4.33	
2022	82	3	4.46	124.88	5.99	0.4	835,428	812,863	6.51	6.69	59.1	6.01	
2023	0	0	--	--	--	--	819,270	796,511	2.96	3.05	57.1	3.04	
2024	0	0	--	--	--	--	814,871	791,957	2.47	2.55	56.7	2.57	
Year 2022													
January	0	0	--	--	--	--	76,455	74,275	4.68	4.82	59.9	4.42	
February	0	0	--	--	--	--	65,784	63,860	5.74	5.91	59.0	5.34	
March	0	0	--	--	--	--	71,461	69,559	4.69	4.82	60.3	4.39	
April	0	0	--	--	--	--	67,470	65,714	5.97	6.13	60.8	5.55	
May	0	0	--	--	--	--	67,025	65,283	7.68	7.89	58.9	6.90	
June	0	0	--	--	--	--	68,964	67,264	8.29	8.50	60.1	7.47	
July	0	0	--	--	--	--	72,749	70,916	6.93	7.11	58.8	6.33	
August	0	0	--	--	--	--	73,848	72,011	8.69	8.91	59.1	7.94	
September	0	0	--	--	--	--	66,052	64,306	8.40	8.63	57.9	7.65	
October	82	3	4.46	124.88	5.99	4.6	65,621	63,673	5.82	5.99	57.1	5.52	
November	0	0	--	--	--	--	69,498	67,553	5.11	5.26	58.9	4.92	
December	0	0	--	--	--	--	70,500	68,450	6.26	6.45	58.4	5.81	
Year 2023													
January	0	0	--	--	--	--	71,716	69,675	5.00	5.14	58.3	4.78	
February	0	0	--	--	--	--	64,329	62,549	3.21	3.31	58.2	3.36	
March	0	0	--	--	--	--	69,643	67,835	2.75	2.82	57.9	2.94	
April	0	0	--	--	--	--	63,498	61,740	2.31	2.38	58.5	2.55	
May	0	0	--	--	--	--	66,713	64,886	2.36	2.43	57.7	2.56	
June	0	0	--	--	--	--	66,989	65,355	2.48	2.54	56.0	2.54	
July	0	0	--	--	--	--	67,515	65,565	2.84	2.93	53.9	2.87	
August	0	0	--	--	--	--	68,641	66,678	2.82	2.90	54.9	2.88	
September	0	0	--	--	--	--	67,506	65,578	2.80	2.88	55.9	2.93	
October	0	0	--	--	--	--	67,344	65,433	2.86	2.94	57.5	2.96	
November	0	0	--	--	--	--	70,348	68,333	3.08	3.18	58.2	3.12	
December	0	0	--	--	--	--	75,027	72,883	2.86	2.95	58.3	2.92	
Year 2024													
January	0	0	--	--	--	--	74,708	72,490	3.68	3.79	56.1	3.62	
February	0	0	--	--	--	--	65,778	63,867	2.58	2.65	56.5	2.69	
March	0	0	--	--	--	--	67,919	66,041	1.83	1.88	57.4	2.04	
April	0	0	--	--	--	--	67,078	65,299	1.94	1.99	59.4	2.07	
May	0	0	--	--	--	--	66,345	64,508	1.98	2.04	57.5	2.12	
June	0	0	--	--	--	--	64,633	62,797	2.52	2.59	56.2	2.61	
July	0	0	--	--	--	--	67,769	65,866	2.46	2.53	54.7	2.55	
August	0	0	--	--	--	--	69,890	67,923	2.08	2.14	55.2	2.21	
September	0	0	--	--	--	--	66,925	65,081	2.22	2.29	57.1	2.34	
October	0	0	--	--	--	--	63,855	62,024	2.53	2.61	56.8	2.64	
November	0	0	--	--	--	--	65,486	63,669	2.32	2.39	55.9	2.40	
December	0	0	--	--	--	--	74,487	72,393	3.37	3.46	58.2	3.35	

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- Values are final.

- See Glossary for definitions.

- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.

- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

**Table 7.13. Receipts of Coal Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Tons)**

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	42	120	-65.0%	0	0	42	120	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	42	66	-36.0%	0	0	42	66	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	54	-100.0%	0	0	0	54	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	7,790	8,551	-8.9%	0	0	7,683	8,443	0	0	107	108
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	7,790	8,551	-8.9%	0	0	7,683	8,443	0	0	107	108
East North Central	75,082	86,520	-13.0%	45,885	52,619	27,796	32,298	0	0	1,401	1,603
Illinois	21,009	23,125	-9.2%	3,833	4,040	15,775	17,482	0	0	1,401	1,603
Indiana	17,079	21,554	-21.0%	15,478	19,257	1,601	2,298	0	0	0	0
Michigan	13,764	13,700	0.5%	13,764	13,598	0	102	0	0	0	0
Ohio	12,622	14,980	-16.0%	2,202	2,563	10,420	12,417	0	0	0	0
Wisconsin	10,608	13,161	-19.0%	10,608	13,161	0	0	0	0	0	0
West North Central	79,285	95,536	-17.0%	76,573	92,829	0	0	6	3	2,706	2,704
Iowa	9,928	13,137	-24.0%	7,788	11,043	0	0	0	0	2,140	2,094
Kansas	9,142	12,351	-26.0%	9,142	12,351	0	0	0	0	0	0
Minnesota	6,583	8,693	-24.0%	6,583	8,693	0	0	0	0	0	0
Missouri	22,243	27,819	-20.0%	22,238	27,816	0	0	6	3	0	0
Nebraska	9,803	12,365	-21.0%	9,237	11,754	0	0	0	0	567	610
North Dakota	20,498	20,090	2.0%	20,498	20,090	0	0	0	0	0	0
South Dakota	1,087	1,082	0.4%	1,087	1,082	0	0	0	0	0	0
South Atlantic	44,613	52,480	-15.0%	40,845	47,058	3,447	5,006	0	0	321	416
Delaware	0	95	-100.0%	0	0	0	95	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,625	5,943	-39.0%	3,595	5,913	0	0	0	0	30	30
Georgia	8,291	10,336	-20.0%	8,178	10,204	0	0	0	0	113	132
Maryland	703	1,135	-38.0%	0	0	703	1,135	0	0	0	0
North Carolina	6,460	5,608	15.0%	6,460	5,531	0	0	0	0	0	77
South Carolina	6,778	7,443	-8.9%	6,756	7,319	0	88	0	0	22	37
Virginia	1,118	1,089	2.7%	962	949	0	0	0	0	156	140
West Virginia	17,638	20,830	-15.0%	14,894	17,142	2,744	3,688	0	0	0	0
East South Central	43,938	47,995	-8.5%	41,355	44,448	1,867	2,926	0	0	716	622
Alabama	10,876	13,185	-18.0%	10,876	13,185	0	0	0	0	0	0
Kentucky	25,989	27,297	-4.8%	25,989	27,297	0	0	0	0	0	0
Mississippi	2,869	4,098	-30.0%	1,002	1,172	1,867	2,926	0	0	0	0
Tennessee	4,203	3,415	23.0%	3,488	2,793	0	0	0	0	716	622
West South Central	60,627	76,160	-20.0%	24,949	36,967	35,615	39,009	0	0	63	184
Arkansas	8,762	11,174	-22.0%	7,108	9,042	1,607	2,076	0	0	47	56
Louisiana	3,134	4,928	-36.0%	1,743	2,906	1,391	2,022	0	0	0	0
Oklahoma	3,250	5,869	-45.0%	3,235	5,741	0	0	0	0	15	129
Texas	45,481	54,190	-16.0%	12,864	19,279	32,617	34,911	0	0	0	0
Mountain	55,176	60,535	-8.9%	47,600	51,947	7,576	8,589	0	0	0	0
Arizona	6,244	8,510	-27.0%	6,244	8,510	0	0	0	0	0	0
Colorado	9,556	12,453	-23.0%	9,556	12,453	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	6,096	7,092	-14.0%	0	0	6,096	7,092	0	0	0	0
Nevada	1,699	1,467	16.0%	1,036	800	662	667	0	0	0	0
New Mexico	4,630	3,504	32.0%	4,630	3,504	0	0	0	0	0	0
Utah	9,452	7,177	32.0%	9,060	6,843	392	334	0	0	0	0
Wyoming	17,499	20,333	-14.0%	17,074	19,838	425	495	0	0	0	0
Pacific Contiguous	2,196	3,135	-30.0%	0	0	1,629	2,599	0	0	566	536
California	566	536	5.6%	0	0	0	0	0	0	566	536
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	1,629	2,599	-37.0%	0	0	1,629	2,599	0	0	0	0
Pacific Noncontiguous	386	342	13.0%	386	342	0	0	0	0	0	0
Alaska	386	342	13.0%	386	342	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	369,134	431,375	-14.0%	277,592	326,208	85,656	98,990	6	3	5,880	6,174

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W = Withheld to avoid disclosure of individual company data.

Notes:

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.14. Receipts of Petroleum Liquids Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Barrels)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	421	987	-57.0%	61	101	360	885	0	0	0	0
Connecticut	92	100	-8.0%	0	0	92	100	0	0	0	0
Maine	103	331	-69.0%	0	0	103	331	0	0	0	0
Massachusetts	76	336	-77.0%	61	101	14	234	0	0	0	0
New Hampshire	135	164	-17.0%	0	0	135	164	0	0	0	0
Rhode Island	14	55	-74.0%	0	0	14	55	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	369	1,768	-79.0%	96	806	212	897	0	0	61	65
New Jersey	16	28	-45.0%	0	0	16	28	0	0	0	0
New York	160	1,355	-88.0%	96	806	64	549	0	0	0	0
Pennsylvania	193	384	-50.0%	0	0	132	320	0	0	61	64
East North Central	726	831	-13.0%	401	510	280	269	0	0	45	51
Illinois	76	78	-2.8%	20	21	56	56	0	0	0	0
Indiana	185	185	0.1%	185	185	0	0	0	0	0	0
Michigan	153	251	-39.0%	139	223	0	0	0	0	14	28
Ohio	289	297	-2.5%	34	61	224	213	0	0	31	23
Wisconsin	22	20	14.0%	22	20	0	0	0	0	0	0
West North Central	871	950	-8.4%	871	950	0	1	0	0	0	0
Iowa	106	115	-7.6%	106	115	0	0	0	0	0	0
Kansas	245	152	60.0%	245	152	0	0	0	0	0	0
Minnesota	28	154	-82.0%	28	154	0	1	0	0	0	0
Missouri	368	390	-5.6%	368	390	0	0	0	0	0	0
Nebraska	24	22	6.3%	24	22	0	0	0	0	0	0
North Dakota	90	105	-14.0%	90	105	0	0	0	0	0	0
South Dakota	10	12	-13.0%	10	12	0	0	0	0	0	0
South Atlantic	1,794	2,905	-38.0%	1,043	2,063	514	495	0	0	237	347
Delaware	18	86	-80.0%	0	0	18	86	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	192	745	-74.0%	171	661	0	55	0	0	21	29
Georgia	283	438	-35.0%	116	263	12	9	0	0	155	166
Maryland	416	211	97.0%	0	0	416	211	0	0	0	0
North Carolina	111	348	-68.0%	111	266	0	0	0	0	0	82
South Carolina	190	228	-17.0%	162	186	0	12	0	0	28	30
Virginia	384	530	-28.0%	283	400	69	91	0	0	32	39
West Virginia	201	317	-37.0%	201	287	0	30	0	0	0	0
East South Central	184	515	-64.0%	181	510	0	0	0	0	3	5
Alabama	10	52	-80.0%	10	52	0	0	0	0	0	0
Kentucky	140	184	-24.0%	140	184	0	0	0	0	0	0
Mississippi	10	7	48.0%	10	7	0	0	0	0	0	0
Tennessee	24	273	-91.0%	21	267	0	0	0	0	3	5
West South Central	461	490	-5.9%	245	165	217	325	0	0	0	0
Arkansas	91	83	9.8%	73	62	17	21	0	0	0	0
Louisiana	17	12	45.0%	17	12	0	0	0	0	0	0
Oklahoma	35	45	-23.0%	35	45	0	0	0	0	0	0
Texas	319	351	-9.1%	119	46	199	304	0	0	0	0
Mountain	236	221	6.3%	207	200	28	21	0	0	0	0
Arizona	46	56	-17.0%	46	56	0	0	0	0	0	0
Colorado	25	18	41.0%	25	18	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	35	13	175.0%	12	0	24	13	0	0	0	0
Nevada	12	16	-27.0%	10	13	2	3	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	52	37	40.0%	50	32	2	5	0	0	0	0
Wyoming	65	81	-20.0%	65	81	0	0	0	0	0	0
Pacific Contiguous	43	43	2.0%	29	32	15	11	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	43	43	2.0%	29	32	15	11	0	0	0	0
Pacific Noncontiguous	9,404	9,631	-2.4%	7,345	7,686	2,059	1,945	0	0	0	0
Alaska	14	18	-23.0%	14	18	0	0	0	0	0	0
Hawaii	9,390	9,614	-2.3%	7,332	7,669	2,059	1,945	0	0	0	0
U.S. Total	14,510	18,341	-21.0%	10,480	13,023	3,685	4,849	0	0	346	468

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 W = Withheld to avoid disclosure of individual company data.

Notes:
 See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.
 Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
 Petroleum Liquids includes distillate and residual fuel oils.
 See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.15. Receipts of Petroleum Coke Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	615	641	-4.2%	615	641	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	612	619	-1.2%	612	619	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	3	22	-86.0%	3	22	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	229	431	-47.0%	229	431	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	229	431	-47.0%	229	431	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	109	378	-71.0%	109	378	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	109	378	-71.0%	109	378	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	953	1,450	-34.0%	953	1,450	0	0	0	0	0	0

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Petroleum Coke includes petroleum coke-derived synthesis gas.

See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.16. Receipts of Natural Gas Delivered for Electricity Generation by State, 2024 and 2023
(Million Cubic Feet)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	423,716	400,731	5.7%	347	318	423,368	400,413	0	0	0	0
Connecticut	168,669	163,651	3.1%	0	0	168,669	163,651	0	0	0	0
Maine	43,467	26,981	61.0%	0	0	43,467	26,981	0	0	0	0
Massachusetts	114,967	106,804	7.6%	347	318	114,620	106,486	0	0	0	0
New Hampshire	31,526	30,878	2.1%	0	0	31,526	30,878	0	0	0	0
Rhode Island	65,086	72,417	-10.0%	0	0	65,086	72,417	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	1,682,696	1,613,381	4.3%	112,428	102,567	1,546,911	1,486,256	0	0	23,356	24,558
New Jersey	218,212	240,430	-9.2%	0	0	218,212	240,430	0	0	0	0
New York	475,862	433,635	9.7%	112,428	102,567	356,388	324,377	0	0	7,045	6,692
Pennsylvania	988,622	939,315	5.2%	0	0	972,311	921,449	0	0	16,311	17,866
East North Central	1,651,296	1,547,784	6.7%	655,446	596,441	988,555	925,377	5,228	5,488	22,067	20,478
Illinois	202,165	196,069	3.1%	21,028	19,106	175,098	170,809	0	0	6,039	6,154
Indiana	275,410	245,235	12.0%	155,680	127,925	119,731	117,310	0	0	0	0
Michigan	395,420	382,379	3.4%	214,369	207,219	171,219	164,590	5,228	5,488	4,604	5,082
Ohio	590,626	545,984	8.2%	81,324	67,570	502,508	472,668	0	0	6,794	5,745
Wisconsin	187,675	178,118	5.4%	183,045	174,621	0	0	0	0	4,630	3,498
West North Central	347,393	332,994	4.3%	289,328	273,532	49,742	51,408	2,317	2,372	6,007	5,683
Iowa	72,015	75,387	-4.5%	66,009	69,705	0	0	0	0	6,007	5,683
Kansas	44,659	34,113	31.0%	44,659	34,113	0	0	0	0	0	0
Minnesota	102,420	89,633	14.0%	67,423	56,907	34,980	32,709	16	17	0	0
Missouri	75,918	77,363	-1.9%	58,856	56,310	14,762	18,698	2,300	2,355	0	0
Nebraska	12,821	13,670	-6.2%	12,821	13,670	0	0	0	0	0	0
North Dakota	25,139	28,868	-13.0%	25,139	28,868	0	0	0	0	0	0
South Dakota	14,421	13,960	3.3%	14,421	13,960	0	0	0	0	0	0
South Atlantic	3,050,531	2,956,451	3.2%	2,557,166	2,481,716	454,802	438,180	0	0	38,564	36,555
Delaware	24,242	24,782	-2.2%	0	0	24,242	24,782	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	1,428,330	1,377,415	3.7%	1,363,618	1,319,876	59,989	53,407	0	0	4,723	4,131
Georgia	410,473	442,228	-7.2%	340,633	359,343	58,880	72,776	0	0	10,960	10,108
Maryland	99,892	109,516	-8.8%	20,546	30,070	79,346	79,446	0	0	0	0
North Carolina	430,335	403,276	6.7%	369,735	341,075	60,600	61,117	0	0	0	1,084
South Carolina	169,953	188,627	-9.9%	161,819	183,305	5,416	3,086	0	0	2,718	2,236
Virginia	448,881	372,762	20.0%	295,424	242,564	140,695	117,904	0	0	12,761	12,294
West Virginia	38,425	37,846	1.5%	5,391	5,482	25,634	25,662	0	0	7,400	6,702
East South Central	1,160,002	1,069,590	8.5%	902,465	786,335	229,237	258,275	0	0	28,300	24,980
Alabama	436,723	428,575	1.9%	214,403	176,158	222,320	252,417	0	0	0	0
Kentucky	139,124	107,514	29.0%	132,332	101,821	6,792	5,692	0	0	0	0
Mississippi	438,365	404,871	8.3%	438,240	404,704	125	167	0	0	0	0
Tennessee	145,789	128,631	13.0%	117,490	103,651	0	0	0	0	28,300	24,980
West South Central	3,639,532	3,538,619	2.9%	1,350,215	1,250,595	1,642,022	1,630,050	0	0	647,295	657,974
Arkansas	172,753	188,168	-8.2%	158,827	173,665	10,477	11,743	0	0	3,449	2,759
Louisiana	590,712	582,914	1.3%	350,549	328,480	37,713	42,319	0	0	202,450	212,115
Oklahoma	361,359	344,298	5.0%	256,520	237,147	98,702	100,248	0	0	6,137	6,903
Texas	2,514,707	2,423,240	3.8%	584,318	511,303	1,495,130	1,475,740	0	0	435,260	436,196
Mountain	957,752	910,018	5.2%	789,327	740,999	168,053	168,870	0	0	372	149
Arizona	411,133	389,864	5.5%	293,122	279,143	118,011	110,721	0	0	0	0
Colorado	129,967	126,143	3.0%	108,565	108,562	21,401	17,581	0	0	0	0
Idaho	33,433	29,658	13.0%	24,216	17,468	9,217	12,190	0	0	0	0
Montana	5,793	6,226	-7.0%	5,743	6,171	50	56	0	0	0	0
Nevada	175,017	168,209	4.0%	175,017	168,209	0	0	0	0	0	0
New Mexico	85,286	99,119	-14.0%	65,925	70,806	19,361	28,313	0	0	0	0
Utah	76,661	76,793	-0.2%	76,289	76,644	0	0	0	0	372	149
Wyoming	40,463	14,005	189.0%	40,451	13,996	12	9	0	0	0	0
Pacific Contiguous	815,788	854,903	-4.6%	349,054	351,527	440,738	477,243	0	0	25,997	26,133
California	535,140	579,502	-7.7%	177,538	181,047	331,605	372,322	0	0	25,997	26,133
Oregon	174,285	161,864	7.7%	95,782	93,963	78,503	67,901	0	0	0	0
Washington	106,363	113,537	-6.3%	75,734	76,517	30,630	37,019	0	0	0	0
Pacific Noncontiguous	12,460	12,908	-3.5%	12,460	12,908	0	0	0	0	0	0
Alaska	12,460	12,908	-3.5%	12,460	12,908	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	13,741,165	13,237,380	3.8%	7,018,235	6,596,937	5,923,429	5,836,072	7,544	7,861	791,957	796,511

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Notes:

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.17. Average Cost of Coal Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	W	W	W	--	--	W	W
Connecticut	--	--	--	--	--	--	--
Maine	W	W	W	--	--	W	W
Massachusetts	--	--	--	--	--	--	--
New Hampshire	--	W	W	--	--	--	W
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	2.23	2.31	-3.5%	--	--	2.23	2.31
New Jersey	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	--
Pennsylvania	2.23	2.31	-3.5%	--	--	2.23	2.31
East North Central	2.41	2.54	-5.1%	2.59	2.69	2.12	2.32
Illinois	1.80	1.85	-2.7%	2.02	2.09	1.75	1.79
Indiana	W	W	W	2.87	2.99	W	W
Michigan	2.53	W	W	2.53	2.58	--	W
Ohio	2.55	2.67	-4.5%	2.77	2.56	2.50	2.69
Wisconsin	2.32	2.48	-6.5%	2.32	2.48	--	--
West North Central	1.81	1.83	-1.1%	1.81	1.83	--	--
Iowa	1.89	1.76	7.4%	1.89	1.76	--	--
Kansas	1.61	1.70	-5.3%	1.61	1.70	--	--
Minnesota	2.29	2.40	-4.6%	2.29	2.40	--	--
Missouri	1.84	1.92	-4.2%	1.84	1.92	--	--
Nebraska	1.32	1.33	-0.8%	1.32	1.33	--	--
North Dakota	1.90	1.86	2.2%	1.90	1.86	--	--
South Dakota	2.36	2.25	4.9%	2.36	2.25	--	--
South Atlantic	3.45	3.55	-2.8%	3.53	3.64	2.47	2.72
Delaware	--	W	W	--	--	--	W
District of Columbia	--	--	--	--	--	--	--
Florida	3.62	3.37	7.4%	3.62	3.37	--	--
Georgia	4.14	4.48	-7.6%	4.14	4.48	--	--
Maryland	W	W	W	--	--	W	W
North Carolina	4.50	4.68	-3.8%	4.50	4.68	--	--
South Carolina	3.28	W	W	3.28	3.57	--	W
Virginia	4.46	5.20	-14.0%	4.46	5.20	--	--
West Virginia	2.78	2.81	-1.1%	2.90	2.94	2.10	2.13
East South Central	W	W	W	2.54	2.74	W	W
Alabama	2.65	3.04	-13.0%	2.65	3.04	--	--
Kentucky	2.40	2.50	-4.0%	2.40	2.50	--	--
Mississippi	W	W	W	3.70	3.96	W	W
Tennessee	3.01	3.54	-15.0%	3.01	3.54	--	--
West South Central	2.10	2.17	-3.2%	2.08	2.21	2.12	2.12
Arkansas	W	W	W	2.02	2.19	W	W
Louisiana	W	W	W	2.80	2.97	W	W
Oklahoma	2.16	2.27	-4.8%	2.16	2.27	--	--
Texas	2.02	2.03	-0.5%	1.98	2.08	2.04	2.00
Mountain	2.61	W	W	2.69	2.39	2.05	W
Arizona	3.24	3.04	6.6%	3.24	3.04	--	--
Colorado	2.23	2.11	5.7%	2.23	2.11	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	--	--	W	W
Nevada	W	W	W	4.52	5.15	W	W
New Mexico	3.66	3.57	2.5%	3.66	3.57	--	--
Utah	3.64	2.51	45.0%	3.64	2.51	--	--
Wyoming	W	W	W	1.71	1.88	W	W
Pacific Contiguous	W	W	W	--	--	W	W
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	W	W	W	--	--	W	W
Pacific Noncontiguous	4.43	4.57	-3.1%	4.43	4.57	--	--
Alaska	4.43	4.57	-3.1%	4.43	4.57	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.46	2.50	-1.6%	2.55	2.56	2.17	2.28

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Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.18. Average Cost of Petroleum Liquids Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	16.78	17.21	-2.5%	15.83	21.04	16.96	16.76
Connecticut	23.86	27.98	-15.0%	--	--	23.86	27.98
Maine	W	15.78	W	--	--	W	15.78
Massachusetts	W	W	W	15.83	21.04	W	W
New Hampshire	W	W	W	--	--	W	W
Rhode Island	W	W	W	--	--	W	W
Vermont	--	--	--	--	--	--	--
Middle Atlantic	18.37	19.57	-6.1%	18.48	18.25	18.32	21.05
New Jersey	W	23.54	W	--	--	W	23.54
New York	W	18.78	W	18.48	18.25	W	19.65
Pennsylvania	19.21	24.22	-21.0%	--	--	19.21	24.22
East North Central	18.34	20.20	-9.2%	18.05	19.82	18.75	20.95
Illinois	20.40	23.48	-13.0%	20.71	23.88	20.29	23.28
Indiana	18.25	21.24	-14.0%	18.25	21.24	--	--
Michigan	17.48	17.31	1.0%	17.48	17.31	--	--
Ohio	18.35	21.15	-13.0%	18.23	23.56	18.37	20.47
Wisconsin	17.35	19.67	-12.0%	17.35	19.67	--	--
West North Central	18.28	W	W	18.28	21.38	--	W
Iowa	18.35	21.80	-16.0%	18.35	21.80	--	--
Kansas	18.50	20.56	-10.0%	18.50	20.56	--	--
Minnesota	17.68	W	W	17.68	20.07	--	W
Missouri	18.12	22.06	-18.0%	18.12	22.06	--	--
Nebraska	17.84	21.75	-18.0%	17.84	21.75	--	--
North Dakota	18.93	21.07	-10.0%	18.93	21.07	--	--
South Dakota	15.16	24.42	-38.0%	15.16	24.42	--	--
South Atlantic	18.65	22.30	-16.0%	19.40	22.10	17.12	23.37
Delaware	W	W	W	--	--	W	W
District of Columbia	--	--	--	--	--	--	--
Florida	19.72	W	W	19.72	21.70	--	W
Georgia	22.43	W	W	22.43	24.66	--	W
Maryland	16.83	21.36	-21.0%	--	--	16.83	21.36
North Carolina	18.80	24.50	-23.0%	18.80	24.50	--	--
South Carolina	18.34	W	W	18.34	22.28	--	W
Virginia	W	W	W	19.62	19.71	W	W
West Virginia	18.27	W	W	18.27	21.71	--	W
East South Central	18.46	21.61	-15.0%	18.46	21.61	--	--
Alabama	19.27	23.02	-16.0%	19.27	23.02	--	--
Kentucky	18.54	22.14	-16.0%	18.54	22.14	--	--
Mississippi	18.63	20.99	-11.0%	18.63	20.99	--	--
Tennessee	17.38	20.98	-17.0%	17.38	20.98	--	--
West South Central	18.86	22.02	-14.0%	18.42	21.55	19.36	22.26
Arkansas	W	W	W	18.42	22.02	W	W
Louisiana	16.53	19.58	-16.0%	16.53	19.58	--	--
Oklahoma	17.77	22.10	-20.0%	17.77	22.10	--	--
Texas	19.16	22.04	-13.0%	18.82	20.90	19.37	22.22
Mountain	W	24.78	W	20.19	24.67	W	25.81
Arizona	21.56	23.97	-10.0%	21.56	23.97	--	--
Colorado	19.63	26.51	-26.0%	19.63	26.51	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	20.32	--	W	W
Nevada	W	W	W	22.74	26.76	W	W
New Mexico	--	--	--	--	--	--	--
Utah	W	W	W	19.42	24.65	W	W
Wyoming	19.60	24.40	-20.0%	19.60	24.40	--	--
Pacific Contiguous	W	W	W	24.76	25.90	W	W
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	W	W	W	24.76	25.90	W	W
Pacific Noncontiguous	W	W	W	17.99	20.02	W	W
Alaska	21.28	25.12	-15.0%	21.28	25.12	--	--
Hawaii	W	W	W	17.98	20.01	W	W
U.S. Total	18.33	20.51	-11.0%	18.22	20.48	18.64	20.59

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Petroleum Liquids includes distillate and residual fuel oils.

See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.19. Average Cost of Petroleum Coke Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	--	--	--	--	--	--	--
Connecticut	--	--	--	--	--	--	--
Maine	--	--	--	--	--	--	--
Massachusetts	--	--	--	--	--	--	--
New Hampshire	--	--	--	--	--	--	--
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	--	--	--	--	--	--	--
New Jersey	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	--
Pennsylvania	--	--	--	--	--	--	--
East North Central	2.63	2.97	-11.0%	2.63	2.97	--	--
Illinois	--	--	--	--	--	--	--
Indiana	--	--	--	--	--	--	--
Michigan	2.63	2.89	-9.0%	2.63	2.89	--	--
Ohio	--	--	--	--	--	--	--
Wisconsin	2.36	5.15	-54.0%	2.36	5.15	--	--
West North Central	--	--	--	--	--	--	--
Iowa	--	--	--	--	--	--	--
Kansas	--	--	--	--	--	--	--
Minnesota	--	--	--	--	--	--	--
Missouri	--	--	--	--	--	--	--
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	--
South Dakota	--	--	--	--	--	--	--
South Atlantic	3.64	5.20	-30.0%	3.64	5.20	--	--
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	3.64	5.20	-30.0%	3.64	5.20	--	--
Georgia	--	--	--	--	--	--	--
Maryland	--	--	--	--	--	--	--
North Carolina	--	--	--	--	--	--	--
South Carolina	--	--	--	--	--	--	--
Virginia	--	--	--	--	--	--	--
West Virginia	--	--	--	--	--	--	--
East South Central	--	--	--	--	--	--	--
Alabama	--	--	--	--	--	--	--
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	--	--	--	--
Tennessee	--	--	--	--	--	--	--
West South Central	3.34	4.49	-26.0%	3.34	4.49	--	--
Arkansas	--	--	--	--	--	--	--
Louisiana	3.34	4.49	-26.0%	3.34	4.49	--	--
Oklahoma	--	--	--	--	--	--	--
Texas	--	--	--	--	--	--	--
Mountain	--	--	--	--	--	--	--
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	--	--	--
Idaho	--	--	--	--	--	--	--
Montana	--	--	--	--	--	--	--
Nevada	--	--	--	--	--	--	--
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	--	--	--
Wyoming	--	--	--	--	--	--	--
Pacific Contiguous	--	--	--	--	--	--	--
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	--	--	--	--	--	--	--
Pacific Noncontiguous	--	--	--	--	--	--	--
Alaska	--	--	--	--	--	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.96	4.05	-27.0%	2.96	4.05	--	--

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

See Glossary for definitions. Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Petroleum Coke includes petroleum coke-derived synthesis gas.

See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.20. Average Cost of Natural Gas Delivered for Electricity Generation by State, 2024 and 2023
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2024	Year 2023	Percentage Change	Year 2024	Year 2023	Year 2024	Year 2023
New England	3.60	4.43	-19.0%	3.37	5.70	3.60	4.43
Connecticut	3.06	3.75	-18.0%	--	--	3.06	3.75
Maine	W	W	W	--	--	W	W
Massachusetts	4.85	6.91	-30.0%	3.37	5.70	4.85	6.92
New Hampshire	W	W	W	--	--	W	W
Rhode Island	2.95	2.97	-0.7%	--	--	2.95	2.97
Vermont	--	--	--	--	--	--	--
Middle Atlantic	2.28	2.32	-1.7%	2.63	3.07	2.24	2.26
New Jersey	2.34	2.07	13.0%	--	--	2.34	2.07
New York	2.71	2.93	-7.5%	2.63	3.07	2.73	2.87
Pennsylvania	2.03	2.09	-2.9%	--	--	2.03	2.09
East North Central	2.38	2.67	-11.0%	2.60	3.14	2.23	2.37
Illinois	2.39	2.55	-6.3%	2.35	2.84	2.40	2.52
Indiana	2.48	2.88	-14.0%	2.68	3.12	2.22	2.63
Michigan	2.36	2.69	-12.0%	2.51	2.80	2.18	2.55
Ohio	2.23	2.24	-0.4%	2.46	2.50	2.20	2.20
Wisconsin	2.74	3.84	-29.0%	2.74	3.84	--	--
West North Central	2.77	3.31	-16.0%	2.79	3.38	2.56	2.69
Iowa	2.47	2.92	-15.0%	2.47	2.92	--	--
Kansas	2.70	3.07	-12.0%	2.70	3.07	--	--
Minnesota	W	W	W	3.04	4.94	W	W
Missouri	W	W	W	2.82	2.85	W	W
Nebraska	4.16	3.45	21.0%	4.16	3.45	--	--
North Dakota	2.57	2.74	-6.2%	2.57	2.74	--	--
South Dakota	2.53	3.35	-24.0%	2.53	3.35	--	--
South Atlantic	3.51	3.84	-8.6%	3.64	3.99	2.62	2.81
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	3.62	3.99	-9.3%	3.64	4.00	2.93	3.47
Georgia	W	W	W	2.93	3.05	W	W
Maryland	3.04	2.90	4.8%	2.83	2.45	3.09	3.07
North Carolina	W	4.97	W	4.79	5.35	W	2.79
South Carolina	3.59	3.95	-9.1%	3.59	3.95	--	--
Virginia	2.85	3.30	-14.0%	3.10	3.71	2.17	2.18
West Virginia	1.91	W	W	2.22	1.93	1.84	W
East South Central	2.77	2.92	-5.1%	2.77	2.94	2.77	2.84
Alabama	2.77	3.00	-7.7%	2.77	3.18	2.78	2.85
Kentucky	W	W	W	3.11	3.41	W	W
Mississippi	W	W	W	2.70	2.75	W	W
Tennessee	2.64	2.83	-6.7%	2.64	2.83	--	--
West South Central	2.34	2.66	-12.0%	2.53	2.79	2.15	2.55
Arkansas	W	W	W	2.72	2.69	W	W
Louisiana	2.60	2.80	-7.1%	2.64	2.84	2.29	2.50
Oklahoma	W	W	W	3.23	2.97	W	W
Texas	2.13	2.60	-18.0%	2.10	2.70	2.15	2.56
Mountain	2.47	5.12	-52.0%	2.46	5.19	2.58	4.51
Arizona	2.24	4.30	-48.0%	2.19	4.16	2.51	4.86
Colorado	W	W	W	2.64	3.84	W	W
Idaho	2.88	6.57	-56.0%	2.88	6.57	--	--
Montana	W	W	W	1.41	2.29	W	W
Nevada	2.97	7.23	-59.0%	2.97	7.23	--	--
New Mexico	0.99	2.62	-62.0%	0.99	2.62	--	--
Utah	3.14	7.98	-61.0%	3.14	7.98	--	--
Wyoming	W	W	W	2.52	6.91	W	W
Pacific Contiguous	3.32	6.39	-48.0%	3.42	6.78	3.18	5.87
California	3.85	7.31	-47.0%	4.25	8.33	3.43	6.41
Oregon	W	W	W	2.21	5.07	W	W
Washington	W	W	W	3.28	5.78	W	W
Pacific Noncontiguous	6.38	7.29	-12.0%	6.38	7.29	--	--
Alaska	6.38	7.29	-12.0%	6.38	7.29	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.77	3.39	-18.0%	3.03	3.81	2.41	2.82

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

See Glossary for definitions. Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.21. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Total (All Sectors) by State, 2024

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	42	0.97	5.1	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	42	0.97	5.1	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	2,377	2.68	8.1	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	2,377	2.68	8.1	0	--	--	0	--	--
East North Central	39,211	3.14	11.2	35,871	0.25	4.7	0	--	--
Illinois	8,268	3.38	22.1	12,742	0.23	4.6	0	--	--
Indiana	16,640	2.92	9.2	439	0.26	4.7	0	--	--
Michigan	1,097	2.37	7.8	12,667	0.26	4.7	0	--	--
Ohio	12,622	3.39	8.8	0	--	--	0	--	--
Wisconsin	584	2.57	7.8	10,024	0.25	4.8	0	--	--
West North Central	466	3.21	8.6	58,320	0.26	4.9	20,386	0.77	10.7
Iowa	186	3.65	8.7	9,742	0.27	4.8	0	--	--
Kansas	0	--	--	9,142	0.27	5.1	0	--	--
Minnesota	0	--	--	6,583	0.27	5.0	0	--	--
Missouri	280	2.93	8.5	21,963	0.23	4.7	0	--	--
Nebraska	0	--	--	9,803	0.27	5.1	0	--	--
North Dakota	0	--	--	0	--	--	20,386	0.77	10.7
South Dakota	0	--	--	1,087	0.33	5.3	0	--	--
South Atlantic	39,465	2.51	9.9	4,608	0.35	5.3	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	3,625	2.83	8.9	0	--	--	0	--	--
Georgia	3,683	2.55	9.0	4,608	0.35	5.3	0	--	--
Maryland	703	2.76	8.9	0	--	--	0	--	--
North Carolina	6,460	1.54	10.1	0	--	--	0	--	--
South Carolina	6,778	2.02	9.2	0	--	--	0	--	--
Virginia	1,118	1.00	20.8	0	--	--	0	--	--
West Virginia	17,098	3.05	9.9	0	--	--	0	--	--
East South Central	23,918	2.83	9.7	18,153	0.25	4.9	1,867	0.57	14.1
Alabama	1,072	1.21	13.0	9,804	0.27	5.0	0	--	--
Kentucky	19,588	2.99	9.7	6,401	0.22	4.8	0	--	--
Mississippi	207	1.79	10.6	795	0.23	4.7	1,867	0.57	14.1
Tennessee	3,051	2.42	8.7	1,153	0.22	4.9	0	--	--
West South Central	270	2.85	9.1	48,256	0.29	5.1	12,102	1.09	16.9
Arkansas	47	0.86	12.2	8,715	0.23	4.7	0	--	--
Louisiana	222	3.31	8.4	2,912	0.25	4.8	0	--	--
Oklahoma	0	--	--	3,250	0.25	5.2	0	--	--
Texas	0	--	--	33,379	0.32	5.3	12,102	1.09	16.9
Mountain	14,669	0.68	13.5	40,115	0.45	7.1	0	--	--
Arizona	0	--	--	6,244	0.47	8.9	0	--	--
Colorado	841	0.43	10.5	8,715	0.31	6.4	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	5	0.45	5.7	6,091	0.71	8.9	0	--	--
Nevada	562	0.39	7.3	1,137	0.38	4.6	0	--	--
New Mexico	4,630	0.83	19.5	0	--	--	0	--	--
Utah	8,631	0.65	11.5	429	0.25	5.0	0	--	--
Wyoming	0	--	--	17,499	0.42	6.5	0	--	--
Pacific Contiguous	566	0.37	6.7	1,629	0.38	8.2	0	--	--
California	566	0.37	6.7	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	1,629	0.38	8.2	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	321	0.14	7.9
Alaska	0	--	--	0	--	--	321	0.14	7.9
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	120,985	2.57	10.6	206,952	0.30	5.4	34,677	0.87	13.0

Displayed values of zero may represent small values that round to zero.
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 W = Withheld to avoid disclosure of individual company data.

Notes:
 Bituminous coal includes anthracite coal and coal-derived synthesis gas.
 See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.22. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Electric Utilities by State, 2024**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	19,729	2.87	9.2	26,156	0.25	4.7	0	--	--
Illinois	807	2.57	10.9	3,026	0.21	4.6	0	--	--
Indiana	15,039	2.87	9.3	439	0.26	4.7	0	--	--
Michigan	1,097	2.37	7.8	12,667	0.26	4.7	0	--	--
Ohio	2,202	3.31	8.8	0	--	--	0	--	--
Wisconsin	584	2.57	7.8	10,024	0.25	4.8	0	--	--
West North Central	277	2.92	8.5	55,798	0.26	4.9	20,386	0.77	10.7
Iowa	2	3.16	8.7	7,786	0.27	4.8	0	--	--
Kansas	0	--	--	9,142	0.27	5.1	0	--	--
Minnesota	0	--	--	6,583	0.27	5.0	0	--	--
Missouri	275	2.92	8.5	21,963	0.23	4.7	0	--	--
Nebraska	0	--	--	9,237	0.27	5.1	0	--	--
North Dakota	0	--	--	0	--	--	20,386	0.77	10.7
South Dakota	0	--	--	1,087	0.33	5.3	0	--	--
South Atlantic	36,237	2.47	10.0	4,608	0.35	5.3	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	3,595	2.85	8.9	0	--	--	0	--	--
Georgia	3,570	2.60	9.0	4,608	0.35	5.3	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	6,460	1.54	10.1	0	--	--	0	--	--
South Carolina	6,756	2.03	9.2	0	--	--	0	--	--
Virginia	962	0.98	23.7	0	--	--	0	--	--
West Virginia	14,894	3.01	10.1	0	--	--	0	--	--
East South Central	23,202	2.89	9.8	18,153	0.25	4.9	0	--	--
Alabama	1,072	1.21	13.0	9,804	0.27	5.0	0	--	--
Kentucky	19,588	2.99	9.7	6,401	0.22	4.8	0	--	--
Mississippi	207	1.79	10.6	795	0.23	4.7	0	--	--
Tennessee	2,335	2.91	8.9	1,153	0.22	4.9	0	--	--
West South Central	222	3.31	8.4	23,256	0.26	4.9	1,471	2.36	29.5
Arkansas	0	--	--	7,108	0.23	4.7	0	--	--
Louisiana	222	3.31	8.4	1,521	0.21	4.6	0	--	--
Oklahoma	0	--	--	3,235	0.25	5.2	0	--	--
Texas	0	--	--	11,393	0.30	5.1	1,471	2.36	29.5
Mountain	14,664	0.68	13.5	32,936	0.40	6.9	0	--	--
Arizona	0	--	--	6,244	0.47	8.9	0	--	--
Colorado	841	0.43	10.5	8,715	0.31	6.4	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	562	0.39	7.3	474	0.51	4.0	0	--	--
New Mexico	4,630	0.83	19.5	0	--	--	0	--	--
Utah	8,631	0.65	11.5	429	0.25	5.0	0	--	--
Wyoming	0	--	--	17,074	0.42	6.5	0	--	--
Pacific Contiguous	0	--	--	0	--	--	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	321	0.14	7.9
Alaska	0	--	--	0	--	--	321	0.14	7.9
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	94,331	2.41	10.2	160,906	0.29	5.3	22,178	0.84	11.6

Displayed values of zero may represent small values that round to zero.

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Notes:

Bituminous coal includes anthracite coal and coal-derived synthesis gas.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.23. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Independent Power Producers by State, 2024**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	42	0.97	5.1	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	42	0.97	5.1	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	2,270	2.71	8.1	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	2,270	2.71	8.1	0	--	--	0	--	--
East North Central	18,753	3.41	13.5	9,043	0.23	4.6	0	--	--
Illinois	6,732	3.47	25.5	9,043	0.23	4.6	0	--	--
Indiana	1,601	3.29	8.1	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	10,420	3.41	8.8	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	0	--	--	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	2,908	3.21	8.9	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	703	2.76	8.9	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	0	--	--	0	--	--	0	--	--
Virginia	0	--	--	0	--	--	0	--	--
West Virginia	2,205	3.36	8.8	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	1,867	0.57	14.1
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	1,867	0.57	14.1
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	24,984	0.32	5.3	10,631	0.96	15.5
Arkansas	0	--	--	1,607	0.25	4.7	0	--	--
Louisiana	0	--	--	1,391	0.29	5.0	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	21,986	0.33	5.4	10,631	0.96	15.5
Mountain	5	0.45	5.7	7,179	0.65	8.5	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	5	0.45	5.7	6,091	0.71	8.9	0	--	--
Nevada	0	--	--	662	0.26	5.1	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	425	0.49	6.9	0	--	--
Pacific Contiguous	0	--	--	1,629	0.38	8.2	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	1,629	0.38	8.2	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	23,978	3.31	12.3	42,836	0.36	5.8	12,498	0.91	15.4

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite coal and coal-derived synthesis gas.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.24. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Commercial Sector by State, 2024

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	0	--	--	0	--	--	0	--	--
Illinois	0	--	--	0	--	--	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	6	3.06	9.3	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	6	3.06	9.3	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	0	--	--	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	0	--	--	0	--	--	0	--	--
Virginia	0	--	--	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	0	--	--	0	--	--
Arkansas	0	--	--	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	0	--	--	0	--	--	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	6	3.06	9.3	0	--	--	0	--	--

Displayed values of zero may represent small values that round to zero.
 NM = Not meaningful due to large relative standard error or excessive percentage change.
 W = Withheld to avoid disclosure of individual company data.

Notes:
 Bituminous coal includes anthracite coal and coal-derived synthesis gas.
 See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.25. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Industrial Sector by State, 2024**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	107	1.96	7.6	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	107	1.96	7.6	0	--	--	0	--	--
East North Central	729	3.54	8.4	672	0.38	5.0	0	--	--
Illinois	729	3.54	8.4	672	0.38	5.0	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	184	3.65	8.7	2,522	0.28	4.8	0	--	--
Iowa	184	3.65	8.7	1,955	0.28	4.8	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	567	0.28	4.8	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	321	0.91	7.9	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	30	0.69	7.7	0	--	--	0	--	--
Georgia	113	0.77	8.3	0	--	--	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	22	0.73	7.3	0	--	--	0	--	--
Virginia	156	1.07	7.8	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	716	0.93	7.8	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	716	0.93	7.8	0	--	--	0	--	--
West South Central	47	0.86	12.2	15	0.23	4.2	0	--	--
Arkansas	47	0.86	12.2	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	15	0.23	4.2	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	566	0.37	6.7	0	--	--	0	--	--
California	566	0.37	6.7	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	2,671	1.70	7.9	3,210	0.30	4.8	0	--	--

Displayed values of zero may represent small values that round to zero.

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite coal and coal-derived synthesis gas.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Chapter 8

Electric Power System Characteristics and Performance

**Table 8.1. Average Operating Heat Rate for Selected Energy Sources,
2014 through 2024 (Btu per Kilowatthour)**

Year	Coal	Petroleum	Natural Gas	Nuclear
2014	10,428	10,814	7,907	10,459
2015	10,495	10,687	7,869	10,458
2016	10,493	10,811	7,863	10,459
2017	10,465	10,834	7,803	10,459
2018	10,481	11,095	7,811	10,455
2019	10,551	11,205	7,725	10,442
2020	10,655	11,259	7,725	10,446
2021	10,583	11,224	7,689	10,429
2022	10,689	11,166	7,740	10,448
2023	10,745	11,465	7,721	10,452
2024	10,777	11,200	7,754	10,443

Note:

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal; and coal-derived synthesis gas.

Petroleum includes distillate fuel oil (all diesel and No. 1 and No. 2 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil, jet fuel, kerosene, petroleum coke, and waste oil.

Notes:

Included in the calculation for coal, petroleum, and natural gas average operating heat rate are electric power plants in the utility and independent power producer sectors.

Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations.

The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and Form EIA-860, "Annual Electric Generator Report."

Table 8.2. Average Tested Heat Rates by Prime Mover and Energy Source, 2014 - 2024
(Btu per Kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
2014				
Steam Generator	10,080	10,156	10,408	10,459
Gas Turbine	--	13,457	11,378	--
Internal Combustion	--	10,403	9,375	--
Combined Cycle	W	9,924	7,658	--
2015				
Steam Generator	10,059	10,197	10,372	10,458
Gas Turbine	--	13,550	11,302	--
Internal Combustion	--	10,379	9,322	--
Combined Cycle	W	9,676	7,655	--
2016				
Steam Generator	10,045	10,189	10,382	10,459
Gas Turbine	--	13,535	11,214	--
Internal Combustion	--	10,331	9,179	--
Combined Cycle	W	9,860	7,652	--
2017				
Steam Generator	10,043	10,199	10,353	10,459
Gas Turbine	--	13,491	11,176	--
Internal Combustion	--	10,301	9,120	--
Combined Cycle	W	9,811	7,649	--
2018				
Steam Generator	10,015	10,270	10,334	10,455
Gas Turbine	--	13,352	11,138	--
Internal Combustion	--	10,326	9,009	--
Combined Cycle	W	9,663	7,627	--
2019				
Steam Generator	10,002	10,236	10,347	10,442
Gas Turbine	--	13,315	11,098	--
Internal Combustion	--	10,325	8,899	--
Combined Cycle	W	9,662	7,633	--
2020				
Steam Generator	9,997	10,339	10,368	10,446
Gas Turbine	--	13,223	11,069	--
Internal Combustion	--	10,334	8,832	--
Combined Cycle	W	9,208	7,604	--
2021				
Steam Generator	10,002	10,347	10,365	10,429
Gas Turbine	--	13,227	11,068	--
Internal Combustion	--	10,461	8,821	--
Combined Cycle	W	9,208	7,580	--
2022				
Steam Generator	10,026	10,263	10,295	10,448
Gas Turbine	--	13,217	11,030	--
Internal Combustion	--	10,475	8,894	--
Combined Cycle	W	9,204	7,596	--
2023				
Steam Generator	10,020	10,314	10,285	10,452
Gas Turbine	--	13,088	11,010	--
Internal Combustion	--	10,506	8,900	--
Combined Cycle	W	9,696	7,549	--
2024				
Steam Generator	10,018	10,331	10,337	10,443
Gas Turbine	--	13,083	10,999	--
Internal Combustion	--	10,512	8,924	--
Combined Cycle	W	9,702	7,548	--

Notes: W = Withheld to avoid disclosure of individual company data.

Heat rate is reported at full load conditions for electric utilities and independent power producers.
The average heat rates above are weighted by Net Summer Capacity.
Coal Combined Cycle represents integrated gasification units.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

**Table 8.3. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities,
2014 through 2024 (Million Dollars)**

Description	2014	2015	2016	2017	2018	2019
Utility Operating Revenues	298,430	282,695	282,499	286,501	293,868	293,000
.....Electric Utility	271,832	260,121	261,047	263,265	268,421	266,876
.....Other Utility	26,598	22,574	21,451	23,235	25,447	26,124
Utility Operating Expenses	258,936	242,728	239,037	240,041	253,944	250,136
.....Electric Utility	240,643	228,366	226,457	226,110	238,526	234,892
.....Operation	165,989	149,939	145,077	142,000	163,479	157,265
.....Production	123,366	107,201	100,852	98,859	104,185	99,518
.....Cost of Fuel	42,545	34,711	32,621	32,165	33,592	29,614
.....Purchased Power	62,066	52,970	49,962	49,030	53,060	50,378
.....Other	18,755	19,521	18,269	17,664	17,533	19,526
.....Transmission	8,902	9,624	10,447	10,804	11,387	11,941
.....Distribution	4,331	4,406	4,734	4,358	4,806	5,218
.....Customer Accounts	5,255	5,184	5,077	4,789	4,969	4,978
.....Customer Service	6,396	6,445	6,187	5,961	6,019	6,156
.....Sales	208	201	205	213	203	204
.....Administrative and General	17,532	16,878	17,575	17,016	31,911	29,248
.....Maintenance	16,801	16,392	16,982	17,996	17,786	19,898
.....Depreciation	25,919	26,847	30,097	30,323	32,125	34,883
.....Taxes and Other	31,934	35,188	34,301	35,791	25,136	22,846
.....Other Utility	18,293	14,362	12,579	13,931	15,418	15,245
Net Utility Operating Income	39,494	39,968	43,462	46,460	39,924	42,864

Description	2020	2021	2022	2023	2024
Utility Operating Revenues	294,756	329,138	381,129	378,230	384,741
.....Electric Utility	269,869	299,956	344,355	343,701	352,516
.....Other Utility	24,888	29,181	36,774	34,529	32,226
Utility Operating Expenses	240,802	271,078	315,491	307,839	306,372
.....Electric Utility	227,084	253,979	292,247	287,611	289,892
.....Operation	144,335	163,952	196,589	185,924	179,919
.....Production	93,505	110,775	140,287	126,857	120,333
.....Cost of Fuel	25,856	34,771	49,486	36,229	32,871
.....Purchased Power	50,407	61,627	80,032	67,897	63,763
.....Other	17,242	14,377	10,768	22,731	23,699
.....Transmission	12,949	15,310	15,872	15,746	17,863
.....Distribution	5,480	5,659	5,973	6,402	6,740
.....Customer Accounts	5,775	5,249	5,658	6,607	7,099
.....Customer Service	5,868	6,192	6,659	6,953	7,462
.....Sales	211	215	255	217	212
.....Administrative and General	20,546	20,553	21,886	23,142	20,211
.....Maintenance	20,030	20,875	21,834	21,570	23,128
.....Depreciation	38,208	39,666	42,104	44,693	47,887
.....Taxes and Other	24,510	29,485	31,720	35,424	38,958
.....Other Utility	13,718	17,100	23,244	20,228	16,480
Net Utility Operating Income	53,954	58,060	65,638	70,391	78,369

Notes: Missing or erroneous respondent data may result in slight imbalances in some of the expense account subtotals.

Total may not equal sum of components due to independent rounding.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned

Electric Utilities, 2014 through 2024 (Mills per Kilowatthour)

Year	Operation				Maintenance			
	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	12.41	4.55	7.30	2.63	6.67	5.11	4.59	2.90
2015	11.17	5.16	8.37	2.34	7.06	5.41	5.06	2.68
2016	10.90	5.05	6.65	2.49	7.01	5.53	4.34	2.74
2017	10.27	5.01	6.33	2.45	6.63	5.13	3.96	2.83
2018	10.78	5.19	6.69	2.37	5.93	5.27	3.96	2.71
2019	10.63	5.52	6.86	2.58	6.29	6.85	3.94	2.64
2020	10.05	6.40	7.72	2.38	5.78	5.60	5.00	2.51
2021	10.55	5.70	7.98	2.12	5.88	5.32	4.33	2.28
2022	10.51	6.75	7.68	2.20	6.10	5.09	4.76	2.36
2023	9.52	6.48	9.18	2.16	6.36	5.61	5.53	2.12
2024	9.87	6.98	8.97	2.25	6.84	5.81	6.10	2.11

Year	Fuel				Total			
	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2014	7.71	29.39	--	37.06	26.79	39.04	11.90	42.60
2015	7.48	26.70	--	28.22	25.71	37.26	13.42	33.24
2016	7.45	25.50	--	24.97	25.36	36.08	10.98	30.19
2017	7.47	25.27	--	26.48	24.38	35.41	10.29	31.76
2018	7.15	25.40	--	27.35	23.86	35.86	10.65	32.43
2019	6.81	24.28	--	23.11	23.73	36.66	10.80	28.33
2020	6.10	22.87	--	19.65	21.92	34.86	12.71	24.55
2021	6.31	24.64	--	25.78	22.74	35.66	12.30	30.18
2022	6.12	32.04	--	38.72	22.73	43.88	12.44	43.28
2023	6.12	30.58	--	22.19	22.00	42.67	14.71	26.47
2024	6.37	28.52	--	18.59	23.08	41.32	15.07	22.95

Hydroelectric category consists of both conventional hydroelectric and pumped storage.

Gas Turbine and Small Scale category consists of gas turbine, internal combustion, photovoltaic, and wind plants.

Notes: Expenses are average expenses weighted by net generation. A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of one cent).

Total may not equal sum of components due to independent rounding.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

Table 8.11.A. U.S. Transmission Circuit Outages by Type and NERC region, 2024

Outage Type	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Circuit Outage Counts									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--
Circuit Outage Hours									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--
Circuit Outage Counts per 1,000 Circuit Miles									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--
Circuit Outage Hours per Outage Incident									
Automatic Outages (Sustained)	--	--	--	--	--	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--	--	--	--	--	--

Notes:

Circuit Miles for each region is displayed in Table 8.10.A.

An Automatic Outage is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

A Sustained Outage is an automatic outage with an outage duration of a minute or greater.

A Non-Automatic Outage is an outage which results from the manual operation (including supervisory control) of a switching device, causing an element to change from an In-Service State to a not In-Service State.

An Operational Outage is a Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred.

A Planned Outage is a Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred.

Detailed information on the Transmission Availability Data System outage definitions is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 8.11.B. U.S. Transformer Outages by Type and NERC region, 2024

Outage Type	Eastern Interconnection	tre	wecc	Contiguous U.S.
Circuit Outage Counts				
Automatic Outages (Sustained)	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--
Non-Automatic Outages (Planned)	--	--	--	--
Circuit Outage Hours				
Automatic Outages (Sustained)	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--
Non-Automatic Outages (Planned)	--	--	--	--
Circuit Outage Hours per Outage Incident				
Automatic Outages (Sustained)	--	--	--	--
Non-Automatic Outages (Operational)	--	--	--	--
Non-Automatic Outages (Planned)	--	--	--	--

Notes:

An Automatic Outage is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

A Sustained Outage is an automatic outage with an outage duration of a minute or greater.

A Non-Automatic Outage is an outage which results from the manual operation (including supervisory control) of a switching device, causing an element to change from an In-Service State to a not In-Service State.

An Operational Outage is a Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred.

A Planned Outage is a Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred.

Detailed information on the Transmission Availability Data System outage definitions is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

**Table 8.12.A. U.S. Transmission Circuit Sustained Automatic Outage Counts and Hours
by High-Voltage Size and NERC Region, 2024**

Sustained Automatic Outage Counts										
Voltage		Region								
Type	Operating (kV)	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Grand Total		.	.	.	.	.	.	.	.	--

Total Outages per 1,000 Circuit Miles										
		Region								
		frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Rate		.	.	.	.	.	.	.	.	--

Sustained Automatic Outage Hours										
Voltage		Region								
Type	Operating (kV)	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Grand Total		.	.	.	.	.	.	.	.	--

Outage Hours per Outage Incident										
		Region								
		frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
Rate		.	.	.	.	.	.	.	.	--

Notes:

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

Circuit Miles for each region is displayed in Table 8.10.A.

An Automatic Outage is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

A Sustained Outage is an automatic outage with an outage duration of a minute or greater.

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 8.12.B. U.S. Transformer Sustained Automatic Outage Counts
and Hours by High-Voltage Size and NERC Region, 2024

Sustained Automatic Outage Counts				
High-Side Voltage (kV)	Eastern Interconnection	tre	wecc	Contiguous U.S.
	--	--	--	--

Sustained Automatic Outage Hours				
High-Side Voltage (kV)	Eastern Interconnection	tre	wecc	Contiguous U.S.
	--	--	--	--

Table 8.13.A. U.S. Transmission Circuit Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 1)

	AC & DC Circuit Outage Counts								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total AC & DC Circuit Outage Counts								
Sustained Outage Causes	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 8.13.A. U.S. Transmission Circuit Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 2)

	AC & DC Circuit Outage Hours								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total AC & DC Circuit Outage Hours								
Sustained Outage Causes	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 8.13.B. U.S. Transformer Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 1)

	Transformer Outage Counts								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total Transformer Outage Counts								
Sustained Outage Causes	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 8.13.B. U.S. Transformer Sustained Automatic Outage Counts and

Hours by Cause Code and by NERC Region, 2024 (Page 2)

	Transformer Outage Hours								
Sustained Outage Causes	frcc	mro	npcc	rfc	serc	spp	tre	wecc	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

	Percentage of Total Transformer Outage Hours								
OUTAGE_CAUSE	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contiguous U.S.
TOTAL	--	--	--	--	--	--	--	--	--

Notes:

Detailed information on the Transmission Availability Data System outage causes is available at:

<http://www.nerc.com/docs/pc/tadswg/Appendix%207%2020101202a%20clean.pdf>

Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Chapter 9

Environmental Data

Table 9.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants 2014 through 2024 (Thousand Metric Tons)

Year	Carbon Dioxide (CO2)	Sulfur Dioxide (SO2)	Nitrogen Oxides (NOx)
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,599	1,493
2018	1,872,330	1,517	1,474
2019	1,724,873	1,267	1,342
2020	1,553,586	1,023	1,211
2021	1,651,911	1,168	1,253
2022	1,650,367	1,079	1,230
2023	1,531,554	848	1,117
2024	1,537,073	808	1,112

Notes:

The emissions data presented include total emissions from both electricity generation and the production of useful thermal output.

See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates.

Source: Calculations made by the Office of Electricity, Renewables, and Uranium Statistics, U.S. Energy Information Administration.

Table 9.2. Quantity and Net Summer Capacity of Operable Environmental Equipment, 2014 - 2024

	Flue Gas Desulfurization Systems		Electrostatic Precipitators		Baghouses		Select Catalytic and Non-Catalytic Reduction Systems		Activated Carbon Injection Systems		Direct Sorbent Injection Systems	
Year	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2014	703	223,850	1,173	284,303	621	105,990	1,485	361,548	280	69,287	105	16,913
2015	694	224,159	1,038	265,268	623	110,820	1,493	363,007	364	106,450	123	23,443
2016	698	228,598	944	253,267	614	112,824	1,497	365,644	482	153,800	126	26,815
2017	683	222,607	887	244,450	603	109,759	1,506	369,042	477	151,208	128	25,916
2018	664	214,176	842	229,774	584	105,546	1,503	369,625	455	143,471	121	26,415
2019	619	203,130	784	217,711	537	102,103	1,476	366,814	431	136,597	116	25,615
2020	595	193,216	749	207,516	514	98,754	1,455	363,480	410	130,761	112	23,917
2021	570	186,400	708	197,689	483	94,981	1,436	360,901	396	127,791	108	22,975
2022	552	178,539	665	183,139	467	91,660	1,410	354,352	364	117,573	103	22,308
2023	523	167,691	621	171,029	457	90,154	1,387	347,508	344	110,996	98	21,257
2024	500	163,094	596	165,540	437	89,328	1,364	344,431	332	107,481	97	21,035

Note:

'Associated Net Summer Capacity' is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment. In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Source: Form EIA-860, "Annual Electric Generator Report."

Table 9.3. Quantity and Net Summer Capacity of Operable Cooling Systems, by Energy Source and

Cooling System Type, 2014 - 2024

Energy Source	Once-Through Cooling Systems		Recirculating Cooling Systems		Cooling Ponds		Dry Cooling Systems		Hybrid Wet and Dry Cooling Systems		Other Cooling System Types	
	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2014												
Coal	328	115,930	340	160,534	74	38,906	4	1,422	1	750	22	8,322
Natural Gas	161	50,985	420	84,984	56	20,294	58	11,878	4	637	3	2,419
Nuclear	44	49,596	35	37,650	13	15,237	--	--	--	--	9	11,886
Petroleum	42	10,893	11	3,473	4	4,691	--	--	--	--	--	--
Solar Thermal	--	--	4	841	--	--	5	900	--	--	--	--
Other	16	1,332	31	2,756	1	66	1	72	--	--	1	128
2015												
Coal	259	93,180	313	153,917	77	45,026	4	1,422	1	750	25	9,883
Natural Gas	160	49,219	437	88,982	59	22,351	59	12,038	3	475	3	2,410
Nuclear	43	47,268	35	37,610	14	17,663	--	--	--	--	9	12,062
Petroleum	29	9,104	9	2,308	4	4,299	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,676	26	2,104	1	66	1	72	--	--	1	128
2016												
Coal	210	82,047	294	149,187	79	44,702	4	1,422	1	750	22	10,148
Natural Gas	168	49,664	441	88,690	58	21,970	64	14,128	3	475	3	2,359
Nuclear	42	47,029	35	38,745	14	17,660	--	--	--	--	9	13,298
Petroleum	27	8,620	8	2,222	3	3,904	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,689	24	2,035	1	66	1	72	--	--	1	128
2017												
Coal	197	76,492	281	142,578	75	44,341	4	1,422	1	750	19	9,581
Natural Gas	172	50,053	440	91,398	59	21,677	66	15,271	4	801	6	3,772
Nuclear	42	47,013	35	38,784	14	17,700	--	--	--	--	9	13,298
Petroleum	26	8,174	8	1,844	4	3,965	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,582	26	2,464	2	97	2	245	--	--	1	128
2018												
Coal	180	70,659	273	138,632	67	39,593	4	1,422	1	750	16	8,089
Natural Gas	161	47,653	446	93,078	59	21,549	77	18,613	4	801	7	4,478
Nuclear	41	46,723	35	38,805	14	17,759	--	--	--	--	9	13,608
Petroleum	27	8,575	8	1,844	3	2,304	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,931	25	2,161	1	31	1	72	--	--	1	128
2019												
Coal	163	67,142	246	129,998	63	37,807	4	1,432	1	750	14	7,629
Natural Gas	150	45,079	448	95,673	56	21,279	78	18,769	4	801	7	4,058
Nuclear	40	46,244	34	37,970	14	17,759	--	--	--	--	10	14,927
Petroleum	26	8,147	7	1,684	3	2,302	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,962	25	2,161	--	--	1	72	--	--	1	128
2020												
Coal	143	61,538	232	123,410	58	35,832	5	1,536	1	750	13	6,703
Natural Gas	152	46,653	453	97,151	56	23,018	83	19,640	4	801	8	4,804
Nuclear	39	43,163	33	37,281	14	17,855	--	--	--	--	9	14,326
Petroleum	24	7,175	6	898	2	682	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	18	1,955	25	2,158	--	--	1	72	--	--	1	128
2021												
Coal	130	59,230	221	119,928	58	35,856	5	1,536	1	750	14	7,992
Natural Gas	144	44,244	460	101,024	52	22,762	82	19,627	4	801	6	3,612
Nuclear	38	42,013	33	37,471	14	17,862	--	--	--	--	9	14,213
Petroleum	24	7,622	6	898	2	684	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	18	1,955	22	2,045	--	--	1	72	--	--	1	128
2022												
Coal	105	46,596	207	112,393	57	35,718	4	1,432	1	750	11	6,581
Natural Gas	146	46,954	458	102,623	52	21,970	85	21,884	4	801	9	4,947
Nuclear	38	42,002	32	36,609	14	17,847	--	--	--	--	9	14,198
Petroleum	27	9,035	6	1,020	1	628	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	15	1,760	19	1,773	--	--	1	72	--	--	1	128
2023												
Coal	94	41,649	198	107,601	54	34,183	4	1,432	1	750	10	5,581
Natural Gas	136	44,252	457	103,564	52	21,758	90	24,794	5	947	7	3,901
Nuclear	38	41,999	33	37,713	14	17,799	--	--	--	--	9	14,198
Petroleum	26	7,954	6	1,020	1	637	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	16	1,806	20	1,826	--	--	1	72	--	--	1	128
2024												
Coal	86	38,413	194	106,748	53	34,044	4	1,432	1	750	10	5,581
Natural Gas	135	44,306	455	103,538	50	21,140	88	24,480	6	1,090	6	3,635
Nuclear	38	41,961	34	38,836	14	17,823	--	--	--	--	9	14,227
Petroleum	25	7,549	5	839	1	603	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	893	1	110	--	--
Other	15	1,645	20	1,823	--	--	1	72	--	--	1	128

Notes:

Associated Net Summer Capacity is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment.

In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal, and coal-derived synthesis gas.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane.

Petroleum Coke includes petroleum coke-derived synthesis gas.

Other Energy Sources consists of wood and wood waste products, biomass, blast furnace gas and Other Fossil Gas.

Source: Form EIA-860, "Annual Electric Generator Report."

**Table 9.4. Average Costs of Existing Flue Gas Desulfurization Units
Operating in Electric Power Sector, 2014 - 2024**

Year	Average Operation and Maintenance Costs (Dollars per Megawatthour)	Average Installed Capital Costs (Dollars per Kilowatt)
2014	1.84	186.45
2015	2.03	154.73
2016	1.96	303.32
2017	2.15	242.88
2018	2.08	--
2019	2.11	452.20
2020	2.21	--
2021	2.14	--
2022	2.36	310.18
2023	2.54	--
2024	2.59	--

Notes:

Average Installed Capital Costs reflect units which began operating in the specified year.

Years in which no new Flue Gas Desulfurization units were installed a '--' is indicated in the Average Installed Capital Cost column.

Average Operation and Maintenance Costs are based on all units in operation during the specified year regardless of installation year.

Commercial and industrial facilities had significantly different costs than units used in the electric power sector. In order to give a more accurate reflection of the electric power sector, commercial and industrial facilities have been excluded from this publication table.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and Form EIA-860, "Annual Electric Generator Report."

Table 9.5. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, by State, 2023 and 2024 (Thousand Metric Tons)

Census Division and State	Carbon Dioxide (CO2)		Sulfur Dioxide (SO2)		Nitrogen Oxides (NOx)	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	28,989	27,434	7	7	21	21
Connecticut	11,002	10,653	0	0	4	5
Maine	3,245	2,434	4	4	4	4
Massachusetts	8,895	8,263	2	2	8	8
New Hampshire	2,159	2,060	0	0	2	2
Rhode Island	3,680	4,014	0	0	2	2
Vermont	8	9	0	0	1	1
Middle Atlantic	117,697	114,738	32	33	64	63
New Jersey	13,861	15,112	0	1	7	8
New York	31,513	29,418	6	6	25	25
Pennsylvania	72,323	70,207	27	26	32	31
East North Central	255,892	249,331	155	149	154	155
Illinois	42,894	42,186	28	29	18	18
Indiana	61,437	61,252	23	23	42	43
Michigan	54,012	50,018	31	31	42	43
Ohio	65,214	63,226	65	59	31	31
Wisconsin	32,335	32,649	7	7	21	20
West North Central	153,777	161,366	150	170	125	133
Iowa	22,400	24,593	10	18	17	19
Kansas	17,842	20,280	2	3	14	14
Minnesota	20,391	20,842	11	11	16	18
Missouri	44,270	45,916	59	66	32	34
Nebraska	18,303	19,770	34	38	16	18
North Dakota	27,555	27,040	33	33	27	27
South Dakota	3,016	2,926	1	1	3	3
South Atlantic	288,907	281,059	136	147	180	176
Delaware	2,456	2,374	0	0	1	1
District of Columbia	80	73	0	0	0	0
Florida	92,505	93,735	18	21	44	44
Georgia	42,718	43,044	40	42	35	35
Maryland	9,718	9,138	2	2	6	5
North Carolina	41,129	36,765	16	18	37	36
South Carolina	26,896	25,599	19	19	16	15
Virginia	29,439	24,587	10	10	16	15
West Virginia	43,967	45,743	30	36	25	26
East South Central	157,357	148,514	94	86	82	78
Alabama	48,517	46,082	27	25	24	23
Kentucky	53,086	50,039	39	34	31	29
Mississippi	27,914	27,096	11	11	13	14
Tennessee	27,840	25,297	18	16	14	11
West South Central	309,487	310,377	146	165	248	241
Arkansas	26,858	28,363	30	32	18	17
Louisiana	41,958	42,944	23	24	57	53
Oklahoma	28,769	26,301	10	9	27	21
Texas	211,902	212,769	84	101	146	150
Mountain	153,836	162,426	54	58	113	119
Arizona	33,418	34,788	5	6	21	22
Colorado	25,602	27,579	7	9	13	15
Idaho	3,482	3,002	3	3	4	4
Montana	11,839	13,774	7	8	12	12
Nevada	13,068	12,540	3	3	10	10
New Mexico	13,402	13,542	2	2	8	7
Utah	21,120	20,620	5	4	21	21
Wyoming	31,905	36,580	23	22	24	28
Pacific Contiguous	61,556	66,670	15	14	90	94
California	39,594	43,360	1	1	57	59
Oregon	10,351	9,636	4	4	22	22
Washington	11,610	13,674	10	10	11	13
Pacific Noncontiguous	9,574	9,639	19	19	35	37
Alaska	3,636	3,605	2	2	18	20
Hawaii	5,938	6,035	16	17	16	16
U.S. Total	1,537,073	1,531,554	808	848	1,112	1,117

Notes:

The emissions data presented include total emissions from both electricity generation and the production of useful thermal output. See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates. Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Source: Calculations made by the Office of Energy Production Conversion and Delivery, U.S. Energy Information Administration.

Chapter 10

Energy Efficiency, Demand Response and Advanced Meters

**Table 10.1. Energy Efficiency
Category, by Sector, 2013 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Incremental Annual Savings - Energy Savings (MWh)					
2015	11,012,627	12,285,000	2,818,448	13,414	26,129,489
2016	11,712,873	13,348,029	2,425,175	14,147	27,500,224
2017	13,199,995	14,095,101	2,592,155	11,776	29,899,028
2018	12,459,323	13,350,203	2,565,238	40,273	28,415,037
2019	13,283,024	12,706,234	2,538,169	35,103	28,562,529
2020	13,136,061	12,464,063	2,559,475	7,859	28,167,459
2021	12,444,823	11,459,062	1,853,577	3,195	25,760,657
2022	11,709,919	10,835,070	1,839,391	139	24,384,518
2023	11,243,272	11,048,142	1,929,875	--	24,221,289
2024	10,200,084	11,498,785	2,140,086	10	23,838,965
Incremental Annual Savings - Peak Demand Savings (MW)					
2015	2,654	2,891	407	--	5,952
2016	2,698	2,556	401	3	5,658
2017	2,790	2,739	540	1	6,071
2018	2,775	3,072	459	4	6,309
2019	3,402	3,116	614	4	7,135
2020	2,985	2,877	424	1	6,287
2021	2,753	2,712	336	1	5,801
2022	2,466	2,499	479	--	5,445
2023	2,204	3,191	366	--	5,761
2024	2,198	3,206	860	*	6,264
Incremental Costs - Customer Incentive (thousand dollars)					
2015	1,488,651	1,616,843	342,773	20	3,448,286
2016	1,541,458	1,733,170	296,321	--	3,570,950
2017	1,657,086	1,713,295	294,026	--	3,664,407
2018	1,602,723	1,608,369	273,676	--	3,484,767
2019	1,712,243	1,659,591	285,643	--	3,657,477
2020	1,358,512	1,557,663	236,198	--	3,152,372
2021	1,574,404	1,594,830	206,571	--	3,375,805
2022	1,644,822	1,531,745	197,812	--	3,374,379
2023	1,826,044	1,771,421	252,897	--	3,850,362
2024	1,917,829	2,015,664	274,988	--	4,208,481
Incremental Costs - All Other Costs (thousand dollars)					
2015	1,152,224	938,021	193,015	40	2,283,300
2016	1,387,122	959,160	176,560	12	2,522,854
2017	1,221,072	900,291	176,585	10	2,297,957
2018	1,127,692	874,427	163,783	78	2,165,981
2019	1,209,389	910,039	168,567	33	2,288,028
2020	1,108,027	844,860	159,365	9	2,112,261
2021	1,178,407	932,133	130,700	3	2,240,600
2022	1,110,656	964,655	141,385	--	2,216,696
2023	1,250,790	1,124,056	163,345	--	2,538,191
2024	1,285,513	1,249,059	158,031	4	2,692,606

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 10.2. Energy Efficiency - Life Cycle
Category, by Sector, 2013 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Life Cycle Savings - Energy Savings (MWh)					
2015	99,512,487	160,045,443	36,589,144	199,328	296,346,403
2016	134,003,597	186,654,713	33,477,182	212,200	354,347,692
2017	137,297,599	204,102,657	33,249,999	176,636	374,826,892
2018	129,572,460	195,288,558	33,981,062	604,095	359,446,175
2019	134,474,216	186,931,400	33,284,347	526,549	355,216,512
2020	144,098,659	190,336,319	33,276,349	117,879	367,829,206
2021	122,339,730	153,947,500	23,992,054	47,932	300,327,216
2022	113,782,935	137,420,139	22,384,375	2,085	273,589,534
2023	101,341,591	146,197,493	22,912,335		270,451,419
2024	106,666,954	149,150,238	25,569,385	149	281,386,727
Life Cycle Savings - Peak Demand Savings (MW)					
2015	3,492	3,104	500		7,096
2016	3,408	3,132	507	3	7,050
2017	2,668	2,698	584	1	5,951
2018	2,649	2,987	436	4	6,075
2019	3,322	2,993	613	4	6,931
2020	2,769	2,807	425	1	6,003
2021	2,628	2,651	351	1	5,631
2022	2,294	2,449	473		5,216
2023	2,069	3,214	372		5,655
2024	2,141	3,165	846		6,152
Life Cycle Costs - Customer Incentive (thousand dollars)					
2015	1,844,246	1,997,677	413,416	30	4,255,368
2016	1,704,458	2,079,373	342,927		4,126,758
2017	2,194,049	2,359,255	296,498		4,849,803
2018	1,808,354	2,093,170	276,381		4,177,905
2019	1,911,197	2,000,492	440,237		4,351,926
2020	1,414,886	1,650,928	495,334		3,561,148
2021	1,636,371	1,713,633	328,872	3	3,678,879
2022	1,920,560	1,885,652	213,120		4,019,332
2023	2,035,217	2,125,178	253,091		4,413,487
2024	2,128,317	2,340,496	275,298		4,744,110
Life Cycle Costs - All Other Costs (thousand dollars)					
2015	2,086,543	1,407,658	216,226	40	3,710,453
2016	1,964,832	1,265,765	202,112	12	3,432,717
2017	1,649,863	1,335,176	177,945	10	3,162,995
2018	2,605,135	1,409,483	164,623	78	4,179,320
2019	1,884,678	1,527,461	243,435	33	3,655,607
2020	1,773,693	1,346,643	228,973	9	3,349,318
2021	1,258,415	1,015,672	192,451	3	2,466,541
2022	1,314,337	1,205,465	147,051		2,666,853
2023	1,420,950	1,335,146	163,528		2,919,623
2024	1,427,688	1,444,307	168,060	4	3,040,059

* = Value is less than half of the smallest unit of measure.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 10.3. Demand Response - Yearly Energy and Demand Savings
Category, by Sector, 2013 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Customers Enrolled					
2015	8,140,688	890,284	63,163	3	9,094,138
2016	8,739,535	1,033,649	66,170	1	9,839,355
2017	8,287,913	1,084,392	68,630	3	9,440,938
2018	8,700,669	986,816	64,753	--	9,752,238
2019	10,447,335	432,669	52,841	--	10,932,845
2020	11,302,017	324,939	38,706	1	11,665,663
2021	10,196,668	255,355	40,560	1	10,492,584
2022	10,044,583	235,825	39,365	1	10,319,774
2023	10,282,113	245,332	39,808	1	10,567,254
2024	10,658,027	249,192	43,608	1	10,950,828
Energy Savings (MWh)					
2015	855,017	273,089	122,900	--	1,251,006
2016	1,005,144	225,174	105,818	--	1,336,136
2017	948,037	244,603	118,230	--	1,310,862
2018	1,099,179	221,502	105,536	--	1,426,211
2019	1,075,567	306,832	80,336	--	1,462,735
2020	1,186,421	251,719	70,984	--	1,509,124
2021	984,129	88,947	80,715	--	1,153,791
2022	1,004,031	126,867	162,081	--	1,292,980
2023	230,285	107,321	69,649	--	407,255
2024	247,973	88,063	73,367	--	409,404
Potential Peak Demand Savings (MW)					
2015	8,703	6,989	17,169	14	32,875
2016	10,518	11,053	14,339	14	35,924
2017	8,996	6,995	15,512	5	31,508
2018	8,539	7,021	15,335	--	30,895
2019	8,867	6,907	15,246	--	31,020
2020	8,535	5,837	15,098	--	29,470
2021	8,705	6,646	13,871	--	29,222
2022	9,039	6,545	14,864	--	30,448
2023	9,667	7,035	13,840	--	30,542
2024	9,706	7,346	14,439	--	31,491
Actual Peak Demand Savings (MW)					
2015	3,430	3,047	6,546	13	13,036
2016	3,608	3,598	4,632	4	11,841
2017	3,960	2,743	5,546	--	12,248
2018	3,788	2,694	6,040	--	12,522
2019	3,426	2,403	5,505	--	11,334
2020	3,504	2,115	4,768	--	10,387
2021	3,836	2,807	5,569	--	12,211
2022	4,606	2,608	6,613	--	13,827
2023	4,082	2,661	4,009	--	10,752
2024	4,785	2,457	5,080	--	12,322

Energy Savings dropped due to a reclassification in the 2023 annual filings.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.4. Demand Response - Program Costs
Category, by Sector, 2013 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Customer Incentives (thousand dollars)					
2015	320,683	338,153	461,271	339	1,120,446
2016	306,635	448,332	284,584	339	1,039,890
2017	292,443	345,226	365,451	--	1,003,124
2018	310,892	347,235	531,157	--	1,189,284
2019	306,152	322,611	490,119	--	1,118,882
2020	274,021	281,304	432,328	--	987,653
2021	293,293	314,739	580,358	--	1,188,390
2022	265,186	287,785	596,309	--	1,149,280
2023	262,583	306,095	550,092	--	1,118,770
2024	273,346	348,692	602,656	--	1,224,694
All Other Costs (thousand dollars)					
2015	256,519	78,758	46,613	28	381,918
2016	253,180	66,084	60,443	--	379,707
2017	245,231	68,251	57,221	--	370,700
2018	235,159	66,024	59,534	--	360,718
2019	223,129	49,407	70,677	--	343,214
2020	213,592	59,905	53,365	10	326,872
2021	218,758	70,615	22,709	10	312,091
2022	244,430	62,832	21,782	10	329,053
2023	222,739	64,259	24,935	10	311,943
2024	262,017	68,914	31,132	10	362,073

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.05. Advanced Metering Count by Technology Type, 2015 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Automated Meter Reading (AMR)					
2015	42,326,302	5,049,978	226,908	1,023	47,604,211
2016	41,508,261	5,074,877	223,584	971	46,807,693
2017	39,325,014	4,813,029	230,099	707	44,368,849
2018	36,365,339	4,591,398	213,108	712	41,170,557
2019	32,750,506	4,160,628	207,286	861	37,119,281
2020	29,345,377	3,769,118	197,641	905	33,313,041
2021	26,098,336	3,550,517	184,358	920	29,834,131
2022	23,296,364	3,185,114	157,857	873	26,640,208
2023	19,591,318	2,982,169	156,330	571	22,730,388
2024	16,572,563	2,546,768	130,377	579	19,250,287
Advanced Metering Infrastructure (AMI)					
2015	57,107,785	7,324,345	310,889	813	64,743,832
2016	62,360,132	8,119,223	342,766	1,345	70,823,466
2017	69,474,626	9,060,128	365,447	1,389	78,901,590
2018	76,498,388	9,932,993	411,287	1,489	86,844,157
2019	83,539,594	10,850,886	446,871	1,504	94,838,855
2020	90,692,768	11,771,565	468,071	1,499	102,933,903
2021	97,708,824	12,930,423	535,725	1,786	111,176,758
2022	104,237,855	13,908,481	574,526	1,879	118,722,741
2023	112,175,762	14,830,952	755,067	2,584	127,764,365
2024	123,019,799	16,529,599	940,214	2,369	140,491,981
Standard (non-AMR/AMI) Meters					
2015	32,430,105	5,744,831	290,354	432	38,465,722
2016	28,491,094	4,929,344	280,406	416	33,701,260
2017	24,351,523	4,261,918	225,949	445	28,839,835
2018	21,982,727	3,884,695	186,001	414	26,053,837
2019	20,778,995	3,734,399	175,344	478	24,689,216
2020	18,941,774	3,572,152	140,087	510	22,654,523
2021	17,551,772	3,225,410	127,901	716	20,905,799
2022	15,675,775	2,953,060	106,426	691	18,735,952
2023	13,233,236	2,404,543	102,080	563	15,740,422
2024	6,958,631	1,284,234	100,308	558	8,343,731
Total Number of Meters					
2015	131,864,192	18,119,154	828,151	2,268	150,813,765
2016	132,359,487	18,123,444	846,756	2,732	151,332,419
2017	133,151,163	18,135,075	821,495	2,541	152,110,274
2018	134,846,454	18,409,086	810,396	2,615	154,068,551
2019	137,069,095	18,745,913	829,501	2,843	156,647,352
2020	138,979,919	19,112,835	805,799	2,914	158,901,467
2021	141,358,932	19,706,350	847,984	3,422	161,916,688
2022	143,209,994	20,046,655	838,809	3,443	164,098,901
2023	145,000,316	20,217,664	1,013,477	3,718	166,235,175
2024	146,550,993	20,360,601	1,170,899	3,506	168,085,999

Prior to 2010, the count was the number of customers, not number of meters.

Starting in 2013 Standard (Non-AMR/AMI) meter data was collected on the EIA-861.

This data is not collected on the EIA-861S.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Chapter 11

Distribution System Reliability

Table 11.1 Reliability Metrics of U.S. Distribution System

Year	IEEE									Any Method					
	All Events (With Major Event Days)			Without Major Event Days			Loss of Supply Removed			All Events (With Major Events)			Without Major Events		
	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)	SAIDI (minutes per year)	SAIFI (times per year)	CAIDI (minutes per interruption)
2014	236.2	1.3	188.0	114.2	1.0	110.0	244.8	1.2	203.7	219.0	1.2	179.6	109.7	1.0	107.7
2015	209.0	1.3	163.9	117.0	1.1	109.1	198.2	1.2	170.4	205.0	1.2	164.5	113.1	1.0	108.1
2016	268.4	1.3	202.2	119.8	1.1	110.7	257.0	1.2	209.0	249.2	1.3	192.9	116.9	1.1	110.0
2017	505.9	1.4	356.2	117.0	1.0	114.3	489.6	1.3	390.6	473.1	1.4	339.3	114.4	1.0	113.6
2018	349.2	1.3	260.5	121.4	1.1	115.5	338.5	1.2	283.8	346.4	1.3	261.5	117.2	1.0	114.0
2019	295.5	1.3	221.8	122.2	1.0	117.5	289.1	1.2	243.0	284.6	1.3	214.8	118.6	1.0	116.6
2020	456.1	1.4	329.3	116.0	1.0	114.5	460.5	1.2	371.9	491.9	1.4	341.7	119.0	1.0	114.7
2021	475.8	1.4	331.2	125.7	1.0	120.9	404.5	1.3	312.6	440.0	1.4	308.8	121.5	1.0	118.5
2022	333.0	1.4	233.5	131.1	1.1	120.2	324.7	1.3	246.9	335.5	1.4	238.8	125.7	1.1	118.1
2023	366.6	1.3	271.8	123.9	1.0	121.3	357.7	1.2	288.0	342.0	1.3	256.6	118.4	1.0	118.5
2024	662.6	1.5	432.7	131.6	1.1	123.6	646.1	1.4	451.6	611.3	1.5	401.9	126.0	1.0	120.8

SAIDI = System Average Interruption Duration Index. It is the minutes of non-momentary electric interruptions, per year, the average customer experienced.

SAIFI = System Average Interruption Frequency Index. It is the number of non-momentary electric interruptions, per year, the average customer experienced.

CAIDI = Customer Average Interruption Duration Index. It is average number of minutes it takes to restore non-momentary electric interruptions.

IEEE refers to the IEEE 1366-2003 or the IEEE 1366-2012 standard. Any method combines data from utilities that use IEEE standard with data from utilities that do not.

For utilities using the IEEE method, a Major Event Day is any day that exceeds a daily SAIDI threshold called Tmed. Tmed is a duration statistic calculated from daily SAIDI values from the past five years. For utilities not using IEEE methods, Major Events are self-determined by the reporting utility.

Loss of Supply Removed excludes outages due to loss of supply from the high-voltage/bulk power system.

For a five minute video explanation of these metrics, go to <https://youtu.be/oVH9L0fCMTU>.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 11.2 Reliability Metrics Using IEEE of U.S. Distribution System by State, 2024 and 2023

Census Division and State	Percent of Customers Reported		All Events (With Major Event Days)						Without Major Event Days						Loss of Supply Removed					
			SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	89.7%	83.3%	389.8	489.3	1.3	1.4	299.6	357.7	101.4	103.4	0.9	0.9	111.9	112.5	387.1	481.2	1.2	1.3	311.8	370.7
Connecticut	99.8%	79.0%	152.8	193.4	0.9	0.9	174.3	212.4	73.6	77.7	0.6	0.7	113.3	114.0	152.3	188.2	0.9	0.9	177.4	214.9
Maine	100.3%	100.8%	1,748.6	1,863.0	3.6	3.3	480.9	562.2	274.0	247.4	2.1	2.0	128.1	125.0	1,701.0	1,781.4	3.3	3.0	511.5	590.9
Massachusetts	90.2%	86.0%	103.7	265.3	0.9	1.1	121.8	248.2	77.0	83.5	0.7	0.8	102.9	105.7	103.9	268.5	0.8	1.0	125.3	262.0
New Hampshire	88.1%	88.2%	735.5	590.6	1.6	1.5	455.2	397.7	84.2	89.3	0.8	0.8	108.5	116.6	733.0	587.7	1.6	1.5	459.0	397.2
Rhode Island	97.6%	98.3%	104.3	104.6	0.9	0.8	116.4	133.7	60.8	52.2	0.8	0.7	79.9	78.3	99.0	100.8	0.9	0.7	114.9	136.9
Vermont	10.5%	10.4%	895.8	486.3	3.3	2.3	268.2	216.1	231.8	204.3	1.4	1.4	165.6	148.1	884.6	480.1	2.1	2.0	429.4	235.3
Middle Atlantic	60.5%	58.8%	309.1	196.8	1.3	1.0	230.7	189.0	121.5	112.2	1.0	0.9	123.3	126.1	299.7	185.9	1.2	1.0	243.2	195.5
New Jersey	99.2%	99.3%	173.3	108.2	1.1	0.9	155.3	122.9	98.8	88.0	0.9	0.8	104.7	106.0	161.2	99.2	1.0	0.8	166.0	126.8
New York	23.8%	20.0%	477.3	204.8	1.7	1.1	286.1	181.7	142.8	130.1	1.1	1.0	134.4	135.1	483.6	207.5	1.7	1.1	291.1	182.0
Pennsylvania	84.4%	84.3%	353.1	265.1	1.4	1.1	253.5	232.0	131.5	125.9	1.0	0.9	133.0	137.7	340.9	248.3	1.3	1.0	266.7	242.3
East North Central	91.2%	91.0%	357.8	489.5	1.2	1.2	308.6	412.3	114.3	108.8	0.9	0.8	131.5	134.6	342.5	483.4	1.1	1.1	323.7	434.5
Illinois	96.6%	96.3%	158.0	210.4	0.8	0.8	186.3	252.4	59.1	56.2	0.6	0.6	92.7	93.0	154.7	209.9	0.8	0.8	189.9	256.4
Indiana	84.3%	83.4%	310.0	467.4	1.3	1.4	242.9	330.6	123.3	111.3	1.0	0.9	122.4	118.0	252.3	462.1	1.1	1.3	221.4	357.6
Michigan	94.3%	94.2%	481.7	1,127.7	1.4	1.5	353.0	730.9	161.3	164.8	1.0	0.9	164.0	177.1	456.2	1,131.2	1.3	1.5	364.5	738.0
Ohio	96.5%	96.4%	511.0	366.6	1.3	1.3	393.7	292.7	133.3	127.1	1.0	0.9	133.4	138.4	500.3	336.0	1.1	1.1	445.1	312.6
Wisconsin	74.2%	74.5%	296.8	203.8	1.0	0.9	285.2	223.3	97.5	76.8	0.7	0.6	134.3	121.4	294.8	200.9	1.0	0.9	288.8	228.0
West North Central	76.9%	76.2%	255.3	222.7	1.2	1.1	207.8	203.8	93.9	84.6	0.9	0.8	106.8	104.3	254.7	215.6	1.1	1.0	228.9	221.5
Iowa	52.9%	52.8%	200.3	83.9	1.2	0.9	165.1	97.7	84.1	60.7	0.8	0.6	103.6	94.1	187.0	75.5	1.0	0.7	179.3	101.9
Kansas	80.0%	80.1%	289.8	287.1	1.5	1.3	192.8	216.3	104.0	101.8	1.0	1.0	103.5	101.4	277.9	274.4	1.4	1.2	205.9	234.3
Minnesota	86.9%	86.7%	222.4	127.1	1.3	1.0	176.3	130.6	91.5	72.8	0.9	0.8	101.5	93.6	222.3	123.6	1.1	0.9	194.3	143.9
Missouri	82.7%	83.6%	212.6	379.0	1.2	1.3	180.8	286.1	106.6	104.4	0.9	0.9	115.4	118.9	206.0	391.2	1.1	1.3	192.5	309.8
Nebraska	66.2%	67.0%	697.8	69.4	1.2	0.6	560.8	125.2	69.8	55.6	0.6	0.5	116.3	116.2	696.7	66.4	1.2	0.5	564.0	121.8
North Dakota	83.6%	63.2%	102.7	262.3	0.9	1.2	109.0	227.9	87.0	93.9	0.9	0.9	98.7	99.7	82.2	259.0	0.7	0.8	120.7	307.2
South Dakota	70.8%	67.9%	85.6	78.1	0.8	1.0	105.0	76.8	61.5	63.9	0.7	0.9	85.4	71.4	67.5	62.2	0.6	0.7	116.0	90.1
South Atlantic	81.8%	81.7%	1,405.8	240.4	1.8	1.3	768.3	179.4	133.1	119.7	1.0	1.1	129.0	111.9	1,352.3	211.7	1.7	1.2	809.3	180.0
Delaware	87.5%	87.4%	117.9	109.7	0.9	0.8	138.0	130.4	66.8	61.2	0.7	0.7	91.9	87.2	118.9	112.1	0.9	0.9	138.7	130.6
District of Columbia	98.9%	98.9%	32.6	71.9	0.3	0.4	120.2	194.2	26.4	33.3	0.2	0.3	107.2	104.6	32.6	71.9	0.3	0.4	120.2	194.2
Florida	84.1%	84.4%	1,487.6	172.3	1.8	1.0	833.9	175.5	66.7	69.4	0.7	0.8	90.0	89.0	1,485.6	160.0	1.7	0.9	865.9	172.3
Georgia	87.0%	87.8%	1,208.1	342.7	2.1	1.9	574.3	184.5	211.4	133.4	1.2	1.3	170.0	99.9	768.0	300.3	1.9	1.8	403.2	170.1
Maryland	98.6%	98.7%	118.1	166.2	0.8	0.9	144.5	180.7	75.1	66.9	0.7	0.7	109.6	95.1	116.7	156.1	0.8	0.9	145.6	176.9
North Carolina	90.6%	88.5%	1,518.1	262.5	1.8	1.5	831.3	172.1	143.9	156.4	1.2	1.3	122.4	121.9	1,475.0	249.9	1.7	1.4	879.2	178.6
South Carolina	92.6%	92.2%	3,155.0	169.8	2.4	1.5	1,332.3	112.3	115.9	126.5	1.2	1.3	96.7	98.1	2,972.9	140.4	2.1	1.2	1,447.2	117.3
Virginia	30.6%	30.8%	962.1	292.8	2.2	1.7	429.9	176.9	245.1	239.9	1.6	1.5	149.4	157.6	911.2	280.6	2.0	1.6	447.0	179.8
West Virginia	97.3%	97.8%	1,165.5	751.5	2.8	2.4	411.5	319.4	486.1	385.7	2.3	1.9	212.6	206.2	1,067.4	700.4	2.5	2.1	427.0	333.5
East South Central	62.1%	61.5%	423.7	864.3	2.0	2.4	216.7	359.0	176.3	186.5	1.6	1.6	113.6	114.7	423.0	876.2	1.9	2.3	226.0	375.6
Alabama	15.5%	14.3%	197.7	400.2	1.7	2.3	113.0	175.4	120.8	189.5	1.3	1.5	93.6	128.0	189.6	380.2	1.7	2.0	114.6	192.8
Kentucky	93.8%	93.2%	537.7	861.5	1.8	1.9	301.6	463.4	145.7	140.6	1.2	1.1	119.8	124.5	520.1	841.1	1.6	1.7	329.2	507.5
Mississippi	69.3%	68.8%	607.3	877.8	2.5	2.6	244.7	334.1	279.0	266.6	1.9	2.1	148.3	126.2	693.8	991.9	2.7	2.9	255.7	338.3
Tennessee	73.5%	73.2%	289.3	926.9	1.9	2.8	149.2	330.7	169.9	192.7	1.8	1.9	97.0	101.9	283.3	933.4	1.9	2.8	149.4	336.5
West South Central	65.2%	64.8%	1,268.9	685.6	2.2	1.9	568.9	355.7	164.2	163.3	1.4	1.4	113.5	116.2	1,295.8	671.2	2.1	1.8	608.6	376.3
Arkansas	82.0%	82.0%	527.8	915.3	2.1	2.1	247.0	431.2	201.9	230.7	1.6	1.6	124.8	146.2	377.8	879.0	1.8	1.9	209.2	460.4
Louisiana	72.3%	72.3%	630.6	663.2	2.4	1.9	267.7	352.5	215.9	199.3	1.7	1.5	130.0	132.8	603.0	633.7	2.2	1.8	272.8	360.3
Oklahoma	46.2%	45.9%	220.7	1,339.4	1.6	2.1	139.3	644.3	121.3	123.8	1.3	1.1	95.9	109.2	188.1	1,012.7	1.3	1.7	150.4	591.2
Texas	64.9%	64.3%	1,614.3	583.1	2.3	1.9	704.2	308.7	153.4	150.3	1.4	1.4	109.7	108.1	1,724.6	604.3	2.3	1.8	759.9	340.0
Mountain	91.5%	90.2%	176.3	117.9	1.2	1.0	148.8	122.0	102.4	90.4	1.0	0.8	105.2	106.5	169.5	101.2	1.1	0.9	152.9	114.5
Arizona	95.7%	95.8%	83.6	103.8	1.0	1.0	86.8	109.2	69.8	66.9	0.9	0.8	79.4	84.9	75.8	88.7	0.9	0.9	81.1	96.8
Colorado	92.3%	88.8%	257.0	100.2	1.4	0.9	181.6	108.4	118.9	89.2	1.1	0.9	103.9	102.2	251.2	96.2	1.3	0.9	188.1	113.1
Idaho	93.2%	93.1%	204.4	134.4	1.3	1.1	155.5	125.5	152.5	121.8	1.1	1.0	134.2	123.6	150.5	95.9	1.0	0.8	157.1	126.7
Montana	72.3%	68.4%	341.7	113.9	1.6	1.1	209.8	108.3	152.3	113.9	1.2	1.1	130.9	108.3	298.1	93.9	1.4	0.9	219.2	110.2
Nevada	103.1%	102.7%	158.9	138.7	1.1	0.9	143.4	147.2	63.8	81.2	0.7	0.7	97.0	108.9	116.7	96.9	1.3	1.1	88.9	85.7
New Mexico	85.2%	85.1%	272.6	156.0	1.3	1.1	205.7	141.6	152.0	123.7	1.1	0.9	137.4	136.3	255.4	139.0	1.1	1.0	226.5	143.9
Utah	85.4%	85.5%	115.4	127.7	1.0	0.9	114.5	140.0	105.0	108.5	1.0	0.9	109.9	125.3						

Table 11.3 Reliability Metrics Using Any Method of U.S. Distribution System by State, 2024 and 2023

Census Division and State	Percent of Customers Reported		All Events (With Major Events)						Without Major Events					
	Reported		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)	
	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023	Year 2024	Year 2023
New England	96.0%	94.2%	419.6	480.5	1.4	1.4	303.6	343.7	112.3	107.8	1.0	0.9	118.0	114.2
Connecticut	101.2%	100.6%	153.6	164.6	0.9	0.9	175.5	188.8	73.1	70.3	0.6	0.7	113.4	107.3
Maine	100.3%	100.8%	1,748.6	1,863.0	3.6	3.3	480.9	562.2	274.0	247.4	2.1	2.0	128.1	125.0
Massachusetts	92.3%	88.2%	102.0	259.4	0.8	1.1	120.9	245.4	76.1	82.2	0.7	0.8	102.3	105.4
New Hampshire	99.2%	99.3%	922.7	645.8	2.0	1.8	456.6	368.5	132.3	124.6	1.0	1.0	134.3	126.1
Rhode Island	97.6%	98.3%	104.3	104.6	0.9	0.8	116.4	133.7	60.8	52.2	0.8	0.7	79.9	78.3
Vermont	87.0%	87.0%	696.7	744.4	2.5	2.4	276.9	316.5	275.0	221.3	1.7	1.6	165.5	140.0
Middle Atlantic	97.6%	97.3%	246.2	159.5	1.1	0.9	224.0	180.7	97.2	89.9	0.8	0.7	120.9	122.2
New Jersey	100.9%	101.0%	174.2	108.3	1.1	0.9	155.7	123.0	99.7	88.5	0.9	0.8	105.2	106.5
New York	98.2%	97.7%	219.9	120.0	0.9	0.7	241.7	165.6	72.0	70.0	0.6	0.6	117.8	119.4
Pennsylvania	94.5%	94.4%	336.1	252.7	1.4	1.1	248.3	228.0	131.0	119.2	1.0	0.9	134.9	135.8
East North Central	95.9%	95.7%	349.2	472.8	1.2	1.2	302.2	401.6	112.8	107.1	0.9	0.8	130.0	133.3
Illinois	98.1%	97.8%	156.9	208.2	0.9	0.8	184.0	249.2	59.4	56.2	0.6	0.6	92.3	92.9
Indiana	92.0%	91.1%	312.4	455.4	1.3	1.4	243.5	314.8	121.4	110.3	1.0	0.9	121.8	116.6
Michigan	97.5%	97.4%	470.4	1,093.6	1.4	1.5	346.8	723.5	160.1	162.7	1.0	0.9	162.4	176.7
Ohio	96.6%	96.5%	510.5	366.2	1.3	1.3	393.4	292.5	133.2	127.0	1.0	0.9	133.4	138.4
Wisconsin	92.3%	92.5%	266.1	183.0	1.0	0.9	260.8	208.6	91.3	72.4	0.7	0.6	125.2	114.7
West North Central	84.8%	84.9%	246.9	213.8	1.2	1.1	202.9	198.1	94.3	85.5	0.9	0.8	106.8	105.5
Iowa	85.4%	85.2%	166.7	104.9	1.2	0.9	145.0	115.7	89.8	70.4	0.9	0.7	101.3	99.3
Kansas	82.4%	82.5%	285.6	283.1	1.5	1.3	189.7	214.9	103.6	101.7	1.0	1.0	103.3	101.9
Minnesota	89.0%	88.7%	219.6	126.4	1.3	1.0	175.6	129.9	92.2	73.4	0.9	0.8	102.3	93.5
Missouri	86.7%	87.6%	224.3	371.8	1.2	1.3	188.6	282.9	106.0	106.7	0.9	0.9	115.3	121.7
Nebraska	73.7%	73.6%	641.7	72.6	1.2	0.6	520.8	130.1	73.6	56.8	0.6	0.5	123.8	118.3
North Dakota	88.5%	89.0%	99.1	208.6	0.9	1.1	108.4	197.7	84.2	89.9	0.9	0.9	98.3	99.1
South Dakota	75.4%	74.3%	84.7	77.0	0.8	1.0	104.0	76.2	62.1	63.2	0.7	0.9	86.2	70.8
South Atlantic	96.6%	96.7%	1,247.3	227.4	1.8	1.3	698.7	169.3	129.3	117.5	1.0	1.1	124.0	108.6
Delaware	89.1%	89.0%	116.1	108.2	0.8	0.8	137.8	130.3	65.9	60.4	0.7	0.7	91.9	87.3
District of Columbia	98.9%	98.9%	32.6	71.9	0.3	0.4	120.2	194.2	26.4	33.3	0.2	0.3	107.2	104.6
Florida	100.4%	100.2%	1,321.5	160.1	1.8	1.0	746.6	157.7	66.4	69.2	0.8	0.8	87.1	84.1
Georgia	88.9%	89.5%	1,229.1	349.2	2.1	1.9	579.2	185.2	212.3	136.8	1.3	1.4	168.0	100.8
Maryland	98.6%	98.7%	118.1	166.2	0.8	0.9	144.5	180.7	75.1	66.9	0.7	0.7	109.6	95.1
North Carolina	96.0%	96.1%	1,441.0	252.0	1.8	1.5	795.0	167.4	141.4	153.5	1.2	1.3	120.6	120.5
South Carolina	96.5%	95.6%	3,136.5	167.2	2.4	1.5	1,326.3	110.9	117.8	126.1	1.2	1.3	97.6	97.7
Virginia	96.4%	96.8%	418.3	221.1	1.6	1.5	257.1	151.3	166.4	159.3	1.3	1.3	124.0	124.2
West Virginia	97.3%	97.8%	1,165.5	751.5	2.8	2.4	411.5	319.4	486.1	385.7	2.3	1.9	212.6	206.2
East South Central	86.5%	86.8%	415.7	715.5	2.0	2.3	204.7	317.2	162.8	168.7	1.5	1.5	109.1	111.7
Alabama	80.7%	80.0%	279.4	294.2	1.9	1.6	149.4	186.9	117.8	120.2	1.0	1.0	113.6	122.8
Kentucky	96.5%	96.6%	648.3	868.2	2.0	1.9	331.7	456.3	153.3	143.4	1.3	1.2	116.1	122.9
Mississippi	83.2%	83.6%	567.1	802.1	2.6	2.7	221.9	295.2	266.3	252.8	2.0	2.1	135.6	118.0
Tennessee	85.9%	87.0%	278.6	857.9	2.0	2.8	139.3	305.1	159.5	186.1	1.8	1.9	90.4	98.1
West South Central	96.1%	95.1%	1,050.4	579.1	2.1	1.8	489.0	314.2	142.3	142.0	1.3	1.3	109.3	113.0
Arkansas	89.2%	89.3%	509.1	911.2	2.1	2.1	239.3	433.4	194.6	221.7	1.6	1.5	122.7	144.0
Louisiana	93.5%	93.6%	727.5	584.2	2.7	2.1	267.2	275.1	206.0	195.0	1.8	1.6	117.6	118.8
Oklahoma	90.6%	90.0%	270.9	896.6	1.7	1.9	156.5	481.6	119.6	139.3	1.1	1.1	104.3	121.8
Texas	98.1%	96.9%	1,270.6	496.2	2.1	1.8	600.9	281.5	129.4	124.7	1.2	1.2	106.2	106.1
Mountain	93.3%	92.8%	181.3	120.2	1.2	1.0	152.1	121.6	105.8	91.7	1.0	0.9	108.1	106.3
Arizona	96.6%	96.7%	87.5	106.8	1.0	1.0	88.6	108.6	72.0	69.3	0.9	0.8	80.1	84.8
Colorado	93.7%	91.8%	255.1	99.2	1.4	0.9	181.0	108.3	119.0	88.4	1.1	0.9	104.3	102.2
Idaho	95.1%	94.9%	232.8	137.5	1.3	1.1	177.1	128.4	174.0	119.4	1.1	1.0	153.2	121.2
Montana	74.7%	75.0%	351.5	118.7	1.6	1.1	216.9	111.1	156.6	117.1	1.2	1.1	134.9	111.0
Nevada	103.1%	102.7%	158.9	138.7	1.1	0.9	143.4	147.2	63.8	81.2	0.7	0.7	97.0	108.9
New Mexico	90.1%	90.1%	278.8	168.9	1.3	1.2	211.1	136.0	156.5	132.3	1.1	1.0	141.1	132.7
Utah	88.3%	88.4%	119.8	127.1	1.0	0.9	116.3	138.7	106.7	109.8	1.0	0.9	110.4	124.9
Wyoming	76.0%	75.9%	137.8	127.0	1.0	1.0	138.0	127.8	109.1	96.0	0.9	0.8	125.6	124.7
Pacific Contiguous	98.5%	98.6%	365.4	294.2	1.4	1.3	258.7	229.2	155.8	144.6	1.1	1.0	139.5	140.8
California	100.0%	100.2%	279.6	346.6	1.3	1.4	208.0	248.1	158.2	152.0	1.2	1.1	137.1	140.0
Oregon	93.0%	92.9%	591.0	126.9	1.3	0.8	439.1	153.8	130.9	108.0	0.9	0.8	152.8	143.7
Washington	95.2%	95.1%	623.5	151.7	1.8	1.0	355.9	148.0	158.6	130.6	1.1	0.9	146.0	143.8
Pacific Noncontiguous	93.4%	93.6%	323.0	448.4	2.6	2.1	123.9	210.8	213.7	184.6	2.1	1.6	103.4	115.8
Alaska	84.2%	84.5%	327.1	374.8	2.6	2.7	126.3	138.8	192.4	325.7	1.9	2.4	103.3	137.6
Hawaii	99.9%	99.9%	320.6	491.8	2.6	1.8	122.6	275.1	225.6	148.6	2.2	1.4	103.5	106.3
U.S. Total	95.0%	94.8%	611.3	342.0	1.5	1.3	401.9	256.6	126.0	118.4	1.0	1.0	120.8	118.5

SAIFI = System Average Interruption Frequency Index. It is the number of non-momentary electric interruptions, per year, the average customer experienced.

CAIDI = Customer Average Interruption Duration Index. It is average number of minutes it takes to restore non-momentary electric interruptions.

Any method combines data from utilities that use IEEE standard with data from utilities that do not.

For utilities using the IEEE method, a Major Event Day is any day that exceeds a daily SAIDI threshold called Tmed. Tmed is a duration statistic calculated from daily SAIDI values from the past five years. For utilities not using IEEE methods, Major Events are self-determined by the reporting utility.

Percent of Customers Reported is an estimate of the percentage of total customers covered by these metrics. The numerator is reported number of meters used on the reliability schedule, while the denominator is the number of customers reported on the sales to ultimate customers schedule. It is possible, in some instances, for this metric to exceed 100%.

For a five minute video explanation of these metrics, go to <https://youtu.be/oVH9l0fCMTU>.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 11.5 SAIFI Values (Times Per Year) of U.S. Distribution System by State, 2014 - 2024

Census Division and State	All Events (99th Major Event Days)																																										All Events (99th Major Event Days)																																										All Events (99th Major Event Days)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																							
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	1024	1023	1022	1021	1020	1019	1018	1017	1016	1015	1014	1013	1012	1011	1010	1009	1008	1007	1006	1005	1004	1003	1002	1001	1000	999	998	997	996	995	994	993	992	991	990	989	988	987	986	985	984	983	982	981	980	979	978	977	976	975	974	973	972	971	970	969	968	967	966	965	964	963	962	961	960	959	958	957	956	955	954	953	952	951	950	949	948	947	946	945	944	943	942	941	940	939	938	937	936	935	934	933	932	931	930	929	928	927	926	925	924	923	922	921	920	919	918	917	916	915	914	913	912	911	910	909	908	907	906	905	904	903	902	901	900	899	898	897	896	895	894	893	892	891	890	889	888	887	886	885	884	883	882	881	880	879	878	877	876	875	874	873	872	871	870	869	868	867	866	865	864	863	862	861	860	859	858	857	856	855	854	853	852	851	850	849	848	847	846	845	844	843	842	841	840	839	838	837	836	835	834	833	832	831	830	829	828	827	826	825	824	823	822	821	820	819	818	817	816	815	814	813	812	811	810	809	808	807	806	805	804	803	802	801	800	799	798	797	796	795	794	793	792	791	790	789	788	787	786	785	784	783	782	781	780	779	778	777	776	775	774	773	772	771	770	769	768	767	766	765	764	763	762	761	760	759	758	757	756	755	754	753	752	751	750	749	748	747	746	745	744	743	742	741	740	739	738	737	736	735	734	733	732	731	730	729	728	727	726	725	724	723	722	721	720	719	718	717	716	715	714	713	712	711	710	709	708	707	706	705	704	703	702	701	700	699	698	697	696	695	694	693	692	691	690	689	688	687	686	685	684	683	682	681	680	679	678	677	676	675	674	673	672	671	670	669	668	667	666	665	664	663	662	661	660	659	658	657	656	655	654	653	652	651	650	649	648	647	646	645	644	643	642	641	640	639	638	637	636	635	634	633	632	631	630	629	628	627	626	625	624	623	622	621

S&P50 = System Average Interruption Frequency Index. It is the number of non-momentary electric interruptions, per year, the average customer experienced.

IEEE refers to the IEEE 1366-2003 or the IEEE 1366-2002 standard. Any method combines data from utilities that use IEEE standard with data from utilities that do not.

For utilities using the IEEE method, a Major Event Day is any day that exceeds a daily SAIDI threshold called *Timed*. *Timed* is a duration statistic calculated from daily SAIDI values from the past five years. For utilities not using IEEE methods, Major Events are self-determined by the reporting utility.

Loss of Supply Removed excludes outages due to loss of supply from the high-voltage/bulk power system.

For a five minute video explanation of these metrics, go to <https://youtu.be/0WH5LOfCMTU>.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Chapter 12

U.S. Territories

**Table 12.1 Puerto Rico- Number of Ultimate Customers Served:
by Sector, 2014 through 2024**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	1,328,546	129,122	662	--	1,458,330
2015	1,326,631	127,365	647	--	1,454,643
2016	1,332,152	127,179	633	--	1,459,964
2017	1,337,756	127,065	618	--	1,465,439
2018	1,346,102	126,527	602	--	1,473,231
2019	1,341,424	124,912	588	--	1,466,924
2020	1,351,190	125,391	587	--	1,477,168
2021	1,358,513	126,159	591	--	1,485,263
2022	1,370,811	127,741	589	--	1,499,141
2023	1,379,341	127,792	582	--	1,507,715
2024	1,383,774	127,491	583	--	1,511,848
Year 2022					
January	1,366,102	127,193	590	--	1,493,885
February	1,365,877	127,084	590	--	1,493,551
March	1,366,362	127,176	589	--	1,494,127
April	1,368,406	127,392	587	--	1,496,385
May	1,369,833	127,589	585	--	1,498,007
June	1,372,587	127,921	588	--	1,501,096
July	1,372,079	127,976	588	--	1,500,643
August	1,372,668	127,954	589	--	1,501,211
September	1,373,141	128,077	590	--	1,501,808
October	1,374,149	128,107	590	--	1,502,846
November	1,374,192	128,189	589	--	1,502,970
December	1,374,331	128,237	590	--	1,503,158
Year 2023					
January	1,374,717	128,302	589	--	1,503,608
February	1,375,176	128,312	588	--	1,504,076
March	1,376,298	128,040	580	--	1,504,918
April	1,377,070	127,611	580	--	1,505,261
May	1,378,115	127,668	579	--	1,506,362
June	1,379,369	127,598	580	--	1,507,547
July	1,380,020	127,637	581	--	1,508,238
August	1,380,809	127,612	580	--	1,509,001
September	1,381,572	127,766	581	--	1,509,919
October	1,382,416	127,596	582	--	1,510,594
November	1,383,057	127,673	583	--	1,511,313
December	1,383,477	127,690	585	--	1,511,752
Year 2024					
January	1,383,758	126,967	584	--	1,511,309
February	1,382,595	126,777	584	--	1,509,956
March	1,383,053	126,808	584	--	1,510,445
April	1,383,157	126,802	584	--	1,510,543
May	1,383,293	127,693	585	--	1,511,571
June	1,382,822	127,663	585	--	1,511,070
July	1,383,420	127,965	585	--	1,511,970
August	1,384,098	128,003	585	--	1,512,686
September	1,383,799	127,930	582	--	1,512,311
October	1,384,566	127,787	582	--	1,512,935
November	1,385,486	127,813	580	--	1,513,879
December	1,385,241	127,685	579	--	1,513,505

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.2 Puerto Rico- Sales of Electricity to Ultimate Customers:
by Sector, 2014 through 2024 (Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	6,218,352	8,761,182	2,376,022	--	17,355,556
2015	6,313,615	8,586,457	2,355,385	--	17,255,457
2016	6,524,304	8,568,874	2,251,095	--	17,344,273
2017	5,045,346	6,819,591	1,746,554	--	13,611,491
2018	6,102,980	8,202,893	2,128,354	--	16,434,227
2019	6,205,152	7,905,084	2,048,192	--	16,158,428
2020	6,908,138	7,320,018	1,909,660	--	16,137,816
2021	7,119,383	7,484,529	1,853,200	--	16,457,112
2022	6,723,199	7,511,478	1,768,396	--	16,003,073
2023	7,402,045	8,083,092	1,684,002	--	17,169,139
2024	7,853,014	8,369,293	1,558,835	--	17,781,142
Year 2022					
January	529,162	572,918	163,052	--	1,265,132
February	447,525	578,680	141,256	--	1,167,461
March	504,302	569,385	146,676	--	1,220,362
April	509,408	552,580	128,935	--	1,190,924
May	558,688	724,155	178,453	--	1,461,296
June	691,409	696,464	137,232	--	1,525,105
July	677,481	707,421	160,056	--	1,544,958
August	641,604	644,816	159,043	--	1,445,462
September	614,175	676,030	144,496	--	1,434,702
October	426,129	525,960	116,067	--	1,068,155
November	587,283	624,719	149,591	--	1,361,593
December	536,033	638,350	143,540	--	1,317,923
Year 2023					
January	476,437	585,902	125,879	--	1,188,218
February	428,728	547,881	123,762	--	1,100,372
March	497,284	606,624	142,910	--	1,246,818
April	522,925	621,366	143,333	--	1,287,624
May	630,969	689,494	125,636	--	1,446,100
June	695,670	698,032	145,894	--	1,539,596
July	765,237	722,232	146,190	--	1,633,660
August	743,125	723,022	163,155	--	1,629,302
September	725,204	747,147	146,118	--	1,618,469
October	742,232	768,617	149,438	--	1,660,286
November	598,657	688,244	133,467	--	1,420,367
December	575,576	684,531	138,220	--	1,398,327
Year 2024					
January	512,524	632,826	108,457	--	1,253,808
February	493,736	612,821	132,288	--	1,238,845
March	646,496	698,774	131,864	--	1,477,135
April	639,471	656,801	145,230	--	1,441,502
May	629,170	771,788	103,158	--	1,504,116
June	751,556	697,964	143,444	--	1,592,964
July	796,135	733,371	130,559	--	1,660,065
August	748,382	733,371	136,500	--	1,618,253
September	697,473	696,856	112,124	--	1,506,453
October	740,475	756,853	152,639	--	1,649,966
November	615,724	685,972	122,842	--	1,424,538
December	581,873	691,895	139,728	--	1,413,497

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.3 Puerto Rico- Revenue from Sales of Electricity to Ultimate Customers:
by Sector, 2014 through 2024 (Thousand Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	1,636,166	2,394,155	550,673	--	4,580,994
2015	1,282,008	1,850,101	417,158	--	3,549,267
2016	1,169,715	1,677,209	356,310	--	3,203,233
2017	1,123,005	1,549,337	344,034	--	3,016,376
2018	1,265,179	1,893,330	405,173	--	3,563,682
2019	1,329,706	1,810,611	420,178	--	3,560,495
2020	1,329,048	1,568,470	360,707	--	3,258,225
2021	1,506,288	1,799,862	380,303	--	3,686,454
2022	1,901,871	2,334,964	505,081	--	4,741,916
2023	1,685,843	1,978,615	390,129	--	4,054,587
2024	1,859,196	2,056,541	368,709	--	4,284,446
Year 2022					
January	136,075	154,251	40,378	--	330,704
February	116,007	168,487	36,286	--	320,780
March	138,639	188,166	40,864	--	367,669
April	135,982	182,484	34,936	--	353,402
May	151,008	225,891	47,947	--	424,846
June	190,133	204,465	40,191	--	434,788
July	237,463	238,282	56,584	--	532,329
August	190,956	212,419	48,442	--	451,816
September	170,168	202,916	40,893	--	413,977
October	140,294	194,981	40,032	--	375,307
November	157,125	187,145	40,552	--	384,822
December	138,021	175,478	37,978	--	351,476
Year 2023					
January	107,600	147,132	28,698	--	283,431
February	101,169	144,459	29,577	--	275,205
March	123,536	167,523	37,382	--	328,442
April	127,840	167,604	36,386	--	331,829
May	152,487	187,613	31,346	--	371,446
June	153,899	145,348	32,048	--	331,294
July	184,185	198,081	38,885	--	421,151
August	173,819	180,163	36,641	--	390,624
September	142,739	158,096	28,399	--	329,233
October	178,311	193,748	37,359	--	409,418
November	128,361	150,841	26,953	--	306,156
December	111,895	138,007	26,455	--	276,358
Year 2024					
January	112,384	143,417	23,649	--	279,450
February	114,038	149,219	29,746	--	293,004
March	150,972	170,528	30,735	--	352,234
April	148,863	160,347	33,277	--	342,486
May	168,442	217,368	29,129	--	414,939
June	186,227	180,266	34,775	--	401,267
July	200,221	201,775	35,455	--	437,451
August	192,232	180,702	33,555	--	406,489
September	172,212	176,112	29,813	--	378,137
October	157,810	172,526	33,275	--	363,611
November	123,826	140,027	23,802	--	287,654
December	131,968	164,255	31,500	--	327,723

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.4 Puerto Rico- Average Price of Electricity to Ultimate Customers:
by Sector, 2014 through 2024 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2014	26.31	27.33	23.18	--	26.39
2015	20.31	21.55	17.71	--	20.57
2016	17.93	19.57	15.83	--	18.47
2017	22.26	22.72	19.70	--	22.16
2018	20.73	23.08	19.04	--	21.68
2019	21.43	22.90	20.51	--	22.03
2020	19.24	21.43	18.89	--	20.19
2021	21.16	24.05	20.52	--	22.40
2022	28.29	31.09	28.56	--	29.63
2023	22.78	24.48	23.17	--	23.62
2024	23.67	24.57	23.65	--	24.10
Year 2022					
January	25.72	26.92	24.76	--	26.14
February	25.92	29.12	25.69	--	27.48
March	27.49	33.05	27.86	--	30.13
April	26.69	33.02	27.10	--	29.67
May	27.03	31.19	26.87	--	29.07
June	27.50	29.36	29.29	--	28.51
July	35.05	33.68	35.35	--	34.46
August	29.76	32.94	30.46	--	31.26
September	27.71	30.02	28.30	--	28.85
October	32.92	37.07	34.49	--	35.14
November	26.75	29.96	27.11	--	28.26
December	25.75	27.49	26.46	--	26.67
Year 2023					
January	22.58	25.11	22.80	--	23.85
February	23.60	26.37	23.90	--	25.01
March	24.84	27.62	26.16	--	26.34
April	24.45	26.97	25.39	--	25.77
May	24.17	27.21	24.95	--	25.69
June	22.12	20.82	21.97	--	21.52
July	24.07	27.43	26.60	--	25.78
August	23.39	24.92	22.46	--	23.97
September	19.68	21.16	19.44	--	20.34
October	24.02	25.21	25.00	--	24.66
November	21.44	21.92	20.19	--	21.55
December	19.44	20.16	19.14	--	19.76
Year 2024					
January	21.93	22.66	21.80	--	22.29
February	23.10	24.35	22.49	--	23.65
March	23.35	24.40	23.31	--	23.85
April	23.28	24.41	22.91	--	23.76
May	26.77	28.16	28.24	--	27.59
June	24.78	25.83	24.24	--	25.19
July	25.15	27.51	27.16	--	26.35
August	25.69	24.64	24.58	--	25.12
September	24.69	25.27	26.59	--	25.10
October	21.31	22.80	21.80	--	22.04
November	20.11	20.41	19.38	--	20.19
December	22.68	23.74	22.54	--	23.19

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 12.5. American Samoa
By Sector, 2014 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	11,561	1,386	4	--	12,951
2015	11,023	1,356	4	--	12,383
2016	10,916	1,363	6	--	12,285
2017	10,930	1,386	4	--	12,320
2018	10,866	1,395	4	--	12,265
2019	10,762	1,450	4	--	12,216
2020	10,720	1,452	4	--	12,176
2021	10,802	1,522	4	--	12,328
2022	10,893	1,575	4	--	12,472
2023	10,903	1,581	12	--	12,496
2024	10,998	1,674	12	--	12,684
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	41,029	70,598	23,142	--	134,769
2015	43,306	72,007	25,974	--	141,287
2016	46,493	69,617	32,232	--	148,342
2017	49,538	71,173	26,699	--	147,410
2018	45,621	72,185	24,546	--	142,352
2019	47,127	75,151	25,415	--	147,693
2020	50,304	74,463	25,714	--	150,481
2021	55,625	72,814	24,867	--	153,306
2022	56,424	70,418	24,745	--	151,587
2023	57,015	70,466	28,750	--	156,231
2024	62,505	74,799	30,763	--	168,067
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	17,286	27,553	8,076	--	52,915
2015	15,035	22,981	7,695	--	45,710
2016	13,184	18,402	7,962	--	39,548
2017	15,020	20,626	7,294	--	42,940
2018	15,434	23,557	7,668	--	46,659
2019	16,617	25,328	8,211	--	50,155
2020	16,513	23,480	7,680	--	47,672
2021	17,640	22,745	7,335	--	47,720
2022	25,373	31,668	10,835	--	67,875
2023	25,286	30,386	12,115	--	67,787
2024	26,519	30,482	12,099	--	69,100
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	42.13	39.03	34.90	--	39.26
2015	34.72	31.91	29.63	--	32.35
2016	28.36	26.43	24.70	--	26.66
2017	30.32	28.98	27.32	--	29.13
2018	33.83	32.63	31.24	--	32.78
2019	35.26	33.70	32.31	--	33.96
2020	32.83	31.53	29.87	--	31.68
2021	31.71	31.24	29.50	--	31.13
2022	44.97	44.97	43.79	--	44.78
2023	44.35	43.12	42.14	--	43.39
2024	42.43	40.75	39.33	--	41.11

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 12.6. Guam
By Sector, 2014 through 2024

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	41,999	6,925	--	--	48,924
2015	42,752	6,940	--	--	49,692
2016	43,943	6,956	--	--	50,899
2017	43,756	7,087	--	--	50,843
2018	44,006	7,366	--	--	51,372
2019	44,226	7,517	--	--	51,743
2020	44,420	7,518	--	--	51,938
2021	44,748	7,516	--	--	52,264
2022	45,271	7,602	--	--	52,873
2023	45,302	7,708	--	--	53,010
2024	45,808	7,751	--	--	53,559
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	457,835	1,075,511	--	--	1,533,346
2015	463,990	1,078,018	--	--	1,542,008
2016	494,842	1,087,317	--	--	1,582,159
2017	516,682	1,103,757	--	--	1,620,439
2018	510,725	1,071,705	--	--	1,582,430
2019	514,829	1,071,513	--	--	1,586,342
2020	552,083	991,159	--	--	1,543,242
2021	603,924	970,623	--	--	1,574,547
2022	574,292	984,602	--	--	1,558,894
2023	495,407	952,195	--	--	1,447,602
2024	549,816	1,018,473	--	--	1,568,289
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	125,028	309,439	--	--	434,467
2015	106,057	260,652	--	--	366,709
2016	93,568	214,840	--	--	308,408
2017	103,327	230,472	--	--	333,799
2018	121,331	260,506	--	--	381,837
2019	128,641	275,267	--	--	403,908
2020	116,537	221,583	--	--	338,121
2021	121,239	207,645	--	--	328,883
2022	172,623	305,997	--	--	478,620
2023	188,415	360,267	--	--	548,681
2024	192,509	355,416	--	--	547,925
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	27.31	28.77	--	--	28.33
2015	22.86	24.18	--	--	23.78
2016	18.91	19.76	--	--	19.49
2017	20.00	20.88	--	--	20.60
2018	23.76	24.31	--	--	24.13
2019	24.99	25.69	--	--	25.46
2020	21.11	22.36	--	--	21.91
2021	20.08	21.39	--	--	20.89
2022	30.06	31.08	--	--	30.70
2023	38.03	37.84	--	--	37.90
2024	35.01	34.90	--	--	34.94

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 12.7. Northern Mariana Islands
By Sector, 2011 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	11,045	3,651	--	--	14,696
2015	11,318	3,612	--	--	14,930
2016	11,869	3,952	--	--	15,821
2017	12,106	3,952	--	--	16,058
2018	12,323	4,243	--	--	16,566
2019	11,525	3,983	--	--	15,508
2020	12,329	3,212	--	--	15,541
2021	12,394	4,381	--	--	16,775
2022	12,770	4,195	--	--	16,965
2023	13,027	4,256	--	--	17,283
2024	13,052	4,503	--	--	17,555
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	57,532	153,959	--	--	211,491
2015	52,928	145,170	--	--	198,098
2016	70,404	177,766	--	--	248,170
2017	80,502	193,399	--	--	273,901
2018	75,128	182,533	--	--	257,661
2019	76,795	180,421	--	--	257,216
2020	86,601	121,698	--	--	208,299
2021	98,119	106,158	--	--	204,277
2022	94,566	163,706	--	--	258,272
2023	92,078	169,896	--	--	261,974
2024	95,199	180,702	--	--	275,901
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	20,714	66,034	--	--	86,749
2015	12,197	43,521	--	--	55,718
2016	12,657	42,870	--	--	55,527
2017	18,653	52,614	--	--	71,268
2018	20,530	58,788	--	--	79,318
2019	19,410	55,434	--	--	74,844
2020	18,655	32,784	--	--	51,439
2021	24,881	30,748	--	--	55,629
2022	25,079	37,702	--	--	62,781
2023	33,050	68,374	--	--	101,424
2024	27,592	31,062	--	--	58,653
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	36.01	42.89	--	--	41.02
2015	23.04	29.98	--	--	28.13
2016	17.98	24.12	--	--	22.37
2017	23.17	27.21	--	--	26.02
2018	27.33	32.21	--	--	30.78
2019	25.28	30.72	--	--	29.10
2020	21.54	26.94	--	--	24.69
2021	25.36	28.96	--	--	27.23
2022	26.52	23.03	--	--	24.31
2023	35.89	40.24	--	--	38.72
2024	28.98	17.19	--	--	21.26

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 12.8. Virgin Islands
By Sector, 2014 through 2024**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2014	45,066	8,808	1,043	--	54,917
2015	45,090	8,747	1,044	--	54,881
2016	49,559	9,951	1,089	--	60,599
2017	49,559	9,951	1,089	--	60,599
2018	46,721	7,491	2,238	--	56,450
2019	46,283	7,526	2,324	--	56,133
2020	46,283	7,526	2,324	--	56,133
2021	46,386	7,535	2,386	--	56,307
2022	45,850	7,524	2,292	--	55,666
2023	44,216	7,924	2,292	--	54,432
2024	44,319	7,915	2,286	--	54,520
Sales of Electricity to Ultimate Customers (megawatthours)					
2014	219,402	113,517	308,119	--	641,038
2015	211,753	109,530	299,598	--	620,881
2016	224,268	115,464	298,959	--	638,691
2017	174,208	85,273	201,822	--	461,303
2018	191,200	75,000	256,100	--	522,300
2019	217,003	87,000	257,313	--	561,316
2020	244,849	86,350	256,827	--	588,026
2021	253,666	100,239	263,702	--	617,607
2022	258,812	101,485	261,772	--	622,069
2023	266,288	148,402	234,226	--	648,916
2024	267,063	148,381	209,582	--	625,026
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2014	108,204	58,361	153,232	--	319,797
2015	90,567	43,840	134,197	--	268,603
2016	76,907	45,969	101,434	--	224,310
2017	72,035	38,703	93,206	--	203,944
2018	66,093	36,220	83,192	--	185,505
2019	84,090	43,842	95,311	--	223,243
2020	84,094	43,816	95,297	--	223,207
2021	85,613	43,653	95,974	--	225,240
2022	87,199	43,788	95,359	--	226,347
2023	88,316	64,490	96,543	--	249,349
2024	88,624	64,489	87,197	--	240,311
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2014	49.32	51.41	49.73	--	49.89
2015	42.77	40.03	44.79	--	43.26
2016	34.29	39.81	33.93	--	35.12
2017	41.35	45.39	46.18	--	44.21
2018	34.57	48.29	32.48	--	35.52
2019	38.75	50.39	37.04	--	39.77
2020	34.35	50.74	37.11	--	37.96
2021	33.75	43.55	36.39	--	36.47
2022	33.69	43.15	36.43	--	36.39
2023	33.17	43.46	41.22	--	38.43
2024	33.18	43.46	41.61	--	38.45

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Appendix

Table A.1. Sulfur Dioxide Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration						
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons	Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Tangential Firing Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Distillate Fuel Oil*	DFO	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Jet Fuel*	JF	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Kerosene*	KER	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Other Biomass Liquids*	OBL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Residual Fuel Oil*	RFO	Source: 2, Table 1.3-1; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	157.00	15.70	157.00	157.00	157.00	140.00	140.00
Wood Waste Liquids*	WDL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Waste Oil*	WO	Source: 2, Table 1.11-2; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	147.00	14.70	147.00	147.00	147.00	140.00	140.00
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Landfill Gas	LFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Natural Gas	NG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Gases	OG	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Propane Gas	PG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Coal-Derived Synthesis Gas	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Synthesis Gas from Petroleum Coke	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Agricultural Byproducts	AB	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	N/A	N/A
Bituminous Coal*	BIT	Source: 2, Table 1.1-3	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Lignite Coal*	LIG	Source: 2, Table 1.7-1	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	1.70	0.17	1.70	1.70	1.70	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	N/A	N/A
Petroleum Coke*	PC	Source: 1	Lbs per ton	39.00	3.90	39.00	39.00	39.00	N/A	N/A
Refined Coal*	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Subbituminous Coal*	SUB	Source: 2, Table 1.1-3	Lbs per ton	35.00	3.50	35.00	35.00	35.00	N/A	N/A
Tire-Derived Fuel*	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Waste Coal*	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	0.29	0.08	0.08	0.29	0.29	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	7.00	0.70	7.00	7.00	7.00	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.80	0.28	2.80	2.80	2.80	N/A	N/A

Notes:

* For these fuels, emissions are estimated by multiplying the emissions factor by the physical volume of fuel and the sulfur percentage of the fuel (other fuels do not require the sulfur percentage in the calculation). Note that EIA data do not provide the sulfur content of TDF. The value used (1.56 percent) is from U.S. EPA, Control of Mercury Emissions from Coal-Fired Electric Utility Boilers, April 2002, EPA-600/R-01-109, Table A-11.

** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., Documentation for the 2002 Electric Generating Unit National Emissions Inventory, Table 6, September 2004.
Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park.
2. U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources

Table A.2. Nitrogen Oxides Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration								
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons				Tangential Boiler		All Other Boiler Types		Combustion Turbine	Internal Combustion Engine
				Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Dry-Bottom Boilers	Wet-Bottom Boilers	Dry-Bottom Boilers	Wet-Bottom Boilers		
Distillate Fuel Oil	DFO	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	122.00	443.80
Jet Fuel	JF	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Kerosene	KER	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Other Biomass Liquids	OBL	Source: 1 (including footnote 3 within source); EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	112.30	408.30
Residual Fuel Oil	RFO	Source: 2, Table 1.3-1; EIA estimates	Lbs per MG	47.00	47.00	47.00	32.00	32.00	47.00	47.00	131.70	479.00
Wood Waste Liquids	WDL	Source: 1 (including footnote 16 within source); EIA estimates	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	5.43	230.50	838.10
Waste Oil	WO	Source: 2, Table 1.11-2; EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	92.20	335.20
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40	15.40	30.40	256.55
Landfill Gas	LFG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	72.44	72.44	72.44	72.44	72.44	72.44	72.44	144.00	1,215.22
Natural Gas	NG	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	112.83	313.60	2,646.48
Other Gases	OG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	152.82	152.82	152.82	152.82	152.82	152.82	152.82	263.82	2,226.41
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Propane Gas	PG	Sources: 3; EIA estimates	Lbs per MMCF	522.26	522.26	522.26	522.26	522.26	522.26	522.26	803.36	6,779.57
Synthesis Gas from Petroleum Coke	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Coal-Derived Synthesis Gas	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Agricultural Byproducts	AB	Source: 1	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20	1.20	N/A	N/A
Bituminous Coal	BIT	Source: 2, Table 1.1-3	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Lignite Coal	LIG	Source: 2, Table 1.7-1	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	2.00	2.00	2.00	2.00	2.00	2.00	2.00	N/A	N/A
Petroleum Coke	PC	Source: 1 (including footnote 8 within source)	Lbs per ton	21.00	5.00	21.00	21.00	21.00	21.00	21.00	N/A	N/A
Refined Coal	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Subbituminous Coal	SUB	Source: 2, Table 1.1-3	Lbs per ton	17.00	5.00	8.80	7.20	7.20	7.40	24.00	N/A	N/A
Tire-Derived Fuel	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Waste Coal	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	2.51	2.00	1.50	2.51	2.51	2.51	2.51	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	1.50	1.50	1.50	1.50	1.50	1.50	1.50	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A

sources:
1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., Documentation for the 2002 Electric Generating Unit National Emissions Inventory, Table 6, September 2004.

Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park.

2. U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources).

3. U.S. Environmental Protection Agency, Factor Information Retrieval (FIRE) Database, Version 6.25.

Table A.3. Carbon Dioxide Uncontrolled Emission Factors

Fuel	EIA Fuel Code	Factor (Kilograms of CO2 Per Million Btu)**	Notes
Bituminous Coal	BIT	93.24	
Distillate Fuel Oil	DFO	74.14	
Geothermal (Steam)	GEO	11.81	
Geothermal (Binary Cycle)	GEO	0.00	
Jet Fuel	JF	72.23	
Kerosene	KER	73.19	
Lignite Coal	LIG	98.27	
Municipal Solid Waste	MSW	49.89	
Natural Gas	NG	52.91	
Petroleum Coke	PC	102.12	
Propane Gas	PG	62.88	
Refined Coal	RC	93.24	Assumed to have emissions similar to Bituminous Coal.
Residual Fuel Oil	RFO	75.09	
Synthesis Gas Derived from Coal	SGC	*	* Factor is based on the fuel source used to produce the synthesis gas
Synthesis Gas Derived from Petroleum Coke	SGP	*	* Factor is based on the fuel source used to produce the synthesis gas
Subbituminous Coal	SUB	97.13	
Tire-Derived Fuel	TDF	85.97	
Waste Coal	WC	93.24	Assumed to have emissions similar to Bituminous Coal.
Waste Oil	WO	74.00	

Notes:

* Factors for synthesis gas derived from coal and synthesis gas derived from petroleum coke are based on the fuel source used to produce the synthesis gas.

** CO2 factors do not vary by combustion system type or boiler firing configuration.

Source: Energy Information Administration estimates:

http://www.eia.gov/environment/emissions/co2_vol_mass.cfm

Table A.4. Nitrogen Oxides Control Technology Emissions Reduction Factors

Nitrogen Oxides Control Technology	EIA Code	Reduction Factor							
		Coal	Residual Fuel Oil and Distillate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Fossil Gas	Other Fuels
Burner Out of Service	BO	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Low Excess Air	LA	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Biased Firing (Alternative Burners)	BF	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Overfire Air	OV	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Advanced Overfire Air	AA	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Low NOx Burners	LN	45.00%	45.00%	50.00%	45.00%	45.00%	45.00%	50.00%	45.00%
Fuel Reburning	FU	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%
Selective Noncatalytic Reduction	SN	45.00%	32.50%	32.50%	55.00%	45.00%	32.50%	32.50%	45.00%
Selective Catalytic Reduction	SR	80.00%	80.00%	85.00%	80.00%	80.00%	80.00%	85.00%	80.00%
Ammonia Injection	NH3	62.50%	56.25%	58.75%	67.50%	62.50%	56.25%	58.75%	62.50%
Flue Gas Recirculation	FR	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Water Injection	H2O	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Steam Injection	STM	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Other	OT	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%

Nitrogen Oxides Control Technology	EIA Code	Source of Selected Reduction Factor							
		Coal	Residual Fuel Oil and Distillate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Fossil Gas	Other Fuels
Burner Out of Service	BO	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low Excess Air	LA	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Biased Firing (Alternative Burners)	BF	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Overfire Air	OV	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Advanced Overfire Air	AA	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low NOx Burners	LN	Source: 1	Source: 2	Source: 3	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Fuel Reburning	FU	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Selective Noncatalytic Reduction	SN	Source: 1	Source: 2	Source: 4	Source: 5	Source: 9	Source: 10	Source: 11	Source: 9
Selective Catalytic Reduction	SR	Source: 1	Source: 2	Source: 4	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Ammonia Injection	NH3	Source: 6	Source: 6	Source: 6	Source: 6	Source: 9	Source: 10	Source: 11	Source: 9
Flue Gas Recirculation	FR	Source: 10	Source: 2	Source: 10	Source: 10	Source: 9	Source: 10	Source: 11	Source: 9
Water Injection	H2O	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Steam Injection	STM	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Other	OT	Source: 7	Source: 7	Source: 7	Source: 7	Source: 9	Source: 10	Source: 11	Source: 9

Source: U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources); available at: <http://www.epa.gov/ttn/chief/ap42/>

Source 1: AP-42, Table 1.1-2

Source 2: AP-42, Section 1.3.4.3 Text

Source 3: AP-42, Table 1.4-1

Source 4: AP-42, Section 1.4.4 Text

Source 5: AP-42, Section 1.6.4 Text

Source 6: Average of Selective Catalytic Reduction and Selective Noncatalytic Reduction

Source 7: Minimum of other technologies for fuel group

Source 8: Matches Other selection

Source 9: Assumed to have reduction similar to coal

Source 10: Assumed to have reduction similar to Residual Fuel Oil and Distillate Fuel Oil

Source 11: Assumed to have reduction similar to natural gas

Notes:

Coal reduction factors are applied to Bituminous Coal, Subbituminous Coal, Lignite Coal, and Waste Coal.

Wood reduction factors are applied to Wood Waste Solids, Black Liquor, and Wood Waste Liquids.

Other Solids reduction factors are applied to Petroleum Coke, Municipal Solid Waste, Tire-Derived Fuels, Sludge Waste, Agricultural Byproducts, and Other Biomass Solids.

Other Liquids reduction factors are applied to Jet Fuel, Kerosene, Waste Oil, and Other Biomass Liquids.

Other Fossil Gas reduction factors are applied to Blast Furnace Gas, Landfill Gas, Propane Gas, Coal-Derived Synthesis Gas, Synthesis Gas from Petroleum Coke, Other Biomass Gas, and Other Fossil Gas.

Table A.5. Unit of Measure Equivalents

Unit	Equivalent
Kilowatt (kW)	1,000 (One Thousand) Watts
Megawatt (MW)	1,000,000 (One Million) Watts
Gigawatt (GW)	1,000,000,000 (One Billion) Watts
Terawatt (TW)	1,000,000,000,000 (One Trillion) Watts
Gigawatt	1,000,000 (One Million) Kilowatts
Thousand Gigawatts	1,000,000,000 (One Billion) Kilowatts
Kilowatthours (kWh)	1,000 (One Thousand) Watthours
Megawatthours (MWh)	1,000,000 (One Million) Watthours
Gigawatthours (GWh)	1,000,000,000 (One Billion) Watthours
Terawatthours (TWh)	1,000,000,000,000 (One Trillion) Watthours
Gigawatthours	1,000,000 (One Million) Kilowatthours
Thousand Gigawatthours	1,000,000,000 (One Billion) Kilowatthours
U.S. Dollar	1,000 (One Thousand) Mills
U.S. Cent	10 (Ten) Mills
Barrel of Oil	42 Gallons

Source: U.S. Energy Information Administration

Technical Notes

This appendix describes how the U.S. Energy Information Administration collects, estimates, and reports electric power data in the Electric Power Annual.

Data Quality and Submission

The Electric Power Annual (EPA) is prepared by the Office of Energy Production, Conversion, and Delivery (EPCD), U.S. Energy Information Administration (EIA), U.S. Department of Energy (DOE). EPCD performs routine reviews of the data collection respondent frames, survey forms, and reviews the quality of the data received.

Data are entered directly by respondents into the EIA's Internet Data Collection (IDC) system. A small number of hard copy forms are keyed into the system by EIA personnel. All data are subject to review via interactive edits built into the IDC system, internal quality assurance reports, and review by subject matter experts. Questionable data values are verified through contacts with respondents, and survey non-respondents are identified and contacted.

IDC edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, because of these checks, must either be corrected by the respondent or the respondent must enter an explanation as to why the data are correct. If these explanations are unsatisfactory the respondent is contacted by EIA for clarification or corrected data.

Those respondents unable to use the electronic reporting method provide the data in hard copy, typically via fax and email. These data are manually entered into the computerized database and are subjected to the same data edits as those performed during e-filing by the respondent.

Reliability of Data

Annual survey data have non-sampling errors. Non-sampling errors can be attributed to many sources: (1) inability to obtain complete information about all cases (i.e., non-response); (2) response errors; (3) definitional difficulties; (4) differences in the interpretation of questions; (5) mistakes in recording or coding the data; and (6) other errors of collection, response, coverage, and estimation for missing data.

Although no direct measurement of the biases due to non-sampling errors can be obtained, precautionary steps were taken in all phases of the frame development and data collection, processing, and tabulation processes to minimize their influence.

Imputation: If the reported values appear to be in error and the data issue cannot be resolved with the respondent, or if the facility is a non-respondent, a regression methodology is used to impute for the facility. The regression methodology relies on other data to make estimates for erroneous or missing responses. The basis for the current methodology involves a 'borrowing of strength' technique for small domains.¹

Data Revision Procedure

The EPA presents the most current and complete data available to the EIA. The statistics may differ from those published previously in EIA publications due to corrections, revisions, or other adjustments to the data after its original release.

After data are disseminated as final, revisions will be considered if a correction would make a difference of 1 percent or greater at the national level. Revisions for differences that do not meet the 1 percent or greater threshold will be determined by the Office Director. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.

Sensitive Data (Formerly Identified as Data Confidentiality): Most of the data collected on the electric power surveys are not considered business sensitive. However, the data that are classified as sensitive are handled consistent with EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 Federal Register 59812 (1980)).

Rounding and Percent Change Calculations

Rounding Rules for Data: To round a number to n digits (decimal places), add one unit to the n th digit if the $(n+1)$ digit is 5 or larger and keep the n th digit unchanged if the $(n+1)$ digit is less than 5.

Percent Change: The following formula is used to calculate percent changes:

$$\text{Percent Change} = \left(\frac{x(t_2) - x(t_1)}{x(t_1)} \right) \times 100,$$

where $x(t_1)$ and $x(t_2)$ denote the quantity at period t_1 and subsequent period t_2 .

Data Sources for Electric Power Annual

Data published in the EPA are compiled from forms filed annually or aggregated to an annual basis from monthly forms (see figure on EIA Electric Industry Data Collection in Appendix A). The respondents to these forms include electric utilities, other generators and sellers of electricity, and North American Electric Reliability Corporation (NERC) reliability entities. The EIA forms used are:

- Form EIA-111, "Quarterly Electricity Imports and Exports Report;"
- Form EIA-860, "Annual Electric Generator Report;"
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-861M, "Monthly Electric Power Industry Report;"
- Form EIA-861S, "Annual Electric Power Industry Report (Short Form);"
- Form EIA-923, "Power Plant Operations Report."

These forms can be found on the EIA Internet website at: <https://www.eia.gov/survey/>

Survey data from other Federal sources are also utilized for this publication. They include:

- FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others;"

Additionally, some data reported in this publication were acquired from public reports of the National Energy Board of Canada on electricity imports and exports.

Form EIA-111

The Form EIA-111 is a mandatory census that collects import/export data from importers and exporters of electricity, border balancing authorities, and entities authorized to export electric energy and to construct, connect, operate, or maintain facilities for the transmission of electric energy at an international boundary. Respondents report monthly data quarterly. These data are used by EIA to track electricity being imported into and exported from the United States. There are currently 173 respondents to the EIA-111. These data were first collected for the 2016 data year.

Form EIA-860

The Form EIA-860 is a mandatory annual census of all existing and planned electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The survey is used to collect data on existing power plants and 10-year plans for constructing new plants, as well as generating unit additions, modifications, and retirements in existing plants. Data on the survey are collected at the individual generator level. Certain power plant environmental-related data are collected at the boiler level. These data include environmental equipment design parameters and boiler air emission standards and boiler emission controls. There are approximately 6,700 respondents on the EIA-860 data collection.

Instrument and Design History: The Form EIA-860 was originally implemented in January 1985 to collect plant data on electric utilities as of year-end 1984. It was preceded by several Federal Power Commission (FPC) forms including the FPC Form 4, Form 12 and 12E, Form 67, and Form 411. In January 1999, the Form EIA-860 was renamed the Form EIA-860A and was implemented to collect data as of January 1, 1999.

In 1989, the Form EIA-867, "Annual Nonutility Power Producer Report," was initiated to collect plant data on unregulated entities with a total generator nameplate capacity of 5 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. In 1998, the Form EIA-867, was renamed Form EIA-860B, "Annual Electric Generator Report – Nonutility." The Form EIA-860B was a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts.

Beginning with data collected for the year 2001, the infrastructure data collected on the Form EIA-860A and the Form EIA-860B were combined into the new Form EIA-860 and the monthly and annual versions of the Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Starting with 2007, design parameters data formerly collected on Form EIA-767 were collected on Form EIA-860. These include design parameters associated with certain steam-electric plants' boilers, cooling systems, flue gas particulate collectors, flue gas desulfurization units, and stacks and flues.

Estimation of EIA-860 Data: No imputation is required for EIA-860 data.

Issues within Historical Data Series Regarding Categorization of Capacity by Business Sector: There are a small number of electric utility CHP plants, as well as a small number of industrial and commercial generating facilities that are not CHP. For the purposes of this report the data for these plants are included, respectively, in the following categories: “Electricity Generators, Electric Utilities,” “Combined Heat and Power, Industrial,” and “Combined Heat and Power, Commercial.”

Some capacity in 2001 through 2004 is classified based on the operating company's classification as an electric utility or an independent power producer. Starting in the EPA 2006, capacity by producer type was determined at the power plant level for 2005 and all subsequent data collections. This change required revisions to the original published 2005 data.

Issues within Historical Data Series Regarding Planned Capacity: Delays and cancellations may have occurred after respondent data reporting as of December 31 of the data year.

Issues within Historical Data Series Regarding Capacity by Energy Source: Prior to the EPA 2005, the capacity for generators for which natural gas or petroleum was the most predominant energy source was presented in the following three categories: petroleum only, natural gas only, and dual-fired. The dual-fired category, which was EIA's effort to infer which generators could fuel-switch between natural gas and fuel oil, included only the capacity of generators for which the most predominant energy source and second most predominant energy source were reported as natural gas or petroleum. Beginning in 2005, capacity is assigned to energy source based solely on the most predominant (primary) energy source reported for a generator. The “dual-fired” category was eliminated. Separately, summaries of capacity associated with generators with fuel-switching capability are presented for 2005 and later years. These summaries are based on data collected from new questions added to the Form EIA-860 survey that directly address the ability of generators to switch fuels and co-fire fuels.

In the EPA 2005, certain petroleum-fired capacity was misclassified as natural gas-fired capacity for 1995 – 2003. This was corrected in the EPA 2006. Corrections were noted as revised data.

Prime Movers: The Form EIA-860 sometimes represents a generator's prime mover by using the abbreviations in the table below.

Prime Mover Code	Prime Mover Description
BA	Energy Storage, Battery
BT	Turbines Used in a Binary Cycle. Including those used for geothermal applications
CA	Combined-Cycle -- Steam Part
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
CS	Combined-Cycle Single-Shaft Combustion Turbine and Steam Turbine share of single generator
CT	Combined-Cycle Combustion Turbine Part
ES	Energy Storage, Other (Specify on Schedule 9, Comments)
FC	Fuel Cell
FW	Energy Storage, Flywheel
GT	Combustion (Gas) Turbine. Including Jet Engine design
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other
HY	Hydraulic Turbine. Including turbines associated with delivery of water by pipeline.
IC	Internal Combustion (diesel, piston, reciprocating) Engine
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
OT	Other
ST	Steam Turbine. Including Nuclear, Geothermal, and Solar Steam (does not include Combined Cycle).
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore

Energy Sources: The Form EIA-860 sometimes represents the energy sources associated with generators by using the abbreviations and/or groupings in the table below.

Energy Source Grouping	Energy Source Code	Energy Source Description
Fossil Fuels		
Coal	ANT	Anthracite Coal
	BIT	Bituminous Coal
	LIG	Lignite Coal
	RC	Refined Coal (A coal product that is created when impurities and/or moisture are removed to improve heat content and reduce emissions. Includes any coal which meets the IRS definition of refined coal [Notice 2010-54 or any superseding IRS notices]. Does not include coal processed by coal preparation plants.)
	SGC	Coal-Derived Synthesis Gas
	SUB	Subbituminous Coal
	WC	Waste/Other Coal (including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
Petroleum Products	DFO	Distillate Fuel Oil (including diesel, No. 1, No. 2, and No. 4 fuel oils)
	JF	Jet Fuel
	KER	Kerosene
	PC	Petroleum Coke
	PG	Propane, gaseous
	RFO	Residual Fuel Oil (including No. 5 and No. 6 fuel oils, and bunker C fuel oil)
	SGP	Petroleum Coke Derived Synthesis Gas
	WO	Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)
Natural Gas and Other Fossil Gas	BFG	Blast Furnace Gas
	NG	Natural Gas
	OG	Other Gas (Specify the fuel in the text box in the applicable schedule.)
Renewable Fuels		
Solid Renewable Fuels	AB	Agricultural By-products
	MSW	Municipal Solid Waste
	OBS	Other Biomass Solids

Energy Source Grouping	Energy Source Code	Energy Source Description
Liquid Renewable (Biomass) Fuels	WDS	Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
	BLQ	Black Liquor
	OBL	Other Biomass Liquids
	SLW	Sludge Waste
	WDL	Wood Waste Liquids excluding Black Liquor (includes red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
Gaseous Renewable (Biomass) Fuels	LFG	Landfill Gas
	OBG	Other Biomass Gas (includes digester gas, methane, and other biomass gasses)
All Other Renewable Fuels	GEO	Geothermal
	SUN	Solar
	WAT	Water at a Conventional Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology.
	WND	Wind
All Other Fuels		
	H2	Hydrogen
	MWH	Electricity used for energy storage
	NUC	Nuclear Uranium, Plutonium, Thorium
	PUR	Purchased Steam
	TDF	Tire-derived Fuels
	WAT	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
	WH	Waste heat not directly attributed to a fuel source
	OTH	Other

Sensitive Data: The tested heat rate and generator cost data collected on the Form EIA-860 are considered business sensitive.

Form EIA-861

The Form EIA-861 is a mandatory annual census of electric power industry participants in the United States. Prior to data year 2012, the survey was used to collect information on power sales and revenue data from approximately 3,300 respondents. About 3,100 are electric utilities, and the remainders are nontraditional entities such as energy service providers or the unregulated subsidiaries of electric utilities and power marketers. The current frame has since expanded to about 3,400 respondents, with about 3,000 of those respondents being electric utilities and about 400 nontraditional entities.

For data year 2012 and forward, EIA modified the frame of the Form EIA-861, “Annual Electric Power Industry Report,” from a census to a sample, and EIA is using model-based methods to estimate the sales, revenues, and customer counts by sector and state for those respondents that have been removed from the frame. EIA created a new Form EIA-861S, “Annual Electric Power Industry Report (Short Form),” for the respondents that have been removed from the Form EIA-861 frame. Respondents removed from the EIA-861 frame and placed on the EIA-861S are smaller utilities with annual sales volumes. Form EIA-861S with fewer data elements compared to the EIA-861, collects limited data on total sales, revenues, and customer counts by state. Every eighth data year, EIA-861S respondents are required to fill out the full EIA-861 form. For data year 2019, EIA-861S respondents were required to complete the full EIA-861 form. There are about 1,700 respondents on the EIA-861S data collection.

Transportation Sector: Prior to 2003, sales of electric power for transportation (e.g., city subway systems) were included in a sector labeled other, along with sales to customers for public buildings, traffic signals and public street lighting. Beginning with the 2003 data collection, sales to the other sector was removed and the transportation was created. Non transportation that was previously reported in the sector other was reclassified as commercial.

The transportation sector is defined as electrified rail, primarily urban transit, light rail, automated guideway, and other rail systems whose primary propulsive energy source is electricity. Electricity sales to transportation sector consumers whose primary propulsive energy source is not electricity (i.e., gasoline, diesel fuel, etc.) are not included.

Benchmark statistics were reviewed from outside surveys, most notably the U.S. Department of Transportation (DOT) Federal Transit Administration’s National Transportation Database, a source previously used by EIA to estimate electricity transportation consumption. The DOT survey indicated the state and city locations of expected respondents. The Form EIA-861 survey methodology assumed that sales, revenue, and customer counts associated with these mass transit systems would be provided by the incumbent utilities in these areas, relying on information drawn routinely from rate schedules and classifications designed to serve the sector separately and distinctly.

Data Reconciliation: The Electric Power Annual reports total sales volumes (megawatthours) of electricity to ultimate consumers and customer counts in states with deregulated markets as the sum of bundled sales reported by full-service providers and delivery reported by transmission and distribution

utilities. EIA has concluded that the sales of electricity to ultimate consumers data reported by delivery utilities are more reliable than data reported by power marketers and Energy Service Providers (ESPs).

The reporting methodology change uses sales volumes and a customer count reported by distribution utilities, and modifies only an incremental revenue value, representing revenue associated with misreported sales assumed to be attributable to the ESPs that were under-represented in the survey frame.

Instrument and Design History: The Form EIA-861 was implemented in January 1985 for collection of data as of year-end 1984. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Average Retail Price of Electricity: This value represents the average cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector.

The electric revenue used to calculate the average retail price of electricity is the operating revenue reported by the electric power industry participant. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric power industry participant operating revenues also include ratepayer reimbursements for state and federal income taxes and other taxes paid by the utility.

This computed average retail price of electricity reported in this publication by is a weighted average of consumer revenue and sales and does not equal the per kWh rate charged by the electric power industry participant to the individual consumers. Electric utilities typically employ several rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs of the electric power industry participant for providing electrical service.

Issues within Historical Data Series: Changes from year to year in consumer counts, sales, and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. The number of ultimate customers is an average of the number of customers at the close of each month. Also see the discussion of the transportation sector, above.

Net-Metering: This section was expanded in 2011. Previously, customer count by sector was the only data collected and published. In 2010, the EIA-861 started collecting the capacity of the net-metered installations by sector and technology. The technology types are photovoltaic (PV), wind, and other. Starting with the 2016 data collection year, storage and virtual net metering were added to the PV section.

Demand-Side Management (DSM): Prior to 2011, DSM data was separated into two categories, large and small utilities. Some tables contained data for just large utilities and others contained both

categories, published separately. Starting in 2011, there is no longer a division in the data. All tables now include all DSM data from utilities; this change is also reflected in the historical data.

Starting in 2011, a new category of respondents was added to the EIA-861, non-utility DSM administrators: Efficiency Maine Trust, Energy trust of Oregon, Focus on Energy, NYSERDA, and Vermont Energy Investment Corporation.

The following definitions are supplied to assist in interpreting DSM data. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that used to support DSM programs.

- **Actual Peak Load Reduction** is the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (potential peak load reduction). Actual peak load reduction is reported by large utilities only.
- **Energy Savings** is the change in aggregate electricity use (measured in megawatthours) for consumers that participate in a utility DSM program. These savings represent changes at the consumer's meter (i.e., exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility.
- **Large Utilities** are those electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2009 and, for years prior, the threshold was set at 120 million kilowatthours.
- **Potential Peak Load Reduction** is the potential peak load reduction that may occur if all demand response is called and/or participates.

Advanced Metering: New in 2011, Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI), including historical data back to 2007. From 2007-2009, the count by sector is for number of customers, for 2010-2011, the count is the actual number of meters. For example, if an industrial customer had 12 meters, in 2007-2009 the count would have been 1, in 2010-2011, the count would be 12.

In 2013, the number of standard meters (non-AMR/AMI) was added to this schedule. Starting in 2020, EIA imputes the number of standard meters for the short form (EIA-861S) by estimating the number of total meters based on the revenue, sales, and customer count schedule and subtracting the number of advanced meters.

Reliability: New in 2021, reliability metrics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index) are reported in aggregate by the state, census, and U.S. level dating back to 2013. Data are weighted by customers reported on the schedule and divided by all customers who reported by that metric. For example,

$$SAIDI_{All\ Events} = \frac{\sum(SAIDI_{All\ Events} * customers\ reported_{All\ Events})}{\sum customers\ reported_{All\ Events}}$$

Some respondents may report SAIDI for all events, but not with major events removed. In this case their values would be included in the calculations for SAIDI_{All Events} but their values (and customers reported) would not be included in the SAIDI_{w/o Major Events}.

CAIDI is not collected on the form and is a derived value of SAIDI/SAIFI. If a utility reports only one of these values (such as SAIDI) and not the other (SAIFI), it would be included in the regional CAIDI value. The final metric of percent reporting in some of the tables is a sum of customers who reported at least one reliability metric divided by the total number of customers on the revenue, sales, and customer counts schedule.

Form EIA-861M (formerly the EIA-826)

The Form EIA 861M, “Monthly Electric Power Industry Report,” is a monthly collection of data from a sample of approximately 650 of the largest electric utilities (primarily investor and publicly owned) as well as a census of energy service providers with sales to ultimate consumers in deregulated States. Form EIA-861 (see below), with approximately 3,400 respondents, serves as a frame from which the Form EIA-861M sample is drawn. Based on this sample, a model is used to estimate for the entire universe of U.S. electric utilities monthly.

Instrument and design history: The collection of electric power sales data and related information began in the early 1940’s and was established as FPC Form 5 by FPC Order 141 in 1947. In 1980, the report was revised with only selected income items remaining and became the FERC Form 5. The survey has gone by various other names, such as “Electric Utility Company Monthly Statement,” “Monthly Electric Utility Sales and Revenue Report with State Distributions,” and “Monthly Electric Utility Sales and Revenues with State Distributions Report.”

In 1993, EIA for the first time used a model sample for the Form EIA-861M. A stratified random sample, employing auxiliary data, was used for each of the four previous years. The sample for the Form EIA-861M was designed to obtain estimates of electricity sales and average retail price of electricity at the state level by end use sector.

Starting with data for January 2001, the restructuring of the electric power industry was considered by forming different schedules on the Form EIA-861M. These schedules group customers based on services provided by the utility: full service (or bundled) providers), electric service providers (energy) only, distribution service (delivery) only, and energy service providers that also provide the customers’ bill. -

With the revised definitions for the commercial and industrial sectors to include all data previously reported as ‘other’ data except transportation, and a separate transportation sector, all responses that would formerly have been reported under the “other” sector are now to be reported under one of the sectors that currently exist. This means there is probably a lower correlation between commercial and industrial data 2003 and after with data prior.

Average retail price of electricity represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector.

The electric revenue used to calculate the average retail price of electricity is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric utility operating revenues also include State and Federal income taxes and taxes other than income taxes paid by the utility.

The average retail price of electricity reported in this publication by sector represents a weighted average of consumer revenue and sales within sectors and across sectors for all consumers and does not reflect the per kWh rate charged by the electric utility to the individual consumers. Electric utilities typically employ several rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric utility for providing electrical service.

Adjusting monthly data to annual data: As a final adjustment based on our most complete data, use is made of final Form EIA-861 data, when available. The annual totals for Form EIA-861M data by state and end-use sector are compared to the corresponding Form EIA-861 values for sales and revenue. The ratio of these two values in each case is then used to adjust each corresponding monthly value.

Form EIA-861S (Short Form)

The Form EIA 861S, “Annual Electric Power Industry Report (Short Form),” which started in year 2012. EIA-861S was created to lower the burden for bundled-service utilities with small annual sales that model-based estimation methods can be used to estimate the remaining parts of the survey. Starting in data year 2020, EIA raised the thresholds of utilities that could report on the short form and still ensure acceptable quality of statistical estimates. Respondents report on the long form (EIA-861) once every eight years. The most recent year all respondents were required to complete the full EIA-861 form was 2019. There are currently about 1,700 respondents on the Form EIA-861S.

Short form respondents report data on total sales, revenues, and customer counts by state. They answer a yes/no questions about demand side management (DSM) programs and the number of water heaters added to DSM programs. For time-based rate programs they provide the number of customers enrolled by state. Number of advanced meters are also provided by state, as well as a yes/no question about having any net-metering programs.

Form EIA-923

Form EIA-923, “Power Plant Operations Report,” is used to collect information on receipts and cost of fossil fuels, fuel stocks, generation, consumption of fuel for generation, nonutility source and disposition of electricity, combustion by-product collection and disposal, and cooling systems, as well as operational data for flue gas desulfurization, particulates, and nitrous oxide controls. Data are collected from a monthly sample of approximately 3,300 plants, which includes a census of nuclear and pumped-storage hydroelectric plants. The plants in the monthly sample report their receipts, cost and stocks of fossil

fuels, electric power generation, and the total consumption of fuels for both electric power generation and, at combined heat and power (CHP) plants, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), operational data for air emissions controls and cooling systems, and the collection and disposal of combustion by-products on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 10,200 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report applicable data on the entire form annually. In addition to electric power generating plants, respondents include fuel storage terminals without generating capacity that receive shipments of fossil fuel for eventual use in electric power generation. The monthly data are due by the last day of the month following the reporting period.

Receipts of fossil fuels, fuel cost and quality information, and fuel stocks at the end of the reporting period are all reported at the plant level. Fuel receipts and costs are collected from plants with a total generator nameplate capacity of 50 megawatts or greater where coal is the primary fuel; or the total generator nameplate capacity is 200 megawatts or greater where the primary fuel is any combination of natural gas, petroleum coke, distillate fuel oil, or residual fuel oil. Plants that burn organic fuels and have a steam turbine capacity of at least 10 megawatts report consumption at the boiler level and generation at the generator level for each month, regardless of whether the plant reports in the monthly sample or reports annually. For all other plants, consumption is reported at the prime-mover level and generation is reported at the prime-mover level or, for noncombustible sources (e.g., wind, nuclear), at the prime-mover and energy source levels (including generating units for nuclear only). The source and disposition of electricity are reported annually for nonutilities at the plant level, as is revenue from sales for resale. Operational data for air emissions equipment are collected annually from facilities that have a steam turbine capacity of at least 10 megawatts, and operational data on cooling systems and data on the collection and disposal of combustion by-products are collected from facilities that have a steam turbine capacity of at least 100 megawatts.

Instrument and Design History: See discussion of predecessor forms (EIA-906, -920, -767, and -423, and FERC Form 423).

Imputation: For data collected monthly, regression prediction, or imputation, is done for all missing data including non-sampled units and any non-respondents. For data collected annually, imputation is performed for non-respondents. For gross generation and total fuel consumption, multiple regression is used for imputation (see discussion, above). Approximately 0.12 percent of the national total generation for is imputed, although this will vary by State and energy source.

When gross generation is reported and net generation is not available, or vice versa, net or gross generation is estimated by using a fixed ratio of net to gross generation by prime-mover type and installed emissions equipment. These ratios are:

Net Generation = (Factor) x Gross Generation
<u>Prime Movers:</u>
Combined Cycle Steam - 0.97
Combined Cycle Single Shaft - 0.97
Combined Cycle Combustion Turbine - 0.97
Compressed Air - 0.97
Fuel Cell - 0.99
Gas Turbine - 0.98
Hydroelectric Turbine - 0.99
Hydroelectric Pumped Storage - 0.99
Internal Combustion Engine - 0.98
Other - 0.97
Photovoltaic - 0.99
Steam Turbine - 0.97
Wind Turbine - 0.99
<u>Environmental Equipment:</u>
Flue Gas Desulfurization - 0.97
Flue Gas Particulate 0.99
All Others - 0.97

For stocks, a linear combination of the prior month's ending stocks value and the current month's consumption and receipts values is used.

Receipts of Fossil Fuels: Receipts data, including cost and quality of fuels, are collected at the plant level from selected electric generating plants and fossil-fuel storage terminals in the United States. Power plants include independent power producers, electric utilities, and commercial and industrial CHP facilities. Power plants required to report receipts data are plants with 50 megawatts of capacity that has coal as its primary fuel, as well as plants with a combined capacity of 200 megawatts with its primary fuel being any combination of natural gas, petroleum coke, distillate fuel oil, or residual fuel oil. The data on cost and quality of fuel shipments are used to produce aggregates and weighted averages for each fuel type at the State, Census division, and U.S. levels.

The units for receipts are: 1) coal and petroleum coke, tons and million Btu per ton; 2) petroleum, barrels and million Btu per barrel.; and gases, thousand cubic feet (Mcf) and million Btu per thousand cubic feet.

Net and Gross Generation and Fuel Consumption and Stocks: Generation data are collected in megawatthours from all power plants with a sum of nameplate capacity at least 1 MW. The fuels consumed are collected in tons (solids), barrels (liquids) and thousand cubic feet (gases). Fuels are grouped into coal, petroleum liquids, petroleum coke, natural gas, other gases, and other miscellaneous fuels. Energy consumption is not collected for nuclear, wind, solar, geothermal, or other plants that do not burn fuels. For information on fuel groupings, see the instructions to the Form EIA-923 at http://www.eia.gov/survey/form/eia_923/instructions.pdf.

Combustion By-Product Collection and Disposal: Data are collected in thousand tons. Associated financial data for by-products (O&M and capital expenses and revenue) are collected in thousand dollars.

Air Emissions Equipment: Operational efficiencies and emission rates are collected for flue gas desulfurization, particulate matter, and nitrous oxide control equipment for steam-electric units with at least 10 MW nameplate capacity.

Cooling Systems: Operational data on water use is collected from steam-electric plants, including nuclear plants, with at least 100 MW nameplate capacity.

Methodology to Estimate Biogenic and Non-biogenic Municipal Solid Waste:² Municipal solid waste (MSW) consumption for generation of electric power is split into its biogenic and non-biogenic components beginning with the 2001 data year.

The tonnage of MSW consumed is reported on the Form EIA-923. The composition of MSW and categorization of the components were obtained from the U.S. Environmental Protection Agency (USEPA). For data years 2001 through 2009, the MSW composition was based on the USEPA annual publication, *Municipal Solid Waste in the United States: Facts and Figures*. The compositions developed for the 2009 data year were carried forward for the 2010 through 2018 data years. The most updated composition and categorization of MSW (for the 2019 data year) were also derived from a USEPA publication: *Advancing Sustainable Materials Management: Facts and Figures Report: 2015 Data Tables*. The updated composition values were applied in the October EPM 2019 on the preliminary 2019 values and will be applied going forward in future data years until EIA revises the MSW composition ratios again. The Btu contents of the components of MSW were obtained from various sources.

The numbers in Tables 1 and 2 illustrate two interrelated trends in the composition of the MSW stream. First, the heat content (per unit weight) of the waste stream has been steadily increasing overtime due to higher concentrations of non-biogenic materials. Second, the shares of energy contributed to the waste stream by biogenic and non-biogenic components have been changing over time with the percentage of biogenic materials falling and the share of non-biogenic materials rising.

The potential quantities of combustible MSW discards (which include all MSW material available for combustion with energy recovery, discards to landfill, and other disposal) were multiplied by their respective Btu contents. The EPA-based categories of MSW were then classified into renewable and non-renewable groupings. From this, EIA calculated how much of the energy potentially consumed from MSW was attributed to biogenic components and how much was attributed to non-biogenic components (see Tables 1 and 2, below). Note, biogenic components include newsprint, paper, containers and packaging, leather, textiles, yard trimmings, food wastes, and wood. Non-biogenic components include plastics, rubber, and other miscellaneous non-biogenic waste.

These values are used to allocate net generation published in the Electric Power Monthly generation tables. The tons of biogenic and non-biogenic components were estimated with the assumption that

glass and metals were removed prior to combustion. The average Btu/ton for the biogenic and non-biogenic components is estimated by dividing the total Btu consumption by the total tons. Published net generation attributed to biogenic MSW and non-biogenic MSW is classified under Other Renewables and Other, respectively.

Table 1. Btu consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	...	2018	2019
Biogenic	57	56	55	55	56	57	55	54	51	51	51	45
Non-biogenic	43	44	45	45	44	43	46	46	49	49	49	55

Table 2. Tonnage consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	...	2018	2019
Biogenic	77	77	76	76	75	67	65	65	64	64	64	61
Non-biogenic	23	23	24	24	25	34	35	35	36	36	36	39

Useful Thermal Output (UTO): With the implementation of the Form EIA-923, “Power Plant Operations Report,” in 2008, combined heat and power (CHP) plants were required to report total fuel consumed and electric power generation. Beginning with preliminary January 2008 data, EIA estimated the allocation of the total fuel consumed at CHP plants between electric power generation and UTO.

The estimated allocation methodology is summarized in the following paragraphs. The methodology was retroactively applied to 2004-2007 data. Prior to 2004, UTO was collected on the Form EIA-906 and an estimated allocation of fuel for electricity was not necessary.

First, an efficiency factor is determined for each plant and prime mover type. Based on data for electric power generation and UTO collected in 2003 (on Form EIA-906, “Power Plant Report”), efficiency was calculated for each prime mover type at a plant. The efficiency factor is the total output in Btu, including electric power and UTO, divided by the total input in Btu. Electric power is converted to Btu at 3,412 Btu per kilowatthour.

Second, to calculate the amount of fuel for electric power, the gross generation in Btu is divided by the efficiency factor. The fuel for UTO is the difference between the total fuel reported and the fuel for electric power generation. UTO is calculated by multiplying the fuel for UTO by the efficiency factor.

In addition, if the total fuel reported is less than the estimated fuel for electric power generation, then the fuel for electric power generation is equal to the total fuel consumed, and the UTO will be zero.

Beginning with 2016 Form EIA-923 data, reported efficiency factors by survey respondents replaced the previously EIA estimated efficiency factors used in the fuel allocation process. For the processing of 2016 CHP data, EIA used for each plant an average of the efficiency factors reported by the CHP plants on the 2013, 2014, and 2015 Form EIA-923, “Power Plant Operations Report” surveys. An average was used to smooth out variations in any one year’s data. Once efficiency of each plant was established, the value was input into the above methodology to allocate the consumption of fuel between electric power and UTO. This update applies to the 2016 data and going forward but was not retroactively applied to previous years.

Issues within Historical Data Series for Receipts and Cost and Quality of Fossil Fuels: Values for receipts of natural gas for 2001 forward do not include blast furnace gas or other gas.

Historical data collected on FERC Form 423 and published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. However, these data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 data. In 2003, EIA introduced a procedure to estimate for late or non-responding entities that were required to report on the FERC Form 423. Due to the introduction of this procedure, 2003 and later data cannot be directly compared to previous years’ data.

Prior to 2008, regulated plants reported receipts data on the FERC Form 423. These plants, along with unregulated plants, now report receipts data on Schedule 2 of Form EIA-923. Because FERC issued waivers to Form 423 filing requirements to some plants who met certain criteria, and because not all types of generators were required to report (only steam turbines and combined cycle units reported), a significant number of plants either did not submit fossil fuel receipts data or submitted only a portion of their fossil fuel receipts. Since Form EIA-923 does not have exemptions based on generator type, or reporting waivers, receipts data from 2008 and later cannot be directly compared to previous years’ data for the regulated sector. Also beginning with January 2008 data, tables for total receipts included imputed quantities for plants with capacity one megawatt or more, to be consistent with other electric power data. Previous published receipts data were from plants at or over a 50 megawatt threshold, which was a legacy of their original collection as information for a regulatory agency, not as a survey to provide more meaningful estimates of totals for statistical purposes. Totals appeared to become smaller as more electric production came from unregulated plants, until the Form EIA-423 was created to help fill that gap. As a further improvement, estimation of all receipts for the universe normally depicted in the Electric Power Annual (i.e., one megawatt and above), with associated relative standard errors, provides a more complete assessment of the market.

Issues within Historical Data Series for Generation and Consumption: Beginning in 2008, a new method of allocating fuel consumption between electric power generation and UTO was implemented (see above). This new methodology evenly distributes a CHP plant’s losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change causes the fuel for electric power to be lower while the fuel for UTO is higher as both are given the same

efficiency. This results in the appearance of an increase in efficiency of production of electric power between periods.

Sensitive Data: The total delivered cost of fuel delivered to nonutilities, the commodity cost of fossil fuels, and fuel stocks are considered business sensitive.

Capacity Factors and Usage Factors

This section describes the methodology for calculating capacity factors and usages factors by fuel and technology type for operating electric power plants. Capacity factor is a measure (expressed as a percent) of how often an electric generator operates over a specific period, using a ratio of the actual output to the maximum possible output over that period.

The monthly capacity factor calculation includes all operating electric generators which operated for the entire month using the net generation reported on the Form EIA-923 and the net summer capacity reported on the Form EIA-860. The capacity factor for a particular fuel/technology type is given by:

$$capacity\ factor = \frac{\sum_{x,m} net\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

where x represents generators of that fuel/technology combination and m represents individual months. Net generation and capacity are specific to a generator, and the generator is categorized by its primary fuel type as reported on the EIA-860. All generation from that generator is included, regardless of other fuels consumed. Net generation and capacity for a generator is excluded from the summations during the month that the generator initially began operation and if applicable during the month that the generator retired. Therefore, these published capacity factors will differ from a simple calculation using annual generation and capacity totals from the appropriate tables in this publication.

Usage factors are calculated for energy storage technologies using gross generation instead of net generation:

$$usage\ factor = \frac{\sum_{x,m} gross\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO₂) from electric generating plants for 1989 through the present, as well as the estimated emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from electric generating plants for 2001 through the present. For a description of the methodology used for other years, see the technical notes to the EPA 2003.

Methodology Overview: Initial estimates of uncontrolled SO₂ and NO_x emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA on the Form EIA-923. An emission factor is the average quantity of a pollutant released from a power plant when a unit of fuel is burned, assuming no use of pollution control equipment. The basic relationship is:

$$\text{Emissions} = \text{Quantity of Fuel Consumed} \times \text{Emission Factor}$$

Quantity is defined in physical units (e.g., tons of solid fuels, million cubic feet of gaseous fuels, and thousands of barrels of liquid fuels) for determining NO_x and SO₂ emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO₂ emissions.

For some fuels, the calculation of SO₂ emissions requires including in the formula the sulfur content of the fuel measured in percentage of weight. Examples include coal and fuel oil. In these cases, the formula is:

$$\text{Emissions} = \text{Quantity of Fuel Consumed} \times \text{Emission Factor} \times \text{Sulfur Content}$$

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A.1., which lists the SO₂ emission factors used for this report.

In the case of SO₂ and NO_x emissions, the factor applied to a fuel can also vary with the combustion system: a steam-producing boiler, a combustion turbine, or an internal combustion engine. In the case of boilers, NO_x emissions can also vary with the firing configuration of a boiler and whether the boiler is a wet-bottom or dry-bottom design.³ These distinctions are shown in Tables A.1. and A.2.

For SO₂ and NO_x, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment are available from the historical Form EIA-767 survey (i.e., data for the years 2005 and earlier) and the EIA-860 and EIA-923 surveys for the years 2007 through 2010. A special case for removal of SO₂ is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO₂ emission factors shown in Table A.1. for fluidized bed boilers already account for 90 percent removal of SO₂ since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO₂ and NO_x emission estimates are made for all plants, in many cases the estimated emissions can be replaced with actual emissions data collected by the U.S. Environmental Protection Agency's (U.S. EPA's) Continuous Emissions Monitoring System (CEMS) program. (CEMS data for CO₂ are incomplete and are not used in this report.) The CEMS data account for the bulk of SO₂ and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO₂ and NO_x emissions are employed for the limited purpose of allocating emissions by fuel, since the CEMS data itself do not provide a detailed breakdown of plant emissions by fuel. For plants for which CEMS data are unavailable, the EIA-computed values are used as the final emissions estimates.

There are several reasons why the historical data are periodically revised. These include data revisions, revisions in emission and technology factors, and changes in methodology. For instance, the 2008 Electric Power Annual report features a revision in historic CO₂ values. This revision occurred due to a change in the accepted methodology regarding adjustments made for the percentage combustion of fuels.

The emissions estimation methodologies are described in more detail below.

CO₂ Emissions: CO₂ emissions are estimated using the information on fuel consumption in physical units and the heat content of fuel collected on the Form EIA-923 and predecessors. Heat content information

is used to convert physical units to millions of Btu (MMBtu) consumed. To estimate CO₂ emissions, the fuel-specific emission factor from Table A.3. is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO₂ emissions. CO₂ control technologies are currently in the early stages of research and there are no commercial systems installed. Therefore, no estimates of controlled CO₂ emissions are made.

SO₂ and NO_x Emissions: To comply with environmental regulations controlling SO₂ emissions, many coal-fired generating plants have installed flue gas desulfurization (FGD) units. Similarly, NO_x control regulations require many fossil-fueled plants to install low-NO_x burners, selective catalytic reduction systems, or other technologies to reduce emissions. It is common for power plants to employ two or even three NO_x control technologies; accordingly, the NO_x emissions estimation approach accounts for the combined effect of the equipment (Table A.4.). However, control equipment information is available only for plants that reported on the Form EIA-923 and for historical data from the Form EIA-767. The Form EIA-860, EIA-923, and the historical EIA-767 surveys are limited to plants with boilers fired by combustible fuels⁴ with a minimum generating capacity of 10 megawatts (nameplate). Pollution control equipment data are unavailable from EIA sources for plants that did not report on the historical EIA-767 survey, or the Forms EIA-860 and EIA-923.

The following method is used to estimate SO₂ and NO_x emissions:

- For steam electric plants, uncontrolled emissions are estimated using the emission factors shown in Tables A.1. and A.2. as well as reported data on fuel consumption, sulfur content, and boiler firing configuration. Controlled emissions are then determined when pollution control equipment is present. Although information on control equipment was not collected in 2006, updates for new installations during this period were made based on EPA data. Beginning in 2007, these data were collected on the Forms EIA-860 and EIA-923. For SO₂, the reported efficiency of the plant's FGD units is used to convert uncontrolled to controlled emission estimates. For NO_x, the reduction percentages shown in Table A.4. are applied to the uncontrolled estimates.
- For plants and prime movers not reported on the historical Form EIA-767 survey or Forms EIA-860 and EIA-923, uncontrolled emissions are estimated using the Table A.1. and Table A.2. emission factors and the following data and assumptions:
- Fuel consumption is taken from the Form EIA-923 and predecessors.
- The sulfur content of the fuel is estimated from fuel receipts for the plant reported on the Form EIA-923. When plant-specific sulfur content data are unavailable, the national average sulfur content for the fuel, computed from the Form EIA-923 is applied to the plant.
- As noted earlier, the emission factor for plants with boilers depends in part on the type of combustion system, including whether a boiler is wet-bottom or dry-bottom, and the boiler firing configuration. However, this boiler information is unavailable for steam electric plants that did not report on the historical Forms EIA-767 or EIA-860. For these cases, the plant is assumed to have a dry-bottom, non-cyclone boiler using a firing method that falls into the "All Other" category shown on Table A.1.⁵

For the plants that did not report on the historical Form EIA-767 or EIA-860, pollution control equipment data are unavailable and the uncontrolled estimates are not reduced.

- If actual emissions of SO₂ or NO_x are reported in the EPA's CEMS data, the EIA estimates are replaced with the CEMS values, using the EIA estimates to allocate the CEMS plant-level data by fuel. If CEMS data are unavailable, the EIA estimates are used as the final values.

Conversion Factors for Propane, Petroleum Coke, and Synthesis Gases.

The quantity conversion for petroleum coke is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds), propane is 1.53 thousand cubic feet per barrel, coal-derived synthesis gas is 98.06 thousand cubic feet per ton, and petroleum coke-derived synthesis gas is 107.31 thousand cubic feet per ton.

Relative Standard Error

The relative standard error (RSE) statistic, usually given as a percent, describes the magnitude of sampling error that might reasonably be incurred. The RSE is the square root of the estimated variance, divided by the variable of interest. The variable of interest may be the ratio of two variables, or a single variable.

The sampling error may be less than the non-sampling error. In fact, large RSE estimates found in preliminary work with these data have often indicated non-sampling errors, which were then identified and corrected. Non-sampling errors may be attributed to many sources, including response errors, definitional difficulties, differences in the interpretation of questions, mistakes in recording or coding data obtained, and other errors of collection, response, or coverage. These non-sampling errors also occur in complete censuses.

Using the Central Limit Theorem, which applies to sums and means such as are applicable here, there is approximately a 68 percent chance that the true total or mean is within one RSE of the estimated total. Note that reported RSEs are always estimates, themselves, and are usually, as here, reported as percents. As an example, suppose that a net generation from coal value is estimated to be 1,507 total million kilowatthours with an estimated RSE of 4.9 percent. This means that, ignoring any non-sampling error, there is approximately a 68 percent chance that the true million kilowatthour value is within approximately 4.9 percent of 1,507 million kilowatthours (that is, between 1,433 and 1,581 million kilowatthours). Also under the Central Limit Theorem, there is approximately a 95 percent chance that the true mean or total is within 2 RSEs of the estimated mean or total.

Note that there are times when a model may not apply, such as in the case of a substantial reclassification of sales, when the relationship between the variable of interest and the regressor data does not hold. In such a case, the new information represents only itself, and such numbers are added to model results when estimating totals. Further, there are times when sample data may be known to be in error or are not reported. Such cases are treated as if they were never part of the model-based sample, and values are imputed.

Business Classification

Nonutility power producers consist of entities that own or operate electric generating units but are not subject to direct economic regulation of rates, such as by state utility commissions. Nonutility power

producers do not have a designated franchised service area. In addition to entities whose primary business is the production and sale of electric power, entities with other primary business classifications can and do sell electric power. These can consist of, for example, manufacturing facilities and paper mills.

The EIA, in the Electric Power Annual and other data products, classifies nonutility power producers into the following categories:

- **Electric Utility (Sector 1):** All regulated plants with a primary purpose of selling electricity in the public markets (NAICS = 22).
- **Independent Power Producers (Sector 2):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with no ability to cogenerate heat and power.
- **Electric Power, Combined Heat and Power (Sector 3):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with the ability to cogenerate heat and power.
- **Commercial, Non-Combined Heat and Power (Sector 4):** All plants with a commercial primary purpose with no ability to cogenerate heat and power.
- **Commercial, Combined Heat and Power (Sector 5):** All plants with a commercial primary purpose with the ability to cogenerate heat and power.
- **Industrial, Non-Combined Heat and Power (Sector 6):** All plants with an industrial primary purpose with no ability to cogenerate heat and power.
- **Industrial, Combined Heat and Power (Sector 7):** All plants with an industrial primary purpose with the ability to cogenerate heat and power.

The following is a list of the North American Industry Classification System (NAICS) classifications used by EIA.

	Agriculture, Forestry, Fishing and Hunting
111	Crop Production
112	Animal Production
113	Forestry and Logging
114	Fishing, Hunting and Trapping
115	Support Activities for Agriculture and Forestry
	Mining, Quarrying, and Oil and Gas Extraction
211	Oil and Gas Extraction
2121	Coal Mining
2122	Metal Ore Mining
2123	Nonmetallic Mineral Mining and Quarrying
	Utilities
22	Electric Power Generation, Transmission and Distribution (other than 2212, 2213, 22131, 22132 or 22133)
2212	Natural Gas Distribution
22131	Water Supply and Irrigation Systems
22132	Sewage Treatment Facilities

22133	Steam and Air-Conditioning Supply
	Manufacturing
311	Food Manufacturing
312	Beverage and Tobacco Product Manufacturing
313	Textile Mills (Fiber, Yarn, Thread, Fabric, and Textiles)
314	Textile Product Mills
315	Apparel Manufacturing
316	Leather and Allied Product Manufacturing
321	Wood Product Manufacturing
322	Paper Manufacturing (other than 322122 or 32213)
322122	Newsprint Mills
32213	Paperboard Mills
323	Printing and Related Support Activities
324	Petroleum and Coal Products Manufacturing (other than 32411)
32411	Petroleum Refineries
325	Chemical Manufacturing (other than 32511, 32512, 325193, 325188, 3252 325211, 3253 or 325311)
32511	Petrochemical Manufacturing
32512	Industrial Gas Manufacturing
325193	Ethyl Alcohol Manufacturing (including Ethanol)
325188	Industrial Inorganic Chemicals
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing (other than 325211)
325211	Plastics Material and Resin Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing (other than 325311)
325311	Nitrogenous Fertilizer Manufacturing
326	Plastics and Rubber Products Manufacturing
327	Nonmetallic Mineral Product Manufacturing (other than 32731)
32731	Cement Manufacturing
331	Primary Metal Manufacturing (other than 331111 or 331312)
331111	Iron and Steel Mills
331312	Primary Aluminum Production
332	Fabricated Metal Product Manufacturing
333	Machinery Manufacturing
334	Computer and Electronic Product Manufacturing
335	Electrical Equipment, Appliance, and Component Manufacturing
336	Transportation Equipment Manufacturing
337	Furniture and Related Product Manufacturing
339	Miscellaneous Manufacturing
421	Wholesale Trade
441	Retail Trade
	Transportation and Warehousing
481	Air Transportation
482	Rail Transportation
483	Water Transportation
484	Truck Transportation
485	Transit and Ground Passenger Transportation
486	Pipeline Transportation
487	Scenic and Sightseeing Transportation

488	Support Activities for Transportation (other than 4881, 4882, 4883 or 4884)
4881	Support Activities for Air Transportation (including Airports)
4882	Support Activities for Rail Transportation (including Rail Stations)
4883	Support Activities for Water Transportation (including Marinas)
4884	Support Activities for Road Transportation
491	Postal Service
492	Couriers and Messengers
493	Warehousing and Storage
	Information
511	Publishing Industries (except Internet)
512	Motion Picture and Sound Recording Industries
515	Broadcasting (except Internet)
517	Telecommunications
518	Data Processing, Hosting, and Related Services
519	Other Information Services
521	Finance and Insurance
53	Real Estate and Rental and Leasing (including Convention Centers and Office Buildings)
541	Professional, Scientific, and Technical Services
55	Management of Companies and Enterprises
	Administrative and Support and Waste Management and Remediation Services
561	Administrative and Support Services
562	Waste Management and Remediation Services (other than 562212 or 562213)
562212	Solid Waste Landfill
562213	Solid Waste Combustors and Incinerators
611	Educational Services
	Health Care and Social Assistance
621	Ambulatory Health Care Services
622	Hospitals
623	Nursing and Residential Care Facilities
624	Social Assistance
	Arts, Entertainment, and Recreation
711	Performing Arts, Spectator Sports, and Related Industries
712	Museums, Historical Sites, and Similar Institutions
713	Amusement, Gambling, and Recreation Industries
	Accommodation and Food Services
721	Accommodation
722	Food Services and Drinking Places
	Other Services (except Public Administration)
811	Repair and Maintenance
812	Personal and Laundry Services
813	Religious, Grantmaking, Civic, Professional, and Similar Organizations
814	Private Households

92	Public Administration (other than 921, 922, 92214 or 928)
921	Executive, Legislative, and Other General Government Services
922	Justice, Public Order and Safety Activities (other than 92214)
92214	Correctional Facilities
928	National Security and International Affairs (including Military Bases)

Multiple Survey Programs- Small Scale PV Solar Estimation of Generation

Monthly generation from small scale PV solar resources is an estimation of the generation produced from PV solar resources and not the results of a data collection effort for generation directly, except for “Third Party Owned” or (TPO) solar installations which has direct data collection. TPO data however is not comprehensive. TPOs do not operate in every state, TPO collected data is not a large portion of the estimated amount, and the data has been collected for limited period. The generation estimate is based on data collected for PV solar capacity.

Capacity of PV solar resources is collected directly from respondents. These data are collected on several EIA forms and from several types of respondents. Monthly data for net-metered PV solar capacity is reported on the Form EIA-861M. Form EIA-61M is a cutoff sample drawn from the annual survey Form EIA-861 which collects this data from all respondents. Using data from both surveys we have a regression model to impute for the non-sampled monthly capacity.

The survey instruments collect solar net metering capacity from reporting utilities by state and customer class. There are four customer classes: residential, commercial, industrial and transportation. However, the estimation process included only the residential, commercial, and industrial customers.¹ Data for these customer classes were further classified by U.S. Census Regions, to ensure adequate number of customer observations in for each estimation group.

Estimation Model: The total PV capacity reported by utilities in the annual EIA-861 survey is the single primary input (regressor) to the monthly estimation of PV capacity by state. The model tested for each census region was of the form:

$$y_{i_{2015,m}} = \beta_1 x_{i_{2013}} + w_i^{-1/2} e_i, \text{ where}$$

$x_{i_{2013}}$ is the i^{th} utility’s 2013 (or the last published year) solar PV capacity

$y_{i_{2015,m}}$ is the i^{th} utility’s month m , 2015 (or the current year) reported solar PV capacity

w_i is the weight factor, which is the inverse of $x_{i_{2013}}$

β_1 is effectively the growth rate of reported month m solar PV capacity

e_i is the error term

The model checks for outliers and removes them from the regression equation inputs. The model calculates RSEs by sector, state, census region, and U.S. total. Once we have imputed for all the monthly net-metered PV solar capacity we add to total net metered capacity, the PV solar capacity collected for the non net-metered capacity.

We use a second model to estimate the generation using this capacity as an input. The original methodology was developed for the “Annual Energy Outlook” based on our “NEMS” modelled projections several years ago. The original method underwent a calibration project designed to develop PV production levels for the NEMS projections consistent with simulations of a National Renewable Energy Laboratory model called PVWatts, which is itself embedded in PC software under the umbrella of the NREL’s System Advisor Model (SAM).

The PVWatts simulations require, panel azimuth orientations and tilts, something that the NEMS projections do not include. Call the combinations of azimuths and tilts “orientations.” The orientation and solar insolation (specific to a location) have a direct effect on the PV production level. The calibration project selected the 100 largest population Metropolitan Statistical Areas (MSAs) and relied on weights derived from orientation data from California Solar Initiative dataset to develop typical outputs for each of the 100 MSAs. It then was expanded from an annual estimate to a monthly estimate. A further description of this model is located here. A listing of the MSAs is included in Appendix 1.

Using Form EIA-861 data for service territories, which lists the counties that each electric distribution company (EDC) provides service, and NREL solar insolation data by county a simple average of insolation values by EDC is calculated.

Using the estimation model, we produce by utility, by state and by sector an estimate of generation. All the utilities’ capacity and generation estimates are summed by state and sector and a KWh/KW rate by state and sector is calculated.

Capacity from the Form EIA-860 that is net metered is subtracted from the total capacity by state and sector as well as the capacity reported on the EIA-861M from TPOs, resulting in a new “net” capacity amount. This capacity amount is multiplied by the KWh/KW rate to produce the non-TPO generation estimate and then it is added to the TPO reported sales to ultimate customers from the EIA-861 to obtain a final estimate for generation and a blended KWh/KW rate is calculated. The estimate for generation is aggregated by US census regions and US totals. The RSEs for capacity are checked for level of error and if they pass, the summary data by state, US census region and US total are reported in the EPM.

Appendix 2 contains a flow diagram of the data inputs, data quality control checks and data analysis required to perform this estimation.

Appendix 1- MSAs

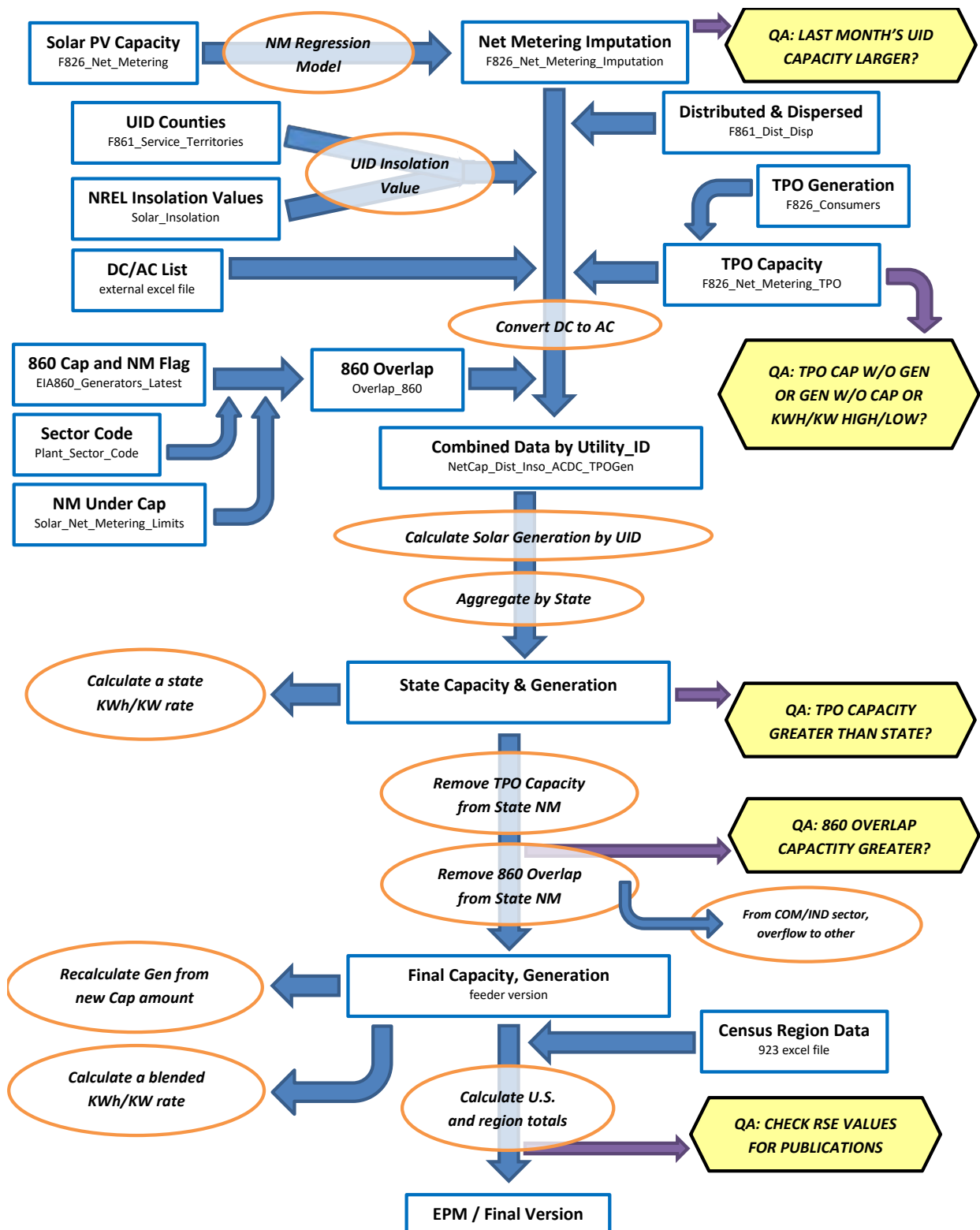
TMY3 (1991-2005) Weather Stations by MSA

Site	Weather Location	MSA
1	USA NY New York Central Park Obs.	New York-Newark-Jersey City, NY-NJ-PA MSA
2	USA CA Los Angeles Intl Airport	Los Angeles-Long Beach-Anaheim, CA MSA
3	USA IL Chicago Midway Airport	Chicago-Naperville-Elgin, IL-IN-WI MSA
4	USA TX Dallas-Fort Worth Intl Airport	Dallas-Fort Worth-Arlington, TX MSA
5	USA TX Houston Bush Intercontinental	Houston-The Woodlands-Sugar Land, TX MSA
6	USA PA Philadelphia Int'l Airport	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA
7	USA VA Washington Dc Reagan Airport	Washington-Arlington-Alexandria, DC-VA-MD-WV MSA
8	USA FL Miami Intl Airport	Miami-Fort Lauderdale-West Palm Beach, FL MSA
9	USA GA Atlanta Hartsfield Intl Airport	Atlanta-Sandy Springs-Roswell, GA MSA
10	USA MA Boston Logan Int'l Airport	Boston-Cambridge-Newton, MA-NH MSA
11	USA CA San Francisco Intl Airport	San Francisco-Oakland-Hayward, CA MSA
12	USA AZ Phoenix Sky Harbor Intl Airport	Phoenix-Mesa-Scottsdale, AZ MSA
13	USA CA Riverside Municipal Airport	Riverside-San Bernardino-Ontario, CA MSA
14	USA MI Detroit City Airport	Detroit-Warren-Dearborn, MI MSA
15	USA WA Seattle Seattle-Tacoma Intl Airport	Seattle-Tacoma-Bellevue, WA MSA
16	USA MN Minneapolis-St. Paul Int'l Arp	Minneapolis-St. Paul-Bloomington, MN-WI MSA
17	USA CA San Diego Lindbergh Field	San Diego-Carlsbad, CA MSA
18	USA FL Tampa Int'l Airport	Tampa-St. Petersburg-Clearwater, FL MSA
19	USA MO St Louis Lambert Int'l Airport	St. Louis, MO-IL MSA
20	USA MD Baltimore-Washington Int'l Airport	Baltimore-Columbia-Towson, MD MSA
21	USA CO Denver Centennial [Golden - NREL]	Denver-Aurora-Lakewood, CO MSA
22	USA PA Pittsburgh Allegheny Co Airport	Pittsburgh, PA MSA
23	USA NC Charlotte Douglas Intl Airport	Charlotte-Concord-Gastonia, NC-SC MSA
24	USA OR Portland Hillsboro	Portland-Vancouver-Hillsboro, OR-WA MSA
25	USA TX San Antonio Intl Airport	San Antonio-New Braunfels, TX MSA
26	USA FL Orlando Intl Airport	Orlando-Kissimmee-Sanford, FL MSA
27	USA CA Sacramento Executive Airport	Sacramento-Roseville-Arden-Arcade, CA MSA
28	USA OH Cincinnati Municipal Airport	Cincinnati, OH-KY-IN MSA
29	USA OH Cleveland Hopkins Intl Airport	Cleveland-Elyria, OH MSA
30	USA MO Kansas City Int'l Airport	Kansas City, MO-KS MSA
31	USA NV Las Vegas McCarran Intl Airport	Las Vegas-Henderson-Paradise, NV MSA
32	USA OH Columbus Port Columbus Intl A	Columbus, OH MSA
33	USA IN Indianapolis Intl Airport	Indianapolis-Carmel-Anderson, IN MSA
34	USA CA San Jose Intl Airport	San Jose-Sunnyvale-Santa Clara, CA MSA
35	USA TX Austin Mueller Municipal Airport	Austin-Round Rock, TX MSA

36	USA TN Nashville Int'l Airport	Nashville-Davidson–Murfreesboro–Franklin, TN MSA
37	USA VA Norfolk Int'l Airport	Virginia Beach-Norfolk-Newport News, VA-NC MSA
38	USA RI Providence T F Green State	Providence-Warwick, RI-MA MSA
39	USA WI Milwaukee Mitchell Intl Airport	Milwaukee-Waukesha-West Allis, WI MSA
40	USA FL Jacksonville Craig	Jacksonville, FL MSA
41	USA TN Memphis Int'l Airport	Memphis, TN-MS-AR MSA
42	USA OK Oklahoma City Will Rogers	Oklahoma City, OK MSA
43	USA KY Louisville Bowman Field	Louisville/Jefferson County, KY-IN MSA
44	USA VA Richmond Int'l Airport	Richmond, VA MSA
45	USA LA New Orleans Alvin Callender	New Orleans-Metairie, LA MSA
46	USA CT Hartford Bradley Intl Airport	Hartford-West Hartford-East Hartford, CT MSA
47	USA NC Raleigh Durham Int'l	Raleigh, NC MSA
48	USA UT Salt Lake City Int'l Airport	Salt Lake City, UT MSA
49	USA AL Birmingham Municipal Airport	Birmingham-Hoover, AL MSA
50	USA NY Buffalo Niagara Intl Airport	Buffalo-Cheektowaga-Niagara Falls, NY MSA
51	USA NY Rochester Greater Rochester	Rochester, NY MSA
52	USA MI Grand Rapids Kent County Int'l Airport	Grand Rapids-Wyoming, MI MSA
53	USA AZ Tucson Int'l Airport	Tucson, AZ MSA
54	USA HI Honolulu Intl Airport	Urban Honolulu, HI MSA
55	USA OK Tulsa Int'l Airport	Tulsa, OK MSA
56	USA CA Fresno Yosemite Intl Airport	Fresno, CA MSA
57	USA CT Bridgeport Sikorsky Memorial	Bridgeport-Stamford-Norwalk, CT MSA
58	USA MA Worcester Regional Airport	Worcester, MA-CT MSA
59	USA NM Albuquerque Intl Airport	Albuquerque, NM MSA
60	USA NE Omaha Eppley Airfield	Omaha-Council Bluffs, NE-IA MSA
61	USA NY Albany County Airport	Albany-Schenectady-Troy, NY MSA
62	USA CA Bakersfield Meadows Field	Bakersfield, CA MSA
63	USA CT New Haven Tweed Airport	New Haven-Milford, CT MSA
64	USA TN Knoxville McGhee Tyson Airport	Knoxville, TN MSA
65	USA SC Greenville Downtown Airport	Greenville-Anderson-Mauldin, SC MSA
66	USA CA Oxnard Airport	Oxnard-Thousand Oaks-Ventura, CA MSA
67	USA TX El Paso Int'l Airport	El Paso, TX MSA
68	USA PA Allentown Lehigh Valley Intl	Allentown-Bethlehem-Easton, PA-NJ MSA
69	USA LA Baton Rouge Ryan Airport	Baton Rouge, LA MSA
70	USA TX McCallen Miller Intl Airport	McAllen-Edinburg-Mission, TX MSA
71	USA OH Dayton Int'l Airport	Dayton, OH MSA
72	USA SC Columbia Metro Airport	Columbia, SC MSA
73	USA NC Greensboro Piedmont Triad Int'l Airport	Greensboro-High Point, NC MSA
74	USA FL Sarasota Bradenton	North Port-Sarasota-Bradenton, FL MSA
75	USA AR Little Rock Adams Field	Little Rock-North Little Rock-Conway, AR MSA
76	USA SC Charleston Intl Airport	Charleston-North Charleston, SC MSA

77	USA OH Akron Akron-canton Reg. Airport	Akron, OH MSA
78	USA CA Stockton Metropolitan Airport	Stockton-Lodi, CA MSA
79	USA CO Colorado Springs Muni Airport	Colorado Springs, CO MSA
80	USA NY Syracuse Hancock Int'l Airport	Syracuse, NY MSA
81	USA FL Fort Myers Page Field	Cape Coral-Fort Myers, FL MSA
82	USA NC Winston-Salem Reynolds Airport	Winston-Salem, NC MSA
83	USA ID Boise Air Terminal	Boise City, ID MSA
84	USA KS Wichita Mid-continent Airport	Wichita, KS MSA
85	USA WI Madison Dane Co Regional Airport	Madison, WI MSA
86	USA MA Worcester Regional Airport	Springfield, MA MSA
87	USA FL Lakeland Linder Regional Airport	Lakeland-Winter Haven, FL MSA
88	USA UT Ogden Hinkley Airport	Ogden-Clearfield, UT MSA
89	USA OH Toledo Express Airport	Toledo, OH MSA
90	USA FL Daytona Beach Intl Airport	Deltona-Daytona Beach-Ormond Beach, FL MSA
91	USA IA Des Moines Intl Airport	Des Moines-West Des Moines, IA MSA
92	USA GA Augusta Bush Field	Augusta-Richmond County, GA-SC MSA
93	USA MS Jackson Int'l Airport	Jackson, MS MSA
94	USA UT Provo Muni	Provo-Orem, UT MSA
95	USA PA Wilkes-Barre Scranton Intl Airport	Scranton-Wilkes-Barre-Hazleton, PA MSA
96	USA PA Harrisburg Capital City Airport	Harrisburg-Carlisle, PA MSA
97	USA OH Youngstown Regional Airport	Youngstown-Warren-Boardman, OH-PA MSA
98	USA FL Melbourne Regional Airport	Palm Bay-Melbourne-Titusville, FL MSA
99	USA TN Chattanooga Lovell Field Airport	Chattanooga, TN-GA MSA
100	USA WA Spokane Int'l Airport	Spokane Spokane Valley, WA MSA

Appendix 2 – Flow diagram of data sources and analysis



Endnotes

- ¹ The basic technique employed is described in the paper “Model-Based Sampling and Inference,” on the EIA website. Additional references can be found on the InterStat website (<http://interstat.statjournals.net/>). See the following sources: Knaub, J.R., Jr. (1999a), “Using Prediction-Oriented Software for Survey Estimation,” InterStat, August 1999, <http://interstat.statjournals.net/>; Knaub, J.R. Jr. (1999b), “Model-Based Sampling, Inference and Imputation,” EIA web site: <http://www.eia.gov/cneaf/electricity/forms/eiawebme.pdf>; Knaub, J.R., Jr. (2005), “Classical Ratio Estimator,” InterStat, October 2005, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2007a), “Cutoff Sampling and Inference,” InterStat, April 2007, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2008), “Cutoff Sampling.” Definition in Encyclopedia of Survey Research Methods, Editor: Paul J. Lavrakas, Sage, to appear; Knaub, J.R., Jr. (2000), “Using Prediction-Oriented Software for Survey Estimation - Part II: Ratios of Totals,” InterStat, June 2000, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2001), “Using Prediction-Oriented Software for Survey Estimation - Part III: Full-Scale Study of Variance and Bias,” InterStat, June 2001, <http://interstat.statjournals.net/>.
- ² See the following sources: Bahillo, A. et al. Journal of Energy Resources Technology, “NOx and N2O Emissions During Fluidized Bed Combustion of Leather Wastes.” Volume 128, Issue 2, June 2006. pp. 99-103; U.S. Energy Information Administration. *Renewable Energy Annual 2004*. “Average Heat Content of Selected Biomass Fuels.” Washington, DC, 2005; Penn State Agricultural College Agricultural and Biological Engineering and Council for Solid Waste Solutions. Garth, J. and Kowal, P. Resource Recovery, Turning Waste into Energy, University Park, PA, 1993; Utah State University Recycling Center Frequently Asked Questions
- ³ A boiler’s firing configuration relates to the arrangement of the fuel burners in the boiler, and whether the boiler is of conventional or cyclone design. Wet- and dry-bottom boilers use different methods to collect a portion of the ash that results from burning coal. For information on wet- and dry-bottom boilers, see the EIA Glossary at <http://www.eia.gov/glossary/index.html>. Additional information on wet- and dry-bottom boilers and on other aspects of boiler design and operation, including the differences between conventional and cyclone designs, can be found in Babcock and Wilcox, *Steam: Its Generation and Use*, 41st Edition, 2005.
- ⁴ Boilers that rely entirely on waste heat to create steam, including the heat recovery portion of most combined cycle plants, did not report on the historical Form EIA-767 or EIA-923.
- ⁵ The “All Other” firing configuration category includes, for example, arch firing and concentric firing. For a full list of firing method options for reporting on the historical Form EIA-767, see the form instructions, page xi, at http://www.eia.gov/survey/form/eia_767/instructions_form.pdf.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-107:
EIA Annual 2019



Independent Statistics & Analysis

U.S. Energy Information
Administration

Electric Power Annual 2019

February 2021

Electric Power Annual 2019 Revision Notice – February 19, 2021

Due to several plant-level data corrections in 2019 net generation and fossil fuel consumption, EIA has revised tables 1.1; 1.2; 1.3; 3.1.A; 3.1.B; 3.2.A; 3.2.B; 3.3.A; 3.3.B; 3.7; 3.8; 3.9; 3.11; 3.15; 3.17; 3.18; 3.23; 3.26; 4.8.B; 5.1.A; 5.1.C; 5.1.D; 5.1.E; 5.1.F; 5.4.A; 5.4.C; 5.4.D; 5.4.F; 5.9; 5.12; 6.1; 6.2; 6.3; 6.4; 7.6; and 8.1.

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government.



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EIA Electric Industry Data Collection

Chapter 1

National Summary Data

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Net Generation and Consumption of Fuels for January through December														
		Total (All Sectors)			Electric Power Sector				Commercial		Industrial		Residential	
					Electric Utilities		Independent Power Producers							
Fuel	Facility Type	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
Net Generation (Thousand Megawatthours)														
Coal	Utility Scale Facilities	964,957	1,149,487	-16.1%	722,885	863,505	235,847	278,668	268	303	5,957	7,011	0	0
Petroleum Liquids	Utility Scale Facilities	11,522	16,245	-29.1%	8,313	10,108	2,669	5,487	116	132	424	517	0	0
Petroleum Coke	Utility Scale Facilities	6,819	8,981	-24.1%	5,112	6,817	1,125	1,516	5	7	576	640	0	0
Natural Gas	Utility Scale Facilities	1,585,814	1,469,133	7.9%	785,026	720,206	692,113	645,616	8,610	8,419	100,065	94,892	0	0
Other Gas	Utility Scale Facilities	12,591	13,463	-6.5%	154	151	3,883	3,935	0	0	8,554	9,377	0	0
Nuclear	Utility Scale Facilities	809,409	807,084	0.3%	430,672	424,251	378,738	382,833	0	0	0	0	0	0
Hydroelectric Conventional	Utility Scale Facilities	287,874	292,524	-1.6%	262,364	267,336	24,288	23,812	188	227	1,033	1,149	0	0
Renewable Sources Excluding Hydroelectric	Utility Scale Facilities	440,799	414,292	6.4%	55,188	49,100	354,823	333,491	3,426	3,214	27,361	28,487	0	0
... Wind	Utility Scale Facilities	295,882	272,667	8.5%	43,636	38,466	251,968	233,931	179	174	100	97	0	0
... Solar Thermal and Photovoltaic	Utility Scale Facilities	71,937	63,825	12.7%	6,785	4,916	64,480	58,337	587	525	85	47	0	0
... Wood and Wood-Derived Fuels	Utility Scale Facilities	38,543	40,936	-5.8%	2,784	3,364	9,237	10,021	90	77	26,433	27,475	0	0
... Other Biomass	Utility Scale Facilities	18,964	20,896	-9.2%	1,213	1,344	14,878	16,279	2,129	2,404	743	868	0	0
... Geothermal	Utility Scale Facilities	15,473	15,967	-3.1%	771	1,009	14,260	14,924	442	33	0	0	0	0
Hydroelectric Pumped Storage	Utility Scale Facilities	-5,261	-5,905	-10.9%	-4,261	-4,785	-1,000	-1,119	0	0	0	0	0	0
Other Energy Sources	Utility Scale Facilities	13,331	12,973	2.8%	551	561	7,138	6,677	1,076	1,010	4,567	4,725	0	0
All Energy Sources	Utility Scale Facilities	4,127,855	4,178,277	-1.2%	2,266,004	2,337,250	1,699,625	1,680,917	13,689	13,312	148,537	146,798	0	0
Estimated Small Scale Solar Photovoltaic	Small Scale Facilities	34,957	29,539	18.3%	0	0	0	0	11,002	9,798	3,041	2,636	20,914	17,105
Estimated Total Solar Photovoltaic	All Facilities	103,676	89,773	15.5%	6,757	4,865	61,290	54,796	11,588	10,324	3,127	2,683	20,914	17,105
Estimated Total Solar	All Facilities	106,894	93,365	14.5%	6,785	4,916	64,480	58,337	11,588	10,324	3,127	2,683	20,914	17,105
Consumption of Fossil Fuels for Electricity Generation														
Coal (1000 tons)	Utility Scale Facilities	537,620	636,213	-15.5%	399,545	473,617	135,838	159,976	76	87	2,161	2,534	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	20,836	28,614	-27.2%	15,677	18,345	4,464	9,467	251	269	444	534	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	2,724	3,623	-24.8%	2,067	2,740	478	704	1	2	177	177	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	11,601,600	10,833,043	7.1%	5,969,422	5,551,181	4,958,798	4,663,935	55,575	52,650	617,805	565,276	0	0
Consumption of Fossil Fuels for Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	12,397	13,813	-10.3%	2,062	2,268	1,161	1,356	443	490	8,731	9,700	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	2,162	2,614	-17.3%	71	103	226	354	419	350	1,446	1,807	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	839	929	-9.7%	17	12	93	93	6	10	724	814	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	1,196,025	1,205,962	-0.8%	42,645	43,156	317,231	331,952	79,734	81,856	756,415	748,997	0	0
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output														
Coal (1000 tons)	Utility Scale Facilities	550,017	650,027	-15.4%	401,607	475,885	136,998	161,332	519	577	10,892	12,233	0	0
Petroleum Liquids (1000 barrels)	Utility Scale Facilities	22,998	31,228	-26.4%	15,748	18,448	4,690	9,820	670	619	1,890	2,341	0	0
Petroleum Coke (1000 tons)	Utility Scale Facilities	3,563	4,552	-21.7%	2,083	2,752	571	797	7	12	900	991	0	0
Natural Gas (1000 Mcf)	Utility Scale Facilities	12,797,626	12,039,005	6.3%	6,012,067	5,594,338	5,276,029	4,995,888	135,310	134,507	1,374,220	1,314,273	0	0

Sales, Revenue, and Average Price of Electricity to Ultimate Customers for January through December									
Total U.S. Electric Power Industry									
	Sales of Electricity to Ultimate Customers (million kWh)			Revenue from Sales of Electricity to Ultimate Customers (million dollars)			Average Price of Electricity to Ultimate Customers (cents/kWh)		
Sector	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Percentage Change
Residential	1,440,289	1,469,093	-2.0%	187,436	189,033	-0.8%	13.01	12.87	1.1%
Commercial	1,360,877	1,381,755	-1.5%	145,280	147,425	-1.5%	10.68	10.67	0.1%
Industrial	1,002,353	1,000,673	0.2%	68,285	69,218	-1.3%	6.81	6.92	-1.6%
Transportation	7,632	7,665	-0.4%	737	744	-0.8%	9.66	9.70	-0.4%
All Sectors	3,811,150	3,859,185	-1.2%	401,738	406,420	-1.2%	10.54	10.53	0.1%

NM = Not meaningful due to large relative standard error.
W = Withheld to avoid disclosure of individual company data.
Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Coal generation and consumption includes anthracite, bituminous, subbituminous, lignite, waste coal, refined coal, synthetic coal, and coal-derived synthesis gas.
Petroleum Liquids includes distillate fuel oil, residual fuel oil, jet fuel, kerosene, propane, and waste oil.
Petroleum Coke includes petroleum coke and synthesis gas derived from petroleum coke.
Natural gas includes a small amount of supplemental gaseous fuels that cannot be identified separately.
Other Gases includes blast furnace gas and other manufactured and waste gases derived from fossil fuels.
Wood and Wood-Derived Fuels include wood, black liquor, and other wood waste.
Other Biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, and other biomass.
Coal stocks include anthracite, bituminous, subbituminous, lignite, refined coal, and synthetic coal; waste coal is excluded.
Sales of electricity to ultimate customers and net generation may not correspond exactly for a particular month for a variety of reasons (e.g., sales data may include imported electricity).
Net generation is presented for the calendar month while sales of electricity to ultimate customers and associated revenue accumulate from bills collected for periods of time that vary depending

Table 1.2. Summary Statistics for the United States, 2009 - 2019

(From Table 2.1.) Number of Ultimate Customers

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	125,208,829	17,562,235	757,537	704	N/A	143,529,305
2010	125,717,935	17,674,338	747,747	239	N/A	144,140,259
2011	126,143,072	17,638,062	727,920	92	N/A	144,509,146
2012	126,832,343	17,729,029	732,385	83	N/A	145,293,840
2013	127,777,153	17,679,562	831,790	75	N/A	146,288,580
2014	128,680,416	17,853,995	839,212	79	N/A	147,373,702
2015	129,811,718	17,985,690	835,536	78	N/A	148,633,022
2016	131,068,760	18,148,353	838,059	86	N/A	150,055,258
2017	132,579,747	18,359,427	840,329	86	N/A	151,779,589
2018	133,893,321	18,605,393	840,321	83	N/A	153,339,118
2019	135,249,616	18,694,240	954,222	83	N/A	154,898,161

(From Table 2.2.) Sales to Ultimate Customers

(Thousand Megawatthours)

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	1,364,758	1,306,853	917,416	7,768	N/A	3,596,795
2010	1,445,708	1,330,199	971,221	7,712	N/A	3,754,841
2011	1,422,801	1,328,057	991,316	7,672	N/A	3,749,846
2012	1,374,515	1,327,101	985,714	7,320	N/A	3,694,650
2013	1,394,812	1,337,079	985,352	7,625	N/A	3,724,868
2014	1,407,208	1,352,158	997,576	7,758	N/A	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	N/A	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	N/A	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	N/A	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	N/A	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	N/A	3,811,150

(From Table 2.3.) Revenue From Ultimate Customers

(Million Dollars)

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	157,044	132,747	62,670	828	N/A	353,289
2010	166,778	135,554	65,772	814	N/A	368,918
2011	166,714	135,927	67,606	803	N/A	371,049
2012	163,280	133,898	65,761	747	N/A	363,687
2013	169,131	137,188	67,934	805	N/A	375,058
2014	176,178	145,253	70,855	810	N/A	393,096
2015	177,624	144,781	68,166	771	N/A	391,341
2016	177,077	142,643	66,068	722	N/A	386,509
2017	177,661	144,242	67,691	728	N/A	390,322
2018	189,033	147,425	69,218	744	N/A	406,420
2019	187,436	145,280	68,285	737	N/A	401,738

Table 1.2. Summary Statistics for the United States, 2009 - 2019

(From Table 2.4.) Average Price

(Cents per Kilowatthour)

Year	Residential	Commer- cial	Industrial	Transpor- tation	Other	Total
2009	11.51	10.16	6.83	10.66	N/A	9.82
2010	11.54	10.19	6.77	10.56	N/A	9.83
2011	11.72	10.24	6.82	10.46	N/A	9.90
2012	11.88	10.09	6.67	10.21	N/A	9.84
2013	12.13	10.26	6.89	10.55	N/A	10.07
2014	12.52	10.74	7.10	10.45	N/A	10.44
2015	12.65	10.64	6.91	10.09	N/A	10.41
2016	12.55	10.43	6.76	9.63	N/A	10.27
2017	12.89	10.66	6.88	9.68	N/A	10.48
2018	12.87	10.67	6.92	9.70	N/A	10.53
2019	13.01	10.68	6.81	9.66	N/A	10.54

(From Tables 2.12. - 2.14.) Trade

(Thousand Megawatthours)

Year	Purchases	Sales for Resale	Imports	Exports
2009	5,028,647	5,065,031	52,191	18,138
2010	5,770,134	5,929,211	45,083	19,106
2011	5,024,621	5,143,121	52,300	15,049
2012	4,984,933	5,013,765	59,257	11,996
2013	4,684,977	4,842,508	68,947	11,373
2014	4,802,227	4,908,839	66,510	13,298
2015	4,761,523	4,797,395	75,770	9,100
2016	4,723,571	4,746,967	72,716	6,214
2017	4,861,257	4,889,947	65,685	9,371
2018	5,168,874	5,127,276	58,261	13,804
2019	5,371,635	5,172,430	59,052	20,008

(From Tables 3.1.A. and 3.1.B.) Net Generation (Thousand Megawatthours)

Generation at Utility Scale Facilities									
Year	Coal	Petroleum	Natural Gas	Other Gas	Nuclear	Hydro Conven- tional	Hydro Pumped Storage	Geothermal	Wind
2009	1,755,904	38,937	920,979	10,632	798,855	273,445	-4,627	15,009	73,886
2010	1,847,290	37,061	987,697	11,313	806,968	260,203	-5,501	15,219	94,652
2011	1,733,430	30,182	1,013,689	11,566	790,204	319,355	-6,421	15,316	120,177
2012	1,514,043	23,190	1,225,894	11,898	769,331	276,240	-4,950	15,562	140,822
2013	1,581,115	27,164	1,124,836	12,853	789,016	268,565	-4,681	15,775	167,840
2014	1,581,710	30,232	1,126,609	12,022	797,166	259,367	-6,174	15,877	181,655
2015	1,352,398	28,249	1,333,482	13,117	797,178	249,080	-5,091	15,918	190,719
2016	1,239,149	24,205	1,378,307	12,807	805,694	267,812	-6,686	15,826	226,993
2017	1,205,835	21,390	1,296,442	12,469	804,950	300,333	-6,495	15,927	254,303
2018	1,149,487	25,226	1,469,133	13,463	807,084	292,524	-5,905	15,967	272,667
2019	964,957	18,341	1,585,814	12,591	809,409	287,874	-5,261	15,473	295,882

Table 1.2. Summary Statistics for the United States, 2009 - 2019

Generation at Utility Scale Facilities							Small Scale Generation	Utility and Small Scale Generation	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Generation	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2009	157	735	36,050	18,443	11,928	3,950,331	--	157	891
2010	423	789	37,172	18,917	12,855	4,125,060	--	423	1,212
2011	1,012	806	37,449	19,222	14,154	4,100,141	--	1,012	1,818
2012	3,451	876	37,799	19,823	13,787	4,047,765	--	3,451	4,327
2013	8,121	915	40,028	20,830	13,588	4,065,964	--	8,121	9,036
2014	15,250	2,441	42,340	21,650	13,461	4,093,606	11,233	26,482	28,924
2015	21,666	3,227	41,929	21,703	14,028	4,077,601	14,139	35,805	39,032
2016	32,670	3,384	40,947	21,813	13,754	4,076,675	18,812	51,483	54,866
2017	50,018	3,269	41,124	21,610	13,096	4,034,271	23,990	74,008	77,277
2018	60,234	3,592	40,936	20,896	12,973	4,178,277	29,539	89,773	93,365
2019	68,719	3,218	38,543	18,964	13,331	4,127,855	34,957	103,676	106,894

(From Tables 4.2.A. and 4.2.B.) Net Summer Generating Capacity (Megawatts)

Utility Scale Capacity									
Year	Coal	Petroleum	Natural Gas	Other Gas	Nuclear	Hydro Conventional	Hydro Pumped Storage	Geothermal	Wind
2009	314,294.1	56,780.5	401,271.8	1,932.4	101,003.7	78,517.7	22,160.4	2,381.9	34,295.8
2010	316,800.1	55,646.9	407,028.4	2,700.3	101,167.4	78,824.7	22,198.9	2,404.6	39,134.5
2011	317,640.3	51,481.6	415,191.3	1,934.2	101,418.8	78,651.6	22,292.6	2,409.2	45,675.9
2012	309,680.4	47,167.2	422,364.4	1,945.6	101,885.0	78,738.0	22,368.3	2,592.1	59,074.8
2013	303,306.3	43,523.0	425,389.7	2,107.8	99,240.3	79,200.0	22,389.3	2,607.0	59,973.4
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	22,485.1	2,514.3	64,231.5
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	22,575.1	2,541.5	72,573.4
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	22,778.7	2,516.6	81,286.6
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	22,810.4	2,483.3	87,597.5
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	22,830.2	2,444.3	94,417.7
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	22,778.3	2,555.4	103,571.2

Utility Scale Capacity							Small Scale Capacity	Utility and Small Scale Capacity	
Year	Solar Photo-voltaic	Solar Thermal	Wood and Wood-Derived Fuels	Other Biomass	Other Energy Sources	Total Utility Scale Capacity	Estimated Photo-voltaic	Total Photo-voltaic	Total Solar
2009	145.5	473.0	6,939.3	4,316.5	887.8	1,025,400.4	--	145.5	618.5
2010	393.4	473.0	7,037.3	4,368.5	883.8	1,039,061.8	--	393.4	866.4
2011	1,052.0	471.5	7,076.5	4,535.9	1,419.6	1,051,251.0	--	1,052.0	1,523.5
2012	2,694.1	476.0	7,507.6	4,810.6	1,728.9	1,063,033.0	--	2,694.1	3,170.1
2013	5,336.1	1,286.4	8,354.2	5,043.0	2,307.0	1,060,063.5	--	5,336.1	6,622.5
2014	8,656.6	1,666.7	8,368.1	5,166.5	2,792.6	1,068,422.2	7,326.6	15,983.2	17,649.9
2015	11,905.4	1,757.9	8,968.9	5,124.5	1,795.6	1,064,054.5	9,778.5	21,683.9	23,441.8
2016	20,192.9	1,757.9	8,936.1	5,088.8	2,015.1	1,074,332.8	12,765.1	32,958.0	34,715.9

Table 1.2. Summary Statistics for the United States, 2009 - 2019

2017	25,209.0	1,757.9	8,830.9	5,129.5	2,886.3	1,084,369.6	16,147.8	41,356.8	43,114.7
2018	30,120.5	1,757.9	8,694.6	5,038.6	2,346.7	1,094,739.8	19,547.1	49,667.6	51,425.5
2019	35,710.2	1,758.1	8,374.5	4,738.8	2,606.4	1,099,109.3	23,213.6	58,923.8	60,681.9

(From Chapter 5.) Consumption of Fossil Fuels

	For Electricity Generation				For Useful Thermal Output			
Year	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Gas (Millions of BTU)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Gas (Millions of BTU)
2009	934,683	67,668	7,121,069	83,593	20,507	13,161	816,787	175,671
2010	979,684	65,071	7,680,185	90,058	21,727	10,161	821,775	172,081
2011	934,938	52,387	7,883,865	91,290	21,532	9,223	839,681	191,138
2012	825,734	40,977	9,484,710	103,353	19,333	9,828	886,103	199,121
2013	860,729	47,492	8,596,299	115,303	18,350	10,886	882,385	189,902
2014	853,634	53,593	8,544,387	110,010	18,107	9,513	865,146	194,088
2015	739,594	49,145	10,016,576	105,997	16,632	8,864	935,098	183,596
2016	677,371	43,671	10,170,110	73,785	16,586	7,770	1,151,866	221,835
2017	663,911	39,144	9,508,062	70,721	14,667	6,899	1,168,544	227,981
2018	636,213	46,727	10,833,043	78,757	13,813	7,261	1,205,962	274,612
2019	537,620	34,454	11,601,600	71,854	12,397	6,357	1,196,025	209,000

	Total			
Year	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Other Gas (Millions of BTU)
2009	955,190	80,830	7,937,856	259,265
2010	1,001,411	75,231	8,501,960	262,138
2011	956,470	61,610	8,723,546	282,428
2012	845,066	50,805	10,370,812	302,475
2013	879,078	58,378	9,478,685	305,205
2014	871,741	63,106	9,409,532	304,098
2015	756,226	58,009	10,951,674	289,593
2016	693,958	51,441	11,321,975	295,619
2017	678,578	46,043	10,676,606	298,702
2018	650,027	53,988	12,039,005	353,369
2019	550,017	40,811	12,797,626	280,854

(From Tables 6.1. and 7.1)

Year End Stocks, Annual Receipts and Average Costs

	Electric Power Sector Year End Stocks		Annual Receipts at All Electricity Generators			Average Cost of Fuel at All Electricity Generators		
Year	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Coal (Thousand Tons)	Petroleum (Thousand Barrels)	Natural Gas (Millions of Cubic Feet)	Coal (Dollars per MMBtu)	Petroleum (Dollars per MMBtu)	Natural Gas (Dollars per MMBtu)
2009	189,467	45,575	981,477	88,951	8,118,550	2.21	7.02	4.74
2010	174,917	39,936	979,918	75,285	8,673,070	2.27	9.54	5.09
2011	172,387	36,282	956,538	66,058	9,056,164	2.39	12.48	4.72
2012	185,116	33,336	841,183	40,364	9,531,389	2.38	12.48	3.42

Table 1.2. Summary Statistics for the United States, 2009 - 2019

2013	147,884	32,336	823,222	43,714	8,503,424	2.34	11.57	4.33
2014	151,548	36,459	854,560	54,488	8,431,423	2.37	11.60	5.00
2015	195,548	38,396	782,929	48,804	9,842,581	2.22	6.74	3.23
2016	162,009	34,818	650,770	37,637	10,271,180	2.11	5.24	2.87
2017	137,687	32,407	642,364	32,672	9,628,733	2.06	7.10	3.37
2018	102,793	28,674	596,215	37,341	10,885,764	2.06	9.68	3.55
2019	128,176	28,317	560,153	24,556	11,693,486	2.02	9.07	2.89

(From Table 9.1.) Emissions

(Thousand Metric Tons)

Year	Carbon Dioxide (CO ₂)	Sulfur Dioxide (SO ₂)	Nitrogen Oxides (NO _x)
2009	2,269,508	5,970	2,395
2010	2,388,596	5,400	2,491
2011	2,287,071	4,845	2,406
2012	2,156,875	3,704	2,148
2013	2,173,806	3,609	2,163
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,657	1,506
2018	1,874,346	1,571	1,485
2019	1,724,396	1,267	1,342

(From Tables 10.6. and 10.7.) Energy Efficiency

Year	Savings		Incremental Costs		Life Cycle Savings		Life Cycle Costs	
	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)	Energy (MWh)	Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2013	24,653,124	11,078	2,871,654	1,944,597	249,940,645	10,956	6,028,810	3,994,889
2014	26,466,020	6,453	3,410,854	2,209,098	301,956,123	8,040	4,007,452	3,120,898
2015	26,129,489	5,952	3,448,286	2,283,300	296,346,403	7,096	4,255,368	3,710,453
2016	27,500,224	5,658	3,570,950	2,522,854	354,347,692	7,050	4,126,758	3,432,717
2017	29,899,028	6,071	3,664,407	2,297,957	374,826,892	5,951	4,849,803	3,162,995
2018	28,415,037	6,309	3,484,767	2,165,981	359,446,175	6,075	4,177,905	4,179,320
2019	28,562,529	7,135	3,657,477	2,288,028	355,216,512	6,931	4,351,926	3,655,607

(From Tables 10.8. and 10.9.) Demand Response

Year	Yearly Energy and Demand Savings				Program Costs	
	Customers	Energy (MWh)	Potential Peak Demand (MW)	Actual Peak Demand (MW)	Incentives (thousand dollars)	Other (thousand dollars)
2013	9,187,350	1,401,987	27,095	11,883	1,112,782	485,133
2014	9,265,629	1,436,449	31,191	12,683	1,217,796	447,659
2015	9,094,138	1,251,006	32,875	13,036	1,120,446	381,918
2016	9,839,355	1,336,136	35,924	11,841	1,039,890	379,707
2017	9,440,938	1,310,862	31,508	12,248	1,003,124	370,700
2018	9,752,238	1,426,211	30,895	12,522	1,189,284	360,718
2019	10,932,845	1,462,735	31,020	11,334	1,118,882	343,214

Table 1.2. Summary Statistics for the United States, 2009 - 2019

Coal includes anthracite, bituminous, subbituminous and lignite coal. Starting in 2002 waste coal is included in all coal metrics except for year-end stocks. Starting in 2002 Synthetic coal is included in all coal metrics. Starting in 2011 Coal-derived synthesis gas is included in all coal metrics. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum includes Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil. Prior to 2011 propane was in the Other Gas category. Beginning in 2004 small quantities of waste oil were excluded from petroleum stocks.

Natural gas includes a small number of generators for which waste heat is the primary energy source. Natural gas also includes a small amount of supplemental gaseous fuels that cannot be identified separately.

Prior to 2011, synthesis gas derived from petroleum coke was in the Other Gas category. Other Gas includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

Conventional hydroelectric power excludes pumped storage facilities.

Wood and wood derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases). The reported summer capacity for other biomass also includes non-biogenic municipal solid waste.

Pumped storage is the capacity to generate electricity from water previously pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level. The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping.

Other energy sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources, and for generation values, non-biogenic municipal solid waste.

Costs of fuels for 2002 through 2007 include data from the Form EIA-423 for independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Beginning in 2008, data are collected on the Form EIA-923 for utilities, independent power producers, commercial power-producing facilities, and industrial power-producing facilities. Receipts, cost, and quality data are collected from plants above a 50 MW threshold, and imputed for plants between 1 and 50 MW. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data. Receipts of coal include imported coal.

N/A = Not available.

Notes: See Glossary reference for definitions. See Technical Notes Appendix for conversion to different units of measure. Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. Dual-fired capacity returned to respective fuel categories for current and all historical years. New fuel switchable capacity tables have replaced dual-fired breakouts. Totals may not equal sum of components because of independent rounding.

In 2013, EIA revised its approach to estimating imports from Mexico.

Sources: U.S. Energy Information Administration Form EIA-411, 'Coordinated Bulk Power Supply Program Report;' Form EIA-412, 'Annual Electric Industry Financial Report'. The Form EIA-412 was terminated in 2003; Form EIA-767, 'Steam-Electric Plant Operation and Design Report' was suspended; Form EIA-860, 'Annual Electric Generator Report;' Form EIA-861, 'Annual Electric Power Industry Report;' Form EIA-923, 'Power Plant Operations Report' replaces several form(s) including: Form EIA-906, 'Power Plant Report;' Form EIA-920 'Combined Heat and Power Plant Report;' Form EIA-423, 'Monthly Cost and Quality of Fuels for Electric Plants Report;' and FERC Form 423, 'Monthly Report of Cost and Quality of Fuels for Electric Plants,' and their predecessor forms. Federal Energy Regulatory Commission, FERC Form 1, 'Annual Report of Major Utilities, Licensees and Others;' FERC Form 1-F, 'Annual Report for Nonmajor Public Utilities and Licensees;' Rural Utilities Service (RUS) Form 7, 'Operating Report;' RUS Form 12, 'Operating Report;'

Imports and Exports: National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates

Table 1.3. Supply and Disposition of Electricity, 2009 through 2019

(From Chapter 3.) Supply (Thousand Megawatthours)

	Generation						
Year	Electric Utilities	IPP (Non-CHP)	IPP (CHP)	Commercial Sector	Industrial Sector	Total Imports	Total Supply
2009	2,372,776	1,277,916	159,146	8,165	132,329	52,191	4,002,522
2010	2,471,632	1,338,712	162,042	8,592	144,082	45,083	4,170,143
2011	2,460,851	1,331,303	156,032	10,080	141,875	52,300	4,152,441
2012	2,339,172	1,386,991	164,194	11,301	146,107	59,257	4,107,022
2013	2,388,058	1,368,038	147,619	12,234	150,015	68,947	4,134,911
2014	2,382,473	1,404,324	150,205	12,520	144,083	66,510	4,160,116
2015	2,315,323	1,448,799	155,173	12,595	145,712	75,770	4,153,371
2016	2,304,923	1,459,624	153,532	12,706	145,890	72,716	4,149,391
2017	2,274,279	1,464,590	138,584	13,060	143,758	65,685	4,099,955
2018	2,337,250	1,538,235	142,682	13,312	146,798	58,261	4,236,538
2019	2,266,004	1,559,801	139,824	13,689	148,537	59,052	4,186,908

(From Chapter 2.) Disposition (Thousand Megawatthours)

	Retail Sales						
Year	Full-Service Providers	Energy-Only Providers	Facility Direct	Direct Use	Total Exports	Losses and Unaccounted For	Total Disposition
2009	3,289,877	294,229	12,689	126,938	18,138	260,650	4,002,522
2010	3,365,338	379,277	10,226	131,910	19,106	264,285	4,170,143
2011	3,272,622	466,964	10,259	132,754	15,049	254,792	4,152,441
2012	3,172,096	514,290	8,263	137,657	11,996	262,720	4,107,022
2013	3,147,192	559,211	18,465	143,462	11,373	255,208	4,134,911
2014	3,184,841	563,441	16,418	138,574	13,298	243,544	4,160,116
2015	3,191,425	554,944	12,624	141,168	9,100	244,112	4,153,371
2016	3,189,541	560,015	12,905	139,844	6,214	240,871	4,149,391
2017	3,149,973	559,727	13,656	141,114	9,371	226,114	4,099,955
2018	3,260,944	584,077	14,164	144,114	13,804	219,434	4,236,538
2019	3,213,129	583,431	14,591	143,458	20,008	212,291	4,186,908

N/A = Not Available.

Facility Direct Retail Sales typically represent bilateral electric power sales between industrial and commercial generating facilities.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions. Losses and Unaccounted For includes: (1) reporting by utilities and power marketers that represent losses incurred in transmission and distribution, as well as volumes unaccounted for in their own energy balance; and (2) discrepancies among the differing categories upon balancing the table.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-861, "Annual Electric Power Industry Report;" and predecessor forms. Imports and Exports: Mexico data - DOE, Fossil Fuels, Office of Fuels Programs, Form OE-781R, "Annual Report of International Electrical Export/Import Data;" Canada data - National Energy Board of Canada (metered energy firm and interruptible).

Chapter 2

Electricity Sales

Table 2.1. Number of Ultimate Customers Served by Sector, by Provider, 2009 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2009	125,208,829	17,562,235	757,537	704	143,529,305
2010	125,717,935	17,674,338	747,747	239	144,140,259
2011	126,143,072	17,638,062	727,920	92	144,509,146
2012	126,832,343	17,729,029	732,385	83	145,293,840
2013	127,777,153	17,679,562	831,790	75	146,288,580
2014	128,680,416	17,853,995	839,212	79	147,373,702
2015	129,811,718	17,985,690	835,536	78	148,633,022
2016	131,068,760	18,148,353	838,059	86	150,055,258
2017	132,579,747	18,359,427	840,329	86	151,779,589
2018	133,893,321	18,605,393	840,321	83	153,339,118
2019	135,249,616	18,694,240	954,222	83	154,898,161
Full-Service Providers					
2009	122,560,533	16,852,697	736,326	666	140,150,222
2010	121,555,089	16,675,341	718,652	198	138,949,280
2011	120,306,190	16,321,174	682,906	56	137,310,326
2012	118,650,233	16,111,883	681,074	48	135,443,238
2013	116,624,884	15,817,442	780,759	48	133,223,133
2014	117,230,661	15,942,158	789,803	50	133,962,672
2015	119,477,949	16,108,931	787,466	48	136,374,394
2016	120,875,548	16,197,174	788,641	53	137,861,416
2017	121,964,414	16,329,808	789,732	52	139,084,006
2018	122,767,933	16,415,207	794,548	49	139,977,737
2019	122,422,722	16,367,082	904,443	50	139,694,297
Energy-Only Providers					
2009	2,648,296	709,538	21,211	38	3,379,083
2010	4,162,846	998,997	29,095	41	5,190,979
2011	5,836,882	1,316,888	45,014	36	7,198,820
2012	8,182,110	1,617,146	51,311	35	9,850,602
2013	11,152,269	1,862,120	51,031	27	13,065,447
2014	11,449,755	1,911,837	49,409	29	13,411,030
2015	10,333,769	1,876,759	48,070	30	12,258,628
2016	10,193,212	1,951,179	49,418	33	12,193,842
2017	10,615,333	2,029,619	50,597	34	12,695,583
2018	11,125,388	2,190,186	45,773	34	13,361,381
2019	12,826,894	2,327,158	49,779	33	15,203,864

N/A = Not Available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." and Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.2. Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 2009 through 2019 (Megawatthours)

Year	Residential	Commercial	Industrial	Transportation	Total	Direct Use	Total End Use
Total Electric Industry							
2009	1,364,758,153	1,306,852,524	917,416,468	7,767,989	3,596,795,134	126,937,958	3,723,733,092
2010	1,445,708,403	1,330,199,364	971,221,189	7,712,412	3,754,841,368	131,910,249	3,886,751,617
2011	1,422,801,093	1,328,057,439	991,315,564	7,672,084	3,749,846,180	132,754,037	3,882,600,217
2012	1,374,514,708	1,327,101,196	985,713,854	7,320,028	3,694,649,786	137,656,510	3,832,306,296
2013	1,394,812,129	1,337,078,777	985,351,874	7,625,041	3,724,867,821	143,461,937	3,868,329,758
2014	1,407,208,311	1,352,158,263	997,576,138	7,757,555	3,764,700,267	138,573,884	3,903,274,151
2015	1,404,096,499	1,360,751,527	986,507,732	7,636,632	3,758,992,390	141,167,519	3,900,159,909
2016	1,411,058,153	1,367,191,386	976,715,181	7,496,910	3,762,461,630	139,844,397	3,902,306,027
2017	1,378,647,742	1,352,887,694	984,297,945	7,522,593	3,723,355,974	141,114,442	3,864,470,416
2018	1,469,093,059	1,381,754,845	1,000,672,553	7,664,804	3,859,185,261	144,113,808	4,003,299,069
2019	1,440,288,909	1,360,876,555	1,002,352,849	7,632,150	3,811,150,463	143,458,489	3,954,608,952
Full-Service Providers							
2009	1,345,314,362	1,143,473,246	811,314,045	2,464,259	3,302,565,912	N/A	3,302,565,912
2010	1,409,355,244	1,123,328,313	840,439,791	2,440,567	3,375,563,915	N/A	3,375,563,915
2011	1,368,453,770	1,090,292,969	822,404,124	1,730,820	3,282,881,683	N/A	3,282,881,683
2012	1,297,818,441	1,073,346,766	807,805,140	1,389,340	3,180,359,687	N/A	3,180,359,687
2013	1,291,368,071	1,074,915,884	797,769,849	1,603,318	3,165,657,122	N/A	3,165,657,122
2014	1,301,458,851	1,083,806,639	814,206,541	1,787,408	3,201,259,439	N/A	3,201,259,439
2015	1,307,918,081	1,089,268,864	805,111,979	1,749,450	3,204,048,374	N/A	3,204,048,374
2016	1,316,113,416	1,091,957,177	792,712,354	1,663,475	3,202,446,422	N/A	3,202,446,422
2017	1,285,787,376	1,078,679,288	797,505,332	1,656,960	3,163,628,956	N/A	3,163,628,956
2018	1,368,032,531	1,096,773,561	808,613,290	1,688,442	3,275,107,824	N/A	3,275,107,824
2019	1,335,937,347	1,078,046,650	811,871,096	1,864,134	3,227,719,227	N/A	3,227,719,227
Energy-Only Providers							
2009	19,443,791	163,379,278	106,102,423	5,303,730	294,229,222	N/A	294,229,222
2010	36,353,159	206,871,051	130,781,398	5,271,845	379,277,453	N/A	379,277,453
2011	54,347,323	237,764,470	168,911,440	5,941,264	466,964,497	N/A	466,964,497
2012	76,696,267	253,754,430	177,908,714	5,930,688	514,290,099	N/A	514,290,099
2013	103,444,058	262,162,893	187,582,025	6,021,723	559,210,699	N/A	559,210,699
2014	105,749,460	268,351,624	183,369,597	5,970,147	563,440,828	N/A	563,440,828
2015	96,178,418	271,482,663	181,395,753	5,887,182	554,944,016	N/A	554,944,016
2016	94,944,737	275,234,209	184,002,827	5,833,435	560,015,208	N/A	560,015,208
2017	92,860,366	274,208,406	186,792,613	5,865,633	559,727,018	N/A	559,727,018
2018	101,060,528	284,981,284	192,059,263	5,976,362	584,077,437	N/A	584,077,437
2019	104,351,562	282,829,905	190,481,753	5,768,016	583,431,236	N/A	583,431,236

N/A = Not Available.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report.", Form EIA-861S, "Annual Electric Power Industry Report (Short Form)" and Form EIA-923, "Power Plant Operations Report"

Table 2.3. Revenue from Sales of Electricity to Ultimate Customers by Sector, by Provider, 2009 through 2019 (Million Dollars)

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2009	157,044	132,747	62,670	828	353,289
2010	166,778	135,554	65,772	814	368,918
2011	166,714	135,927	67,606	803	371,049
2012	163,280	133,898	65,761	747	363,687
2013	169,131	137,188	67,934	805	375,058
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
Full-Service Providers					
2009	153,741	112,254	53,284	226	319,506
2010	161,221	110,298	54,582	233	326,334
2011	158,788	108,318	54,285	162	321,552
2012	152,817	106,012	52,667	132	311,628
2013	155,203	108,460	54,309	167	318,138
2014	160,637	113,880	57,140	187	331,845
2015	162,857	113,225	54,787	170	331,038
2016	162,395	111,218	52,958	164	326,735
2017	162,762	112,576	54,412	171	329,921
2018	172,556	114,007	55,058	176	341,797
2019	169,867	112,036	54,782	190	336,876
Competitive Service Providers					
2009	3,302	20,493	9,386	602	33,783
2010	5,557	25,256	11,190	581	42,584
2011	7,926	27,609	13,321	641	49,497
2012	10,464	27,886	13,094	615	52,059
2013	13,928	28,729	13,625	638	56,919
2014	15,541	31,373	13,715	623	61,251
2015	14,767	31,557	13,379	601	60,303
2016	14,682	31,425	13,110	557	59,774
2017	14,899	31,666	13,279	557	60,402
2018	16,477	33,418	14,161	567	64,623
2019	17,569	33,244	13,502	547	64,863
Energy-Only Providers					
2009	1,889	14,045	7,369	460	23,763
2010	3,226	16,994	8,664	424	29,308
2011	4,578	18,086	10,392	463	33,519
2012	5,776	17,397	9,895	432	33,500
2013	7,755	17,876	10,330	451	36,412
2014	9,079	19,948	10,813	436	40,277
2015	8,428	19,657	10,298	407	38,791
2016	7,947	18,850	9,896	360	37,053
2017	7,666	18,368	9,829	363	36,227
2018	8,438	19,279	10,424	378	38,518
2019	8,718	18,436	9,738	360	37,253
Delivery-Only Providers					
2009	1,413	6,448	2,017	143	10,021
2010	2,330	8,262	2,526	157	13,276
2011	3,348	9,523	2,929	178	15,978
2012	4,687	10,489	3,199	183	18,559
2013	6,172	10,853	3,295	187	20,507
2014	6,462	11,425	2,901	187	20,975
2015	6,339	11,900	3,081	193	21,512
2016	6,735	12,575	3,213	197	22,720
2017	7,232	13,298	3,450	194	24,174
2018	8,039	14,139	3,737	190	26,105
2019	8,850	14,809	3,764	187	27,610

N/A = Not Available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Table 2.4. Average Price of Electricity to Ultimate Customers

by End-Use Sectors 2009 through 2019 (Cents per kilowatthour)

Year	Residential	Commercial	Industrial	Transportation	Total
Total Electric Industry					
2009	11.51	10.16	6.83	10.66	9.82
2010	11.54	10.19	6.77	10.56	9.83
2011	11.72	10.24	6.82	10.46	9.90
2012	11.88	10.09	6.67	10.21	9.84
2013	12.13	10.26	6.89	10.55	10.07
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
Full-Service Providers					
2009	11.43	9.82	6.57	9.17	9.67
2010	11.44	9.82	6.49	9.55	9.67
2011	11.60	9.93	6.60	9.35	9.79
2012	11.77	9.88	6.52	9.50	9.80
2013	12.02	10.09	6.81	10.40	10.05
2014	12.34	10.51	7.02	10.49	10.37
2015	12.45	10.39	6.80	9.71	10.33
2016	12.34	10.19	6.68	9.87	10.20
2017	12.66	10.44	6.82	10.32	10.43
2018	12.61	10.39	6.81	10.44	10.44
2019	12.72	10.39	6.75	10.20	10.44
Competitive Service Providers					
2009	16.98	12.54	8.85	11.36	11.48
2010	15.29	12.21	8.56	11.03	11.23
2011	14.58	11.61	7.89	10.79	10.60
2012	13.64	10.99	7.36	10.38	10.12
2013	13.46	10.96	7.26	10.60	10.18
2014	14.70	11.69	7.48	10.44	10.87
2015	15.35	11.62	7.38	10.20	10.87
2016	15.46	11.42	7.12	9.56	10.67
2017	16.04	11.55	7.11	9.50	10.79
2018	16.30	11.73	7.37	9.49	11.06
2019	16.84	11.75	7.09	9.49	11.12
Energy-Only Providers					
2009	9.72	8.60	6.94	8.67	8.08
2010	8.88	8.21	6.62	8.05	7.73
2011	8.42	7.61	6.15	7.80	7.18
2012	7.53	6.86	5.56	7.29	6.51
2013	7.50	6.82	5.51	7.49	6.51
2014	8.59	7.43	5.90	7.31	7.15
2015	8.76	7.24	5.68	6.92	6.99
2016	8.37	6.85	5.38	6.17	6.62
2017	8.26	6.70	5.26	6.19	6.47
2018	8.35	6.77	5.43	6.32	6.59
2019	8.35	6.52	5.11	6.25	6.39
Delivery-Only Providers					
2009	7.27	3.95	1.90	2.69	3.41
2010	6.41	3.99	1.93	2.98	3.50
2011	6.16	4.01	1.73	2.99	3.42
2012	6.11	4.13	1.80	3.09	3.61
2013	5.97	4.14	1.76	3.11	3.67
2014	6.11	4.26	1.58	3.12	3.72
2015	6.59	4.38	1.70	3.28	3.88
2016	7.09	4.57	1.75	3.38	4.06
2017	7.79	4.85	1.85	3.31	4.32
2018	7.95	4.96	1.95	3.17	4.47
2019	8.48	5.24	1.98	3.24	4.73

N/A = Not Available.

Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas (ERCOT), all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so they are included under "Full-Service Providers".

Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers may purchase electricity from others (such as Independent Power Producers or other Full-Service Providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full-Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Competitive Service Providers represent the sum of Energy-Only and Delivery-Only Services."

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

**Table 2.5. Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2009 - December 2019 (Thousand Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	1,364,758	1,306,853	917,416	7,768	3,596,795
2010	1,445,708	1,330,199	971,221	7,712	3,754,841
2011	1,422,801	1,328,057	991,316	7,672	3,749,846
2012	1,374,515	1,327,101	985,714	7,320	3,694,650
2013	1,394,812	1,337,079	985,352	7,625	3,724,868
2014	1,407,208	1,352,158	997,576	7,758	3,764,700
2015	1,404,096	1,360,752	986,508	7,637	3,758,992
2016	1,411,058	1,367,191	976,715	7,497	3,762,462
2017	1,378,648	1,352,888	984,298	7,523	3,723,356
2018	1,469,093	1,381,755	1,000,673	7,665	3,859,185
2019	1,440,289	1,360,877	1,002,353	7,632	3,811,150
Year 2017					
January	129,212	109,488	78,809	667	318,177
February	100,968	99,640	74,534	635	275,777
March	103,096	107,173	80,530	645	291,444
April	90,725	102,589	78,899	589	272,801
May	98,281	109,872	83,134	583	291,871
June	122,543	120,013	85,399	628	328,583
July	149,900	129,277	87,806	630	367,613
August	142,007	128,481	89,134	640	360,263
September	118,779	118,789	83,540	618	321,726
October	102,811	113,287	82,815	626	299,539
November	98,321	104,973	79,456	598	283,347
December	122,005	109,306	80,242	664	312,216
Year 2018					
January	148,917	114,925	79,890	745	344,478
February	113,751	102,685	75,661	634	292,732
March	107,218	108,108	81,053	620	296,999
April	95,454	103,331	79,083	599	278,468
May	103,848	113,175	85,638	587	303,248
June	129,913	122,011	85,536	623	338,083
July	153,566	131,522	89,301	634	375,023
August	153,496	134,848	92,106	680	381,131
September	128,910	122,033	85,679	640	337,263
October	107,049	116,133	85,301	631	309,114
November	103,790	104,983	81,118	616	290,507
December	123,180	107,998	80,306	655	312,140
Year 2019					
January	133,318	112,012	82,610	670	328,609
February	116,608	102,071	76,447	672	295,798
March	112,605	107,468	81,093	686	301,853
April	90,384	102,446	80,460	610	273,900
May	100,331	111,201	84,661	608	296,802
June	120,116	115,745	84,992	608	321,462
July	153,749	130,951	90,752	642	376,095
August	150,083	130,776	91,062	653	372,574
September	131,567	122,059	86,160	677	340,463
October	107,997	115,305	84,396	543	308,241
November	102,453	102,840	79,625	614	285,532
December	121,078	108,001	80,095	648	309,823

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.6. Revenue from Sales of Electricity to Ultimate Customers:
Total by End-Use Sector, 2009 - December 2019 (Million Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	157,044	132,747	62,670	828	353,289
2010	166,778	135,554	65,772	814	368,918
2011	166,714	135,927	67,606	803	371,049
2012	163,280	133,898	65,761	747	363,687
2013	169,131	137,188	67,934	805	375,058
2014	176,178	145,253	70,855	810	393,096
2015	177,624	144,781	68,166	771	391,341
2016	177,077	142,643	66,068	722	386,509
2017	177,661	144,242	67,691	728	390,322
2018	189,033	147,425	69,218	744	406,420
2019	187,436	145,280	68,285	737	401,738
Year 2017					
January	15,781	11,183	5,190	63	32,216
February	12,911	10,442	4,941	60	28,354
March	13,289	11,208	5,407	61	29,965
April	11,536	10,669	5,209	56	27,470
May	12,843	11,638	5,639	56	30,176
June	16,171	13,209	6,141	64	35,585
July	19,606	14,184	6,416	64	40,269
August	18,679	14,141	6,435	64	39,320
September	15,772	13,104	5,992	62	34,930
October	13,164	12,208	5,725	60	31,157
November	12,721	11,016	5,345	57	29,139
December	15,189	11,239	5,249	62	31,739
Year 2018					
January	18,193	12,053	5,543	70	35,859
February	14,364	10,936	5,128	62	30,490
March	13,905	11,365	5,373	58	30,701
April	12,290	10,806	5,194	57	28,347
May	13,625	11,890	5,819	55	31,388
June	16,922	13,223	6,136	64	36,344
July	20,156	14,466	6,540	64	41,226
August	20,351	14,874	6,673	65	41,963
September	16,775	13,085	6,038	64	35,962
October	13,751	12,506	5,864	62	32,182
November	13,389	11,069	5,557	60	30,074
December	15,311	11,155	5,353	64	31,883
Year 2019					
January	16,620	11,541	5,433	66	33,660
February	14,831	10,761	5,116	67	30,775
March	14,457	11,238	5,454	63	31,212
April	11,976	10,777	5,239	58	28,050
May	13,356	11,725	5,667	58	30,805
June	16,005	12,618	5,843	61	34,526
July	20,382	14,433	6,476	63	41,354
August	19,955	14,407	6,739	63	41,164
September	17,317	13,379	6,085	66	36,847
October	13,837	12,380	5,770	53	32,039
November	13,346	10,874	5,350	58	29,629
December	15,354	11,146	5,112	61	31,674

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-826. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Sales and net generation may not correspond exactly for a particular month for a variety of reasons (i.e., sales data may include purchases of electricity from nonutilities or imported electricity). Net generation is for the calendar month while sales and associated revenue accumulate from bills collected for periods of time (28 to 35 days) that vary dependent upon customer class and consumption occurring in and outside the calendar month.

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

**Table 2.7. Average Price of Electricity to Ultimate Customers:
Total by End-Use Sector, 2009 - December 2019 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	11.51	10.16	6.83	10.66	9.82
2010	11.54	10.19	6.77	10.56	9.83
2011	11.72	10.24	6.82	10.46	9.90
2012	11.88	10.09	6.67	10.21	9.84
2013	12.13	10.26	6.89	10.55	10.07
2014	12.52	10.74	7.10	10.45	10.44
2015	12.65	10.64	6.91	10.09	10.41
2016	12.55	10.43	6.76	9.63	10.27
2017	12.89	10.66	6.88	9.68	10.48
2018	12.87	10.67	6.92	9.70	10.53
2019	13.01	10.68	6.81	9.66	10.54
Year 2017					
January	12.21	10.21	6.59	9.39	10.13
February	12.79	10.48	6.63	9.50	10.28
March	12.89	10.46	6.71	9.49	10.28
April	12.72	10.40	6.60	9.46	10.07
May	13.07	10.59	6.78	9.61	10.34
June	13.20	11.01	7.19	10.18	10.83
July	13.08	10.97	7.31	10.12	10.95
August	13.15	11.01	7.22	10.06	10.91
September	13.28	11.03	7.17	9.99	10.86
October	12.80	10.78	6.91	9.57	10.40
November	12.94	10.49	6.73	9.50	10.28
December	12.45	10.28	6.54	9.35	10.17
Year 2018					
January	12.22	10.49	6.94	9.39	10.41
February	12.63	10.65	6.78	9.78	10.42
March	12.97	10.51	6.63	9.40	10.34
April	12.88	10.46	6.57	9.47	10.18
May	13.12	10.51	6.79	9.39	10.35
June	13.03	10.84	7.17	10.23	10.75
July	13.13	11.00	7.32	10.05	10.99
August	13.26	11.03	7.25	9.50	11.01
September	13.01	10.72	7.05	10.05	10.66
October	12.85	10.77	6.87	9.79	10.41
November	12.90	10.54	6.85	9.70	10.35
December	12.43	10.33	6.67	9.71	10.21
Year 2019					
January	12.47	10.30	6.58	9.83	10.24
February	12.72	10.54	6.69	10.02	10.40
March	12.84	10.46	6.73	9.25	10.34
April	13.25	10.52	6.51	9.45	10.24
May	13.31	10.54	6.69	9.46	10.38
June	13.32	10.90	6.87	10.01	10.74
July	13.26	11.02	7.14	9.82	11.00
August	13.30	11.02	7.40	9.65	11.05
September	13.16	10.96	7.06	9.78	10.82
October	12.81	10.74	6.84	9.72	10.39
November	13.03	10.57	6.72	9.52	10.38
December	12.68	10.32	6.38	9.46	10.22

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors. NA = Not available. See Glossary for definitions.

Geographic coverage is the 50 States and the District of Columbia. Values include energy service provider (power marketer) data.

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Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.

Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;

Form EIA-861, Annual Electric Power Industry Report; and Form EIA-861S, Annual Electric Power Industry Report (Short Form).

Table 2.8. Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	46,173	48,099	51,503	52,924	16,234	17,054	547	557	114,458	118,634
Connecticut	12,494	13,061	12,158	12,381	3,072	3,210	177	181	27,900	28,834
Maine	4,794	4,872	4,148	4,447	2,790	3,036	0	0	11,732	12,355
Massachusetts	19,315	20,285	25,337	25,952	6,342	6,699	343	349	51,337	53,285
New Hampshire	4,507	4,641	4,281	4,443	1,924	1,963	0	0	10,712	11,046
Rhode Island	2,983	3,124	3,644	3,698	695	735	27	27	7,350	7,583
Vermont	2,082	2,116	1,934	2,004	1,412	1,411	0	0	5,428	5,531
Middle Atlantic	133,150	137,580	153,246	158,774	74,961	74,601	3,740	3,968	365,097	374,923
New Jersey	28,613	29,531	38,013	38,807	6,990	7,369	301	310	73,917	76,017
New York	50,141	52,153	75,091	76,745	17,548	18,077	2,820	2,954	145,600	149,930
Pennsylvania	54,396	55,896	40,143	43,222	50,423	49,155	619	703	145,580	148,977
East North Central	186,187	193,825	180,212	185,278	192,318	195,875	636	615	559,352	575,593
Illinois	45,220	47,226	49,279	50,763	43,250	44,115	570	551	138,319	142,655
Indiana	33,249	34,575	23,518	24,305	45,317	45,293	21	21	102,104	104,194
Michigan	33,496	35,131	37,861	38,925	29,886	30,806	6	7	101,249	104,869
Ohio	52,226	54,452	46,009	47,192	50,249	51,236	38	36	148,522	152,915
Wisconsin	21,995	22,441	23,546	24,093	23,615	24,425	1	0	69,158	70,960
West North Central	106,595	109,892	102,643	104,457	93,550	94,080	49	49	302,838	308,478
Iowa	14,495	14,840	12,310	12,418	24,239	23,953	0	0	51,043	51,211
Kansas	13,631	14,187	15,916	16,169	11,613	11,681	0	0	41,160	42,037
Minnesota	22,288	22,837	22,904	23,399	21,748	22,447	25	26	66,966	68,708
Missouri	35,691	37,463	30,133	31,179	13,010	13,390	24	24	78,858	82,056
Nebraska	10,308	10,412	9,457	9,553	10,619	10,974	0	0	30,383	30,939
North Dakota	5,125	5,133	7,035	6,836	9,399	8,700	0	0	21,559	20,670
South Dakota	5,057	5,018	4,888	4,903	2,924	2,935	0	0	12,869	12,857
South Atlantic	370,430	374,135	318,135	317,277	141,243	142,648	1,383	1,331	831,191	835,391
Delaware	5,004	5,070	4,421	4,342	2,044	2,361	0	0	11,469	11,773
District of Columbia	2,547	2,592	7,952	8,236	180	193	350	337	11,028	11,358
Florida	127,182	125,528	96,567	96,265	16,514	16,689	85	83	240,348	238,565
Georgia	59,331	59,689	47,412	47,312	32,393	32,696	164	170	139,301	139,866
Maryland	27,534	28,138	28,893	29,548	3,718	3,870	575	530	60,721	62,086
North Carolina	59,853	61,622	49,173	49,298	27,391	27,354	19	13	136,436	138,287
South Carolina	31,160	31,852	22,168	22,233	26,877	27,556	0	0	80,206	81,641
Virginia	46,666	47,963	53,981	52,268	17,598	17,737	190	199	118,435	118,166
West Virginia	11,153	11,679	7,567	7,774	14,527	14,193	0	0	33,247	33,647
East South Central	120,280	124,486	93,078	94,924	98,863	100,783	0	0	312,221	320,192
Alabama	32,416	33,080	23,076	23,483	32,603	33,717	0	0	88,095	90,280
Kentucky	26,573	27,713	19,612	19,980	29,161	28,917	0	0	75,345	76,611
Mississippi	18,718	19,311	14,239	14,530	15,994	16,549	0	0	48,951	50,390
Tennessee	42,573	44,382	36,151	36,930	21,105	21,599	0	0	99,829	102,911
West South Central	229,006	232,709	198,321	201,723	207,836	198,150	199	201	635,361	632,783
Arkansas	18,732	19,259	11,949	12,278	17,412	18,065	0	0	48,093	49,603
Louisiana	30,986	32,066	24,284	24,691	37,846	37,417	12	13	93,129	94,186
Oklahoma	23,806	24,117	20,086	21,229	20,904	19,229	0	0	64,796	64,575
Texas	155,481	157,268	142,002	143,525	131,674	123,439	187	187	429,343	424,419
Mountain	100,458	100,312	98,070	99,065	84,813	83,788	185	161	283,525	283,325
Arizona	34,720	34,660	29,415	29,684	13,783	13,994	11	8	77,929	78,346
Colorado	19,405	19,287	21,111	21,023	15,891	16,047	114	93	56,521	56,450
Idaho	8,697	8,428	6,441	6,437	8,847	8,889	0	0	23,985	23,754
Montana	5,308	5,198	4,956	4,921	5,057	4,720	0	0	15,321	14,839
Nevada	12,868	13,450	11,681	12,124	12,426	12,198	8	8	36,982	37,780
New Mexico	6,872	6,826	9,029	9,035	8,980	8,187	0	0	24,880	24,049
Utah	9,740	9,715	11,860	12,084	9,491	9,393	52	51	31,143	31,242
Wyoming	2,849	2,748	3,575	3,757	10,339	10,359	0	0	16,763	16,865
Pacific Contiguous	143,323	143,370	159,972	161,653	87,648	88,750	893	783	391,836	394,556
California	87,524	89,100	114,279	115,786	47,808	49,588	768	750	250,379	255,224
Oregon	19,286	18,931	16,423	16,470	14,668	13,899	27	26	50,404	49,326
Washington	36,512	35,339	29,270	29,396	25,172	25,263	99	7	91,053	90,006
Pacific Noncontiguous	4,688	4,686	5,697	5,679	4,887	4,945	0	0	15,272	15,310
Alaska	1,928	1,975	2,639	2,646	1,252	1,352	0	0	5,819	5,972
Hawaii	2,760	2,711	3,058	3,033	3,635	3,593	0	0	9,453	9,337
U.S. Total	1,440,289	1,469,093	1,360,877	1,381,755	1,002,353	1,000,673	7,632	7,665	3,811,150	3,859,185

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

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Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 2.9. Revenue from Sales of Electricity to Ultimate Customers by End-Use Sector, by State, 2019 and 2018 (Million Dollars)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	9,744	9,910	8,412	8,709	2,122	2,249	50	50	20,328	20,918
Connecticut	2,733	2,769	2,036	2,075	413	442	24	23	5,206	5,309
Maine	858	821	532	556	257	283	0	0	1,647	1,660
Massachusetts	4,233	4,383	4,255	4,457	936	998	21	22	9,445	9,860
New Hampshire	904	914	682	703	252	263	0	0	1,838	1,880
Rhode Island	648	642	597	613	108	113	5	5	1,359	1,373
Vermont	369	381	309	305	156	150	0	0	834	837
Middle Atlantic	21,039	21,974	18,705	19,729	4,925	5,191	418	441	45,088	47,336
New Jersey	4,535	4,550	4,651	4,737	710	742	27	28	9,922	10,057
New York	8,995	9,659	10,557	11,128	985	1,088	346	359	20,884	22,233
Pennsylvania	7,509	7,765	3,498	3,864	3,230	3,362	45	55	14,282	15,045
East North Central	24,929	25,681	18,378	18,887	13,290	13,912	45	43	56,642	58,523
Illinois	5,891	6,029	4,476	4,631	2,822	2,999	39	37	13,228	13,696
Indiana	4,183	4,240	2,594	2,576	3,335	3,343	2	2	10,114	10,161
Michigan	5,273	5,427	4,313	4,339	2,114	2,187	1	1	11,701	11,954
Ohio	6,464	6,840	4,470	4,769	3,292	3,592	3	3	14,229	15,203
Wisconsin	3,118	3,146	2,525	2,571	1,727	1,791	0	0	7,370	7,508
West North Central	12,643	13,184	9,911	10,223	6,802	6,845	4	4	29,360	30,256
Iowa	1,806	1,817	1,230	1,203	1,600	1,546	0	0	4,636	4,566
Kansas	1,733	1,894	1,638	1,723	853	887	0	0	4,224	4,505
Minnesota	2,907	3,001	2,369	2,429	1,637	1,689	2	2	6,915	7,122
Missouri	3,976	4,249	2,734	2,931	925	966	2	2	7,636	8,148
Nebraska	1,110	1,114	837	843	813	834	0	0	2,759	2,792
North Dakota	528	526	634	622	747	694	0	0	1,908	1,842
South Dakota	584	582	469	472	228	228	0	0	1,281	1,282
South Atlantic	44,201	43,771	29,764	29,507	9,175	9,299	109	105	83,250	82,683
Delaware	628	635	421	419	157	188	0	0	1,207	1,242
District of Columbia	331	333	975	986	15	16	33	32	1,354	1,367
Florida	14,883	14,485	8,950	8,845	1,263	1,276	7	7	25,103	24,614
Georgia	6,979	6,847	4,752	4,633	1,999	1,963	10	9	13,740	13,453
Maryland	3,611	3,742	2,880	3,083	290	318	42	39	6,823	7,182
North Carolina	6,834	6,835	4,331	4,229	1,727	1,732	2	1	12,893	12,797
South Carolina	4,048	3,963	2,345	2,248	1,643	1,681	0	0	8,036	7,891
Virginia	5,632	5,624	4,417	4,347	1,206	1,217	16	16	11,271	11,204
West Virginia	1,255	1,306	693	719	875	908	0	0	2,823	2,933
East South Central	13,668	13,862	9,997	9,983	5,699	5,891	0	0	29,364	29,736
Alabama	4,061	4,028	2,658	2,639	1,940	2,028	0	0	8,659	8,694
Kentucky	2,869	2,936	1,991	1,946	1,624	1,643	0	0	6,484	6,525
Mississippi	2,109	2,147	1,498	1,516	936	993	0	0	4,543	4,655
Tennessee	4,629	4,752	3,851	3,882	1,198	1,228	0	0	9,678	9,861
West South Central	25,587	25,056	16,257	16,564	11,277	10,703	13	16	53,134	52,340
Arkansas	1,835	1,889	1,050	951	1,068	1,019	0	0	3,952	3,859
Louisiana	3,035	3,074	2,164	2,185	1,979	2,003	1	1	7,179	7,263
Oklahoma	2,430	2,484	1,603	1,713	1,059	1,027	0	0	5,092	5,224
Texas	18,287	17,610	11,440	11,715	7,171	6,654	12	15	36,910	35,994
Mountain	11,866	11,974	9,373	9,470	5,372	5,407	17	15	26,629	26,866
Arizona	4,317	4,425	3,014	3,158	865	916	1	1	8,197	8,501
Colorado	2,363	2,343	2,203	2,106	1,175	1,199	10	8	5,750	5,655
Idaho	860	855	494	511	538	575	0	0	1,892	1,941
Montana	591	570	516	497	276	245	0	0	1,382	1,312
Nevada	1,545	1,593	939	939	763	744	1	1	3,247	3,277
New Mexico	860	866	884	905	492	478	0	0	2,236	2,250
Utah	1,013	1,011	979	994	567	554	5	5	2,565	2,565
Wyoming	318	310	345	360	695	695	0	0	1,358	1,365
Pacific Contiguous	22,432	22,308	23,067	22,954	8,474	8,552	80	68	54,053	53,882
California	16,764	16,782	19,052	18,924	6,406	6,546	68	65	42,290	42,318
Oregon	2,124	2,079	1,453	1,468	859	814	2	2	4,438	4,364
Washington	3,545	3,446	2,561	2,562	1,209	1,191	9	1	7,325	7,200
Pacific Noncontiguous	1,327	1,313	1,416	1,398	1,148	1,169	0	0	3,891	3,881
Alaska	442	433	522	492	212	231	0	0	1,176	1,156
Hawaii	885	880	894	907	936	938	0	0	2,715	2,725
U.S. Total	187,436	189,033	145,280	147,425	68,285	69,218	737	744	401,738	406,420

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

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Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 2.10. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, 2019 and 2018 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	21.10	20.60	16.33	16.46	13.07	13.19	9.20	9.00	17.76	17.63
Connecticut	21.87	21.20	16.75	16.76	13.44	13.77	13.69	12.84	18.66	18.41
Maine	17.89	16.84	12.83	12.51	9.22	9.32	--	--	14.04	13.44
Massachusetts	21.92	21.61	16.80	17.17	14.76	14.89	6.15	6.38	18.40	18.50
New Hampshire	20.05	19.69	15.93	15.81	13.09	13.42	--	--	17.15	17.01
Rhode Island	21.73	20.55	16.38	16.58	15.59	15.39	18.49	17.00	18.49	18.10
Vermont	17.71	18.02	15.98	15.24	11.05	10.66	--	--	15.36	15.13
Middle Atlantic	15.80	15.97	12.21	12.43	6.57	6.96	11.17	11.13	12.35	12.63
New Jersey	15.85	15.41	12.23	12.21	10.16	10.07	8.80	9.07	13.42	13.23
New York	17.94	18.52	14.06	14.50	5.61	6.02	12.28	12.14	14.34	14.83
Pennsylvania	13.80	13.89	8.71	8.94	6.41	6.84	7.26	7.78	9.81	10.10
East North Central	13.39	13.25	10.20	10.19	6.91	7.10	7.08	6.96	10.13	10.17
Illinois	13.03	12.77	9.08	9.12	6.52	6.80	6.91	6.75	9.56	9.60
Indiana	12.58	12.26	11.03	10.60	7.36	7.38	10.76	10.44	9.91	9.75
Michigan	15.74	15.45	11.39	11.15	7.07	7.10	10.56	10.76	11.56	11.40
Ohio	12.38	12.56	9.72	10.11	6.55	7.01	6.83	7.33	9.58	9.94
Wisconsin	14.18	14.02	10.72	10.67	7.31	7.33	13.85	13.85	10.66	10.58
West North Central	11.86	12.00	9.66	9.79	7.27	7.28	8.72	9.07	9.69	9.81
Iowa	12.46	12.24	9.99	9.68	6.60	6.45	--	--	9.08	8.92
Kansas	12.71	13.35	10.29	10.66	7.35	7.60	--	--	10.26	10.72
Minnesota	13.04	13.14	10.34	10.38	7.53	7.52	9.49	9.58	10.33	10.37
Missouri	11.14	11.34	9.07	9.40	7.11	7.22	7.89	8.52	9.68	9.93
Nebraska	10.77	10.70	8.85	8.83	7.65	7.60	--	--	9.08	9.02
North Dakota	10.30	10.25	9.01	9.10	7.94	7.98	--	--	8.85	8.91
South Dakota	11.55	11.59	9.59	9.62	7.81	7.77	--	--	9.96	9.97
South Atlantic	11.93	11.70	9.36	9.30	6.50	6.52	7.92	7.91	10.02	9.90
Delaware	12.55	12.53	9.53	9.65	7.70	7.95	--	--	10.52	10.55
District of Columbia	12.98	12.84	12.26	11.97	8.22	8.30	9.50	9.54	12.27	12.03
Florida	11.70	11.54	9.27	9.19	7.65	7.65	8.32	8.26	10.44	10.32
Georgia	11.76	11.47	10.02	9.79	6.17	6.00	5.85	5.52	9.86	9.62
Maryland	13.12	13.30	9.97	10.43	7.80	8.23	7.37	7.44	11.24	11.57
North Carolina	11.42	11.09	8.81	8.58	6.30	6.33	8.20	8.02	9.45	9.25
South Carolina	12.99	12.44	10.58	10.11	6.11	6.10	--	--	10.02	9.67
Virginia	12.07	11.73	8.18	8.32	6.85	6.86	8.27	8.28	9.52	9.48
West Virginia	11.25	11.18	9.16	9.24	6.02	6.40	--	--	8.49	8.72
East South Central	11.36	11.14	10.74	10.52	5.76	5.85	--	--	9.40	9.29
Alabama	12.53	12.18	11.52	11.24	5.95	6.01	--	--	9.83	9.63
Kentucky	10.80	10.60	10.15	9.74	5.57	5.68	--	--	8.61	8.52
Mississippi	11.27	11.12	10.52	10.43	5.85	6.00	--	--	9.28	9.24
Tennessee	10.87	10.71	10.65	10.51	5.68	5.68	--	--	9.69	9.58
West South Central	11.17	10.77	8.20	8.21	5.43	5.40	6.61	8.16	8.36	8.27
Arkansas	9.80	9.81	8.78	7.75	6.13	5.64	11.73	11.35	8.22	7.78
Louisiana	9.80	9.59	8.91	8.85	5.23	5.35	9.08	9.21	7.71	7.71
Oklahoma	10.21	10.30	7.98	8.07	5.07	5.34	--	--	7.86	8.09
Texas	11.76	11.20	8.06	8.16	5.45	5.39	6.44	8.08	8.60	8.48
Mountain	11.81	11.94	9.56	9.56	6.33	6.45	9.29	9.53	9.39	9.48
Arizona	12.43	12.77	10.25	10.64	6.28	6.55	9.68	10.02	10.52	10.85
Colorado	12.18	12.15	10.43	10.02	7.40	7.47	8.70	9.00	10.17	10.02
Idaho	9.89	10.15	7.67	7.93	6.08	6.47	--	--	7.89	8.17
Montana	11.13	10.96	10.41	10.11	5.45	5.19	--	--	9.02	8.84
Nevada	12.00	11.85	8.04	7.74	6.14	6.10	8.51	8.31	8.78	8.67
New Mexico	12.51	12.68	9.79	10.02	5.48	5.84	--	--	8.99	9.35
Utah	10.40	10.41	8.26	8.23	5.98	5.90	10.62	10.59	8.24	8.21
Wyoming	11.18	11.29	9.64	9.58	6.73	6.71	--	--	8.10	8.09
Pacific Contiguous	15.65	15.56	14.42	14.20	9.67	9.64	8.98	8.67	13.79	13.66
California	19.15	18.84	16.67	16.34	13.40	13.20	8.91	8.64	16.89	16.58
Oregon	11.01	10.98	8.85	8.91	5.86	5.86	9.14	9.16	8.81	8.85
Washington	9.71	9.75	8.75	8.72	4.80	4.71	9.45	9.38	8.04	8.00
Pacific Noncontiguous	28.30	28.03	24.86	24.62	23.50	23.64	--	--	25.48	25.35
Alaska	22.92	21.94	19.80	18.58	16.94	17.10	--	--	20.22	19.36
Hawaii	32.06	32.47	29.23	29.90	25.76	26.10	--	--	28.72	29.18
U.S. Total	13.01	12.87	10.68	10.67	6.81	6.92	9.66	9.70	10.54	10.53

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values are final.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.

Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

Table 2.11. Number of Ultimate Customers by Sector
by State, 2018 and 2019

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	6,411,587	6,377,606	889,951	883,832	23,310	23,028	6	7	7,324,854	7,284,473
Connecticut	1,510,966	1,503,701	151,979	153,824	4,204	4,308	3	4	1,667,152	1,661,837
Maine	710,869	709,848	99,738	96,066	2,893	3,064	--	--	813,500	808,978
Massachusetts	2,802,099	2,784,243	410,995	408,972	11,020	10,503	2	2	3,224,116	3,203,720
New Hampshire	627,257	622,671	108,247	107,805	3,193	3,176	--	--	738,697	733,652
Rhode Island	444,216	442,005	60,672	60,128	1,758	1,773	1	1	506,647	503,907
Vermont	316,180	315,138	58,320	57,037	242	204	--	--	374,742	372,379
Middle Atlantic	16,251,104	16,149,378	2,361,895	2,345,015	33,176	30,504	21	20	18,646,196	18,524,917
New Jersey	3,596,834	3,568,044	523,796	521,429	11,781	11,877	7	6	4,132,418	4,101,356
New York	7,235,400	7,190,906	1,121,107	1,106,650	7,607	6,884	8	8	8,364,122	8,304,448
Pennsylvania	5,418,870	5,390,428	716,992	716,936	13,788	11,743	6	6	6,149,656	6,119,113
East North Central	20,287,076	20,183,560	2,515,638	2,498,950	55,588	53,956	10	9	22,858,312	22,736,475
Illinois	5,314,522	5,289,573	622,802	616,192	5,737	5,717	3	3	5,943,064	5,911,485
Indiana	2,887,031	2,863,358	358,791	354,730	18,805	17,763	1	1	3,264,628	3,235,852
Michigan	4,384,305	4,365,529	544,690	543,261	5,726	5,972	2	2	4,934,723	4,914,764
Ohio	4,980,931	4,964,855	632,794	630,210	19,798	18,715	2	2	5,633,525	5,613,782
Wisconsin	2,720,287	2,700,245	356,561	354,557	5,522	5,789	2	1	3,082,372	3,060,592
West North Central	9,570,282	9,497,228	1,465,470	1,455,145	126,985	124,102	3	3	11,162,740	11,076,478
Iowa	1,392,979	1,385,756	241,734	239,703	8,565	7,890	--	--	1,643,278	1,633,349
Kansas	1,274,955	1,266,044	235,236	234,091	24,230	24,185	--	--	1,534,421	1,524,320
Minnesota	2,446,111	2,420,325	299,995	295,855	8,998	9,066	1	1	2,755,105	2,725,247
Missouri	2,811,863	2,792,459	384,787	384,493	10,096	8,085	2	2	3,206,748	3,185,039
Nebraska	855,619	849,898	153,814	153,749	62,204	61,968	--	--	1,071,637	1,065,615
North Dakota	385,038	382,596	76,355	75,148	8,803	8,985	--	--	470,196	466,729
South Dakota	403,717	400,150	73,549	72,106	4,089	3,923	--	--	481,355	476,179
South Atlantic	28,325,448	27,947,855	3,835,185	3,788,481	85,778	83,599	13	13	32,246,424	31,819,948
Delaware	439,167	432,449	55,802	54,904	865	837	--	--	495,834	488,190
District of Columbia	282,277	274,613	26,471	26,336	1	1	3	3	308,752	300,953
Florida	9,565,846	9,423,022	1,240,902	1,229,559	23,579	21,327	2	2	10,830,329	10,673,910
Georgia	4,411,521	4,354,021	585,573	579,468	23,539	23,065	1	1	5,020,634	4,956,555
Maryland	2,352,535	2,332,517	256,165	254,163	8,935	8,801	5	5	2,617,640	2,595,486
North Carolina	4,620,856	4,550,420	705,587	691,673	9,871	10,025	1	1	5,336,315	5,252,119
South Carolina	2,330,903	2,290,200	385,285	376,842	3,703	4,324	--	--	2,719,891	2,671,366
Virginia	3,464,677	3,431,574	434,175	431,058	3,723	3,704	1	1	3,902,576	3,866,337
West Virginia	857,666	859,039	145,225	144,478	11,562	11,515	--	--	1,014,453	1,015,032
East South Central	8,448,897	8,382,954	1,414,750	1,404,952	24,787	26,090	--	--	9,888,434	9,813,996
Alabama	2,249,425	2,229,472	369,798	371,097	7,245	7,342	--	--	2,626,468	2,607,911
Kentucky	1,991,137	1,980,209	309,830	305,417	6,147	6,750	--	--	2,307,114	2,292,376
Mississippi	1,293,419	1,290,281	237,625	236,871	10,379	10,988	--	--	1,541,423	1,538,140
Tennessee	2,914,916	2,882,992	497,497	491,567	1,016	1,010	--	--	3,413,429	3,375,569
West South Central	16,636,131	16,387,177	2,316,766	2,363,259	306,569	200,568	6	6	19,259,472	18,951,010
Arkansas	1,396,870	1,388,358	198,861	196,482	34,864	36,596	2	2	1,630,597	1,621,438
Louisiana	2,095,466	2,085,055	295,153	292,752	19,373	19,558	1	1	2,409,993	2,397,366
Oklahoma	1,777,156	1,764,980	285,641	282,875	19,905	18,700	--	--	2,082,702	2,066,555
Texas	11,366,639	11,148,784	1,537,111	1,591,150	232,427	125,714	3	3	13,136,180	12,865,651
Mountain	9,994,348	9,825,511	1,431,391	1,414,958	96,422	95,524	5	5	11,522,166	11,335,998
Arizona	2,853,183	2,808,352	326,191	322,135	7,899	7,794	2	2	3,187,275	3,138,283
Colorado	2,370,164	2,326,976	380,609	376,104	14,386	15,985	1	1	2,765,160	2,719,066
Idaho	763,841	743,567	112,137	110,797	28,493	28,418	--	--	904,471	882,782
Montana	516,052	509,526	109,459	108,695	11,286	9,915	--	--	636,797	628,136
Nevada	1,204,996	1,183,660	167,628	164,982	3,265	3,446	1	1	1,375,890	1,352,089
New Mexico	895,086	889,841	144,960	143,874	9,456	9,360	--	--	1,049,502	1,043,075
Utah	1,116,145	1,091,162	132,082	130,053	10,343	9,666	1	1	1,258,571	1,230,882
Wyoming	274,881	272,427	58,325	58,318	11,294	10,940	--	--	344,500	341,685
Pacific Contiguous	18,597,101	18,418,260	2,348,236	2,337,183	199,658	200,749	19	20	21,145,014	20,956,212
California	13,707,126	13,591,152	1,718,601	1,714,875	147,660	148,644	12	12	15,573,399	15,454,683
Oregon	1,763,783	1,750,240	240,488	237,942	25,169	24,821	2	2	2,029,442	2,013,005
Washington	3,126,192	3,076,868	389,147	384,366	26,829	27,284	5	6	3,542,173	3,488,524
Pacific Noncontiguous	727,642	723,792	114,958	113,618	1,949	2,201	--	--	844,549	839,611
Alaska	289,290	287,526	55,080	53,957	1,126	1,387	--	--	345,496	342,870
Hawaii	438,352	436,266	59,878	59,661	823	814	--	--	499,053	496,741
U.S. Total	135,249,616	133,893,321	18,694,240	18,605,393	954,222	840,321	83	83	154,898,161	153,339,118

**Table 2.12. Electric Power Industry - Electricity Purchases,
2009 through 2019 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2010	2,353,086	3,319,211	23,976	73,861	5,770,134
2011	2,245,381	2,679,803	21,844	77,593	5,024,621
2012	2,148,346	2,740,043	17,726	78,818	4,984,933
2013	2,099,528	2,482,928	16,101	86,420	4,684,977
2014	2,145,378	2,559,875	17,000	79,975	4,802,227
2015	2,101,788	2,506,185	54,046	99,505	4,761,523
2016	2,089,540	2,438,204	8,520	187,307	4,723,571
2017	2,102,971	2,552,146	9,372	196,768	4,861,257
2018	2,187,615	2,713,174	8,730	259,354	5,168,874
2019	2,231,042	2,778,349	9,391	352,854	5,371,635

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" and Form EIA-923, "Power Plant Operations Report"

**Table 2.13. Electric Power Industry - Electricity Sales for Resale,
2009 through 2019 (Thousand Megawatthours)**

Year	Electric Utilities	Energy-Only Providers	Independent Power Producers	Combined Heat and Power	U.S. Total
2009	1,495,636	2,240,399	1,295,857	33,139	5,065,031
2010	1,541,554	2,946,452	1,404,137	37,068	5,929,211
2011	1,529,434	2,206,981	1,372,306	34,400	5,143,121
2012	1,456,774	2,135,819	1,384,155	37,017	5,013,765
2013	1,472,124	2,036,460	1,298,528	35,396	4,842,508
2014	1,485,964	2,081,235	1,301,724	39,916	4,908,839
2015	1,393,396	2,033,705	1,331,181	39,113	4,797,395
2016	1,391,873	1,947,036	1,372,928	35,131	4,746,967
2017	1,396,838	2,066,455	1,389,083	37,571	4,889,947
2018	1,431,952	2,193,414	1,463,236	38,674	5,127,276
2019	1,402,200	2,259,028	1,466,561	44,641	5,172,430

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" and Form EIA-923, "Power Plant Operations Report"

Table 2.14. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 2009-2019 (Megawatthours)

Year	Canada		Mexico		U.S. Total	
	Imports from	Exports to	Imports from	Exports to	Imports	Exports
2009	50,870,451	17,517,112	1,320,144	620,872	52,190,595	18,137,984
2010	43,763,091	18,481,678	1,320,095	624,502	45,083,186	19,106,180
2011	51,075,952	14,398,470	1,223,758	650,082	52,299,710	15,048,552
2012	57,971,110	11,392,267	1,285,959	603,382	59,257,069	11,995,649
2013	62,739,038	10,694,907	6,207,597	678,300	68,946,635	11,373,207
2014	59,369,660	12,860,889	7,140,624	437,364	66,510,284	13,298,253
2015	68,462,277	8,707,873	7,308,192	392,016	75,770,469	9,099,889
2016	65,173,818	2,682,381	7,542,445	3,531,636	72,716,263	6,214,017
2017	59,909,320	3,312,798	5,775,597	6,058,005	65,684,917	9,370,803
2018	51,494,627	7,290,070	6,765,975	6,514,422	58,260,602	13,804,492
2019	52,309,254	13,532,067	6,743,207	6,475,965	59,052,461	20,008,032

Notes: As of November 2017, the data for 2016 and going forward will be published using data from the Form EIA-111, "Quarterly Electricity Imports and Exports Report." During 2013-2015, EIA revised its approach to estimating imports from Mexico.

Sources: 2016-2019, U.S. Energy Information Administration, Form EIA-111, "Quarterly Electricity Imports and Exports Report"; 2006-2015 data, National Energy Board of Canada; FERC 714, Annual Electric Balancing Authority Area and Planning Report; California Energy Commission; and EIA estimates.

Chapter 3

Net Generation

Table 3.1.A. Net Generation by Energy Source: Total (All Sectors), 2009 - 2019
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2009	1,755,904	25,972	12,964	920,979	10,632	798,855	273,445	891	143,388	-4,627	11,928	3,950,331	N/A	N/A	N/A
2010	1,847,290	23,337	13,724	987,697	11,313	806,968	260,203	1,212	165,961	-5,501	12,855	4,125,060	N/A	N/A	N/A
2011	1,733,430	16,086	14,096	1,013,689	11,566	790,204	319,355	1,818	192,163	-6,421	14,154	4,100,141	N/A	N/A	N/A
2012	1,514,043	13,403	9,787	1,225,894	11,898	769,331	276,240	4,327	214,006	-4,950	13,787	4,047,765	N/A	N/A	N/A
2013	1,581,115	13,820	13,344	1,124,836	12,853	789,016	268,565	9,036	244,472	-4,681	13,588	4,065,964	N/A	N/A	N/A
2014	1,581,710	18,276	11,955	1,126,609	12,022	797,166	259,367	17,691	261,522	-6,174	13,461	4,093,606	11,233	26,482	28,924
2015	1,352,398	17,372	10,877	1,333,482	13,117	797,178	249,080	24,893	270,268	-5,091	14,028	4,077,601	14,139	35,805	39,032
2016	1,239,149	13,008	11,197	1,378,307	12,807	805,694	267,812	36,054	305,579	-6,686	13,754	4,076,675	18,812	51,483	54,866
2017	1,205,835	12,414	8,976	1,296,442	12,469	804,950	300,333	53,287	332,963	-6,495	13,096	4,034,271	23,990	74,008	77,277
2018	1,149,487	16,245	8,981	1,469,133	13,463	807,084	292,524	63,825	350,467	-5,905	12,973	4,178,277	29,539	89,773	93,365
2019	964,957	11,522	6,819	1,585,814	12,591	809,409	287,874	71,937	368,862	-5,261	13,331	4,127,855	34,957	103,676	106,894
Year 2017															
January	115,333	1,102	944	95,572	1,047	73,121	26,628	2,324	27,605	-435	1,092	344,332	1,246	3,480	3,570
February	86,822	869	723	82,768	978	63,560	23,882	2,751	23,882	-508	992	291,050	1,384	4,000	4,135
March	89,365	956	699	95,074	1,060	65,093	29,613	4,514	32,421	-521	1,061	319,336	1,972	6,190	6,487
April	81,335	860	431	88,455	1,001	56,743	29,409	4,907	31,607	-439	1,050	295,361	2,195	6,791	7,102
May	92,777	970	847	98,019	1,056	61,313	32,607	5,785	29,408	-423	1,089	323,447	2,423	7,806	8,208
June	107,508	991	901	117,236	993	67,011	30,575	6,115	26,659	-568	1,099	358,522	2,487	8,137	8,602
July	127,698	920	889	146,929	1,047	71,314	26,598	5,569	23,019	-759	1,207	404,432	2,555	7,812	8,124
August	119,488	968	765	141,201	1,133	72,384	22,034	5,369	20,817	-638	1,217	384,739	2,480	7,507	7,848
September	98,202	931	712	118,036	1,059	68,098	19,152	5,059	24,238	-606	1,034	335,915	2,225	6,935	7,285
October	89,776	973	572	106,826	998	65,995	17,698	4,650	30,614	-463	1,031	318,670	1,990	6,325	6,640
November	90,986	915	755	94,928	1,001	66,618	19,888	3,209	29,150	-478	1,079	308,052	1,561	4,639	4,770
December	106,545	1,958	737	111,398	1,095	73,700	22,248	3,035	29,211	-656	1,145	350,416	1,472	4,384	4,507
Year 2018															
January	119,284	5,555	965	110,293	1,097	74,649	25,064	3,319	32,443	-547	1,109	373,230	1,619	4,810	4,938
February	82,050	804	754	98,512	1,092	64,790	24,902	3,896	29,415	-315	994	306,894	1,766	5,472	5,663
March	80,626	830	642	106,524	1,158	67,033	25,861	5,056	33,200	-490	1,108	321,547	2,434	7,233	7,490
April	73,346	872	666	98,371	1,099	59,133	28,115	6,057	32,446	-377	1,028	300,756	2,740	8,482	8,796
May	85,227	1,040	517	115,284	1,167	67,320	30,444	6,849	30,419	-390	1,070	338,948	3,011	9,430	9,860
June	101,503	1,066	834	130,826	1,091	69,688	27,597	7,415	31,193	-433	1,104	371,886	3,059	9,957	10,474
July	115,376	988	913	164,749	1,172	72,456	25,100	6,755	23,316	-644	1,111	411,290	3,146	9,521	9,901
August	115,129	1,047	879	161,676	1,301	72,282	22,017	6,695	26,601	-747	1,146	408,028	3,017	9,303	9,712
September	96,544	1,055	799	141,786	1,104	64,725	19,166	5,961	24,718	-603	1,004	356,258	2,674	8,205	8,635
October	87,264	1,015	562	123,142	1,016	59,397	19,548	4,970	27,426	-492	1,084	324,932	2,392	7,087	7,361
November	92,819	1,006	656	108,168	1,045	63,954	21,913	3,743	28,334	-343	1,075	322,369	1,905	5,480	5,648
December	100,319	966	795	109,802	1,120	71,657	22,797	3,110	30,956	-522	1,139	342,139	1,775	4,792	4,885
Year 2019															
January	100,905	1,413	800	121,589	1,025	73,701	24,798	3,580	30,829	-323	1,194	359,509	1,903	5,373	5,483
February	79,929	815	692	112,142	948	64,715	22,881	3,836	28,455	-389	1,003	315,026	2,059	5,763	5,895
March	78,352	816	574	115,813	1,086	65,080	26,334	5,899	32,036	-409	1,077	326,657	2,914	8,553	8,813
April	59,922	782	401	104,059	948	60,581	27,820	6,752	34,486	-103	1,015	296,663	3,245	9,672	9,997
May	71,885	937	737	117,059	1,054	67,124	31,982	7,162	31,736	-368	1,117	330,423	3,549	10,375	10,711
June	78,540	957	563	137,836	1,009	68,805	28,078	7,971	28,514	-385	1,101	352,988	3,604	11,136	11,575
July	100,771	1,004	791	171,955	1,185	72,199	24,875	8,133	28,591	-622	1,157	410,038	3,760	11,493	11,893
August	94,040	1,047	684	174,968	1,147	71,911	22,579	7,877	26,546	-579	1,211	401,430	3,611	11,075	11,488
September	85,707	923	581	149,697	1,112	66,064	18,526	6,817	30,622	-671	1,142	360,518	3,205	9,728	10,022
October	66,777	942	200	130,948	924	62,033	18,306	6,093	33,402	-373	1,100	320,352	2,833	8,628	8,926
November	75,549	899	333	117,910	1,047	64,125	20,218	4,364	30,830	-509	1,082	315,849	2,228	6,450	6,592
December	72,581	988	463	131,839	1,107	73,074	21,478	3,453	32,815	-529	1,133	338,402	2,047	5,430	5,500

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report;

Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.1.B. Net Generation from Renewable Sources: Total (All Sectors), 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2009	73,886	157	735	36,050	7,924	8,058	2,461	15,009	273,445	417,724	N/A	N/A	N/A
	2010	94,652	423	789	37,172	8,377	7,927	2,613	15,219	260,203	427,376	N/A	N/A	N/A
	2011	120,177	1,012	806	37,449	9,044	7,354	2,824	15,316	319,355	513,336	N/A	N/A	N/A
	2012	140,822	3,451	876	37,799	9,803	7,320	2,700	15,562	276,240	494,573	N/A	N/A	N/A
	2013	167,840	8,121	915	40,028	10,658	7,186	2,986	15,775	268,565	522,073	N/A	N/A	N/A
	2014	181,655	15,250	2,441	42,340	11,220	7,228	3,202	15,877	259,367	538,579	11,233	26,482	28,924
	2015	190,719	21,666	3,227	41,929	11,291	7,211	3,201	15,918	249,080	544,241	14,139	35,805	39,032
	2016	226,993	32,670	3,384	40,947	11,218	7,265	3,331	15,826	267,812	609,445	18,812	51,483	54,866
	2017	254,303	50,018	3,269	41,124	11,543	6,951	3,115	15,927	300,333	686,583	23,990	74,008	77,277
	2018	272,667	60,234	3,592	40,936	11,036	7,136	2,724	15,967	292,524	706,816	29,539	89,773	93,365
	2019	295,882	68,719	3,218	38,543	10,468	6,093	2,402	15,473	287,874	728,673	34,957	103,676	106,894
Year 2017														
	January	20,799	2,234	90	3,502	999	617	281	1,407	26,628	56,557	1,246	3,480	3,570
	February	22,091	2,616	136	3,186	912	528	257	1,239	23,882	54,846	1,384	4,000	4,135
	March	25,731	4,217	297	3,456	1,000	557	291	1,387	29,613	66,548	1,972	6,190	6,487
	April	25,378	4,596	310	3,146	943	544	255	1,341	29,409	65,923	2,195	6,791	7,102
	May	23,068	5,383	402	3,188	980	604	266	1,302	32,607	67,800	2,423	7,806	8,208
	June	20,142	5,651	465	3,437	957	588	252	1,284	30,575	63,350	2,487	8,137	8,602
	July	16,120	5,258	311	3,703	960	604	260	1,373	26,598	55,187	2,555	7,812	8,124
	August	13,879	5,028	341	3,751	963	617	245	1,363	22,034	48,220	2,480	7,507	7,848
	September	17,912	4,710	349	3,292	922	558	224	1,332	19,152	48,449	2,225	6,935	7,285
	October	24,369	4,335	314	3,303	933	558	237	1,214	17,698	52,962	1,990	6,325	6,640
	November	22,615	3,078	131	3,426	963	571	271	1,305	19,888	52,248	1,561	4,639	4,770
	December	22,201	2,912	123	3,734	1,014	606	276	1,381	22,248	54,494	1,472	4,384	4,507
Year 2018														
	January	25,599	3,191	128	3,686	964	588	265	1,341	25,064	60,826	1,619	4,810	4,938
	February	23,189	3,705	191	3,235	906	559	251	1,274	24,902	58,213	1,766	5,472	5,663
	March	26,464	4,799	258	3,547	972	597	253	1,367	25,861	64,117	2,434	7,233	7,490
	April	26,431	5,743	314	3,102	920	566	239	1,188	28,115	66,618	2,740	8,482	8,796
	May	23,953	6,419	430	3,352	930	573	228	1,383	30,444	67,712	3,011	9,430	9,860
	June	24,703	6,898	517	3,471	889	629	202	1,300	27,597	66,206	3,059	9,957	10,474
	July	16,447	6,374	380	3,749	909	638	202	1,370	25,100	55,170	3,146	9,521	9,901
	August	19,846	6,286	409	3,630	919	630	208	1,367	22,017	55,313	3,017	9,303	9,712
	September	18,520	5,531	430	3,281	836	562	192	1,328	19,166	49,844	2,674	8,205	8,635
	October	21,194	4,695	275	3,216	918	594	231	1,273	19,548	51,944	2,392	7,087	7,361
	November	22,016	3,575	168	3,264	920	584	220	1,331	21,913	53,990	1,905	5,480	5,648
	December	24,306	3,018	92	3,404	951	616	233	1,446	22,797	56,863	1,775	4,792	4,885
Year 2019														
	January	24,301	3,470	111	3,465	930	528	214	1,390	24,798	59,207	1,903	5,373	5,483
	February	22,623	3,704	131	3,042	843	464	191	1,293	22,881	55,172	2,059	5,763	5,895
	March	25,773	5,639	260	3,217	908	490	227	1,422	26,334	64,269	2,914	8,553	8,813
	April	28,915	6,427	325	2,807	833	468	208	1,254	27,820	69,059	3,245	9,672	9,997
	May	25,779	6,826	336	3,051	859	526	179	1,342	31,982	70,880	3,549	10,375	10,711
	June	22,446	7,532	439	3,159	868	523	191	1,328	28,078	64,563	3,604	11,136	11,575
	July	22,101	7,733	400	3,498	884	538	194	1,375	24,875	61,599	3,760	11,493	11,893
	August	19,978	7,464	413	3,539	886	546	204	1,393	22,579	57,001	3,611	11,075	11,488
	September	24,513	6,523	294	3,211	838	512	179	1,368	18,526	55,965	3,205	9,728	10,022
	October	27,625	5,796	298	3,063	868	500	206	1,141	18,306	57,801	2,833	8,628	8,926
	November	25,184	4,223	141	3,137	844	484	198	984	20,218	55,412	2,228	6,450	6,592
	December	26,644	3,383	70	3,355	908	513	213	1,183	21,478	57,746	2,047	5,430	5,500

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.2.A. Net Generation by Energy Source: Electric Utilities, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities											
									Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage		
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar			Other	Total
Annual Totals												
2009	1,322,092	18,035	7,182	349,166	96	417,275	247,198	28	14,589	-3,369	483	2,372,776
2010	1,378,028	17,258	8,807	392,616	52	424,843	236,104	101	17,826	-4,466	462	2,471,632
2011	1,301,107	11,688	9,428	414,843	29	415,298	291,413	216	21,717	-5,492	604	2,460,851
2012	1,146,480	9,892	5,664	504,958	0	394,823	252,936	639	27,378	-4,202	603	2,339,172
2013	1,188,452	9,446	9,522	501,427	798	406,114	243,040	943	31,474	-3,773	615	2,388,058
2014	1,173,073	10,696	9,147	501,414	112	419,871	238,185	1,218	33,278	-5,144	622	2,382,473
2015	998,385	10,386	8,278	617,817	199	416,680	229,640	1,494	35,992	-4,105	558	2,315,323
2016	922,399	9,069	8,881	654,780	154	424,400	247,787	1,995	40,666	-5,629	421	2,304,923
2017	893,639	8,567	6,711	623,834	149	424,485	275,677	3,348	42,763	-5,448	553	2,274,279
2018	863,505	10,108	6,817	720,206	151	424,251	267,336	4,916	44,184	-4,785	561	2,337,250
2019	722,885	8,313	5,112	785,026	154	430,672	262,364	6,785	48,403	-4,261	551	2,266,004
Year 2017												
January	85,985	796	743	45,737	13	38,425	24,538	158	3,381	-346	43	199,474
February	64,844	627	540	39,552	17	33,911	21,937	194	3,796	-418	37	165,037
March	65,992	752	535	46,425	16	34,693	27,285	279	4,428	-455	42	179,993
April	58,913	641	260	43,439	18	30,217	26,825	307	4,178	-368	45	164,476
May	69,099	708	654	48,492	5	31,728	29,918	347	3,665	-350	42	184,308
June	81,297	707	698	56,422	10	35,022	28,240	344	3,407	-474	45	205,719
July	96,782	651	673	71,139	19	37,874	24,415	322	2,692	-646	50	233,972
August	90,517	696	540	67,676	2	38,667	20,221	322	2,358	-531	54	220,522
September	71,859	665	523	56,361	0	35,496	17,664	308	2,943	-522	48	185,345
October	66,498	734	405	50,125	9	35,038	16,270	283	4,185	-388	48	173,207
November	64,983	639	583	45,119	15	34,541	17,894	237	3,870	-394	49	167,537
December	76,870	950	556	53,347	24	38,871	20,469	246	3,859	-557	50	194,686
Year 2018												
January	88,718	2,491	770	55,797	26	39,366	23,106	288	4,399	-475	41	214,525
February	61,138	617	575	48,715	17	33,941	22,864	314	3,853	-226	38	171,847
March	58,606	595	491	52,161	16	35,262	23,638	446	4,276	-408	48	175,132
April	55,281	632	477	48,151	28	30,580	25,598	480	4,120	-295	39	165,093
May	64,034	745	336	58,251	11	34,479	28,055	463	3,427	-309	45	189,538
June	77,899	756	670	66,774	13	36,437	25,778	503	3,691	-339	50	212,232
July	88,102	668	716	81,297	15	38,293	23,303	477	2,824	-522	55	235,229
August	87,359	711	686	78,025	24	38,885	20,050	476	3,122	-626	56	228,767
September	73,021	781	639	68,655	3	34,377	17,368	436	3,288	-500	47	198,116
October	64,902	751	378	59,071	0	31,364	17,571	418	3,447	-405	43	177,541
November	68,864	703	477	51,796	0	33,043	19,630	325	3,631	-254	50	178,265
December	75,578	657	601	51,512	0	38,223	20,373	290	4,105	-426	49	190,963
Year 2019												
January	74,950	884	634	59,221	12	39,806	22,391	379	3,980	-247	42	202,052
February	59,507	580	564	55,553	22	34,243	20,610	403	3,431	-310	30	174,633
March	56,482	616	464	57,144	31	34,213	23,839	598	4,349	-309	31	177,458
April	44,228	545	276	51,616	0	32,063	25,266	667	4,820	-26	35	159,490
May	55,130	685	552	59,603	0	35,416	29,266	689	4,057	-305	41	185,133
June	60,199	723	398	70,460	23	36,847	25,767	662	3,649	-299	39	198,468
July	77,085	713	551	85,011	18	39,023	22,846	673	3,631	-505	36	229,082
August	72,032	802	501	87,745	16	39,218	20,913	640	3,139	-470	66	224,601
September	64,955	694	460	74,912	10	34,770	17,045	641	4,185	-583	59	197,147
October	49,301	701	146	64,537	0	32,289	16,625	574	4,600	-316	58	168,516
November	55,455	638	251	56,508	19	32,923	18,467	464	4,237	-424	56	168,594
December	53,561	730	315	62,718	2	39,861	19,330	395	4,325	-465	57	180,830

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report;

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Table 3.2.B. Net Generation from Renewable Sources: Electric Utilities, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities									Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals													
2009	10,348	28	1	1,748	866	184	261	1,182	247,198	261,815	N/A	N/A	N/A
2010	13,089	101	0	2,328	879	154	259	1,118	236,104	254,031	N/A	N/A	N/A
2011	17,140	187	29	2,023	957	165	295	1,137	291,413	313,346	N/A	N/A	N/A
2012	22,926	551	89	1,836	1,022	184	265	1,143	252,936	280,953	N/A	N/A	N/A
2013	26,436	841	102	2,534	1,114	197	188	1,005	243,040	275,457	N/A	N/A	N/A
2014	27,671	1,094	124	3,050	1,068	191	182	1,116	238,185	272,681	0	1,094	1,218
2015	30,412	1,388	106	3,018	1,061	195	218	1,089	229,640	267,125	0	1,388	1,494
2016	35,070	1,920	75	3,038	1,040	201	237	1,080	247,787	290,448	0	1,920	1,995
2017	37,068	3,326	22	3,226	1,103	184	161	1,022	275,677	321,788	0	3,326	3,348
2018	38,466	4,865	51	3,364	1,004	203	138	1,009	267,336	316,436	0	4,865	4,916
2019	43,636	6,757	28	2,784	964	122	126	771	262,364	317,552	0	6,757	6,785
Year 2017													
January	2,836	158	0	329	96	14	13	94	24,538	28,078	0	158	158
February	3,338	194	0	265	90	9	15	80	21,937	25,927	0	194	194
March	3,907	279	0	311	98	15	19	78	27,285	31,992	0	279	279
April	3,721	307	0	246	95	16	11	90	26,825	31,311	0	307	307
May	3,239	346	1	213	99	15	13	88	29,918	33,930	0	346	347
June	2,960	343	1	245	86	17	14	86	28,240	31,991	0	343	344
July	2,203	321	1	282	88	17	13	89	24,415	27,429	0	321	322
August	1,865	318	4	280	90	19	15	89	20,221	22,901	0	318	322
September	2,575	302	7	166	83	18	13	87	17,664	20,915	0	302	308
October	3,742	282	1	252	89	14	11	77	16,270	20,739	0	282	283
November	3,376	235	2	288	93	15	10	88	17,894	22,001	0	235	237
December	3,306	241	6	350	98	14	15	75	20,469	24,574	0	241	246
Year 2018													
January	3,832	286	1	364	102	11	17	73	23,106	27,793	0	286	288
February	3,363	311	3	291	92	12	12	82	22,864	27,031	0	311	314
March	3,717	437	9	343	100	17	10	89	23,638	28,361	0	437	446
April	3,707	472	9	221	94	16	10	73	25,598	30,199	0	472	480
May	2,990	460	3	228	93	20	6	90	28,055	31,945	0	460	463
June	3,227	498	5	278	75	18	7	85	25,778	29,972	0	498	503
July	2,297	472	6	327	77	21	14	88	23,303	26,604	0	472	477
August	2,612	470	6	317	73	21	11	88	20,050	23,647	0	470	476
September	2,875	432	4	234	68	15	11	85	17,368	21,092	0	432	436
October	3,007	413	5	251	76	18	14	81	17,571	21,437	0	413	418
November	3,164	324	1	277	76	17	14	84	19,630	23,586	0	324	325
December	3,676	290	1	233	77	17	12	90	20,373	24,769	0	290	290
Year 2019													
January	3,505	377	2	284	86	13	14	78	22,391	26,750	0	377	379
February	3,034	400	3	229	77	8	15	70	20,610	24,444	0	400	403
March	3,957	594	4	206	86	8	16	76	23,839	28,786	0	594	598
April	4,495	661	6	165	81	12	12	56	25,266	30,753	0	661	667
May	3,659	686	3	234	83	11	10	60	29,266	34,012	0	686	689
June	3,284	661	1	194	79	11	10	72	25,767	30,078	0	661	662
July	3,142	672	1	316	79	10	11	73	22,846	27,150	0	672	673
August	2,630	636	4	329	80	12	14	74	20,913	24,691	0	636	640
September	3,777	639	2	241	76	8	8	74	17,045	21,871	0	639	641
October	4,255	573	2	198	78	12	5	51	16,625	21,800	0	573	574
November	3,965	464	0	142	76	10	3	40	18,467	23,168	0	464	464
December	3,932	395	1	246	82	8	9	48	19,330	24,051	0	395	395

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

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Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.3.A. Net Generation by Energy Source: Independent Power Producers, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities												
										Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage		
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar				Other	Total
Annual Totals													
2009	419,031	6,306	4,288	491,839	2,962	381,579	24,308	863	100,997	-1,259		6,146	1,437,061
2010	449,709	5,117	3,497	508,774	2,915	382,126	22,351	1,105	119,851	-1,035		6,345	1,500,754
2011	416,783	3,655	3,431	511,447	2,911	374,906	26,117	1,511	140,442	-928		7,059	1,487,335
2012	354,076	2,757	1,758	627,833	2,984	374,509	20,923	3,525	156,539	-748		7,030	1,551,186
2013	379,270	3,761	1,780	527,522	3,524	382,902	22,018	7,782	181,263	-908		6,742	1,515,657
2014	395,701	6,789	1,410	531,758	3,246	377,295	19,861	16,086	196,723	-1,030		6,690	1,554,530
2015	342,608	6,240	1,601	619,839	3,517	380,498	17,996	22,962	202,858	-987		6,838	1,603,971
2016	307,263	3,360	1,401	624,600	3,758	381,294	18,539	33,502	233,553	-1,057		6,941	1,613,156
2017	304,198	3,281	1,480	572,919	3,978	380,465	23,034	49,376	258,962	-1,047		6,527	1,603,174
2018	278,668	5,487	1,516	645,616	3,935	382,833	23,812	58,337	275,154	-1,119		6,677	1,680,917
2019	235,847	2,669	1,125	692,113	3,883	378,738	24,288	64,480	290,343	-1,000		7,138	1,699,625
Year 2017													
January	28,587	251	139	41,210	336	34,695	1,941	2,140	21,591	-90		583	131,384
February	21,314	198	123	35,536	291	29,650	1,809	2,523	22,000	-90		514	113,867
March	22,696	157	81	40,477	343	30,400	2,175	4,185	25,419	-66		523	126,389
April	21,829	178	113	37,158	282	26,526	2,410	4,546	24,944	-71		507	118,422
May	23,043	221	136	41,502	346	29,585	2,503	5,378	23,207	-73		548	126,395
June	25,528	245	132	52,358	314	31,988	2,182	5,708	20,610	-93		549	139,521
July	30,237	228	138	66,687	350	33,440	2,045	5,188	17,552	-114		572	156,322
August	28,293	232	140	64,699	358	33,717	1,703	4,989	15,669	-107		580	150,272
September	25,701	226	136	53,795	346	32,602	1,399	4,698	18,801	-84		509	138,127
October	22,616	195	110	48,675	318	30,957	1,336	4,323	23,905	-75		518	132,878
November	25,364	221	111	41,715	337	32,077	1,864	2,937	22,697	-84		539	127,777
December	28,990	930	122	49,108	358	34,828	1,667	2,760	22,569	-99		586	141,819
Year 2018													
January	29,839	2,951	137	45,672	318	35,283	1,856	3,000	25,364	-72		575	144,924
February	20,261	133	126	41,986	320	30,849	1,929	3,549	23,179	-89		543	122,786
March	21,377	186	96	46,436	331	31,770	2,114	4,563	26,260	-82		564	133,615
April	17,506	199	137	42,464	326	28,553	2,392	5,522	25,872	-82		527	123,416
May	20,600	248	124	48,762	379	32,841	2,264	6,325	24,380	-81		526	136,366
June	22,994	268	100	55,398	303	33,251	1,724	6,845	24,920	-95		582	146,291
July	26,647	260	139	73,967	344	34,163	1,700	6,214	17,729	-123		586	161,625
August	27,157	292	139	74,126	369	33,398	1,858	6,158	20,775	-121		579	164,730
September	22,941	233	108	64,337	328	30,348	1,692	5,475	18,927	-103		515	144,800
October	21,834	218	126	55,462	255	28,033	1,855	4,508	21,450	-87		556	134,209
November	23,393	245	140	47,623	311	30,911	2,150	3,386	22,175	-88		551	130,797
December	24,120	254	144	49,384	350	33,434	2,277	2,792	24,124	-96		574	137,357
Year 2019													
January	25,344	462	125	52,923	348	33,895	2,266	3,167	24,193	-76		625	143,272
February	19,875	185	91	48,397	329	30,472	2,162	3,395	22,632	-79		544	128,002
March	21,337	155	71	49,981	352	30,867	2,368	5,243	25,078	-100		573	135,927
April	15,198	189	79	44,245	329	28,518	2,429	6,023	27,340	-78		546	124,819
May	16,258	215	145	48,842	325	31,708	2,591	6,406	25,316	-63		623	132,365
June	17,844	196	117	58,469	306	31,958	2,198	7,236	22,392	-86		610	141,240
July	23,140	254	135	77,238	354	33,176	1,942	7,380	22,329	-118		634	166,465
August	21,485	200	134	77,396	361	32,693	1,592	7,163	20,752	-109		638	162,304
September	20,261	186	77	65,571	332	31,294	1,416	6,112	23,996	-88		590	149,747
October	17,011	200	9	57,397	189	29,744	1,607	5,466	26,335	-56		582	138,483
November	19,591	215	41	52,175	307	31,202	1,672	3,859	24,109	-84		572	133,658
December	18,504	213	102	59,480	352	33,212	2,044	3,028	25,871	-64		601	143,343

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

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Table 3.3.B. Net Generation from Renewable Sources: Independent Power Producers, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2009	63,538	129	734	8,990	6,718	6,829	1,095	13,826	24,308	126,168	N/A	N/A	N/A
	2010	81,547	316	789	9,118	7,227	6,742	1,116	14,101	22,351	143,306	N/A	N/A	N/A
	2011	102,981	734	777	8,709	7,120	6,217	1,237	14,180	26,117	168,071	N/A	N/A	N/A
	2012	117,822	2,737	787	9,214	7,852	6,056	1,176	14,419	20,923	180,987	N/A	N/A	N/A
	2013	141,306	6,969	813	9,768	8,442	5,838	1,139	14,770	22,018	211,063	N/A	N/A	N/A
	2014	153,825	13,769	2,317	11,977	9,062	5,838	1,261	14,761	19,861	232,670	0	13,769	16,086
	2015	160,135	19,841	3,121	11,545	9,202	5,806	1,342	14,829	17,996	243,816	0	19,841	22,962
	2016	191,720	30,194	3,308	10,382	9,255	5,965	1,486	14,746	18,539	285,594	0	30,194	33,502
	2017	217,006	46,128	3,248	10,416	9,505	5,652	1,479	14,905	23,034	331,372	0	46,128	49,376
	2018	233,931	54,796	3,540	10,021	9,162	5,891	1,226	14,924	23,812	357,303	0	54,796	58,337
	2019	251,968	61,290	3,190	9,237	8,739	5,096	1,043	14,260	24,288	379,111	0	61,290	64,480
Year 2017														
	January	17,944	2,051	90	860	819	518	136	1,313	1,941	25,672	0	2,051	2,140
	February	18,734	2,387	136	796	747	440	124	1,158	1,809	26,332	0	2,387	2,523
	March	21,798	3,888	297	905	819	454	134	1,309	2,175	31,779	0	3,888	4,185
	April	21,634	4,236	310	728	774	440	116	1,251	2,410	31,899	0	4,236	4,546
	May	19,808	4,977	402	765	804	484	132	1,214	2,503	31,089	0	4,977	5,378
	June	17,164	5,245	464	848	792	479	129	1,198	2,182	28,501	0	5,245	5,708
	July	13,905	4,877	311	958	796	484	126	1,284	2,045	24,784	0	4,877	5,188
	August	12,004	4,652	337	991	795	494	111	1,274	1,703	22,361	0	4,652	4,989
	September	15,321	4,355	343	922	763	447	104	1,244	1,399	24,898	0	4,355	4,698
	October	20,604	4,009	313	831	773	447	113	1,137	1,336	29,564	0	4,009	4,323
	November	19,217	2,808	130	875	791	466	132	1,216	1,864	27,498	0	2,808	2,937
	December	18,873	2,643	117	936	833	499	123	1,305	1,667	26,996	0	2,643	2,760
Year 2018														
	January	21,738	2,873	127	956	786	492	124	1,268	1,856	30,221	0	2,873	3,000
	February	19,802	3,361	188	846	741	472	125	1,192	1,929	28,657	0	3,361	3,549
	March	22,718	4,314	248	857	794	494	120	1,278	2,114	32,936	0	4,314	4,563
	April	22,700	5,216	306	727	751	466	114	1,115	2,392	33,786	0	5,216	5,522
	May	20,941	5,898	427	810	765	461	110	1,293	2,264	32,969	0	5,898	6,325
	June	21,456	6,333	512	890	745	516	98	1,214	1,724	33,489	0	6,333	6,845
	July	14,135	5,839	374	944	761	524	83	1,281	1,700	25,642	0	5,839	6,214
	August	17,218	5,754	403	900	774	517	87	1,279	1,858	28,792	0	5,754	6,158
	September	15,627	5,049	425	810	700	465	82	1,243	1,692	26,094	0	5,049	5,475
	October	18,162	4,238	270	738	770	489	98	1,192	1,855	27,812	0	4,238	4,508
	November	18,827	3,219	167	753	774	487	86	1,247	2,150	27,712	0	3,219	3,386
	December	20,606	2,701	91	789	802	508	98	1,322	2,277	29,194	0	2,701	2,792
Year 2019														
	January	20,768	3,059	109	857	770	438	91	1,270	2,266	29,627	0	3,059	3,167
	February	19,565	3,266	128	718	700	390	76	1,182	2,162	28,189	0	3,266	3,395
	March	21,789	4,987	256	733	749	409	97	1,302	2,368	32,690	0	4,987	5,243
	April	24,392	5,704	319	604	699	384	90	1,171	2,429	35,793	0	5,704	6,023
	May	22,097	6,073	333	731	729	441	72	1,245	2,591	34,313	0	6,073	6,406
	June	19,142	6,798	439	780	727	437	84	1,223	2,198	31,827	0	6,798	7,236
	July	18,942	6,982	398	836	740	454	88	1,269	1,942	31,651	0	6,982	7,380
	August	17,333	6,754	409	843	739	459	91	1,288	1,592	29,507	0	6,754	7,163
	September	20,717	5,821	292	804	696	431	83	1,264	1,416	31,525	0	5,821	6,112
	October	23,344	5,170	296	701	725	419	95	1,052	1,607	33,407	0	5,170	5,466
	November	21,194	3,718	141	815	705	406	87	901	1,672	29,640	0	3,718	3,859
	December	22,684	2,959	70	815	762	430	88	1,093	2,044	30,943	0	2,959	3,028

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.A. Net Generation by Energy Source: Commercial Sector, 2009 - 2019
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2009	1,096	157	5	4,225	0	0	71	0	1,769	0	842	8,165	N/A	N/A	N/A
2010	1,111	117	7	4,725	3	0	80	5	1,709	0	834	8,592	N/A	N/A	N/A
2011	1,049	86	3	5,487	3	0	26	84	2,392	0	950	10,080	N/A	N/A	N/A
2012	883	191	6	6,603	0	0	28	148	2,397	0	1,046	11,301	N/A	N/A	N/A
2013	839	118	5	7,154	0	0	44	294	2,662	0	1,118	12,234	N/A	N/A	N/A
2014	595	247	9	7,227	0	0	38	371	2,862	0	1,171	12,520	5,146	5,516	5,516
2015	509	183	8	7,471	0	0	35	416	2,803	0	1,170	12,595	5,689	6,106	6,106
2016	383	77	6	7,730	0	0	217	529	2,697	0	1,068	12,706	6,158	6,687	6,687
2017	329	103	8	8,042	0	0	240	521	2,729	0	1,088	13,060	7,685	8,206	8,206
2018	303	132	7	8,419	0	0	227	525	2,688	0	1,010	13,312	9,798	10,324	10,324
2019	268	116	5	8,610	0	0	188	587	2,840	0	1,076	13,689	11,002	11,588	11,588
Year 2017															
January	41	13	1	686	0	0	21	24	232	0	84	1,103	420	445	445
February	32	7	1	603	0	0	20	32	209	0	78	980	458	490	490
March	33	9	1	655	0	0	24	47	232	0	86	1,087	629	676	676
April	20	5	0	577	0	0	25	50	222	0	87	986	699	748	748
May	19	6	0	621	0	0	27	56	243	0	101	1,074	770	826	826
June	21	5	0	715	0	0	24	58	225	0	89	1,138	777	835	835
July	25	7	0	782	0	0	21	55	237	0	99	1,227	808	863	863
August	23	7	1	766	0	0	18	53	233	0	100	1,201	788	841	841
September	27	6	1	694	0	0	15	49	216	0	90	1,098	709	758	758
October	24	6	1	659	0	0	13	40	216	0	94	1,054	632	673	673
November	29	7	1	609	0	0	14	32	226	0	88	1,006	502	534	534
December	35	23	1	674	0	0	16	26	238	0	91	1,105	492	519	519
Year 2018															
January	40	41	1	671	0	0	19	29	229	0	84	1,114	552	581	581
February	32	7	1	626	0	0	19	31	206	0	72	995	605	636	636
March	27	7	1	647	0	0	21	43	227	0	83	1,058	820	863	863
April	24	8	0	585	0	0	24	50	217	0	81	989	907	957	957
May	21	7	0	656	0	0	24	57	221	0	90	1,076	992	1,048	1,048
June	20	7	0	737	0	0	21	62	224	0	92	1,163	1,003	1,065	1,065
July	21	11	0	875	0	0	19	59	223	0	90	1,298	1,036	1,094	1,094
August	23	9	0	892	0	0	17	56	230	0	90	1,318	993	1,049	1,049
September	24	7	1	771	0	0	16	46	213	0	80	1,156	893	938	938
October	20	7	1	668	0	0	14	39	223	0	83	1,055	786	826	826
November	25	12	1	622	0	0	16	29	212	0	77	993	623	652	652
December	24	9	1	669	0	0	17	25	262	0	88	1,095	589	614	614
Year 2019															
January	29	19	1	706	0	0	16	30	263	0	95	1,160	629	659	659
February	27	9	1	654	0	0	15	34	236	0	81	1,057	676	710	710
March	33	8	1	711	0	0	19	50	262	0	90	1,173	933	983	983
April	22	7	1	646	0	0	19	54	216	0	88	1,053	1,032	1,086	1,086
May	18	7	0	663	0	0	22	58	213	0	91	1,072	1,110	1,168	1,168
June	13	6	0	711	0	0	18	63	229	0	93	1,133	1,118	1,181	1,181
July	18	9	0	869	0	0	16	69	240	0	92	1,313	1,171	1,241	1,241
August	17	12	0	852	0	0	15	64	235	0	94	1,290	1,116	1,181	1,181
September	21	10	0	731	0	0	12	55	230	0	91	1,150	994	1,049	1,049
October	21	9	0	666	0	0	11	46	235	0	84	1,072	881	927	927
November	23	9	0	667	0	0	12	36	235	0	84	1,066	683	719	719
December	27	10	1	735	0	0	14	26	246	0	93	1,151	657	684	684

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.4.B. Net Generation from Renewable Sources: Commercial Sector, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar	
Annual Totals														
2009	0	0	0	20	318	1,045	386	0	71	1,839	N/A	N/A	N/A	
2010	16	5	0	21	256	1,031	386	0	80	1,794	N/A	N/A	N/A	
2011	51	84	0	26	952	971	393	0	26	2,502	N/A	N/A	N/A	
2012	54	148	0	24	848	1,070	402	0	28	2,573	N/A	N/A	N/A	
2013	61	294	0	34	925	1,149	493	0	44	3,000	N/A	N/A	N/A	
2014	107	371	0	74	905	1,202	575	0	38	3,271	5,146	5,516	5,516	
2015	118	416	0	48	847	1,199	592	0	35	3,255	5,689	6,106	6,106	
2016	131	529	0	69	753	1,093	649	0	217	3,443	6,158	6,687	6,687	
2017	144	521	0	70	753	1,114	648	0	240	3,490	7,685	8,206	8,206	
2018	174	525	0	77	703	1,038	664	33	227	3,441	9,798	10,324	10,324	
2019	179	587	0	90	626	869	634	442	188	3,615	11,002	11,588	11,588	
Year 2017														
January	11	24	0	8	68	86	59	0	21	277	420	445	445	
February	11	32	0	7	60	79	51	0	20	260	458	490	490	
March	17	47	0	3	67	88	58	0	24	303	629	676	676	
April	15	50	0	5	59	89	54	0	25	297	699	748	748	
May	13	56	0	7	64	103	56	0	27	326	770	826	826	
June	11	58	0	6	63	91	54	0	24	307	777	835	835	
July	8	55	0	7	64	102	57	0	21	313	808	863	863	
August	6	53	0	7	63	102	54	0	18	303	788	841	841	
September	11	49	0	2	62	92	49	0	15	280	709	758	758	
October	15	40	0	5	55	97	45	0	13	269	632	673	673	
November	14	32	0	6	63	90	54	0	14	273	502	534	534	
December	13	26	0	6	67	93	59	0	16	281	492	519	519	
Year 2018														
January	18	29	0	9	61	86	56	0	19	277	552	581	581	
February	15	31	0	6	57	74	53	0	19	256	605	636	636	
March	18	43	0	5	63	85	56	0	21	292	820	863	863	
April	16	50	0	2	60	84	55	0	24	291	907	957	957	
May	14	57	0	4	57	92	54	0	24	302	992	1,048	1,048	
June	14	62	0	8	55	94	54	0	21	308	1,003	1,065	1,065	
July	10	59	0	9	58	92	55	0	19	301	1,036	1,094	1,094	
August	11	56	0	11	59	92	57	0	17	304	993	1,049	1,049	
September	12	46	0	8	57	81	54	0	16	274	893	938	938	
October	15	39	0	4	60	86	58	0	14	276	786	826	826	
November	16	29	0	2	57	81	56	0	16	256	623	652	652	
December	15	25	0	8	59	91	55	33	17	304	589	614	614	
Year 2019														
January	17	30	0	8	62	78	55	42	16	310	629	659	659	
February	15	34	0	9	55	66	50	41	15	284	676	710	710	
March	17	50	0	11	61	73	55	44	19	330	933	983	983	
April	17	54	0	4	42	72	53	27	19	289	1,032	1,086	1,086	
May	14	58	0	2	35	74	51	37	22	292	1,110	1,168	1,168	
June	12	63	0	4	52	75	52	34	18	310	1,118	1,181	1,181	
July	11	69	0	16	54	73	52	33	16	325	1,171	1,241	1,241	
August	9	64	0	9	56	75	54	31	15	315	1,116	1,181	1,181	
September	14	55	0	8	55	73	51	30	12	297	994	1,049	1,049	
October	17	46	0	7	53	67	52	38	11	292	881	927	927	
November	17	36	0	6	51	67	53	42	12	283	683	719	719	
December	17	26	0	5	50	75	56	43	14	286	657	684	684	

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.A. Net Generation by Energy Source: Industrial Sector, 2009 - 2019
(Thousand Megawatthours)

Period	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	Other	Total Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals															
2009	13,686	1,474	1,489	75,748	7,574	0	1,868	0	26,033	0	4,457	132,329	N/A	N/A	N/A
2010	18,441	844	1,414	81,583	8,343	0	1,668	2	26,574	0	5,214	144,082	N/A	N/A	N/A
2011	14,490	657	1,234	81,911	8,624	0	1,799	7	27,612	0	5,541	141,875	N/A	N/A	N/A
2012	12,603	563	2,359	86,500	8,913	0	2,353	14	27,693	0	5,108	146,107	N/A	N/A	N/A
2013	12,554	495	2,036	88,733	8,531	0	3,463	17	29,074	0	5,113	150,015	N/A	N/A	N/A
2014	12,341	544	1,389	86,209	8,664	0	1,282	16	28,659	0	4,978	144,083	1,139	1,156	1,156
2015	10,896	563	990	88,355	9,401	0	1,410	21	28,614	0	5,462	145,712	1,451	1,472	1,472
2016	9,103	503	909	91,197	8,895	0	1,269	27	28,663	0	5,324	145,890	2,060	2,087	2,087
2017	7,669	463	776	91,647	8,343	0	1,382	42	28,508	0	4,928	143,758	2,364	2,406	2,406
2018	7,011	517	640	94,892	9,377	0	1,149	47	28,440	0	4,725	146,798	2,636	2,683	2,683
2019	5,957	424	576	100,065	8,554	0	1,033	85	27,276	0	4,567	148,537	3,041	3,127	3,127
Year 2017															
January	720	42	61	7,939	697	0	127	2	2,401	0	382	12,370	123	124	124
February	633	37	60	7,077	669	0	116	2	2,208	0	364	11,165	137	139	139
March	644	38	82	7,517	702	0	129	3	2,342	0	410	11,867	197	200	200
April	573	36	58	7,281	701	0	149	4	2,264	0	411	11,476	213	217	217
May	616	35	57	7,405	705	0	158	4	2,292	0	398	11,670	239	243	243
June	662	33	71	7,741	669	0	129	5	2,417	0	416	12,143	241	246	246
July	654	34	78	8,322	679	0	117	5	2,539	0	485	12,912	252	257	257
August	655	33	83	8,059	774	0	93	5	2,557	0	483	12,743	246	251	251
September	615	35	52	7,185	714	0	74	4	2,278	0	388	11,345	223	227	227
October	637	39	56	7,367	672	0	79	3	2,308	0	370	11,531	201	204	204
November	610	47	61	7,485	649	0	116	3	2,357	0	404	11,731	156	158	158
December	650	55	58	8,269	712	0	96	2	2,545	0	418	12,806	138	141	141
Year 2018															
January	687	73	57	8,153	752	0	83	2	2,450	0	410	12,668	146	149	149
February	619	47	52	7,184	755	0	89	3	2,177	0	340	11,265	155	158	158
March	616	41	54	7,280	811	0	87	4	2,437	0	413	11,742	221	225	225
April	535	33	51	7,172	744	0	102	4	2,237	0	380	11,258	241	245	245
May	572	41	56	7,614	778	0	101	5	2,390	0	409	11,967	267	271	271
June	590	34	64	7,918	775	0	74	5	2,358	0	381	12,199	268	273	273
July	606	49	57	8,609	813	0	78	5	2,540	0	381	13,138	277	282	282
August	590	35	54	8,634	909	0	91	5	2,474	0	421	13,212	268	273	273
September	558	34	51	8,022	773	0	90	4	2,290	0	363	12,185	242	247	247
October	507	39	58	7,941	762	0	108	4	2,307	0	402	12,127	220	224	224
November	536	46	38	8,127	734	0	116	3	2,318	0	396	12,313	174	177	177
December	596	46	49	8,237	771	0	130	2	2,464	0	429	12,724	157	160	160
Year 2019															
January	581	48	40	8,739	664	0	124	4	2,393	0	432	13,025	168	172	172
February	521	40	36	7,538	597	0	94	5	2,156	0	348	11,335	178	182	182
March	500	37	37	7,978	702	0	108	7	2,348	0	384	12,099	254	261	261
April	475	40	45	7,552	619	0	106	8	2,110	0	346	11,301	278	286	286
May	479	30	41	7,951	730	0	104	9	2,150	0	361	11,854	309	317	317
June	484	31	47	8,196	680	0	95	10	2,244	0	360	12,147	311	320	320
July	528	28	105	8,837	813	0	71	10	2,391	0	394	13,178	321	331	331
August	506	33	50	8,976	770	0	59	9	2,419	0	413	13,236	311	320	320
September	470	34	44	8,483	770	0	52	8	2,211	0	402	12,474	281	289	289
October	445	32	44	8,348	735	0	63	7	2,233	0	375	12,281	255	262	262
November	480	36	41	8,561	721	0	67	5	2,249	0	371	12,531	198	204	204
December	489	35	45	8,906	753	0	91	4	2,372	0	382	13,077	179	183	183

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report;

Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.5.B. Net Generation from Renewable Sources: Industrial Sector, 2009 - 2019
(Thousand Megawatthours)

		Generation at Utility Scale Facilities										Small Scale Generation	Generation From Utility and Small Scale Facilities	
Period		Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Landfill Gas	Biogenic Municipal Solid Waste	Other Waste Biomass	Geothermal	Conventional Hydroelectric	Total Renewable Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
Annual Totals														
	2009	0	0	0	25,292	22	0	718	0	1,868	27,901	N/A	N/A	N/A
	2010	0	2	0	25,706	15	0	853	0	1,668	28,244	N/A	N/A	N/A
	2011	5	7	0	26,691	15	2	900	0	1,799	29,418	N/A	N/A	N/A
	2012	19	14	0	26,725	81	10	857	0	2,353	30,060	N/A	N/A	N/A
	2013	37	17	0	27,691	178	2	1,166	0	3,463	32,554	N/A	N/A	N/A
	2014	53	16	0	27,239	185	-2	1,185	0	1,282	29,957	1,139	1,156	1,156
	2015	53	21	0	27,318	182	12	1,049	0	1,410	30,045	1,451	1,472	1,472
	2016	71	27	0	27,458	170	6	959	0	1,269	29,960	2,060	2,087	2,087
	2017	84	42	0	27,412	183	1	827	0	1,382	29,932	2,364	2,406	2,406
	2018	97	47	0	27,475	168	4	697	0	1,149	29,636	2,636	2,683	2,683
	2019	100	85	0	26,433	139	5	598	0	1,033	28,395	3,041	3,127	3,127
Year 2017														
	January	7	2	0	2,305	16	-1	74	0	127	2,530	123	124	124
	February	8	2	0	2,117	16	-1	68	0	116	2,326	137	139	139
	March	9	3	0	2,237	17	-1	80	0	129	2,474	197	200	200
	April	8	4	0	2,167	15	-1	74	0	149	2,417	213	217	217
	May	8	4	0	2,204	14	1	66	0	158	2,454	239	243	243
	June	7	5	0	2,337	16	0	56	0	129	2,551	241	246	246
	July	4	5	0	2,457	13	1	64	0	117	2,661	252	257	257
	August	4	5	0	2,472	15	1	65	0	93	2,655	246	251	251
	September	4	4	0	2,202	14	1	57	0	74	2,356	223	227	227
	October	8	3	0	2,215	15	1	69	0	79	2,390	201	204	204
	November	9	3	0	2,257	16	0	75	0	116	2,476	156	158	158
	December	8	2	0	2,442	17	0	79	0	96	2,643	138	141	141
Year 2018														
	January	11	2	0	2,357	15	0	67	0	83	2,535	146	149	149
	February	9	3	0	2,091	15	0	61	0	89	2,269	155	158	158
	March	10	4	0	2,342	16	1	68	0	87	2,528	221	225	225
	April	9	4	0	2,151	16	0	60	0	102	2,343	241	245	245
	May	8	5	0	2,310	14	0	58	0	101	2,496	267	271	271
	June	6	5	0	2,294	14	1	43	0	74	2,437	268	273	273
	July	5	5	0	2,470	14	1	51	0	78	2,623	277	282	282
	August	5	5	0	2,402	13	1	53	0	91	2,570	268	273	273
	September	6	4	0	2,228	12	0	44	0	90	2,385	242	247	247
	October	9	4	0	2,223	13	0	62	0	108	2,418	220	224	224
	November	9	3	0	2,231	13	0	65	0	116	2,436	174	177	177
	December	9	2	0	2,374	13	0	67	0	130	2,596	157	160	160
Year 2019														
	January	11	4	0	2,317	12	0	53	0	124	2,520	168	172	172
	February	9	5	0	2,086	11	0	50	0	94	2,255	178	182	182
	March	10	7	0	2,267	12	0	59	0	108	2,462	254	261	261
	April	10	8	0	2,034	12	1	53	0	106	2,224	278	286	286
	May	8	9	0	2,084	12	0	46	0	104	2,263	309	317	317
	June	8	10	0	2,179	11	0	46	0	95	2,349	311	320	320
	July	6	10	0	2,331	11	1	43	0	71	2,473	321	331	331
	August	5	9	0	2,357	11	0	45	0	59	2,488	311	320	320
	September	5	8	0	2,157	11	0	37	0	52	2,271	281	289	289
	October	9	7	0	2,157	12	1	53	0	63	2,302	255	262	262
	November	8	5	0	2,174	12	0	55	0	67	2,321	198	204	204
	December	11	4	0	2,289	13	1	59	0	91	2,466	179	183	183

Wood and Wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Waste Biomass includes sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.6. Net Generation by Energy Source: Residential Sector, 2014 - 2019
(Thousand Megawatthours)

Period	Small Scale Generation
	Estimated Small Scale Solar Photovoltaic Generation
Annual Totals	
2014	4,947
2015	6,999
2016	10,595
2017	13,942
2018	17,105
2019	20,914
Year 2017	
January	703
February	789
March	1,147
April	1,283
May	1,415
June	1,469
July	1,495
August	1,446
September	1,293
October	1,157
November	904
December	841
Year 2018	
January	921
February	1,007
March	1,393
April	1,592
May	1,753
June	1,788
July	1,834
August	1,756
September	1,539
October	1,385
November	1,108
December	1,029
Year 2019	
January	1,107
February	1,205
March	1,727
April	1,935
May	2,130
June	2,175
July	2,268
August	2,184
September	1,930
October	1,697
November	1,346
December	1,210

See Glossary for definitions. Values are final.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Sources:

Estimated small scale solar photovoltaic generation and small scale solar photovoltaic capacity are based on data from Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 3.7. Utility Scale Facility Net Generation
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	99,997	105,548	-5.3%	2,414	2,968	93,277	98,313	1,307	1,371	2,998	2,897
Connecticut	40,050	39,454	1.5%	99	109	38,846	38,267	445	433	661	644
Maine	10,491	11,281	-7.0%	4	0	8,457	9,308	132	165	1,898	1,807
Massachusetts	21,516	27,173	-20.8%	407	587	20,239	25,676	606	642	264	269
New Hampshire	18,027	17,087	5.5%	935	1,417	16,997	15,571	64	69	30	31
Rhode Island	7,624	8,375	-9.0%	0	0	7,421	8,170	57	59	146	146
Vermont	2,290	2,179	5.1%	970	856	1,316	1,320	3	3	0	0
Middle Atlantic	431,617	422,940	2.1%	35,171	35,936	389,911	380,377	2,381	2,286	4,155	4,340
New Jersey	71,019	75,034	-5.4%	145	125	69,390	73,602	704	602	780	704
New York	131,603	132,521	-0.7%	34,926	35,660	94,557	94,641	1,278	1,312	843	908
Pennsylvania	228,995	215,386	6.3%	100	151	225,964	212,134	399	373	2,532	2,728
East North Central	586,452	609,422	-3.8%	215,936	240,648	357,937	356,005	1,751	1,924	10,829	10,845
Illinois	184,470	188,003	-1.9%	5,192	5,450	176,335	179,341	363	405	2,580	2,807
Indiana	102,505	113,460	-9.7%	70,437	84,830	27,387	24,138	292	250	4,390	4,242
Michigan	116,701	115,837	0.7%	78,882	81,450	35,687	32,195	729	867	1,403	1,324
Ohio	120,001	126,185	-4.9%	13,064	17,624	106,004	107,628	230	256	704	676
Wisconsin	62,774	65,937	-4.8%	48,361	51,294	12,524	12,702	137	145	1,752	1,796
West North Central	344,147	353,902	-2.8%	272,591	290,130	66,980	59,134	648	631	3,928	4,006
Iowa	62,650	63,381	-1.2%	47,135	49,513	13,035	11,531	231	227	2,248	2,110
Kansas	50,888	51,710	-1.6%	31,468	34,518	19,305	17,091	17	16	98	86
Minnesota	59,379	61,517	-3.5%	44,812	48,577	13,249	11,416	191	193	1,127	1,331
Missouri	78,279	85,095	-8.0%	72,581	79,780	5,472	5,098	192	175	34	43
Nebraska	37,298	36,966	0.9%	30,018	31,167	6,914	5,407	18	18	348	374
North Dakota	41,147	42,615	-3.4%	34,191	35,946	6,896	6,604	0	NM	60	62
South Dakota	14,507	12,616	15.0%	12,385	10,628	2,109	1,988	0	0	12	0
South Atlantic	811,088	819,993	-1.1%	669,612	674,016	120,785	125,574	2,004	1,728	18,687	18,675
Delaware	5,259	6,241	-15.7%	35	37	3,886	5,124	6	6	1,332	1,073
District of Columbia	174	79	119.4%	0	0	9	0	165	79	0	0
Florida	245,603	244,252	0.6%	229,438	227,284	10,989	11,808	70	80	5,107	5,079
Georgia	128,692	129,239	-0.4%	107,079	109,171	16,421	14,824	7	7	5,184	5,238
Maryland	39,326	43,810	-10.2%	3,359	3,797	34,782	38,930	1,039	840	146	244
North Carolina	131,174	134,249	-2.3%	111,312	117,492	17,822	14,636	347	332	1,692	1,790
South Carolina	100,108	99,364	0.7%	95,689	94,058	2,838	3,602	3	3	1,577	1,702
Virginia	96,828	95,509	1.4%	74,386	72,379	19,670	20,264	368	382	2,404	2,484
West Virginia	63,926	67,249	-4.9%	48,312	49,799	14,367	16,385	0	0	1,246	1,065
East South Central	362,770	368,891	-1.7%	313,578	312,387	39,144	47,022	213	229	9,836	9,253
Alabama	142,679	145,058	-1.6%	102,180	102,665	35,596	37,771	0	0	4,903	4,622
Kentucky	71,804	78,804	-8.9%	70,897	77,557	396	715	0	0	512	533
Mississippi	65,959	63,474	3.9%	61,366	53,311	2,702	8,248	0	0	1,891	1,915
Tennessee	82,327	81,555	0.9%	79,135	78,854	449	289	213	229	2,531	2,183
West South Central	733,035	733,704	-0.1%	244,261	256,469	409,475	398,531	975	957	78,324	77,747
Arkansas	64,443	67,999	-5.2%	57,343	59,485	5,451	6,829	56	44	1,592	1,642
Louisiana	100,175	102,128	-1.9%	59,912	62,152	7,912	9,167	164	170	32,187	30,639
Oklahoma	85,217	86,224	-1.2%	41,188	41,868	43,198	43,469	0	0	830	887
Texas	483,201	477,352	1.2%	85,818	92,965	352,914	339,066	755	743	43,714	44,579
Mountain	372,421	371,498	0.2%	286,297	289,926	82,251	77,889	1,011	576	2,862	3,107
Arizona	113,552	111,925	1.5%	96,645	98,448	16,754	13,323	152	154	0	0
Colorado	56,338	55,386	1.7%	43,713	42,037	12,514	13,248	36	27	75	76
Idaho	18,408	18,172	1.3%	11,986	11,904	5,777	5,695	65	50	580	523
Montana	27,797	28,213	-1.5%	10,708	12,087	17,057	16,090	0	0	32	36
Nevada	39,890	39,640	0.6%	27,293	27,482	11,715	11,667	569	159	312	332
New Mexico	35,175	32,674	7.7%	23,575	21,112	11,486	11,431	109	107	4	24
Utah	39,117	39,375	-0.7%	34,770	34,901	3,747	3,803	80	79	520	592
Wyoming	42,146	46,112	-8.6%	37,607	41,955	3,201	2,633	0	0	1,338	1,525
Pacific Contiguous	370,506	376,336	-1.5%	215,445	223,897	135,809	134,016	2,721	2,885	16,531	15,538
California	201,784	195,466	3.2%	82,940	75,239	102,455	103,882	2,627	2,779	13,762	13,566
Oregon	62,258	64,114	-2.9%	44,038	47,020	17,578	16,410	71	74	570	609
Washington	106,464	116,757	-8.8%	88,467	101,638	15,776	13,724	22	32	2,199	1,363
Pacific Noncontiguous	15,821	16,044	-1.4%	10,699	10,871	4,056	4,057	678	726	388	391
Alaska	6,071	6,247	-2.8%	5,447	5,575	243	234	265	328	116	110
Hawaii	9,750	9,797	-0.5%	5,252	5,296	3,813	3,822	413	398	272	281
U.S. Total	4,127,855	4,178,277	-1.2%	2,266,004	2,337,250	1,699,625	1,680,917	13,689	13,312	148,537	146,798

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.8. Utility Scale Facility Net Generation from Coal
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	467	1,061	-56.0%	343	660	114	386	0	0	11	15
Connecticut	53	330	-83.9%	0	0	53	330	0	0	0	0
Maine	71	71	0.3%	0	0	61	56	0	0	11	15
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	343	660	-48.1%	343	660	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	39,392	45,970	-14.3%	0	0	39,304	45,843	0	0	88	127
New Jersey	1,042	1,193	-12.7%	0	0	1,042	1,193	0	0	0	0
New York	422	690	-38.9%	0	0	422	679	0	0	0	11
Pennsylvania	37,929	44,086	-14.0%	0	0	37,841	43,970	0	0	88	116
East North Central	219,992	271,477	-19.0%	128,525	161,313	89,534	107,879	58	69	1,875	2,217
Illinois	48,788	59,642	-18.2%	3,482	4,052	43,772	53,810	13	31	1,522	1,748
Indiana	60,762	77,455	-21.6%	56,524	73,105	4,193	4,312	45	38	0	0
Michigan	37,341	42,331	-11.8%	36,942	41,830	381	427	0	0	18	73
Ohio	46,765	58,727	-20.4%	5,575	9,391	41,187	49,330	0	0	3	6
Wisconsin	26,335	33,322	-21.0%	26,003	32,933	0	0	0	0	333	389
West North Central	161,119	189,023	-14.8%	158,954	186,667	0	0	79	85	2,086	2,270
Iowa	22,159	28,553	-22.4%	20,551	26,969	0	0	68	74	1,541	1,509
Kansas	17,315	20,474	-15.4%	17,315	20,474	0	0	0	0	0	0
Minnesota	17,805	23,455	-24.1%	17,605	23,068	0	0	2	1	197	387
Missouri	55,686	63,355	-12.1%	55,678	63,345	0	0	9	10	0	0
Nebraska	20,385	23,305	-12.5%	20,038	22,931	0	0	0	0	348	374
North Dakota	25,151	27,541	-8.7%	25,151	27,541	0	0	0	0	0	0
South Dakota	2,617	2,339	11.9%	2,617	2,339	0	0	0	0	0	0
South Atlantic	159,468	195,286	-18.3%	141,570	170,331	17,280	24,215	40	45	577	695
Delaware	119	273	-56.4%	0	0	119	273	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	21,248	30,272	-29.8%	21,197	30,175	0	0	0	0	51	98
Georgia	25,245	32,181	-21.6%	25,065	31,983	0	0	0	0	181	198
Maryland	5,722	10,067	-43.2%	0	0	5,690	10,007	0	0	32	60
North Carolina	30,672	31,690	-3.2%	30,413	31,412	86	98	36	39	137	142
South Carolina	14,861	19,497	-23.8%	14,640	19,481	212	0	0	0	10	16
Virginia	3,418	9,266	-63.1%	3,176	8,453	71	625	4	6	167	182
West Virginia	58,182	62,039	-6.2%	47,080	48,827	11,101	13,211	0	0	0	0
East South Central	101,476	117,192	-13.4%	98,613	113,670	2,363	2,831	0	0	500	691
Alabama	26,655	31,778	-16.1%	26,638	31,734	0	0	0	0	17	44
Kentucky	51,714	59,168	-12.6%	51,714	59,168	0	0	0	0	0	0
Mississippi	4,414	5,280	-16.4%	2,052	2,449	2,363	2,831	0	0	0	0
Tennessee	18,692	20,967	-10.8%	18,209	20,320	0	0	0	0	483	647
West South Central	130,375	168,412	-22.6%	67,575	92,704	62,639	75,458	0	0	161	250
Arkansas	23,313	29,996	-22.3%	19,338	24,754	3,933	5,197	0	0	43	46
Louisiana	7,419	11,787	-37.1%	5,633	7,780	1,786	4,007	0	0	0	0
Oklahoma	7,826	14,907	-47.5%	7,708	12,868	0	1,834	0	0	119	205
Texas	91,817	111,723	-17.8%	34,897	47,302	56,920	64,420	0	0	0	0
Mountain	140,704	151,985	-7.4%	124,330	136,335	15,979	15,208	0	0	395	442
Arizona	23,218	30,745	-24.5%	23,218	30,745	0	0	0	0	0	0
Colorado	25,321	26,382	-4.0%	25,316	26,370	0	0	0	0	5	12
Idaho	21	20	3.3%	0	0	0	0	0	0	21	20
Montana	14,101	13,360	5.5%	261	234	13,831	13,116	0	0	9	10
Nevada	2,735	2,485	10.1%	1,689	1,443	1,047	1,042	0	0	0	0
New Mexico	14,692	13,402	9.6%	14,692	13,402	0	0	0	0	0	0
Utah	25,241	25,912	-2.6%	24,842	25,501	400	412	0	0	0	0
Wyoming	35,376	39,679	-10.8%	34,314	38,642	702	638	0	0	360	400
Pacific Contiguous	9,980	7,141	39.8%	2,569	1,476	7,146	5,359	0	0	264	305
California	240	281	-14.5%	0	0	0	0	0	0	240	281
Oregon	2,569	1,476	74.0%	2,569	1,476	0	0	0	0	0	0
Washington	7,170	5,383	33.2%	0	0	7,146	5,359	0	0	24	24
Pacific Noncontiguous	1,985	1,940	2.3%	406	347	1,489	1,489	91	103	0	0
Alaska	683	629	8.7%	406	347	187	178	91	103	0	0
Hawaii	1,302	1,311	-0.7%	0	0	1,302	1,311	0	0	0	0
U.S. Total	964,957	1,149,487	-16.1%	722,885	863,505	235,847	278,668	268	303	5,957	7,011

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.9. Utility Scale Facility Net Generation from Petroleum Liquids
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	193	1,246	-84.5%	23	184	116	1,006	37	36	17	20
Connecticut	12	339	-96.4%	5	5	1	329	3	3	3	1
Maine	35	189	-81.6%	0	0	20	171	2	2	12	17
Massachusetts	104	461	-77.5%	7	75	79	371	16	13	1	2
New Hampshire	30	178	-83.1%	9	101	7	61	13	16	0	0
Rhode Island	11	76	-85.4%	0	0	9	74	2	2	0	0
Vermont	1	3	-67.1%	1	3	0	0	0	0	0	0
Middle Atlantic	740	2,452	-69.8%	244	621	457	1,767	15	23	24	41
New Jersey	71	302	-76.3%	1	3	67	293	2	5	1	1
New York	512	1,591	-67.8%	242	616	245	926	9	13	16	35
Pennsylvania	157	559	-72.0%	0	2	145	548	4	4	7	5
East North Central	481	556	-13.4%	291	299	175	226	2	6	14	25
Illinois	44	53	-18.0%	8	8	36	45	0	0	0	0
Indiana	127	131	-3.0%	119	110	0	0	NM	1	7	19
Michigan	94	117	-20.3%	90	112	0	0	1	4	2	2
Ohio	164	219	-24.7%	30	34	130	180	0	1	3	3
Wisconsin	53	36	47.3%	43	35	9	1	0	0	1	1
West North Central	353	323	9.3%	339	300	10	19	2	2	1	1
Iowa	63	67	-5.4%	60	63	4	4	0	0	0	0
Kansas	78	52	50.2%	78	52	0	0	0	0	0	0
Minnesota	51	47	8.7%	40	28	7	16	2	2	1	1
Missouri	97	100	-2.6%	97	100	0	0	0	0	0	0
Nebraska	16	12	29.6%	16	12	0	0	0	0	0	0
North Dakota	34	38	-12.4%	34	38	0	0	0	0	0	0
South Dakota	14	6	113.2%	14	6	0	0	0	0	0	0
South Atlantic	1,175	3,398	-65.4%	899	2,386	157	819	45	55	74	138
Delaware	19	201	-90.7%	0	6	18	195	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	324	572	-43.3%	301	537	7	12	0	0	17	23
Georgia	107	279	-61.5%	61	105	5	92	4	5	38	77
Maryland	67	260	-74.1%	-1	3	66	253	1	1	1	3
North Carolina	192	633	-69.7%	177	570	5	41	1	2	9	19
South Carolina	79	344	-77.2%	69	327	3	5	0	0	7	11
Virginia	258	950	-72.9%	164	692	52	207	40	47	2	4
West Virginia	128	159	-19.2%	127	145	1	14	0	0	0	0
East South Central	224	293	-23.6%	209	250	4	30	0	0	11	13
Alabama	20	66	-69.7%	10	29	3	29	0	0	6	7
Kentucky	50	70	-28.3%	50	70	0	0	0	0	0	0
Mississippi	14	27	-49.8%	12	23	0	0	0	0	2	4
Tennessee	140	130	7.8%	137	127	0	0	0	0	2	2
West South Central	147	136	8.1%	101	104	35	24	1	1	10	8
Arkansas	47	36	32.7%	33	27	12	6	0	0	3	3
Louisiana	28	21	33.0%	18	21	11	0	0	0	0	0
Oklahoma	18	18	-2.6%	16	17	0	0	0	0	1	1
Texas	54	61	-11.7%	34	39	13	18	1	1	6	4
Mountain	367	186	97.1%	349	165	18	21	0	0	0	0
Arizona	64	50	27.6%	64	50	0	0	0	0	0	0
Colorado	8	12	-33.0%	8	11	0	0	0	0	0	0
Idaho	0	0	304.3%	0	0	0	0	0	0	0	0
Montana	16	17	-6.2%	2	0	14	16	0	0	0	0
Nevada	12	10	20.5%	10	7	2	3	0	0	0	0
New Mexico	184	21	785.4%	184	21	0	0	0	0	0	0
Utah	40	37	8.8%	38	35	2	1	0	0	0	0
Wyoming	44	40	9.0%	44	40	0	0	0	0	0	0
Pacific Contiguous	77	97	-20.5%	43	43	15	16	1	1	19	38
California	51	69	-26.0%	35	34	6	5	1	1	9	29
Oregon	7	5	36.4%	7	5	0	0	0	0	0	0
Washington	20	24	-16.0%	1	4	9	10	0	0	10	9
Pacific Noncontiguous	7,765	7,558	2.7%	5,817	5,756	1,682	1,560	13	9	254	233
Alaska	901	809	11.4%	845	761	3	0	7	6	47	43
Hawaii	6,864	6,749	1.7%	4,972	4,995	1,679	1,560	6	3	207	191
U.S. Total	11,522	16,245	-29.1%	8,313	10,108	2,669	5,487	116	132	424	517

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.10. Utility Scale Facility Net Generation from Petroleum Coke
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	99	127	-21.5%	0	0	0	0	0	0	99	127
New Jersey	71	60	17.7%	0	0	0	0	0	0	71	60
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	28	66	-57.1%	0	0	0	0	0	0	28	66
East North Central	1,591	2,295	-30.7%	762	1,085	676	1,087	0	0	153	123
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	822	1,096	-25.0%	673	984	0	0	0	0	149	112
Ohio	680	1,097	-38.0%	0	0	676	1,087	0	0	4	10
Wisconsin	90	101	-11.6%	90	101	0	0	0	0	0	0
West North Central	77	44	77.6%	0	0	0	0	5	7	73	36
Iowa	77	44	77.6%	0	0	0	0	5	7	73	36
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	1,341	1,662	-19.3%	1,201	1,506	0	0	0	0	140	156
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	1,201	1,506	-20.2%	1,201	1,506	0	0	0	0	0	0
Georgia	140	156	-10.6%	0	0	0	0	0	0	140	156
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	-100.0%	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	-100.0%	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	3,261	4,425	-26.3%	3,149	4,227	0	0	0	0	111	198
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	3,160	4,356	-27.5%	3,149	4,227	0	0	0	0	11	130
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	100	68	47.4%	0	0	0	0	0	0	100	68
Mountain	449	429	4.6%	0	0	449	429	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	449	429	4.6%	0	0	449	429	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	6,819	8,981	-24.1%	5,112	6,817	1,125	1,516	5	7	576	640

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.11. Utility Scale Facility Net Generation from Natural Gas
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	49,272	51,613	-4.5%	151	258	46,503	48,764	1,055	1,087	1,562	1,504
Connecticut	21,343	20,006	6.7%	54	59	20,195	18,875	437	429	658	643
Maine	1,797	2,331	-22.9%	0	0	1,295	1,878	31	30	472	422
Massachusetts	15,407	18,386	-16.2%	92	167	14,529	17,387	529	570	258	262
New Hampshire	3,583	2,992	19.8%	5	31	3,537	2,922	11	8	30	31
Rhode Island	7,141	7,897	-9.6%	0	0	6,948	7,702	48	49	145	146
Vermont	2	2	3.0%	1	1	0	0	1	1	0	0
Middle Atlantic	186,102	166,065	12.1%	9,947	10,538	172,408	151,816	1,205	1,182	2,542	2,529
New Jersey	40,449	38,863	4.1%	158	161	39,615	38,119	251	181	425	401
New York	47,612	50,810	-6.3%	9,785	10,370	36,437	38,948	812	870	578	623
Pennsylvania	98,040	76,391	28.3%	4	7	96,356	74,749	142	130	1,538	1,505
East North Central	159,477	136,058	17.2%	51,737	45,498	102,150	85,671	1,424	1,462	4,167	3,427
Illinois	21,346	17,241	23.8%	1,534	1,224	18,923	15,040	341	364	548	613
Indiana	32,042	26,817	19.5%	13,069	10,965	16,746	14,156	201	168	2,025	1,528
Michigan	34,430	30,987	11.1%	11,751	10,493	21,475	19,459	604	612	599	423
Ohio	51,325	44,215	16.1%	7,169	7,956	43,706	35,809	214	243	236	207
Wisconsin	20,334	16,799	21.0%	18,214	14,861	1,300	1,207	63	75	758	656
West North Central	35,005	29,103	20.3%	28,492	24,754	5,316	3,245	354	321	843	783
Iowa	7,782	7,340	6.0%	7,088	6,705	0	7	117	98	576	529
Kansas	3,024	3,006	0.6%	2,931	2,922	0	0	0	0	93	84
Minnesota	12,607	8,555	47.4%	9,559	7,221	2,834	1,107	94	108	119	120
Missouri	7,675	7,050	8.9%	5,023	4,767	2,482	2,131	138	112	32	40
Nebraska	1,277	965	32.3%	1,273	961	0	0	4	3	0	0
North Dakota	1,471	1,019	44.3%	1,461	1,009	0	0	0	0	10	10
South Dakota	1,170	1,168	0.2%	1,157	1,168	0	0	0	0	12	0
South Atlantic	385,449	359,797	7.1%	316,793	293,723	62,272	60,703	1,279	970	5,105	4,402
Delaware	4,806	5,400	-11.0%	28	25	3,650	4,567	0	0	1,128	809
District of Columbia	110	23	383.6%	0	0	0	0	110	23	0	0
Florida	182,007	171,872	5.9%	173,358	162,843	6,961	7,450	19	30	1,669	1,550
Georgia	58,620	51,972	12.8%	44,720	39,240	13,356	12,139	0	0	544	594
Maryland	14,605	13,850	5.5%	3,351	3,785	10,184	9,165	1,005	812	65	88
North Carolina	41,147	43,446	-5.3%	32,238	36,506	8,626	6,713	127	90	155	136
South Carolina	23,926	21,654	10.5%	22,793	18,921	1,002	2,604	0	0	130	128
Virginia	57,985	50,160	15.6%	39,928	32,229	17,267	17,172	17	16	773	744
West Virginia	2,243	1,420	57.9%	377	174	1,225	894	0	0	641	352
East South Central	138,274	136,296	1.5%	99,001	90,460	35,589	43,021	208	225	3,477	2,591
Alabama	57,197	58,800	-2.7%	20,447	20,266	35,191	37,234	0	0	1,560	1,300
Kentucky	15,341	14,615	5.0%	14,730	13,717	377	695	0	0	235	204
Mississippi	48,781	49,482	-1.4%	48,270	43,920	4	5,078	0	0	507	484
Tennessee	16,955	13,399	26.5%	15,555	12,557	17	14	208	225	1,175	603
West South Central	391,113	363,732	7.5%	134,611	121,869	186,221	173,564	891	861	69,390	67,437
Arkansas	21,772	20,624	5.6%	20,261	18,983	1,169	1,305	42	38	300	297
Louisiana	69,523	61,782	12.5%	37,045	32,970	4,667	3,902	164	170	27,648	24,740
Oklahoma	44,188	41,613	6.2%	28,190	25,682	15,585	15,560	0	0	413	371
Texas	255,630	239,713	6.6%	49,116	44,234	164,801	152,797	685	653	41,029	42,029
Mountain	115,932	105,259	10.1%	92,575	84,423	21,479	18,878	422	413	1,456	1,545
Arizona	46,084	37,168	24.0%	34,495	28,897	11,453	8,130	136	141	0	0
Colorado	17,097	16,398	4.3%	14,717	13,804	2,351	2,575	6	1	23	19
Idaho	4,267	3,279	30.1%	2,290	1,553	1,801	1,594	39	39	136	92
Montana	507	476	6.5%	346	342	158	131	0	0	3	4
Nevada	25,775	26,689	-3.4%	23,227	24,148	2,175	2,149	63	62	310	330
New Mexico	11,803	11,628	1.5%	8,225	7,277	3,467	4,223	106	104	4	24
Utah	9,369	8,724	7.4%	8,863	8,170	72	75	71	65	363	414
Wyoming	1,029	896	14.9%	412	233	1	1	0	0	616	662
Pacific Contiguous	122,502	118,263	3.6%	49,100	45,800	60,175	59,955	1,772	1,898	11,455	10,609
California	85,841	89,805	-4.4%	28,600	29,994	44,854	47,525	1,721	1,835	10,665	10,451
Oregon	20,932	17,923	16.8%	10,246	9,032	10,570	8,773	44	45	72	73
Washington	15,729	10,535	49.3%	10,253	6,774	4,751	3,657	7	19	718	85
Pacific Noncontiguous	2,687	2,948	-8.9%	2,619	2,883	0	0	0	0	68	65
Alaska	2,687	2,948	-8.9%	2,619	2,883	0	0	0	0	68	65
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,585,814	1,469,133	7.9%	785,026	720,206	692,113	645,616	8,610	8,419	100,065	94,892

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.12. Utility Scale Facility Net Generation from Other Gases
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	713	741	-3.8%	0	0	0	1	0	0	713	739
New Jersey	216	212	2.0%	0	0	0	0	0	0	216	212
New York	2	0	--	0	0	0	0	0	0	2	0
Pennsylvania	494	528	-6.4%	0	0	0	1	0	0	494	527
East North Central	4,717	4,911	-4.0%	154	151	2,174	2,077	0	0	2,390	2,683
Illinois	261	201	29.9%	0	0	0	1	0	0	261	200
Indiana	1,984	2,326	-14.7%	0	0	0	0	0	0	1,984	2,326
Michigan	1,697	1,598	6.2%	154	151	1,543	1,447	0	0	0	0
Ohio	776	787	-1.4%	0	0	631	630	0	0	145	157
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	50	51	-2.6%	0	0	0	0	0	0	50	51
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	50	51	-2.6%	0	0	0	0	0	0	50	51
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	236	283	-16.6%	0	0	0	0	0	0	236	283
Delaware	194	252	-23.1%	0	0	0	0	0	0	194	252
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	5	-97.1%	0	0	0	0	0	0	0	5
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	42	25	67.4%	0	0	0	0	0	0	42	25
East South Central	15	16	-6.8%	0	0	0	0	0	0	15	16
Alabama	3	5	-44.7%	0	0	0	0	0	0	3	5
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	12	11	9.5%	0	0	0	0	0	0	12	11
West South Central	4,744	5,124	-7.4%	0	0	1,699	1,413	0	0	3,045	3,711
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,875	2,598	-27.8%	0	0	0	0	0	0	1,875	2,598
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	2,869	2,526	13.6%	0	0	1,699	1,413	0	0	1,170	1,113
Mountain	313	397	-21.1%	0	0	10	12	0	0	303	384
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	10	12	-19.2%	0	0	10	12	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	17	7	159.5%	0	0	0	0	0	0	17	7
Wyoming	286	378	-24.3%	0	0	0	0	0	0	286	378
Pacific Contiguous	1,798	1,885	-4.6%	0	0	0	431	0	0	1,798	1,454
California	1,476	1,454	1.5%	0	0	0	0	0	0	1,476	1,454
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	322	431	-25.2%	0	0	0	431	0	0	322	0
Pacific Noncontiguous	6	56	-89.9%	0	0	0	0	0	0	6	56
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	6	56	-89.9%	0	0	0	0	0	0	6	56
U.S. Total	12,591	13,463	-6.5%	154	151	3,883	3,935	0	0	8,554	9,377

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.13. Utility Scale Facility Net Generation from Nuclear Energy
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	29,818	31,385	-5.0%	0	0	29,818	31,385	0	0	0	0
Connecticut	16,733	16,881	-0.9%	0	0	16,733	16,881	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	2,177	4,442	-51.0%	0	0	2,177	4,442	0	0	0	0
New Hampshire	10,907	10,062	8.4%	0	0	10,907	10,062	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	154,732	158,378	-2.3%	0	0	154,732	158,378	0	0	0	0
New Jersey	26,637	31,982	-16.7%	0	0	26,637	31,982	0	0	0	0
New York	44,865	42,919	4.5%	0	0	44,865	42,919	0	0	0	0
Pennsylvania	83,230	83,477	-0.3%	0	0	83,230	83,477	0	0	0	0
East North Central	158,686	157,024	1.1%	26,044	25,023	132,642	132,002	0	0	0	0
Illinois	98,735	98,102	0.6%	0	0	98,735	98,102	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	32,909	30,479	8.0%	26,044	25,023	6,865	5,456	0	0	0	0
Ohio	17,011	18,315	-7.1%	0	0	17,011	18,315	0	0	0	0
Wisconsin	10,030	10,129	-1.0%	0	0	10,030	10,129	0	0	0	0
West North Central	44,729	44,952	-0.5%	39,494	40,057	5,236	4,895	0	0	0	0
Iowa	5,236	4,895	7.0%	0	0	5,236	4,895	0	0	0	0
Kansas	9,248	9,168	0.9%	9,248	9,168	0	0	0	0	0	0
Minnesota	14,105	14,601	-3.4%	14,105	14,601	0	0	0	0	0	0
Missouri	9,190	10,655	-13.8%	9,190	10,655	0	0	0	0	0	0
Nebraska	6,952	5,632	23.4%	6,952	5,632	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	205,228	202,708	1.2%	190,215	187,720	15,013	14,988	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	29,108	29,312	-0.7%	29,108	29,312	0	0	0	0	0	0
Georgia	33,591	34,363	-2.2%	33,591	34,363	0	0	0	0	0	0
Maryland	15,013	14,988	0.2%	0	0	15,013	14,988	0	0	0	0
North Carolina	41,916	42,077	-0.4%	41,916	42,077	0	0	0	0	0	0
South Carolina	56,103	52,716	6.4%	56,103	52,716	0	0	0	0	0	0
Virginia	29,498	29,252	0.8%	29,498	29,252	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	90,410	82,559	9.5%	90,410	82,559	0	0	0	0	0	0
Alabama	43,657	39,463	10.6%	43,657	39,463	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	11,033	6,919	59.4%	11,033	6,919	0	0	0	0	0	0
Tennessee	35,720	36,176	-1.3%	35,720	36,176	0	0	0	0	0	0
West South Central	68,854	71,059	-3.1%	27,556	29,873	41,298	41,186	0	0	0	0
Arkansas	13,575	12,721	6.7%	13,575	12,721	0	0	0	0	0	0
Louisiana	13,981	17,153	-18.5%	13,981	17,153	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	41,298	41,186	0.3%	0	0	41,298	41,186	0	0	0	0
Mountain	31,920	31,097	2.6%	31,920	31,097	0	0	0	0	0	0
Arizona	31,920	31,097	2.6%	31,920	31,097	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	25,032	27,922	-10.4%	25,032	27,922	0	0	0	0	0	0
California	16,165	18,214	-11.2%	16,165	18,214	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	8,866	9,708	-8.7%	8,866	9,708	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	809,409	807,084	0.3%	430,672	424,251	378,738	382,833	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.14. Utility Scale Facility Net Generation from Hydroelectric (Conventional) Power by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	7,706	7,577	1.7%	1,068	1,078	6,520	6,380	6	4	113	114
Connecticut	428	555	-22.9%	36	41	391	514	0	0	0	0
Maine	3,499	3,261	7.3%	4	0	3,383	3,147	0	0	113	114
Massachusetts	976	1,134	-13.9%	188	268	782	862	6	4	0	0
New Hampshire	1,462	1,355	7.9%	363	371	1,099	984	0	0	0	0
Rhode Island	4	4	-11.2%	0	0	4	4	0	0	0	0
Vermont	1,337	1,268	5.4%	476	398	861	870	0	0	0	0
Middle Atlantic	34,150	33,927	0.7%	25,310	25,247	8,774	8,615	6	6	59	59
New Jersey	26	36	-25.5%	0	0	26	36	0	0	0	0
New York	30,621	29,630	3.3%	25,215	25,105	5,340	4,460	6	6	59	59
Pennsylvania	3,503	4,262	-17.8%	96	142	3,407	4,120	0	0	0	0
East North Central	5,073	4,574	10.9%	4,474	4,068	475	354	1	1	124	151
Illinois	124	147	-15.5%	42	61	81	84	1	1	0	0
Indiana	256	223	15.0%	256	223	0	0	0	0	0	0
Michigan	1,650	1,569	5.1%	1,526	1,441	114	119	0	0	10	10
Ohio	403	244	65.0%	274	227	129	17	0	0	0	0
Wisconsin	2,641	2,392	10.4%	2,377	2,116	150	135	0	0	114	141
West North Central	16,523	13,662	20.9%	16,197	13,300	230	270	0	0	97	92
Iowa	796	925	-13.9%	788	918	8	7	0	0	0	0
Kansas	20	26	-22.5%	0	0	20	26	0	0	0	0
Minnesota	1,056	1,054	0.2%	758	725	201	237	0	0	97	92
Missouri	2,216	828	167.5%	2,216	828	0	0	0	0	0	0
Nebraska	1,340	1,382	-3.0%	1,340	1,382	0	0	0	0	0	0
North Dakota	3,179	3,180	0.0%	3,179	3,180	0	0	0	0	0	0
South Dakota	7,915	6,266	26.3%	7,915	6,266	0	0	0	0	0	0
South Atlantic	18,741	19,992	-6.3%	15,333	15,729	2,810	3,549	17	15	582	699
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	210	233	-9.8%	210	233	0	0	0	0	0	0
Georgia	3,956	3,697	7.0%	3,929	3,676	9	10	0	0	18	11
Maryland	2,188	2,831	-22.7%	0	0	2,188	2,831	0	0	0	0
North Carolina	6,186	6,605	-6.4%	6,118	6,540	53	53	14	13	0	0
South Carolina	2,976	3,014	-1.2%	2,903	2,931	70	80	2	2	0	0
Virginia	1,519	1,765	-13.9%	1,445	1,696	74	68	0	0	0	0
West Virginia	1,706	1,848	-7.7%	728	653	415	507	0	0	563	688
East South Central	25,767	25,854	-0.3%	25,758	25,843	8	11	0	0	0	0
Alabama	11,405	11,143	2.4%	11,405	11,143	0	0	0	0	0	0
Kentucky	4,232	4,418	-4.2%	4,223	4,407	8	11	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	10,130	10,293	-1.6%	10,130	10,293	0	0	0	0	0	0
West South Central	10,879	7,350	48.0%	9,422	6,086	1,455	1,263	1	1	0	0
Arkansas	4,135	3,009	37.4%	4,085	2,959	50	50	0	0	0	0
Louisiana	1,366	1,180	15.7%	0	0	1,366	1,180	0	0	0	0
Oklahoma	3,903	2,035	91.8%	3,903	2,035	0	0	0	0	0	0
Texas	1,475	1,126	31.0%	1,434	1,092	40	33	1	1	0	0
Mountain	32,621	35,170	-7.2%	31,332	33,878	1,276	1,279	13	13	0	0
Arizona	6,204	6,982	-11.1%	6,204	6,982	0	0	0	0	0	0
Colorado	1,811	1,825	-0.8%	1,578	1,601	220	212	13	13	0	0
Idaho	10,333	11,024	-6.3%	9,517	10,177	816	847	0	0	0	0
Montana	10,005	11,405	-12.3%	9,850	11,269	155	136	0	0	0	0
Nevada	2,242	1,881	19.2%	2,176	1,815	66	67	0	0	0	0
New Mexico	158	150	5.8%	158	150	0	0	0	0	0	0
Utah	875	927	-5.6%	863	919	12	8	0	0	0	0
Wyoming	992	976	1.7%	985	967	8	9	0	0	0	0
Pacific Contiguous	134,695	142,657	-5.6%	131,966	140,598	2,716	2,048	14	11	0	0
California	38,355	26,331	45.7%	36,219	24,915	2,122	1,405	14	11	0	0
Oregon	30,322	35,443	-14.4%	30,069	35,199	253	243	0	0	0	0
Washington	66,018	80,883	-18.4%	65,677	80,483	341	400	0	0	0	0
Pacific Noncontiguous	1,718	1,761	-2.4%	1,504	1,508	24	42	130	176	59	34
Alaska	1,623	1,664	-2.5%	1,493	1,489	0	0	130	176	0	0
Hawaii	95	97	-2.0%	11	20	24	42	0	0	59	34
U.S. Total	287,874	292,524	-1.6%	262,364	267,336	24,288	23,812	188	227	1,033	1,149

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.15. Utility Scale Facility Net Generation from Renewable Sources Excluding Hydroelectric by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	11,095	11,398	-2.7%	830	787	8,935	9,322	155	179	1,175	1,110
Connecticut	900	873	3.0%	3	3	892	869	5	1	0	0
Maine	4,749	5,058	-6.1%	0	0	3,536	3,885	45	68	1,169	1,105
Massachusetts	2,379	2,369	0.4%	120	77	2,197	2,232	55	55	6	5
New Hampshire	1,647	1,793	-8.1%	214	253	1,393	1,495	40	45	0	0
Rhode Island	469	399	17.6%	0	0	461	391	8	7	0	0
Vermont	951	906	4.9%	493	454	456	450	2	2	0	0
Middle Atlantic	14,231	14,280	-0.3%	79	76	12,939	12,865	642	644	570	694
New Jersey	1,984	1,948	1.8%	79	76	1,608	1,588	289	279	7	5
New York	6,926	6,438	7.6%	0	0	6,528	6,037	210	220	188	180
Pennsylvania	5,322	5,894	-9.7%	0	0	4,803	5,240	143	145	375	509
East North Central	36,336	32,376	12.2%	4,628	3,896	30,040	26,619	175	242	1,493	1,618
Illinois	14,934	12,391	20.5%	128	105	14,798	12,279	8	8	0	0
Indiana	7,001	6,188	13.1%	469	427	6,447	5,670	21	22	64	69
Michigan	8,283	8,106	2.2%	2,399	2,115	5,223	5,176	56	129	604	685
Ohio	2,870	2,576	11.4%	18	19	2,536	2,264	16	13	300	280
Wisconsin	3,248	3,114	4.3%	1,614	1,231	1,035	1,231	74	69	526	583
West North Central	85,545	76,235	12.2%	28,594	24,768	56,047	50,564	177	187	726	716
Iowa	26,536	21,557	23.1%	18,649	14,857	7,787	6,619	41	47	59	35
Kansas	21,198	18,979	11.7%	1,896	1,902	19,285	17,065	17	16	0	-3
Minnesota	13,402	13,400	0.0%	2,610	2,751	10,066	9,915	61	54	664	680
Missouri	3,078	3,059	0.6%	41	37	2,990	2,967	45	53	2	3
Nebraska	7,327	5,670	29.2%	400	247	6,914	5,407	13	15	0	0
North Dakota	11,213	10,734	4.5%	4,317	4,127	6,896	6,604	0	NM	0	1
South Dakota	2,791	2,837	-1.6%	682	849	2,109	1,988	0	0	0	0
South Atlantic	37,353	34,921	7.0%	6,213	5,108	20,550	18,830	459	495	10,131	10,488
Delaware	120	114	5.6%	7	6	98	90	6	6	10	12
District of Columbia	64	57	13.1%	0	0	9	0	55	57	0	0
Florida	8,351	7,497	11.4%	4,065	2,680	2,365	2,824	50	51	1,870	1,942
Georgia	7,536	6,994	7.8%	312	293	3,052	2,583	3	2	4,169	4,116
Maryland	1,405	1,488	-5.6%	9	8	1,315	1,360	33	27	49	93
North Carolina	10,524	9,263	13.6%	450	387	8,727	7,429	168	188	1,179	1,259
South Carolina	3,027	2,802	8.0%	90	385	1,543	905	0	0	1,393	1,512
Virginia	4,696	4,936	-4.9%	1,280	1,348	1,810	1,869	144	164	1,461	1,554
West Virginia	1,631	1,770	-7.8%	0	0	1,631	1,770	0	0	0	0
East South Central	7,162	7,230	-0.9%	155	163	1,180	1,129	5	4	5,822	5,933
Alabama	3,742	3,804	-1.6%	23	31	402	507	0	0	3,317	3,266
Kentucky	419	470	-10.8%	132	131	11	10	0	0	276	329
Mississippi	1,718	1,765	-2.7%	0	0	335	338	0	0	1,382	1,427
Tennessee	1,283	1,191	7.7%	0	1	431	274	5	4	847	911
West South Central	122,620	112,403	9.1%	1,815	1,701	116,043	105,502	82	94	4,680	5,106
Arkansas	1,545	1,569	-1.5%	2	2	288	271	14	6	1,242	1,291
Louisiana	2,250	2,609	-13.8%	2	2	83	79	0	0	2,165	2,528
Oklahoma	29,378	27,729	5.9%	1,475	1,401	27,613	26,022	0	0	291	307
Texas	89,447	80,496	11.1%	337	297	88,058	79,130	68	88	983	980
Mountain	49,611	46,478	6.7%	5,912	4,213	42,739	41,742	576	150	383	373
Arizona	6,063	5,890	2.9%	741	681	5,306	5,196	16	13	0	0
Colorado	12,233	10,972	11.5%	2,288	513	9,925	10,443	17	13	3	3
Idaho	3,721	3,785	-1.7%	178	174	3,160	3,253	25	11	358	346
Montana	2,423	2,209	9.7%	250	242	2,153	1,945	0	0	20	21
Nevada	9,103	8,546	6.5%	170	41	8,424	8,406	506	97	2	3
New Mexico	8,339	7,474	11.6%	317	264	8,019	7,208	3	3	0	0
Utah	3,386	3,543	-4.4%	115	223	3,262	3,307	9	14	0	0
Wyoming	4,343	4,058	7.0%	1,853	2,074	2,490	1,984	0	0	0	0
Pacific Contiguous	75,577	77,570	-2.6%	6,775	8,197	65,488	65,952	934	975	2,380	2,446
California	58,921	58,632	0.5%	1,967	2,249	55,307	54,786	892	933	756	665
Oregon	8,392	9,233	-9.1%	1,148	1,308	6,719	7,359	27	29	499	536
Washington	8,263	9,705	-14.9%	3,660	4,641	3,462	3,807	15	13	1,126	1,245
Pacific Noncontiguous	1,269	1,403	-9.5%	186	190	862	966	220	244	1	3
Alaska	180	200	-10.2%	89	99	53	56	37	43	1	3
Hawaii	1,089	1,202	-9.4%	97	91	809	910	183	201	0	0
U.S. Total	440,799	414,292	6.4%	55,188	49,100	354,823	333,491	3,426	3,214	27,361	28,487

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.16. Utility Scale Facility Net Generation from Hydroelectric (Pumped Storage) Power by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	-434	-460	-5.7%	0	0	-434	-460	0	0	0	0
Connecticut	2	3	-37.9%	0	0	2	3	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	-436	-464	-5.9%	0	0	-436	-464	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	-975	-1,205	-19.1%	-409	-546	-566	-659	0	0	0	0
New Jersey	-94	-115	-18.5%	-94	-115	0	0	0	0	0	0
New York	-316	-431	-26.7%	-316	-431	0	0	0	0	0	0
Pennsylvania	-566	-659	-14.2%	0	0	-566	-659	0	0	0	0
East North Central	-696	-698	-0.3%	-696	-698	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	-696	-698	-0.3%	-696	-698	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	337	47	617.9%	337	47	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	337	47	617.9%	337	47	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	-2,612	-2,485	5.1%	-2,612	-2,485	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	-599	-489	22.5%	-599	-489	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	-909	-705	28.9%	-909	-705	0	0	0	0	0	0
Virginia	-1,104	-1,292	-14.5%	-1,104	-1,292	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	-615	-620	-0.7%	-615	-620	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	-615	-620	-0.7%	-615	-620	0	0	0	0	0	0
West South Central	-53	-95	-43.7%	-53	-95	0	0	0	0	0	0
Arkansas	51	40	26.0%	51	40	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	-104	-135	-22.9%	-104	-135	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	-189	-267	-29.1%	-189	-267	0	0	0	0	0	0
Arizona	2	-5	-154.6%	2	-5	0	0	0	0	0	0
Colorado	-192	-263	-27.0%	-192	-263	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	-22	-120	-81.7%	-22	-120	0	0	0	0	0	0
California	-31	-149	-79.4%	-31	-149	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	9	28	-69.8%	9	28	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	-5,261	-5,905	-10.9%	-4,261	-4,785	-1,000	-1,119	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.17. Utility Scale Facility Net Generation from Other Energy Sources
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	1,881	1,729	8.8%	-1	-1	1,707	1,531	54	65	121	134
Connecticut	578	465	24.4%	0	0	578	465	0	0	0	0
Maine	339	371	-8.6%	0	0	162	172	54	65	122	134
Massachusetts	910	846	7.5%	0	0	912	847	0	0	-2	0
New Hampshire	55	48	14.6%	0	0	55	48	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	-1	0	226.7%	-1	0	0	0	0	0	0	0
Middle Atlantic	2,433	2,206	10.3%	0	0	1,861	1,750	512	431	60	25
New Jersey	616	552	11.6%	0	0	394	391	162	136	60	25
New York	960	873	9.9%	0	0	720	671	240	202	0	0
Pennsylvania	857	781	9.8%	0	0	748	688	110	93	0	0
East North Central	795	848	-6.2%	19	14	71	89	91	143	614	601
Illinois	239	227	5.1%	0	0	-10	-19	0	0	249	246
Indiana	333	321	4.0%	0	0	0	0	24	21	310	300
Michigan	173	252	-31.4%	0	0	85	112	67	122	21	18
Ohio	8	5	50.4%	-2	-3	-3	-4	0	0	14	12
Wisconsin	42	43	-1.4%	21	17	0	0	0	0	21	26
West North Central	409	463	-11.6%	184	236	141	141	31	29	53	57
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	5	5	-0.3%	0	0	0	0	0	0	5	5
Minnesota	355	405	-12.4%	135	183	141	141	31	29	48	52
Missouri	0	1	-91.2%	0	1	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	50	52	-4.6%	50	52	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	4,708	4,432	6.2%	-2	-1	2,703	2,469	163	149	1,844	1,815
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,154	2,983	5.7%	-2	0	1,656	1,523	0	0	1,500	1,461
Georgia	94	86	9.3%	0	0	0	0	0	0	94	86
Maryland	325	326	-0.2%	0	0	325	326	0	0	0	0
North Carolina	538	535	0.5%	0	0	325	302	0	0	213	233
South Carolina	45	42	7.1%	0	0	8	7	0	0	37	34
Virginia	558	471	18.5%	0	0	395	323	163	149	0	0
West Virginia	-6	-12	-44.5%	0	0	-6	-11	0	0	0	0
East South Central	58	72	-20.0%	47	64	0	0	0	0	10	8
Alabama	0	0	14.3%	0	0	0	0	0	0	0	0
Kentucky	47	64	-25.4%	47	64	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	10	8	20.3%	0	0	0	0	0	0	10	8
West South Central	1,096	1,158	-5.4%	85	0	85	122	0	0	926	1,036
Arkansas	5	5	-4.9%	0	0	0	0	0	0	5	5
Louisiana	573	643	-10.9%	85	0	0	0	0	0	488	643
Oklahoma	7	57	-87.0%	1	0	0	54	0	0	7	3
Texas	510	453	12.8%	0	0	85	69	0	0	426	384
Mountain	694	764	-9.2%	69	81	301	320	0	0	324	363
Arizona	-4	-3	75.2%	0	0	-4	-3	0	0	0	0
Colorado	60	59	1.9%	-1	0	18	18	0	0	43	42
Idaho	66	64	2.6%	0	0	0	0	0	0	66	64
Montana	287	305	-5.7%	0	0	287	305	0	0	0	0
Nevada	22	29	-25.2%	22	29	0	0	0	0	0	0
New Mexico	-1	-1	9.4%	-1	-1	0	0	0	0	0	0
Utah	189	225	-16.2%	49	53	0	0	0	0	140	172
Wyoming	75	85	-11.5%	0	0	0	0	0	0	75	85
Pacific Contiguous	867	922	-6.0%	-17	-19	269	255	0	0	615	686
California	765	829	-7.7%	-16	-17	166	160	0	0	615	686
Oregon	36	34	4.9%	-1	-1	36	35	0	0	0	0
Washington	66	59	11.7%	0	-1	67	60	0	0	0	0
Pacific Noncontiguous	391	379	3.1%	167	187	0	-1	224	193	0	0
Alaska	-4	-3	25.9%	-4	-3	0	0	0	0	0	0
Hawaii	395	382	3.3%	171	190	0	-1	224	193	0	0
U.S. Total	13,331	12,973	2.8%	551	561	7,138	6,677	1,076	1,010	4,567	4,725

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.18. Utility Scale Facility Net Generation from Wind
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	3,734	3,556	5.0%	220	230	3,480	3,294	31	29	2	3
Connecticut	12	12	-0.7%	0	0	12	12	0	0	0	0
Maine	2,494	2,384	4.6%	0	0	2,494	2,384	0	0	0	0
Massachusetts	211	221	-4.6%	49	58	136	139	24	22	2	3
New Hampshire	433	407	6.6%	0	0	433	407	0	0	0	0
Rhode Island	206	159	30.0%	0	0	199	151	8	7	0	0
Vermont	377	373	1.1%	171	173	207	201	0	0	0	0
Middle Atlantic	7,728	7,588	1.9%	0	0	7,724	7,579	3	3	1	6
New Jersey	22	23	-2.7%	0	0	22	23	0	0	0	0
New York	4,456	3,998	11.4%	0	0	4,452	3,989	3	3	1	6
Pennsylvania	3,250	3,567	-8.9%	0	0	3,250	3,567	0	0	0	0
East North Central	30,422	26,181	16.2%	3,607	2,930	26,706	23,154	30	28	79	70
Illinois	14,460	11,899	21.5%	12	12	14,443	11,882	5	5	0	0
Indiana	6,216	5,437	14.3%	0	0	6,216	5,437	0	0	0	0
Michigan	5,826	5,457	6.8%	2,313	2,029	3,513	3,429	0	0	0	0
Ohio	2,043	1,750	16.7%	11	11	1,956	1,673	3	3	72	63
Wisconsin	1,878	1,638	14.7%	1,270	878	579	733	21	20	7	7
West North Central	82,465	72,907	13.1%	28,295	24,282	54,124	48,578	45	47	0	0
Iowa	26,305	21,334	23.3%	18,628	14,834	7,673	6,497	4	3	0	0
Kansas	21,124	18,908	11.7%	1,894	1,900	19,212	16,992	17	16	0	0
Minnesota	10,965	10,714	2.3%	2,450	2,405	8,490	8,284	25	25	0	0
Missouri	2,858	2,835	0.8%	0	0	2,858	2,835	0	0	0	0
Nebraska	7,211	5,549	30.0%	324	169	6,887	5,380	0	0	0	0
North Dakota	11,213	10,733	4.5%	4,317	4,127	6,896	6,604	0	NM	0	0
South Dakota	2,789	2,835	-1.6%	682	849	2,107	1,986	0	0	0	0
South Atlantic	2,680	2,888	-7.2%	0	0	2,675	2,883	5	5	0	0
Delaware	5	5	1.2%	0	0	0	0	5	5	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	520	570	-8.7%	0	0	520	570	0	0	0	0
North Carolina	523	543	-3.6%	0	0	523	543	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	1,631	1,770	-7.8%	0	0	1,631	1,770	0	0	0	0
East South Central	38	41	-7.4%	0	0	38	41	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	38	41	-7.4%	0	0	38	41	0	0	0	0
West South Central	112,629	103,039	9.3%	1,671	1,628	110,895	101,348	54	53	9	10
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	29,008	27,338	6.1%	1,415	1,339	27,593	25,999	0	0	0	0
Texas	83,620	75,700	10.5%	256	289	83,302	75,349	54	53	9	10
Mountain	28,534	26,339	8.3%	4,548	2,984	23,979	23,349	4	3	3	3
Arizona	554	530	4.6%	0	0	554	530	0	0	0	0
Colorado	10,852	9,745	11.4%	2,282	508	8,566	9,234	2	0	3	3
Idaho	2,551	2,655	-3.9%	163	160	2,388	2,495	0	0	0	0
Montana	2,373	2,153	10.2%	250	242	2,124	1,911	0	0	0	0
Nevada	329	312	5.5%	0	0	329	312	0	0	0	0
New Mexico	6,892	6,092	13.1%	0	0	6,889	6,089	3	3	0	0
Utah	819	795	3.0%	0	0	819	795	0	0	0	0
Wyoming	4,163	4,057	2.6%	1,853	2,074	2,309	1,983	0	0	0	0
Pacific Contiguous	26,981	29,371	-8.1%	5,206	6,313	21,765	23,048	6	6	5	5
California	13,735	14,024	-2.1%	780	850	12,944	13,163	6	6	5	5
Oregon	6,569	7,447	-11.8%	1,081	1,244	5,488	6,204	0	0	0	0
Washington	6,677	7,900	-15.5%	3,344	4,219	3,333	3,681	0	0	0	0
Pacific Noncontiguous	672	757	-11.2%	89	99	583	658	0	0	0	0
Alaska	143	155	-8.0%	89	99	53	56	0	0	0	0
Hawaii	529	602	-12.1%	0	0	529	602	0	0	0	0
U.S. Total	295,882	272,667	8.5%	43,636	38,466	251,968	233,931	179	174	100	97

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.19. Utility Scale Facility Net Generation from Biomass
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
				Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	5,850	6,610	-11.5%	496	498	4,072	4,862	113	146	1,169	1,105
Connecticut	749	756	-0.8%	0	0	749	756	0	0	0	0
Maine	2,248	2,662	-15.5%	0	0	1,035	1,489	45	68	1,169	1,105
Massachusetts	1,004	1,169	-14.1%	0	0	978	1,139	26	30	0	0
New Hampshire	1,214	1,386	-12.4%	214	253	960	1,088	40	45	0	0
Rhode Island	208	211	-1.5%	0	0	208	211	0	0	0	0
Vermont	426	426	0.0%	282	245	142	179	2	2	0	0
Middle Atlantic	4,732	5,342	-11.4%	0	0	3,702	4,157	482	509	547	676
New Jersey	797	935	-14.8%	0	0	650	780	147	155	0	0
New York	1,946	2,142	-9.1%	0	0	1,569	1,754	197	213	180	174
Pennsylvania	1,988	2,265	-12.2%	0	0	1,482	1,623	139	140	367	501
East North Central	5,207	5,561	-6.4%	787	763	2,875	3,051	133	201	1,412	1,546
Illinois	412	426	-3.3%	114	90	299	336	0	0	0	0
Indiana	463	460	0.6%	330	320	49	49	20	22	64	69
Michigan	2,314	2,531	-8.6%	0	0	1,655	1,718	55	127	604	685
Ohio	685	707	-3.1%	0	0	452	484	8	7	226	216
Wisconsin	1,333	1,437	-7.3%	343	352	420	463	51	45	518	577
West North Central	1,671	2,147	-22.1%	271	470	543	823	131	138	726	716
Iowa	216	211	2.1%	12	16	107	117	37	43	59	35
Kansas	63	64	-1.3%	0	0	63	67	0	0	0	-3
Minnesota	1,188	1,645	-27.8%	158	343	330	592	36	29	664	680
Missouri	120	133	-9.6%	30	32	44	47	44	51	2	3
Nebraska	85	93	-9.4%	71	78	0	0	13	15	0	0
North Dakota	0	1	-82.2%	0	0	0	0	0	0	0	1
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	18,795	19,794	-5.0%	1,772	2,244	6,586	6,706	312	358	10,124	10,486
Delaware	61	59	3.9%	0	0	52	47	0	0	10	12
District of Columbia	55	57	-2.5%	0	0	0	0	55	57	0	0
Florida	4,449	5,084	-12.5%	670	654	1,872	2,446	40	45	1,867	1,939
Georgia	5,376	4,999	7.5%	0	0	1,206	882	0	0	4,169	4,116
Maryland	391	521	-25.1%	0	0	326	412	15	17	49	93
North Carolina	2,549	2,610	-2.3%	0	0	1,312	1,275	59	76	1,179	1,259
South Carolina	2,168	2,291	-5.4%	86	383	692	397	0	0	1,390	1,512
Virginia	3,746	4,173	-10.2%	1,016	1,207	1,126	1,248	143	164	1,461	1,554
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	6,045	6,299	-4.0%	88	93	141	278	0	0	5,816	5,927
Alabama	3,357	3,446	-2.6%	0	0	40	180	0	0	3,317	3,266
Kentucky	374	431	-13.1%	88	93	10	8	0	0	276	329
Mississippi	1,395	1,439	-3.1%	0	0	13	13	0	0	1,382	1,427
Tennessee	919	982	-6.5%	0	0	78	77	0	0	840	905
West South Central	5,354	5,892	-9.1%	72	0	596	757	16	39	4,671	5,096
Arkansas	1,335	1,366	-2.3%	0	0	88	69	5	6	1,242	1,291
Louisiana	2,248	2,607	-13.8%	0	0	83	79	0	0	2,165	2,528
Oklahoma	311	329	-5.6%	0	0	20	23	0	0	291	307
Texas	1,461	1,590	-8.1%	72	0	405	586	11	33	974	970
Mountain	1,078	1,049	2.7%	15	15	652	643	34	25	376	367
Arizona	231	219	5.1%	0	0	231	219	0	0	0	0
Colorado	162	164	-1.5%	0	0	162	164	0	0	0	0
Idaho	518	491	5.5%	15	15	121	119	25	11	356	346
Montana	20	21	-5.6%	0	0	0	0	0	0	20	21
Nevada	54	53	2.3%	0	0	54	53	0	0	0	0
New Mexico	23	21	6.7%	0	0	23	21	0	0	0	0
Utah	71	79	-11.0%	0	0	62	66	9	14	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	8,445	8,787	-3.9%	437	573	4,896	4,972	777	821	2,335	2,422
California	5,941	5,946	-0.1%	60	93	4,435	4,434	735	779	710	640
Oregon	962	1,037	-7.3%	61	59	375	413	27	29	499	536
Washington	1,542	1,803	-14.5%	316	421	86	124	15	13	1,126	1,245
Pacific Noncontiguous	329	351	-6.2%	57	53	51	51	220	244	1	3
Alaska	38	45	-17.4%	0	0	0	0	37	43	1	3
Hawaii	292	306	-4.6%	57	53	51	51	183	201	0	0
U.S. Total	57,507	61,832	-7.0%	3,997	4,708	24,115	26,300	2,219	2,481	27,176	28,343

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Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.20. Utility Scale Facility Net Generation from Geothermal
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	0	0	--	0	0	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	0	0	--	0	0	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	4,373	4,004	9.2%	115	223	3,816	3,747	442	33	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	96	83	15.0%	0	0	96	83	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	3,909	3,462	12.9%	0	0	3,467	3,429	442	33	0	0
New Mexico	58	13	342.2%	0	0	58	13	0	0	0	0
Utah	310	446	-30.4%	115	223	195	223	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	11,100	11,853	-6.4%	656	786	10,444	11,067	0	0	0	0
California	10,914	11,677	-6.5%	656	786	10,258	10,891	0	0	0	0
Oregon	185	176	5.2%	0	0	185	176	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	110	-100.0%	0	0	0	110	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	110	-100.0%	0	0	0	110	0	0	0	0
U.S. Total	15,473	15,967	-3.1%	771	1,009	14,260	14,924	442	33	0	0

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Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.21. Net Generation from Solar Photovoltaic
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

	All Sectors						Electric Power Sector				Commercial Sector						Industrial Sector						Residential Sector		
							Electric Utilities		Independent Power Producers								Estimated Generation From Utility and Small Scale Facilities		Generation at Utility Scale Facilities		Estimated Small Scale Generation		Estimated Small Scale Generation		
Census Division and State	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018		
New England	4,767	4,204	13.4%	1,511	1,232	3,255	2,972	114	59	1,382	1,167	1,751	1,629	11	4	1,740	1,626	135	118	5	2	130	116	1,385	1,231
Connecticut	738	605	22.0%	138	106	600	500	3	3	130	101	226	200	5	1	221	199	30	25	0	0	30	25	349	276
Maine	84	68	24.1%	7	12	77	55	0	0	7	12	32	19	0	0	32	19	0	0	0	0	0	0	45	36
Massachusetts	3,280	3,062	7.1%	1,164	978	2,116	2,083	71	19	1,083	954	1,273	1,280	6	3	1,267	1,277	95	84	4	2	90	82	759	724
New Hampshire	130	108	20.2%	0	0	130	108	0	0	0	0	41	32	0	0	41	32	8	7	0	0	8	7	81	69
Rhode Island	235	124	88.9%	55	29	180	95	0	0	55	29	122	51	0	0	122	51	0	0	0	0	0	0	58	44
Vermont	300	237	26.6%	147	107	153	130	40	37	108	70	57	47	0	0	57	47	2	2	0	0	2	2	94	81
Middle Atlantic	6,308	5,176	21.9%	1,771	1,350	4,537	3,825	79	76	1,513	1,129	2,138	1,853	157	132	1,981	1,721	258	214	22	12	236	202	2,320	1,903
New Jersey	3,357	2,903	15.7%	1,165	990	2,193	1,912	79	76	936	785	1,163	1,083	142	124	1,021	959	164	131	7	5	156	126	1,015	827
New York	2,376	1,794	32.4%	524	297	1,852	1,497	0	0	507	294	806	616	10	4	796	612	23	17	6	0	17	17	1,039	868
Pennsylvania	575	479	20.1%	83	62	492	416	0	0	70	50	169	155	4	5	164	150	70	66	8	7	63	59	265	207
East North Central	1,428	1,134	25.9%	707	634	721	501	234	204	459	415	397	326	12	13	385	312	49	28	2	2	47	26	289	162
Illinois	251	161	55.3%	62	66	189	95	2	2	57	60	108	65	3	3	105	61	0	1	0	0	0	1	84	34
Indiana	450	389	15.7%	323	291	128	98	138	107	183	184	73	66	2	0	71	66	3	3	0	0	3	3	54	29
Michigan	253	197	28.0%	143	118	110	79	87	87	55	29	54	45	1	2	52	43	3	2	0	0	3	2	54	34
Ohio	336	272	23.4%	142	119	194	153	7	7	129	107	121	116	4	3	117	113	26	9	2	2	24	7	53	34
Wisconsin	139	115	21.4%	38	40	101	75	0	0	36	35	41	35	2	5	39	30	17	14	0	0	17	14	45	32
West North Central	2,022	1,660	21.8%	1,408	1,181	613	478	28	16	1,379	1,164	290	235	1	2	289	233	24	18	0	0	24	18	301	227
Iowa	176	138	27.8%	15	11	160	126	8	7	7	5	99	80	0	0	99	80	5	4	0	0	5	4	56	43
Kansas	50	35	42.8%	11	8	38	27	2	2	9	6	15	10	0	0	15	10	0	0	0	0	0	0	23	17
Minnesota	1,353	1,123	20.5%	1,249	1,042	104	81	3	3	1,246	1,039	35	28	0	0	35	28	12	10	0	0	12	10	58	43
Missouri	393	324	21.5%	100	91	293	232	11	5	88	85	135	112	1	2	134	111	6	4	0	0	6	4	153	118
Nebraska	46	38	22.6%	31	27	15	11	5	0	27	27	5	4	0	0	5	4	1	1	0	0	1	1	9	6
North Dakota	1	0	92.8%	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Dakota	3	3	16.0%	2	2	1	1	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1	1
South Atlantic	18,775	14,469	29.8%	15,850	12,187	2,925	2,282	4,413	2,812	11,289	9,241	905	788	142	131	763	657	341	307	7	2	334	305	1,828	1,320
Delaware	178	160	11.8%	54	50	124	110	7	6	47	43	35	32	0	1	35	32	8	9	0	0	8	9	81	69
District of Columbia	103	71	44.7%	9	0	94	71	0	0	9	0	50	43	0	0	50	43	0	0	0	0	0	0	44	29
Florida	4,562	2,790	63.5%	3,873	2,361	689	429	3,368	1,974	493	378	145	116	10	6	135	110	13	13	3	2	10	11	544	308
Georgia	2,467	2,265	8.9%	2,161	1,996	307	270	312	293	1,846	1,701	45	37	3	2	42	35	244	218	0	0	244	218	20	17
Maryland	1,460	1,246	17.2%	494	397	965	849	9	8	468	378	275	242	17	11	258	232	36	37	0	0	36	37	672	580
North Carolina	7,725	6,323	22.2%	7,451	6,110	273	212	450	387	6,892	5,611	233	228	109	112	123	117	7	7	0	0	7	7	143	89
South Carolina	1,187	759	56.3%	859	510	329	249	4	2	851	508	79	64	0	0	79	64	30	22	4	0	27	22	222	163
Virginia	1,081	845	27.8%	949	763	132	82	264	141	683	622	38	23	2	0	37	23	2	2	0	0	2	2	93	58
West Virginia	12	10	29.6%	0	0	12	10	0	0	0	0	4	2	0	0	4	2	0	0	0	0	0	0	8	7
East South Central	1,240	1,034	19.9%	1,079	890	162	144	67	69	1,001	810	111	103	5	4	107	98	9	8	6	6	3	2	52	44
Alabama	399	368	8.4%	385	357	14	11	23	31	362	327	10	7	0	0	10	7	1	1	0	0	1	1	3	3
Kentucky	85	71	19.3%	45	39	40	32	43	38	2	2	22	19	0	0	22	19	1	1	0	0	1	1	17	12
Mississippi	336	337	-0.2%	322	326	14	11	0	0	322	326	8	7	0	0	8	7	1	0	0	0	1	0	6	4
Tennessee	420	258	62.8%	326	168	94	90	0	1	315	156	72	70	5	4	67	65	6	6	6	6	0	0	27	25
West South Central	5,933	4,449	33.3%	4,637	3,472	1,297	977	73	73	4,552	3,397	287	215	12	2	274	213	6	2	0	0	6	2	1,016	762
Arkansas	246	225	9.1%	210	203	35	22	2	2	200	202	19	8	9	0	11	8	3	1	0	0	3	1	21	13
Louisiana	242	230	5.2%	2	2	241	229	2	2	0	0	16	15	0	0	16	15	0	0	0	0	0	0	224	214
Oklahoma	79	73	8.8%	60	62	20	11	60	62	0	0	5	4	0	0	5	4	1	0	0	0	1	0	14	7
Texas	5,366	3,921	36.8%	4,365	3,206	1,001	716	10	8	4,352	3,195	246	189	3	2	243	187	2	1	0	0	2	1	756	528
Mountain	19,411	18,058	7.5%	14,673	14,003	4,738	4,055	1,234	991	13,340	12,920	1,378	1,322	96	89	1,282	1,233	72	71	4	3	68	69	3,388	2,754
Arizona	7,058	6,630	6.5%	4,486	4,364	2,572	2,265	741	681	3,729	3,670	776	744	16	13	760	731	14	24	0	0	14	24	1,798	1,511
Colorado	1,852	1,653	12.0%	1,218	1,062	633	590	5	5	1,198	1,045	236	235	15	12	220	222	2	2	0	0	2	2	411	366
Idaho	615	589	4.4%	557	556	58	33	0	0	555	556	6	5	0											

Table 3.22. Utility Scale Facility Net Generation from Solar Thermal
by State, by Sector, 2019 and 2018 (Thousand Megawatthours)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	Generation at Utility Scale Facilities			Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	0	0	--	0	0	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	0	0	--	0	0	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	0	0	--	0	0	0	0	0	0	0	0
West North Central	0	0	--	0	0	0	0	0	0	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	28	51	-45.6%	28	51	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	28	51	-45.6%	28	51	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	0	0	--	0	0	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	952	1,082	-12.0%	0	0	952	1,082	0	0	0	0
Arizona	792	776	2.0%	0	0	792	776	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	160	306	-47.6%	0	0	160	306	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	2,237	2,458	-9.0%	0	0	2,237	2,458	0	0	0	0
California	2,237	2,458	-9.0%	0	0	2,237	2,458	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	3,218	3,592	-10.4%	28	51	3,190	3,540	0	0	0	0

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
NM = Not meaningful due to large relative standard error or excessive percentage change.
Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.
Negative generation denotes that electric power consumed for plant use exceeds gross generation.
Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 3.23. Useful Thermal Output by Energy Source: Total Combined Heat and Power (All Sectors), 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	281,557	32,591	20,308	513,002	99,556	546,974	33,287	1,527,276
2010	300,303	19,914	21,448	524,494	91,439	581,310	28,755	1,567,662
2011	286,210	15,230	21,552	535,150	103,615	586,299	31,067	1,579,124
2012	252,605	12,452	24,419	556,945	113,147	580,513	24,571	1,564,653
2013	243,043	12,828	25,224	553,696	103,719	611,443	22,171	1,572,124
2014	232,509	11,990	23,457	545,624	104,868	624,086	21,390	1,563,923
2015	211,030	11,796	21,748	591,749	98,910	626,887	19,729	1,581,849
2016	220,162	8,607	20,122	785,413	148,881	698,858	25,342	1,907,384
2017	193,164	7,922	17,322	789,485	151,579	674,248	23,685	1,857,405
2018	182,373	9,878	16,581	813,127	172,677	663,644	23,169	1,881,448
2019	162,108	7,992	14,278	802,153	142,229	643,548	22,429	1,794,736
Year 2017								
January	19,055	720	1,525	68,635	13,591	59,191	2,181	164,899
February	15,587	494	1,248	61,025	11,816	53,805	1,874	145,848
March	16,988	610	1,617	65,599	12,595	57,856	2,038	157,304
April	15,081	568	1,336	60,483	12,040	53,825	1,948	145,281
May	14,971	539	1,391	62,274	13,346	53,637	1,868	148,026
June	15,501	462	1,576	64,085	12,285	55,874	2,022	151,806
July	15,676	457	1,521	70,083	12,721	57,072	2,032	159,561
August	15,848	447	1,581	68,728	12,505	58,224	2,147	159,481
September	14,580	552	1,281	65,718	12,212	52,154	1,869	148,366
October	16,389	552	1,485	66,078	12,973	55,368	1,811	154,657
November	16,308	1,040	1,398	64,589	12,441	57,071	1,878	154,727
December	17,179	1,480	1,362	72,187	13,054	60,171	2,017	167,450
Year 2018								
January	18,956	2,597	1,662	72,379	13,963	58,883	1,994	170,434
February	16,841	708	1,539	64,059	13,591	52,908	1,886	151,532
March	16,639	601	1,390	67,685	14,652	57,112	2,034	160,113
April	14,584	532	1,472	62,177	13,569	53,599	1,838	147,771
May	14,238	567	1,435	63,879	14,587	54,802	1,821	151,330
June	14,229	634	1,370	65,579	14,392	53,137	2,053	151,393
July	14,346	534	1,361	72,049	14,604	56,586	2,017	161,498
August	14,217	532	1,308	71,554	16,097	56,410	2,065	162,182
September	13,791	491	1,245	66,851	13,972	51,546	1,662	149,558
October	13,254	768	1,287	66,578	14,976	54,658	1,877	153,399
November	15,056	914	1,141	68,771	13,821	55,116	1,925	156,745
December	16,223	998	1,371	71,565	14,452	58,887	1,997	165,493
Year 2019								
January	17,187	1,511	1,276	72,612	12,164	58,244	2,116	165,110
February	15,124	734	1,182	64,964	11,146	52,831	1,957	147,938
March	14,793	609	1,273	68,303	12,304	55,403	1,998	154,682
April	13,488	529	1,257	61,359	12,016	51,489	1,759	141,898
May	12,639	864	1,243	63,354	11,527	52,084	1,647	143,357
June	12,452	409	1,224	64,013	11,309	51,440	1,833	142,681
July	12,106	376	1,204	68,751	12,492	53,785	1,830	150,545
August	12,265	450	1,146	69,982	12,002	54,256	1,915	152,017
September	11,754	468	1,284	65,274	11,652	50,594	1,683	142,709
October	12,909	507	1,055	65,018	11,765	53,397	1,765	146,417
November	13,417	957	950	67,055	11,641	54,062	1,991	150,074
December	13,973	576	1,183	71,467	12,211	55,962	1,936	157,309

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report;

Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.24. Useful Thermal Output by Energy Source: Electric Power Sector Combined Heat and Power, 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	38,015	5,341	1,445	190,875	19,830	17,625	5,055	278,187
2010	38,325	4,702	1,108	186,772	19,707	17,589	5,040	273,244
2011	35,209	4,484	1,231	190,712	20,435	16,029	6,044	274,143
2012	26,093	4,405	1,246	200,294	20,948	16,369	5,545	274,900
2013	21,306	4,614	993	188,094	10,303	16,225	4,966	246,501
2014	15,513	4,931	936	182,148	7,732	17,736	5,666	234,662
2015	16,036	4,894	1,143	178,167	7,161	16,999	5,180	229,580
2016	13,922	695	1,237	227,427	17,400	24,993	8,046	293,719
2017	11,269	627	1,267	192,299	17,798	24,279	7,422	254,961
2018	13,573	1,023	1,023	207,459	18,692	23,375	7,119	272,265
2019	12,759	655	1,019	197,106	19,684	26,057	7,544	264,823
Year 2017								
January	1,178	102	106	16,884	1,474	2,419	645	22,809
February	1,004	49	104	14,583	1,327	2,107	570	19,744
March	1,047	22	113	16,687	1,467	2,451	641	22,428
April	799	25	109	14,805	1,394	1,786	629	19,549
May	766	32	112	15,047	1,453	1,727	643	19,780
June	797	33	104	16,004	1,448	1,786	645	20,817
July	925	34	104	17,300	1,518	1,893	684	22,459
August	937	27	102	17,112	1,396	1,860	678	22,113
September	872	58	101	15,575	1,535	1,779	577	20,496
October	932	45	105	15,753	1,615	1,985	488	20,922
November	909	64	98	15,335	1,570	2,154	561	20,691
December	1,104	136	109	17,213	1,599	2,331	663	23,154
Year 2018								
January	1,483	437	104	18,095	1,467	2,384	625	24,596
February	1,151	36	88	16,586	1,398	2,279	568	22,104
March	1,194	35	97	17,454	1,412	2,354	632	23,177
April	1,005	32	105	15,767	1,579	1,614	561	20,663
May	1,050	51	64	16,311	1,661	1,542	573	21,253
June	1,069	37	14	16,547	1,535	1,664	643	21,509
July	1,087	28	97	18,937	1,576	1,794	635	24,154
August	1,073	32	99	18,736	1,569	1,763	620	23,891
September	882	35	80	16,902	1,510	1,594	439	21,442
October	793	46	99	17,040	1,776	1,980	578	22,311
November	1,396	49	86	17,026	1,571	2,200	625	22,954
December	1,391	204	90	18,059	1,639	2,208	619	24,210
Year 2019								
January	1,756	131	85	18,139	1,736	2,518	643	25,008
February	1,186	58	89	15,487	1,764	2,366	595	21,547
March	1,241	58	95	17,184	1,790	2,422	622	23,412
April	1,166	46	98	15,213	1,699	2,226	610	21,057
May	1,089	41	94	14,942	1,511	2,078	690	20,445
June	1,051	42	79	15,814	1,424	1,971	672	21,052
July	995	33	84	16,967	1,643	1,874	661	22,257
August	968	29	91	17,942	1,552	1,970	637	23,188
September	782	63	79	15,907	1,519	1,794	525	20,669
October	901	54	23	15,836	1,721	2,051	551	21,137
November	828	51	100	16,240	1,629	2,367	656	21,871
December	795	50	102	17,435	1,697	2,420	680	23,179

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

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See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Table 3.25. Useful Thermal Output by Energy Source: Commercial Sector Combined Heat and Power, 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	20,057	1,095	155	25,902	0	8,450	5,761	61,420
2010	19,216	845	216	29,791	13	7,917	5,333	63,330
2011	17,234	687	111	24,848	14	7,433	5,988	56,314
2012	13,992	523	229	27,922	0	7,970	6,426	57,063
2013	10,942	1,017	222	27,562	0	7,054	5,693	52,489
2014	11,081	820	327	26,876	0	7,610	5,123	51,837
2015	7,966	823	325	26,498	0	8,228	5,641	49,482
2016	8,313	924	140	57,356	0	11,017	5,381	83,131
2017	7,360	806	234	71,149	0	10,762	5,140	95,450
2018	6,943	1,020	165	58,312	0	10,902	4,918	82,260
2019	6,211	1,346	95	56,356	0	8,307	3,335	75,650
Year 2017								
January	848	133	31	6,820	0	1,141	544	9,516
February	689	85	18	5,777	0	946	447	7,962
March	813	94	27	5,569	0	875	444	7,821
April	529	44	9	4,741	0	843	414	6,580
May	493	40	12	4,952	0	830	408	6,734
June	475	29	8	5,725	0	902	448	7,588
July	572	38	6	6,706	0	889	442	8,654
August	506	37	32	6,700	0	920	446	8,641
September	532	34	30	6,039	0	705	357	7,697
October	476	43	20	5,888	0	833	378	7,639
November	632	61	12	5,746	0	929	405	7,785
December	795	166	29	6,486	0	949	407	8,833
Year 2018								
January	952	314	29	5,302	0	964	436	7,998
February	719	87	25	4,783	0	967	423	7,006
March	691	80	23	4,924	0	989	421	7,128
April	573	59	9	4,382	0	904	428	6,354
May	455	43	0	4,357	0	897	449	6,201
June	429	39	0	4,655	0	889	407	6,419
July	474	60	0	5,401	0	914	431	7,280
August	491	53	0	5,442	0	945	421	7,352
September	525	43	14	4,686	0	755	297	6,321
October	496	49	13	4,576	0	831	373	6,338
November	565	93	24	4,858	0	864	403	6,808
December	573	100	26	4,946	0	982	429	7,056
Year 2019								
January	724	200	28	5,239	0	966	482	7,639
February	678	111	16	4,804	0	824	411	6,843
March	691	101	22	4,740	0	816	357	6,728
April	481	52	19	4,242	0	577	178	5,549
May	451	467	0	4,067	0	582	222	5,790
June	305	28	0	4,308	0	613	242	5,497
July	409	48	0	5,172	0	605	213	6,447
August	440	77	0	4,892	0	671	257	6,337
September	474	51	0	4,494	0	647	223	5,888
October	435	55	0	4,370	0	691	242	5,794
November	524	82	0	4,692	0	675	251	6,224
December	599	72	11	5,335	0	640	257	6,914

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report;

Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Table 3.26. Useful Thermal Output by Energy Source: Industrial Sector Combined Heat and Power, 2009 - 2019
(Billion Btus)

Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Renewable Sources	Other	Total
Annual Totals								
2009	223,485	26,155	18,708	296,225	79,726	520,898	22,471	1,187,669
2010	242,762	14,366	20,124	307,931	71,719	555,804	18,382	1,231,088
2011	233,767	10,059	20,209	319,590	83,167	562,838	19,035	1,248,666
2012	212,520	7,524	22,944	328,729	92,199	556,174	12,599	1,232,689
2013	210,795	7,196	24,009	338,041	93,416	588,165	11,512	1,273,134
2014	199,512	6,120	22,167	334,901	97,137	596,087	10,600	1,266,524
2015	180,501	5,965	20,203	384,369	91,749	598,890	8,899	1,290,576
2016	173,589	6,792	18,692	478,068	131,481	655,831	11,904	1,476,358
2017	151,780	6,289	15,721	503,614	133,781	631,768	11,112	1,454,066
2018	142,671	7,535	15,281	521,936	153,985	622,699	11,118	1,475,224
2019	127,411	5,787	13,012	523,919	122,544	607,138	11,535	1,411,347
Year 2017								
January	14,596	452	1,387	42,833	12,117	54,855	992	127,232
February	12,236	341	1,122	38,798	10,489	50,096	856	113,937
March	13,192	483	1,472	41,319	11,127	53,791	952	122,336
April	11,876	490	1,217	39,194	10,646	50,519	904	114,845
May	12,013	457	1,260	40,419	11,893	50,615	818	117,475
June	12,505	386	1,456	40,850	10,837	52,544	928	119,505
July	12,097	374	1,400	44,074	11,203	53,848	905	123,901
August	12,388	373	1,428	43,041	11,109	54,822	1,022	124,183
September	11,528	450	1,140	42,385	10,676	49,080	934	116,192
October	13,159	452	1,352	42,676	11,359	51,977	944	121,920
November	12,704	904	1,277	41,707	10,871	53,411	912	121,785
December	13,486	1,128	1,212	46,318	11,455	56,210	945	130,754
Year 2018								
January	14,472	1,677	1,516	46,673	12,496	54,988	932	132,754
February	13,139	572	1,417	40,743	12,193	49,103	894	118,061
March	13,006	476	1,262	43,193	13,241	53,174	978	125,329
April	11,359	432	1,345	40,349	11,989	50,528	848	116,851
May	11,248	462	1,364	41,234	12,926	51,916	800	119,948
June	11,183	544	1,344	42,224	12,857	50,140	1,002	119,295
July	11,209	437	1,253	45,047	13,028	53,237	950	125,161
August	11,104	436	1,199	44,958	14,528	53,149	1,023	126,397
September	10,875	395	1,143	43,198	12,463	48,750	924	117,747
October	10,610	658	1,172	43,194	13,200	51,191	926	120,951
November	11,718	763	1,022	45,021	12,250	51,484	894	123,152
December	12,749	684	1,245	46,103	12,813	55,038	947	129,578
Year 2019								
January	13,124	1,129	1,151	46,960	10,428	54,504	990	128,286
February	11,791	540	1,065	42,487	9,382	49,408	950	115,622
March	11,431	434	1,148	44,198	10,513	51,928	1,018	120,672
April	10,724	421	1,118	40,351	10,317	48,442	970	112,343
May	10,189	342	1,143	42,727	10,016	49,351	731	114,500
June	9,849	330	1,137	42,011	9,886	48,749	919	112,879
July	9,400	285	1,097	44,343	10,848	51,142	955	118,071
August	9,396	329	1,053	44,741	10,450	51,506	1,019	118,495
September	9,268	340	1,185	42,651	10,133	48,088	933	112,599
October	10,273	385	1,026	43,037	10,045	50,520	972	116,257
November	10,745	812	836	44,067	10,012	50,820	1,082	118,376
December	11,220	440	1,052	46,346	10,514	52,680	996	123,248

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

Other Gas includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Prior to 2011, Other Gas included propane and synthesis gases.

See the Technical Notes for fuel conversion factors.

Renewable Sources include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, and solar thermal.

Other includes non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources.

Notes: Beginning with 2001 data, non-biogenic municipal solid waste and tire-derived fuels are reclassified as non-renewable energy sources and included in Other. Biogenic municipal solid waste is included in Other Renewable Sources.

Beginning with the collection of Form EIA-923 in January 2008, the methodology for separating the fuel used for electricity generation and useful thermal output from combined heat and power plants changed. The new methodology was retroactively applied to 2004-2007, as well as 2008-2015. Beginning with the 2016 Form EIA-923 data, the methodology for separating the fuel used for electricity generation and useful thermal output from CHP plants was updated. This update will apply to the 2016 data and future data years. See the Technical Notes (Appendix C) for further information.

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Totals may not equal sum of components because of independent rounding. NM=Not meaningful due to large standard error. W=Withheld to avoid disclosure of individual company data.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report; and predecessor forms.

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Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Chapter 4

Generation Capacity

Table 4.1. Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within Plant, 2009 through 2019

Year	Coal	Petroleum	Natural Gas	Other Gases	Nuclear	Hydroelectric Conventional	Other Renewables	Hydroelectric Pumped Storage	Other Energy Sources
Total (All Sectors)									
2009	593	1,168	1,652	43	66	1,427	1,219	39	28
2010	580	1,169	1,657	48	66	1,432	1,355	39	32
2011	589	1,146	1,646	41	66	1,434	1,582	40	54
2012	557	1,129	1,714	44	66	1,426	1,956	41	64
2013	518	1,101	1,725	44	63	1,435	2,299	41	78
2014	491	1,082	1,749	43	62	1,441	2,674	41	94
2015	427	1,082	1,779	45	62	1,440	3,043	41	83
2016	381	1,076	1,801	45	61	1,451	3,624	40	117
2017	359	1,080	1,820	44	61	1,458	4,174	40	148
2018	336	1,087	1,854	46	60	1,458	4,667	40	171
2019	308	1,090	1,899	43	58	1,452	5,244	40	212
Electric Utilities									
2009	340	855	768	--	34	887	129	34	1
2010	333	855	775	3	34	888	155	34	--
2011	332	829	777	--	34	884	189	35	1
2012	315	815	797	--	34	875	238	36	5
2013	300	795	787	1	32	873	253	36	15
2014	286	780	803	1	32	889	272	35	20
2015	256	782	816	1	32	890	318	35	15
2016	230	771	819	1	31	893	375	35	36
2017	219	765	820	1	31	894	417	35	53
2018	206	751	819	1	31	896	462	35	60
2019	194	743	818	1	31	898	512	35	71
Independent Power Producers, Non-Combined Heat and Power Plants									
2009	100	173	377	1	32	485	868	5	2
2010	102	175	380	1	32	488	966	5	6
2011	98	166	373	--	32	490	1,106	5	12
2012	88	150	368	--	32	494	1,388	5	16
2013	86	147	384	1	31	505	1,670	5	15
2014	87	148	395	1	30	499	2,006	5	18
2015	80	143	397	--	30	497	2,309	5	21
2016	75	142	406	--	30	500	2,826	5	34
2017	71	145	415	--	30	505	3,320	5	43
2018	65	140	450	--	29	514	3,749	5	59
2019	59	141	476	--	27	506	4,251	5	74
Independent Power Producers, Combined Heat and Power Plants									
2009	51	10	166	3	--	--	41	--	--
2010	48	10	161	2	--	--	41	--	--
2011	45	11	156	1	--	--	38	--	1
2012	42	12	157	2	--	--	47	--	--
2013	35	11	152	2	--	1	51	--	5
2014	30	9	145	2	--	--	54	--	7
2015	27	8	143	3	--	--	58	--	3
2016	24	7	143	3	--	--	57	--	2
2017	22	7	138	3	--	--	56	--	3
2018	19	8	133	3	--	--	56	--	3
2019	14	6	128	3	--	--	56	--	3
Commercial Sector									
2009	18	68	107	1	--	9	47	--	1
2010	17	69	110	1	--	9	57	--	1
2011	22	80	118	--	--	10	105	--	2
2012	22	89	153	--	--	9	129	--	2
2013	19	92	164	--	--	9	160	--	3
2014	17	93	169	--	--	10	178	1	6
2015	12	94	176	--	--	10	186	1	3
2016	9	101	181	--	--	14	195	--	3
2017	9	112	189	--	--	15	203	--	4
2018	7	139	192	--	--	15	220	--	5
2019	6	152	203	--	--	15	242	--	20
Industrial Sector									
2009	84	62	234	38	--	46	134	--	24
2010	80	60	231	41	--	47	136	--	25
2011	92	60	222	40	--	50	144	--	38
2012	90	63	239	42	--	48	154	--	41
2013	78	56	238	40	--	47	165	--	40
2014	71	52	237	39	--	43	164	--	43
2015	52	55	247	41	--	43	172	--	41
2016	43	55	252	41	--	44	171	--	42
2017	38	51	258	40	--	44	178	--	45
2018	39	49	260	42	--	33	180	--	44
2019	35	48	274	39	--	33	183	--	44

generators. If all generators for a site have the same energy source reported as the most predominant, that site will be counted once under that energy source. However, if the most predominant energy source is not the same for all generators within a site, the site is counted more than once, based on the number of most predominant energy sources for generators at a site. In general, this table translates the number of generators by energy source into the number of sites represented by the generators for an energy source. Therefore, the count for Total (All Sectors) above is the sum of the counts for each sector by energy source and does not necessarily represent unique sites. In addition, changes to predominant energy sources and status codes from year to year may result in changes to previously-posted data.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

Table 4.2.A. Existing Net Summer Capacity by Energy Source and Producer Type, 2009 through 2019 (Megawatts)

Utility Scale Capacity											Small Scale Capacity
Year	Coal	Petroleum	Natural Gas	Other Gases	Nuclear	Hydroelectric Conventional	Other Renewable Sources	Hydroelectric Pumped Storage	Other Energy Sources	Utility Total	Estimated Photovoltaic
Total (All Sectors)											
2009	314,294.1	56,780.5	401,271.8	1,932.4	101,003.7	78,517.7	48,552.0	22,160.4	887.8	1,025,400.4	--
2010	316,800.1	55,646.9	407,028.4	2,700.3	101,167.4	78,824.7	53,811.3	22,198.9	883.8	1,039,061.8	--
2011	317,640.3	51,481.6	415,191.3	1,934.2	101,418.8	78,651.6	61,221.0	22,292.6	1,419.6	1,051,251.0	--
2012	309,680.4	47,167.2	422,364.4	1,945.6	101,885.0	78,738.0	77,155.2	22,368.3	1,728.9	1,063,033.0	--
2013	303,306.3	43,523.0	425,389.7	2,107.8	99,240.3	79,200.0	82,600.1	22,389.3	2,307.0	1,060,063.5	--
2014	299,094.2	41,135.4	432,150.3	1,914.3	98,569.3	79,677.3	90,603.7	22,485.1	2,792.6	1,068,422.2	7,326.6
2015	279,719.9	36,830.3	439,425.4	2,500.4	98,672.0	79,664.2	102,871.6	22,575.1	1,795.6	1,064,054.5	9,778.5
2016	266,619.9	34,382.4	446,823.2	2,456.9	99,564.8	79,912.9	119,778.9	22,778.7	2,015.1	1,074,332.8	12,765.1
2017	256,547.3	33,306.7	456,011.6	2,375.8	99,628.9	79,794.5	131,008.1	22,810.4	2,886.3	1,084,369.6	16,147.8
2018	242,785.6	32,218.2	470,236.9	2,543.9	99,432.9	79,871.8	142,473.6	22,830.2	2,346.7	1,094,739.8	19,547.1
2019	228,657.4	31,400.3	476,567.4	2,499.2	98,119.0	79,773.1	156,708.2	22,778.3	2,606.4	1,099,109.3	23,213.6
Electric Utilities											
2009	234,396.6	30,174.1	180,570.7	--	54,355.2	72,689.7	5,613.9	18,930.0	39.0	596,769.2	--
2010	235,706.8	28,971.9	184,230.5	539.0	54,369.3	72,973.9	6,316.1	18,968.5	--	602,076.0	--
2011	236,391.7	27,669.9	193,630.5	--	54,351.6	72,182.4	7,811.1	19,062.2	5.3	611,104.7	--
2012	232,078.5	26,731.8	206,774.4	--	54,716.7	72,505.1	9,823.8	19,093.9	60.7	621,784.9	--
2013	228,478.0	24,648.8	208,485.7	12.0	52,399.1	72,755.2	10,118.4	19,114.9	787.3	616,799.4	--
2014	219,837.9	24,045.0	215,690.8	12.0	52,390.9	73,725.4	10,893.7	19,121.3	914.5	616,631.5	--
2015	202,922.4	22,269.7	223,215.6	12.0	52,457.2	73,713.0	12,654.3	19,211.3	87.5	606,543.0	--
2016	193,122.6	20,285.5	229,677.1	12.0	53,274.1	73,879.3	14,236.4	19,398.3	236.1	604,121.4	--
2017	186,623.1	19,999.9	236,557.8	12.0	53,343.6	73,739.5	15,281.3	19,430.0	519.3	605,506.5	--
2018	179,047.8	18,642.6	241,477.0	12.0	53,725.6	73,818.2	18,155.9	19,449.8	341.8	604,670.7	--
2019	171,088.7	18,219.8	247,018.9	12.0	53,880.6	73,719.7	20,745.8	19,428.9	418.3	604,532.7	--
Independent Power Producers, Non-Combined Heat and Power Plants											
2009	70,122.5	24,657.1	176,034.8	7.6	46,648.5	5,469.6	36,556.4	3,230.4	45.9	362,772.8	--
2010	71,214.4	24,866.8	178,190.4	7.6	46,798.1	5,488.6	41,013.7	3,230.4	76.9	370,886.9	--
2011	72,119.5	22,398.8	176,516.5	--	47,067.2	5,539.0	46,698.4	3,230.4	169.2	373,739.0	--
2012	69,068.4	18,643.9	170,653.8	--	47,168.3	5,568.6	60,116.8	3,274.4	470.2	374,964.4	--
2013	67,153.5	17,444.7	171,653.6	47.0	46,841.2	5,762.2	64,890.5	3,274.4	231.2	377,298.3	--
2014	71,994.6	15,724.4	172,224.5	47.0	46,178.4	5,651.2	72,144.4	3,358.4	238.7	387,561.6	--
2015	70,217.8	13,102.9	172,519.2	--	46,214.8	5,650.5	82,014.6	3,358.4	354.3	393,432.5	--
2016	67,667.7	12,587.4	173,455.8	--	46,290.7	5,676.9	97,408.4	3,380.4	487.5	406,954.8	--
2017	64,419.3	11,777.0	176,029.0	--	46,285.3	5,697.9	107,618.0	3,380.4	989.3	416,196.2	--
2018	58,716.2	11,733.2	186,542.1	--	45,707.3	5,770.0	116,197.3	3,380.4	670.1	428,716.6	--
2019	53,646.5	11,514.8	187,715.6	--	44,238.4	5,764.3	127,964.3	3,349.4	760.7	434,954.0	--
Independent Power Producers, Combined Heat and Power Plants											
2009	5,939.5	897.0	28,875.4	205.8	--	--	739.9	--	--	36,657.6	--
2010	5,450.6	766.0	29,005.6	182.3	--	--	845.5	--	--	36,250.0	--
2011	5,146.0	317.0	29,372.6	30.0	--	--	792.9	--	53.0	35,711.5	--
2012	4,755.9	317.2	29,128.6	83.0	--	--	981.2	--	--	35,265.9	--
2013	4,313.7	322.2	29,081.2	83.0	--	4.3	945.1	--	121.8	34,871.3	--
2014	4,073.0	308.2	27,676.7	83.0	--	--	885.9	--	335.8	33,362.6	--
2015	3,843.6	307.2	27,284.1	350.0	--	--	970.5	--	126.0	32,881.4	--
2016	3,552.4	301.2	27,222.4	350.0	--	--	1,068.3	--	19.0	32,513.3	--
2017	3,338.0	301.2	26,922.1	350.0	--	--	969.8	--	21.0	31,902.1	--
2018	2,922.0	458.0	25,658.1	350.0	--	--	884.2	--	21.0	30,293.3	--
2019	2,074.1	298.8	24,782.0	350.0	--	--	944.9	--	112.0	28,561.8	--
Commercial Sector											
2009	423.7	348.3	1,104.7	4.7	--	21.7	480.1	--	2.8	2,386.0	--
2010	418.2	368.2	1,154.5	4.7	--	21.7	519.7	--	2.8	2,489.8	--
2011	435.7	406.3	1,282.6	--	--	233.5	694.1	--	4.2	3,056.4	--
2012	435.6	442.7	1,544.9	--	--	18.4	776.8	--	4.2	3,222.6	--
2013	341.9	455.7	1,778.9	--	--	17.8	947.6	--	9.1	3,551.0	--
2014	290.1	463.5	1,832.6	--	--	21.4	1,066.8	5.4	15.6	3,695.4	3,279.7
2015	226.6	466.1	1,932.5	--	--	21.4	1,126.5	5.4	6.7	3,785.2	3,706.7
2016	202.4	511.0	1,982.6	--	--	74.5	1,132.0	--	6.7	3,909.2	4,022.8
2017	202.4	596.5	2,018.7	--	--	74.9	1,162.0	--	11.6	4,066.1	5,155.8
2018	144.2	823.6	2,157.6	--	--	74.7	1,241.5	--	13.0	4,454.6	6,271.4
2019	123.2	856.7	2,247.5	--	--	74.9	1,218.6	--	49.1	4,570.0	7,167.9
Industrial Sector											
2009	3,411.8	704.0	14,686.2	1,714.3	--	336.7	5,161.7	--	800.1	26,814.8	--
2010	4,010.1	674.0	14,447.4	1,966.7	--	340.5	5,116.3	--	804.1	27,359.1	--
2011	3,547.4	689.6	14,389.1	1,904.2	--	696.7	5,224.5	--	1,187.9	27,639.4	--
2012	3,342.0	1,031.6	14,262.7	1,862.6	--	645.9	5,456.6	--	1,193.8	27,795.2	--
2013	3,019.2	651.6	14,390.3	1,965.8	--	660.5	5,698.5	--	1,157.6	27,543.5	--
2014	2,898.6	594.3	14,725.7	1,772.3	--	279.3	5,612.9	--	1,288.0	27,171.1	700.6
2015	2,509.5	684.4	14,474.0	2,138.4	--	279.3	6,105.7	--	1,221.1	27,412.4	880.3
2016	2,074.8	697.3	14,485.3	2,094.9	--	282.2	5,933.8	--	1,265.8	26,834.1	1,215.3
2017	1,964.5	632.1	14,484.0	2,013.8	--	282.2	5,977.0	--	1,345.1	26,698.7	1,365.1
2018	1,955.4	560.8	14,402.1	2,181.9	--	208.9	5,994.7	--	1,300.8	26,604.6	1,555.4
2019	1,724.9	510.2	14,803.4	2,137.2	--	214.2	5,834.6	--	1,266.3	26,490.8	1,796.6
Residential Sector											
2014	--	--	--	--	--	--	--	--	--	--	3,346.3
2015	--	--	--	--	--	--	--	--	--	--	5,191.5
2016	--	--	--	--	--	--	--	--	--	--	7,527.0
2017	--	--	--	--	--	--	--	--	--	--	9,626.8
2018	--	--	--	--	--	--	--	--	--	--	11,720.4
2019	--	--	--	--	--	--	--	--	--	--	14,249.0

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Gases. Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Gases. Other Gases also includes blast furnace gas. Prior to 2011, waste heat was included in Natural Gas. Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities. Other Renewable Sources include wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources. In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector. Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.' Estimated small scale solar photovoltaic generation and capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type, 2009 through 2019 (Megawatts) (Page 1)

Utility Scale Capacity								Utility and Small Scale Capacity		
Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Total (All Sectors)										
2009	34,295.8	145.5	473.0	6,939.3	2,381.9	4,316.5	48,552.0	--	145.5	618.5
2010	39,134.5	393.4	473.0	7,037.3	2,404.6	4,368.5	53,811.3	--	393.4	866.4
2011	45,675.9	1,052.0	471.5	7,076.5	2,409.2	4,535.9	61,221.0	--	1,052.0	1,523.5
2012	59,074.8	2,694.1	476.0	7,507.6	2,592.1	4,810.6	77,155.2	--	2,694.1	3,170.1
2013	59,973.4	5,336.1	1,286.4	8,354.2	2,607.0	5,043.0	82,600.1	--	5,336.1	6,622.5
2014	64,231.5	8,656.6	1,666.7	8,368.1	2,514.3	5,166.5	90,603.7	7,326.6	15,983.2	17,649.9
2015	72,573.4	11,905.4	1,757.9	8,968.9	2,541.5	5,124.5	102,871.6	9,778.5	21,683.9	23,441.8
2016	81,286.6	20,192.9	1,757.9	8,936.1	2,516.6	5,088.8	119,778.9	12,765.1	32,958.0	34,715.9
2017	87,597.5	25,209.0	1,757.9	8,830.9	2,483.3	5,129.5	131,008.1	16,147.8	41,356.8	43,114.7
2018	94,417.7	30,120.5	1,757.9	8,694.6	2,444.3	5,038.6	142,473.6	19,547.1	49,667.6	51,425.5
2019	103,571.2	35,710.2	1,758.1	8,374.5	2,555.4	4,738.8	156,708.2	23,213.6	58,923.8	60,681.9
Electric Utilities										
2009	4,654.8	41.0	1.0	431.3	158.9	326.9	5,613.9	--	41.0	42.0
2010	5,338.3	78.2	1.0	414.3	158.9	325.4	6,316.1	--	78.2	79.2
2011	6,735.2	201.4	1.0	359.1	158.9	355.5	7,811.1	--	201.4	202.4
2012	8,488.7	331.2	1.0	364.1	162.1	476.7	9,823.8	--	331.2	332.2
2013	8,424.7	487.9	--	564.3	164.1	477.4	10,118.4	--	487.9	487.9
2014	9,022.6	568.5	--	654.8	164.1	483.7	10,893.7	--	568.5	568.5
2015	10,580.9	842.9	--	623.8	165.9	440.8	12,654.3	--	842.9	842.9
2016	11,552.6	1,388.4	--	708.8	167.9	418.7	14,236.4	--	1,388.4	1,388.4
2017	12,150.8	1,724.5	--	811.3	161.9	432.8	15,281.3	--	1,724.5	1,724.5
2018	14,031.7	2,683.5	--	807.0	148.8	484.9	18,155.9	--	2,683.5	2,683.5
2019	15,715.0	3,851.4	--	696.2	146.5	336.7	20,745.8	--	3,851.4	3,851.4
Independent Power Producers, Non-Combined Heat and Power Plants										
2009	29,639.8	103.4	472.0	1,220.2	2,223.0	2,898.0	36,556.4	--	103.4	575.4
2010	33,783.9	307.9	472.0	1,274.5	2,245.7	2,929.7	41,013.7	--	307.9	779.9
2011	38,911.8	792.1	470.5	1,312.5	2,250.3	2,961.2	46,698.4	--	792.1	1,262.6
2012	50,547.6	2,255.7	475.0	1,398.8	2,384.2	3,055.5	60,116.8	--	2,255.7	2,730.7
2013	51,497.8	4,647.6	1,286.4	1,845.4	2,401.1	3,212.2	64,890.5	--	4,647.6	5,934.0
2014	55,133.0	7,857.0	1,666.7	1,816.6	2,308.8	3,362.3	72,144.4	--	7,857.0	9,523.7
2015	61,905.4	10,768.2	1,757.9	1,873.3	2,375.6	3,334.2	82,014.6	--	10,768.2	12,526.1
2016	69,645.4	18,483.3	1,757.9	1,789.6	2,348.7	3,383.5	97,408.4	--	18,483.3	20,241.2
2017	75,346.6	23,127.0	1,757.9	1,649.1	2,321.4	3,416.0	107,618.0	--	23,127.0	24,884.9
2018	80,267.6	27,055.8	1,757.9	1,576.2	2,246.1	3,293.7	116,197.3	--	27,055.8	28,813.7
2019	87,737.8	31,416.4	1,758.1	1,475.7	2,359.5	3,216.8	127,964.3	--	31,416.4	33,174.5

Notes: Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass includes municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

* = Value is less than half of the smallest unit of measure.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.2.B. Existing Net Summer Capacity of Other Renewable Sources by Producer Type,

2009 through 2019 (Megawatts) (Page 2)

Utility Scale Capacity								Utility and Small Scale Capacity		
Year	Wind	Solar Photovoltaic	Solar Thermal	Wood and Wood-Derived Fuels	Geothermal	Other Biomass	Total Utility (Other Renewable Sources)	Estimated Small Scale Photovoltaic	Total Solar Photovoltaic	Total Solar
Independent Power Producers, Combined Heat and Power Plants										
2009	--	--	--	237.2	--	502.7	739.9	--	--	--
2010	--	--	--	392.8	--	452.7	845.5	--	--	--
2011	--	--	--	356.3	--	436.6	792.9	--	--	--
2012	--	--	--	489.8	45.8	445.6	981.2	--	--	--
2013	--	--	--	469.2	41.8	434.1	945.1	--	--	--
2014	--	--	--	465.5	41.4	379.0	885.9	--	--	--
2015	--	--	--	568.2	--	402.3	970.5	--	--	--
2016	--	1.0	--	667.2	--	400.1	1,068.3	--	1.0	1.0
2017	--	2.5	--	582.0	--	385.3	969.8	--	2.5	2.5
2018	--	3.3	--	492.7	--	388.2	884.2	--	3.3	3.3
2019	--	3.3	--	554.7	--	386.9	944.9	--	3.3	3.3
Commercial Sector										
2009	1.2	0.1	--	7.6	--	471.2	480.1	--	0.1	0.1
2010	10.5	5.9	--	7.6	--	495.7	519.7	--	5.9	5.9
2011	24.6	54.1	--	7.6	--	607.8	694.1	--	54.1	54.1
2012	29.8	99.9	--	7.6	--	639.5	776.8	--	99.9	99.9
2013	33.2	192.9	--	8.4	--	713.1	947.6	--	192.9	192.9
2014	51.6	223.4	--	65.4	--	726.4	1,066.8	3,279.7	3,503.1	3,503.1
2015	55.3	282.1	--	65.3	--	723.8	1,126.5	3,706.7	3,988.8	3,988.8
2016	56.8	300.8	--	67.1	--	707.3	1,132.0	4,022.8	4,323.6	4,323.6
2017	60.8	311.6	--	63.1	--	726.5	1,162.0	5,155.8	5,467.4	5,467.4
2018	73.4	330.6	--	63.1	49.4	725.0	1,241.5	6,271.4	6,602.0	6,602.0
2019	73.4	381.1	--	63.1	49.4	651.6	1,218.6	7,167.9	7,549.0	7,549.0
Industrial Sector										
2009	--	1.0	--	5,043.0	--	117.7	5,161.7	--	1.0	1.0
2010	1.8	1.4	--	4,948.1	--	165.0	5,116.3	--	1.4	1.4
2011	4.3	4.4	--	5,041.0	--	174.8	5,224.5	--	4.4	4.4
2012	8.7	7.3	--	5,247.3	--	193.3	5,456.6	--	7.3	7.3
2013	17.7	7.7	--	5,466.9	--	206.2	5,698.5	--	7.7	7.7
2014	24.3	7.7	--	5,365.8	--	215.1	5,612.9	700.6	708.3	708.3
2015	31.8	12.2	--	5,838.3	--	223.4	6,105.7	880.3	892.5	892.5
2016	31.8	19.4	--	5,703.4	--	179.2	5,933.8	1,215.3	1,234.7	1,234.7
2017	39.3	43.4	--	5,725.4	--	168.9	5,977.0	1,365.1	1,408.5	1,408.5
2018	45.0	47.3	--	5,755.6	--	146.8	5,994.7	1,555.4	1,602.7	1,602.7
2019	45.0	58.0	--	5,584.8	--	146.8	5,834.6	1,796.6	1,854.6	1,854.6
Residential Sector										
2014	--	--	--	--	--	--	--	3,346.3	3,346.3	3,346.3
2015	--	--	--	--	--	--	--	5,191.5	5,191.5	5,191.5
2016	--	--	--	--	--	--	--	7,527.0	7,527.0	7,527.0
2017	--	--	--	--	--	--	--	9,626.8	9,626.8	9,626.8
2018	--	--	--	--	--	--	--	11,720.4	11,720.4	11,720.4
2019	--	--	--	--	--	--	--	14,249.0	14,249.0	14,249.0

Notes: Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
Other Biomass includes municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
* = Value is less than half of the smallest unit of measure.
Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'
Estimated small scale solar photovoltaic generation capacity are based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.3. Existing Capacity by Energy Source, 2019 (Megawatts)

Energy Source	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	Utility Scale	668	248,286.3	228,657.4	229,623.7
Petroleum	Utility Scale	3,691	36,120.0	31,400.3	33,727.7
Natural Gas	Utility Scale	6,020	542,413.2	476,567.4	511,196.1
Other Gases	Utility Scale	91	2,863.3	2,499.2	2,551.1
Nuclear	Utility Scale	96	102,877.3	98,119.0	100,141.5
Hydroelectric Conventional	Utility Scale	4,014	79,787.1	79,773.1	79,172.2
Wind	Utility Scale	1,354	104,333.6	103,571.2	103,667.8
Solar Photovoltaic	Utility Scale	3,948	36,013.4	35,710.2	35,267.9
Solar Thermal	Utility Scale	19	1,774.6	1,758.1	1,597.4
Wood and Wood-Derived Fuels	Utility Scale	333	9,519.1	8,374.5	8,496.2
Geothermal	Utility Scale	172	3,849.3	2,555.4	2,963.3
Other Biomass	Utility Scale	1,917	5,382.7	4,738.8	4,799.2
Hydroelectric Pumped Storage	Utility Scale	153	21,871.3	22,778.3	22,598.6
Other Energy Sources	Utility Scale	255	2,825.9	2,606.4	2,656.5
Total	Utility Scale	22,731	1,197,917.1	1,099,109.3	1,138,459.2
Small Scale Photovoltaic	Small Scale	--	--	23,213.6	--
Estimated Total Photovoltaic	Utility and Small Scale	--	--	58,923.8	--
Estimated Total Solar	Utility and Small Scale	--	--	60,681.9	--

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011, coal-derived synthesis gas was included in Other Gases.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, and beginning in 2011, synthetic gas and propane. Prior to 2011, synthetic gas and propane were included in Other Gases.

Other Gases includes blast furnace gas. Prior to 2011, waste heat was included in Natural Gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In 2011, EIA corrected the NAICS codes of several plants which resulted in a net capacity shift from the electric utility sector to the commercial sector.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.4. Existing Capacity by Producer Type, 2019 (Megawatts)

Producer Type	Facility Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector					
Electric Utilities	Utility Scale	9,559	660,512.2	604,532.7	624,823.4
Independent Power Producers, Non-Combined Heat and Power Plants	Utility Scale	9,629	469,617.6	434,954.0	449,868.6
Independent Power Producers, Combined Heat and Power Plants	Utility Scale	477	32,166.2	28,561.8	30,818.6
Total	Utility Scale	19,665	1,162,296.0	1,068,048.5	1,105,510.6
Commercial and Industrial Sectors					
Commercial Sector	Utility Scale	1,555	5,028.3	4,570.0	4,663.7
Industrial Sector	Utility Scale	1,511	30,592.8	26,490.8	28,284.9
Total	Utility Scale	3,066	35,621.1	31,060.8	32,948.6
All Sectors					
Total	Utility Scale	22,731	1,197,917.1	1,099,109.3	1,138,459.2
Small Scale					
Estimated Solar Photovoltaic	Small Scale	--	--	23,213.6	--

Notes:

See Glossary reference for definitions.

Totals may not equal sum of components because of independent rounding.

In the case of some wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Estimated small scale solar photovoltaic capacity is based on data from Form EIA-826, Form EIA-861M, Form EIA-861 and from estimation methods described in the technical notes.

Table 4.5. Planned Utility-Scale Generating Capacity Changes, by Energy Source, 2020-2024 (Page 1)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2020						
U.S. Total	802	44,866.9	146	12,760.7	656	32,106.2
Coal	1	17.0	35	8,824.2	-34	-8,807.2
Petroleum	9	10.4	13	282.3	-4	-271.9
Natural Gas	64	6,565.6	60	1,805.8	4	4,759.8
Other Gases	--	--	--	--	--	--
Nuclear	--	--	2	1,617.5	-2	-1,617.5
Hydroelectric Conventional	12	161.5	2	1.8	10	159.7
Wind	132	23,470.7	10	123.1	122	23,347.6
Solar Thermal and Photovoltaic	515	13,535.7	--	--	515	13,535.7
Wood and Wood-Derived Fuels	1	8.5	1	20.0	--	-11.5
Geothermal	--	--	--	--	--	--
Other Biomass	12	55.0	23	86.0	-11	-31.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	56	1,042.5	--	--	56	1,042.5
Year 2021						
U.S. Total	447	31,873.8	54	9,635.6	393	22,238.2
Coal	--	--	14	3,308.8	-14	-3,308.8
Petroleum	--	--	15	808.4	-15	-808.4
Natural Gas	90	7,282.1	15	367.7	75	6,914.4
Other Gases	--	--	--	--	--	--
Nuclear	1	1,100.0	5	5,134.9	-4	-4,034.9
Hydroelectric Conventional	22	102.3	4	4.2	18	98.1
Wind	54	7,825.8	1	11.6	53	7,814.2
Solar Thermal and Photovoltaic	211	12,151.1	--	--	211	12,151.1
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	2	42.0	--	--	2	42.0
Other Biomass	1	2.0	--	--	1	2.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	66	3,368.5	--	--	66	3,368.5
Year 2022						
U.S. Total	228	27,124.3	52	11,406.4	176	15,717.9
Coal	--	--	23	7,720.1	-23	-7,720.1
Petroleum	--	--	9	1,749.6	-9	-1,749.6
Natural Gas	47	14,431.8	17	1,155.8	30	13,276.0
Other Gases	--	--	--	--	--	--
Nuclear	1	1,100.0	1	771.6	--	328.4
Hydroelectric Conventional	10	19.8	--	--	10	19.8
Wind	17	2,493.9	--	--	17	2,493.9
Solar Thermal and Photovoltaic	127	7,702.2	--	--	127	7,702.2
Wood and Wood-Derived Fuels	2	48.0	1	7.8	1	40.2
Geothermal	--	--	--	--	--	--
Other Biomass	3	4.2	--	--	3	4.2
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	21	1,324.4	1	1.5	20	1,322.9

Notes: These data reflect plans as of December 31, 2019

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, synthetic gas, and propane.

Other Gases also includes blast furnace gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In the case of wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.5. Planned Generating Capacity Changes, by Energy Source, 2020-2024 (Page 2)

Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity	Number of Generators	Net Summer Capacity
Year 2023						
U.S. Total	117	15,664.7	76	11,738.9	41	3,925.8
Coal	--	--	17	5,309.5	-17	-5,309.5
Petroleum	--	--	12	977.9	-12	-977.9
Natural Gas	24	7,457.5	37	5,411.7	-13	2,045.8
Other Gases	--	--	--	--	--	--
Nuclear	--	--	--	--	--	--
Hydroelectric Conventional	56	177.6	7	22.8	49	154.8
Wind	4	2,050.0	--	--	4	2,050.0
Solar Thermal and Photovoltaic	20	4,623.1	--	--	20	4,623.1
Wood and Wood-Derived Fuels	--	--	2	16.0	-2	-16.0
Geothermal	--	--	--	--	--	--
Other Biomass	2	19.0	--	--	2	19.0
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	11	1,337.5	1	1.0	10	1,336.5
Year 2024						
U.S. Total	18	5,187.6	39	6,664.4	-21	-1,476.8
Coal	--	--	9	3,318.0	-9	-3,318.0
Petroleum	--	--	4	32.4	-4	-32.4
Natural Gas	6	3,188.9	18	2,188.6	-12	1,000.3
Other Gases	--	--	--	--	--	--
Nuclear	--	--	1	1,122.0	-1	-1,122.0
Hydroelectric Conventional	--	--	7	3.4	-7	-3.4
Wind	7	895.5	--	--	7	895.5
Solar Thermal and Photovoltaic	3	1,100.0	--	--	3	1,100.0
Wood and Wood-Derived Fuels	--	--	--	--	--	--
Geothermal	--	--	--	--	--	--
Other Biomass	2	3.2	--	--	2	3.2
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	--	--	--	--	--	--
Years 2020-2024						
U.S. Total	1,612	124,717.3	367	52,206.0	1,245	72,511.3
Coal	1	17.0	98	28,480.6	-97	-28,463.6
Petroleum	9	10.4	53	3,850.6	-44	-3,840.2
Natural Gas	231	38,925.9	147	10,929.6	84	27,996.3
Other Gases	--	--	--	--	--	--
Nuclear	2	2,200.0	9	8,646.0	-7	-6,446.0
Hydroelectric Conventional	100	461.2	20	32.2	80	429.0
Wind	214	36,735.9	11	134.7	203	36,601.2
Solar Thermal and Photovoltaic	876	39,112.1	--	--	876	39,112.1
Wood and Wood-Derived Fuels	3	56.5	4	43.8	-1	12.7
Geothermal	2	42.0	--	--	2	42.0
Other Biomass	20	83.4	23	86.0	-3	-2.6
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	154	7,072.9	2	2.5	152	7,070.4

Notes: These data reflect plans as of December 31, 2019

Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, coal synfuel, refined coal, and coal-derived synthesis gas.

Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, synthetic gas, and propane.

Other Gases also includes blast furnace gas.

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities.

Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

In the case of wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.6. Utility-Scale Capacity Additions, Retirements and Changes by Energy Source, 2019 (Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements			
	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal	--	--	--	--	59	14,352.1	12,895.1	12,914.9
Petroleum	24	49.1	46.6	42.7	53	423.6	353.0	361.5
Natural Gas	106	8,631.8	8,075.3	8,179.7	76	4,843.3	4,292.4	4,418.1
Other Gases	--	--	--	--	3	30.0	14.8	13.0
Nuclear	--	--	--	--	2	1,650.8	1,476.4	1,509.6
Hydroelectric Conventional	3	11.2	11.1	11.1	26	147.2	148.2	148.2
Wind	60	9,328.2	9,314.6	9,314.6	11	132.2	131.0	131.0
Solar Thermal and Photovoltaic	493	5,488.7	5,478.9	5,437.8	16	8.0	8.0	8.0
Wood and Wood-Derived Fuels	3	156.3	145.4	145.7	17	577.3	538.6	540.4
Geothermal	1	26.0	20.0	20.0	4	5.1	3.7	3.5
Other Biomass	19	16.9	16.7	16.7	54	202.7	172.6	175.4
Hydroelectric Pumped Storage	--	--	--	--	--	--	--	--
Other Energy Sources	39	210.0	193.1	200.4	3	42.3	29.7	24.0
Total	748	23,918.2	23,301.7	23,368.7	324	22,414.6	20,063.5	20,247.6

Energy Source	Other Changes to Existing Capacity			
		Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal		-1,944.1	-1,687.5	-2,199.7
Petroleum		-4,535.3	-4,118.2	-4,865.8
Natural Gas		-61.4	1,213.0	345.9
Other Gases		-1.1	-29.9	-20.9
Nuclear		257.9	162.5	-38.7
Hydroelectric Conventional		-86.6	-59.7	-53.1
Wind		41.9	-129.1	-136.9
Solar Thermal and Photovoltaic		-79.1	-25.6	89.4
Wood and Wood-Derived Fuels		90.8	73.1	85.0
Geothermal		22.4	94.8	170.2
Other Biomass		-150.0	-148.7	-150.0
Hydroelectric Pumped Storage		--	-51.9	-91.0
Other Energy Sources		58.6	65.8	65.7
Total		-6,386.0	-4,641.4	-6,799.9

Notes: Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal, coal synfuel, refined coal, and coal-derived synthesis gas. Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), waste oil, synthetic gas, and propane. Other Gases also includes blast furnace gas and other manufactured and waste gases derived from fossil fuels. Hydroelectric Conventional capacity includes conventional hydroelectric power excluding pumped storage facilities. Wood and wood-derived fuels include wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor. Other Biomass include municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases). Other Energy Sources include batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources. Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. In the case of some wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the generator count. Other Changes to Existing Capacity reflect uprates, derates, repowerings, and changes to previously reported generator capacity. * = Value is less than half of the smallest unit of measure.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.7.A. Net Summer Capacity of Utility Scale Units by Technology and by State, 2019 and 2018 (Megawatts)

Census Division and State	Renewable Sources		Fossil Fuels		Hydroelectric Pumped Storage		Other Energy Storage		Nuclear		All Other Sources		All Sources	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	6,027.9	5,862.1	24,227.5	23,024.1	1,797.4	1,797.4	63.1	28.7	3,323.5	4,003.5	48.0	48.0	35,487.4	34,763.8
Connecticut	457.7	412.6	7,866.2	7,290.6	29.4	29.4	1.6	1.6	2,073.1	2,073.1	26.0	26.0	10,454.0	9,833.3
Maine	2,222.0	2,346.5	2,495.3	2,478.8	0.0	0.0	16.2	16.2	0.0	0.0	22.0	22.0	4,755.5	4,863.5
Massachusetts	1,511.5	1,385.0	9,598.4	9,034.8	1,768.0	1,768.0	34.4	7.9	0.0	679.0	0.0	0.0	12,912.3	12,874.7
New Hampshire	956.9	928.1	2,289.9	2,289.9	0.0	0.0	0.0	0.0	1,250.4	1,251.4	0.0	0.0	4,497.2	4,469.4
Rhode Island	195.1	126.2	1,832.1	1,832.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,027.2	1,958.3
Vermont	684.7	663.7	145.6	97.9	0.0	0.0	10.9	3.0	0.0	0.0	0.0	0.0	841.2	764.6
Middle Atlantic	11,532.5	11,202.0	73,131.3	73,664.0	3,383.3	3,411.6	143.5	96.7	17,956.6	18,700.2	11.2	11.2	106,158.4	107,085.7
New Jersey	1,085.5	1,012.0	12,241.5	12,437.7	420.0	420.0	42.1	22.3	3,467.1	3,500.2	11.2	11.2	17,267.4	17,403.4
New York	7,487.2	7,335.6	26,731.2	26,951.1	1,411.3	1,408.6	53.0	26.0	5,396.3	5,403.0	0.0	0.0	41,079.0	41,124.3
Pennsylvania	2,959.8	2,854.4	34,158.6	34,275.2	1,552.0	1,583.0	48.4	48.4	9,093.2	9,797.0	0.0	0.0	47,812.0	48,558.0
East North Central	13,349.2	12,561.2	109,176.8	112,580.4	2,232.0	2,152.0	194.7	188.7	19,007.1	19,034.4	187.1	187.1	144,146.9	146,703.8
Illinois	5,397.1	4,782.3	27,059.7	29,055.3	0.0	0.0	132.7	132.7	11,582.4	11,582.4	78.0	78.0	44,249.9	45,630.7
Indiana	2,691.1	2,657.2	23,857.6	23,928.4	0.0	0.0	28.0	22.0	0.0	0.0	88.0	88.0	26,664.7	26,695.6
Michigan	3,065.1	2,830.6	20,069.2	20,614.2	2,232.0	2,152.0	1.0	1.0	4,089.6	4,122.2	0.0	0.0	29,456.9	29,720.0
Ohio	1,068.0	1,053.7	25,228.6	25,920.9	0.0	0.0	33.0	33.0	2,134.0	2,134.0	0.0	0.0	28,463.6	29,141.6
Wisconsin	1,127.9	1,237.4	12,961.7	13,061.6	0.0	0.0	0.0	0.0	1,201.1	1,195.8	21.1	21.1	15,311.8	15,515.9
West North Central	32,525.2	28,741.4	59,202.2	59,156.2	657.0	657.0	20.1	17.1	5,443.4	5,443.4	22.8	22.8	97,870.7	94,037.9
Iowa	9,964.4	8,433.3	9,842.6	9,806.4	0.0	0.0	1.1	1.1	601.4	601.4	0.0	0.0	20,409.5	18,842.2
Kansas	6,159.6	5,379.4	8,846.1	9,025.4	0.0	0.0	0.0	0.0	1,225.0	1,225.0	0.8	0.8	16,231.5	15,630.6
Minnesota	5,294.1	5,119.5	10,389.6	10,147.5	0.0	0.0	16.0	13.0	1,657.0	1,657.0	16.7	16.7	17,373.4	16,953.7
Missouri	1,579.0	1,579.0	17,625.1	17,650.0	657.0	657.0	2.2	2.2	1,190.0	1,190.0	0.0	0.0	21,053.3	21,078.2
Nebraska	2,499.5	2,011.8	6,196.3	6,202.0	0.0	0.0	0.0	0.0	770.0	770.0	0.0	0.0	9,465.8	8,983.8
North Dakota	4,048.3	3,741.6	4,601.4	4,633.6	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	8,655.0	8,380.5
South Dakota	2,980.3	2,476.8	1,701.1	1,691.3	0.0	0.0	0.8	0.8	0.0	0.0	0.0	0.0	4,682.2	4,168.9
South Atlantic	22,314.5	20,104.1	161,436.8	161,659.0	7,906.4	7,905.2	81.5	76.5	24,688.6	24,706.6	468.9	408.7	216,896.7	214,860.1
Delaware	50.9	47.5	3,321.5	3,330.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,372.4	3,377.9
District of Columbia	18.9	23.0	20.6	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.5	32.0
Florida	3,370.4	2,681.9	53,183.7	50,688.1	0.0	0.0	19.0	14.0	3,626.0	3,626.0	312.9	348.7	60,512.0	57,358.7
Georgia	4,603.2	4,013.8	26,100.8	27,050.6	1,863.4	1,862.2	1.0	1.0	4,061.0	4,061.0	0.0	0.0	36,629.4	36,988.6
Maryland	1,237.4	1,191.4	11,650.7	11,847.1	0.0	0.0	7.0	7.0	1,707.8	1,725.8	6.0	6.0	14,608.9	14,777.3
North Carolina	7,253.8	6,767.0	22,315.8	22,120.5	86.0	86.0	1.0	1.0	5,149.6	5,149.6	54.0	54.0	34,860.2	34,178.1
South Carolina	2,522.6	2,201.5	12,143.1	12,164.3	2,716.0	2,716.0	4.0	4.0	6,576.2	6,576.2	0.0	0.0	23,961.9	23,662.0
Virginia	2,227.0	2,150.9	18,912.7	20,674.9	3,241.0	3,241.0	0.0	0.0	3,568.0	3,568.0	96.0	0.0	28,044.7	29,634.8
West Virginia	1,030.3	1,027.1	13,787.9	13,774.1	0.0	0.0	49.5	49.5	0.0	0.0	0.0	0.0	14,867.7	14,850.7
East South Central	8,909.5	8,814.5	62,718.2	64,592.7	1,616.3	1,616.3	1.0	1.0	11,449.1	11,294.1	1.4	1.4	84,695.5	86,320.0
Alabama	4,119.0	4,086.4	19,610.1	20,660.4	0.0	0.0	1.0	1.0	5,525.4	5,370.4	0.0	0.0	29,255.5	30,118.2
Kentucky	1,247.6	1,245.4	18,247.9	18,874.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19,495.5	20,119.7
Mississippi	520.5	463.0	12,617.9	12,867.7	0.0	0.0	0.0	0.0	1,401.0	1,401.0	1.4	1.4	14,540.8	14,733.1
Tennessee	3,022.4	3,019.7	12,242.3	12,190.3	1,616.3	1,616.3	0.0	0.0	4,522.7	4,522.7	0.0	0.0	21,403.7	21,349.0
West South Central	42,975.7	38,640.3	138,761.3	139,035.5	286.0	286.0	131.7	99.8	8,910.7	8,910.7	548.6	512.5	191,614.0	187,484.8
Arkansas	1,642.7	1,697.1	11,281.0	11,219.7	28.0	28.0	12.0	0.0	1,817.8	1,817.8	0.0	0.0	14,781.5	14,762.6
Louisiana	615.2	683.2	21,262.2	20,056.9	0.0	0.0	0.5	0.5	2,132.9	2,132.9	329.6	288.5	24,340.4	23,162.0
Oklahoma	9,139.0	9,041.0	17,978.6	18,102.0	258.0	258.0	0.0	0.0	0.0	0.0	0.0	0.0	27,375.6	27,401.0
Texas	31,578.8	27,219.0	88,239.5	89,656.9	0.0	0.0	119.2	99.3	4,960.0	4,960.0	219.0	224.0	125,116.5	122,159.2
Mountain	28,373.6	27,308.9	60,068.1	62,239.7	778.8	778.8	54.3	40.6	3,937.0	3,937.0	123.7	123.0	93,335.5	94,428.0
Arizona	5,179.8	5,091.1	17,417.2	19,395.3	216.3	216.3	42.0	32.0	3,937.0	3,937.0	0.0	0.0	26,792.3	28,671.7
Colorado	5,077.3	4,950.1	10,932.9	11,063.0	562.5	562.5	10.5	5.0	0.0	0.0	9.1	9.1	16,592.3	16,589.7
Idaho	4,075.3	4,068.5	1,121.8	1,127.1	0.0	0.0	0.0	0.0	0.0	0.0	14.8	14.8	5,211.9	5,210.4
Montana	3,594.0	3,571.2	2,739.1	2,744.9	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	6,373.1	6,356.1
Nevada	4,109.7	3,665.4	7,821.6	7,821.6	0.0	0.0	0.0	0.0	0.0	0.0	6.5	6.5	11,937.8	11,493.5
New Mexico	2,804.5	2,473.7	5,962.9	5,953.3	0.0	0.0	1.8	3.6	0.0	0.0	0.7	0.0	8,769.9	8,430.6
Utah	1,648.0	1,602.5	7,303.3	7,360.2	0.0	0.0	0.0	0.0	0.0	0.0	40.2	40.2	8,991.5	9,002.9
Wyoming	1,885.0	1,886.4	6,769.3	6,774.3	0.0	0.0	0.0	0.0	0.0	0.0	12.4	12.4	8,666.7	8,673.1
Pacific Contiguous	69,232.0	67,907.2	46,057.2	47,614.6	4,121.1	4,225.9	263.7	242.8	3,403.0	3,403.0	106.3	106.3	123,183.3	123,499.8
California	32,062.2	30,889.7	37,000.4	38,546.7	3,807.1	3,911.9	252.5	231.6	2,240.0	2,240.0	106.3	106.3	75,468.5	75,926.2
Oregon	12,467.2	12,259.2	4,315.2	4,326.1	0.0	0.0	5.0	5.0	0.0	0.0	0.0	0.0	16,787.4	16,590.3
Washington	24,702.6	24,758.3	4,741.6	4,741.8	314.0	314.0	6.2	6.2	1,163.0	1,163.0	0.0	0.0	30,927.4	30,983.3
Pacific Noncontiguous	1,241.2	1,203.7	4,345.9	4,218.4	0.0	0.0	108.2	107.2	0.0	0.0	26.6	26.6	5,721.9	5,555.9
Alaska	538.6	538.2	2,174.6	2,160.1	0.0	0.0	47.2	46.2	0.0	0.0	0.0	0.0	2,760.4	2,744.5
Hawaii	702.6	665.5	2,171.3	2,058.3	0.0	0.0	61.0	61.0	0.0	0.0	26.6	26.6	2,961.5	2,811.4
U.S. Total	236,481.3	222,345.4	739,125.3	747,784.6	22,778.3	22,830.2	1,061.8	899.1	98,119.0	99,432.9	1,544.6	1,447.6	1,099,110.3	1,094,739.8

NM = Not meaningful due to large relative standard error.
Values are final.

NOTES:
Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of capacity for some technologies such as solar photovoltaic generation.
Concentrated Solar Power Energy Storage is included in 'Renewable sources'; it is not included in 'Other Energy Storage'

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.7.B. Net Summer Capacity Using Primarily Renewable Energy Sources and by State, 2019 and 2018 (Megawatts)

	Summer Capacity at Utility Scale Facilities														Small Scale Capacity		Capacity From Utility and Small Scale Facilities			
Census Division and State	Wind		Solar Photovoltaic		Solar Thermal		Conventional Hydroelectric		Biomass Sources		Geothermal		Total Renewable Sources		Estimated Solar Photovoltaic		Estimated Total Solar Photovoltaic		Estimated Total Solar	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	1,463.2	1,403.8	1,198.6	961.1	0.0	0.0	1,957.6	1,959.5	1,408.5	1,537.7	0.0	0.0	6,027.9	5,862.1	2,563.6	2,309.0	3,762.2	3,270.1	3,762.2	3,270.1
Connecticut	1.0	1.0	137.4	86.8	0.0	0.0	119.4	122.2	199.9	202.6	0.0	0.0	457.7	412.6	511.7	416.8	649.1	503.6	649.1	503.6
Maine	921.6	921.6	5.6	5.6	0.0	0.0	734.0	732.4	560.8	686.9	0.0	0.0	2,222.0	2,346.5	60.0	43.6	65.6	49.2	65.6	49.2
Massachusetts	105.7	96.1	854.6	736.6	0.0	0.0	266.3	267.0	284.9	285.3	0.0	0.0	1,511.5	1,385.0	1,587.9	1,568.6	2,442.5	2,305.2	2,442.5	2,305.2
New Hampshire	211.9	183.1	0.0	0.0	0.0	0.0	504.0	504.0	241.0	241.0	0.0	0.0	956.9	928.1	102.3	83.7	102.3	83.7	102.3	83.7
Rhode Island	72.8	51.8	79.5	31.6	0.0	0.0	2.7	2.7	40.1	40.1	0.0	0.0	195.1	126.2	182.3	93.5	261.8	125.1	261.8	125.1
Vermont	150.2	150.2	121.5	100.5	0.0	0.0	331.2	331.2	81.8	81.8	0.0	0.0	684.7	663.7	119.4	102.8	240.9	203.3	240.9	203.3
Middle Atlantic	3,453.3	3,363.3	1,420.1	1,087.1	0.0	0.0	5,471.6	5,473.2	1,187.5	1,278.4	0.0	0.0	11,532.5	11,202.0	3,567.3	2,997.6	4,987.4	4,084.7	4,987.4	4,084.7
New Jersey	7.6	7.6	856.7	764.8	0.0	0.0	12.3	12.3	208.9	227.3	0.0	0.0	1,085.5	1,012.0	1,668.2	1,448.5	2,524.9	2,213.3	2,524.9	2,213.3
New York	1,985.7	1,985.7	482.5	264.5	0.0	0.0	4,559.7	4,561.3	459.3	524.1	0.0	0.0	7,487.2	7,335.6	1,515.3	1,227.1	1,997.8	1,491.6	1,997.8	1,491.6
Pennsylvania	1,460.0	1,370.0	80.9	57.8	0.0	0.0	899.6	899.6	519.3	527.0	0.0	0.0	2,959.8	2,854.4	383.9	322.0	464.8	379.8	464.8	379.8
East North Central	10,764.6	9,985.9	539.5	462.5	0.0	0.0	884.6	859.9	1,160.5	1,252.9	0.0	0.0	13,349.2	12,561.2	644.9	392.0	1,184.4	854.5	1,184.4	854.5
Illinois	5,231.0	4,618.8	43.8	40.6	0.0	0.0	34.1	34.1	88.2	88.8	0.0	0.0	5,397.1	4,782.3	205.9	78.7	249.7	119.3	249.7	119.3
Indiana	2,309.8	2,309.8	244.3	216.2	0.0	0.0	66.2	60.4	70.8	70.8	0.0	0.0	2,691.1	2,657.2	96.2	73.9	340.5	290.1	340.5	290.1
Michigan	2,185.7	1,900.5	102.0	98.2	0.0	0.0	273.4	269.9	504.0	562.0	0.0	0.0	3,065.1	2,830.6	96.2	62.7	198.2	160.9	198.2	160.9
Ohio	718.4	718.4	109.0	83.6	0.0	0.0	101.9	101.9	138.7	149.8	0.0	0.0	1,068.0	1,053.7	161.6	119.5	270.6	203.1	270.6	203.1
Wisconsin	319.7	438.4	40.4	23.9	0.0	0.0	409.0	393.6	358.8	381.5	0.0	0.0	1,127.9	1,237.4	85.0	57.2	125.4	81.1	125.4	81.1
West North Central	27,804.1	24,120.4	1,004.6	828.1	0.0	0.0	3,295.5	3,293.7	421.0	499.2	0.0	0.0	32,525.2	28,741.4	439.7	331.1	1,444.3	1,159.2	1,444.3	1,159.2
Iowa	9,784.0	8,256.6	13.4	8.9	0.0	0.0	146.4	146.4	20.6	21.4	0.0	0.0	9,964.4	8,433.3	117.6	92.7	131.0	101.6	131.0	101.6
Kansas	6,133.4	5,359.2	10.2	4.2	0.0	0.0	7.0	7.0	9.0	9.0	0.0	0.0	6,159.6	5,379.4	25.3	18.6	35.5	22.8	35.5	22.8
Minnesota	3,847.2	3,750.5	894.6	733.9	0.0	0.0	205.9	205.9	346.4	429.2	0.0	0.0	5,294.1	5,119.5	82.2	60.9	976.8	794.8	976.8	794.8
Missouri	954.3	954.3	62.1	62.1	0.0	0.0	548.5	548.5	14.1	14.1	0.0	0.0	1,579.0	1,579.0	203.3	150.4	265.4	212.5	265.4	212.5
Nebraska	2,180.8	1,700.2	23.3	18.0	0.0	0.0	279.7	277.9	15.7	15.7	0.0	0.0	2,499.5	2,011.8	9.9	7.5	33.2	25.5	33.2	25.5
North Dakota	3,528.5	3,221.8	0.0	0.0	0.0	0.0	510.0	510.0	9.8	9.8	0.0	0.0	4,048.3	3,741.6	0.5	0.4	0.5	0.4	0.5	0.4
South Dakota	1,375.9	877.8	1.0	1.0	0.0	0.0	1,598.0	1,598.0	5.4	0.0	0.0	0.0	2,980.3	2,476.8	0.8	0.6	1.8	1.6	1.8	1.6
South Atlantic	1,086.3	1,086.3	9,705.4	7,463.1	0.0	0.0	7,187.2	7,224.4	4,335.6	4,330.3	0.0	0.0	22,314.5	20,104.1	2,130.0	1,691.3	11,835.3	9,154.4	11,835.3	9,154.4
Delaware	2.0	2.0	36.7	33.3	0.0	0.0	0.0	0.0	12.2	12.2	0.0	0.0	50.9	47.5	86.2	78.9	122.9	112.2	122.9	112.2
District of Columbia	0.0	0.0	6.9	0.0	0.0	0.0	0.0	0.0	12.0	23.0	0.0	0.0	18.9	23.0	66.5	50.9	73.4	50.9	73.4	50.9
Florida	0.0	0.0	2,142.8	1,399.5	0.0	0.0	43.5	54.5	1,184.1	1,227.9	0.0	0.0	3,370.4	2,681.9	492.0	281.7	2,634.8	1,681.2	2,634.8	1,681.2
Georgia	0.0	0.0	1,512.4	1,017.2	0.0	0.0	2,031.0	2,047.2	1,059.8	949.4	0.0	0.0	4,603.2	4,013.8	NM	166.7	NM	1,183.9	NM	1,183.9
Maryland	190.0	190.0	316.5	271.4	0.0	0.0	590.0	590.0	140.9	140.0	0.0	0.0	1,237.4	1,191.4	779.7	709.8	1,096.2	981.2	1,096.2	981.2
North Carolina	208.0	208.0	4,477.8	3,998.1	0.0	0.0	2,004.0	2,002.0	564.0	558.9	0.0	0.0	7,253.8	6,767.0	182.4	140.9	4,660.2	4,139.0	4,660.2	4,139.0
South Carolina	0.0	0.0	656.2	351.1	0.0	0.0	1,311.9	1,323.9	554.5	526.5	0.0	0.0	2,522.6	2,201.5	231.4	194.9	887.6	546.0	887.6	546.0
Virginia	0.0	0.0	556.1	392.5	0.0	0.0	866.0	866.0	804.9	892.4	0.0	0.0	2,227.0	2,150.9	100.6	60.7	656.7	453.2	656.7	453.2
West Virginia	686.3	686.3	0.0	0.0	0.0	0.0	340.8	340.8	3.2	0.0	0.0	0.0	1,030.3	1,027.1	9.3	6.8	9.3	6.8	9.3	6.8
East South Central	29.1	29.1	618.8	558.8	0.0	0.0	7,055.3	7,055.5	1,206.3	1,171.1	0.0	0.0	8,909.5	8,814.5	107.1	94.0	725.9	652.8	725.9	652.8
Alabama	0.0	0.0	194.1	194.1	0.0	0.0	3,291.8	3,292.0	633.1	600.3	0.0	0.0	4,119.0	4,086.4	NM	NM	NM	NM	NM	NM
Kentucky	0.0	0.0	26.1	26.3	0.0	0.0	1,146.9	1,146.9	74.6	72.2	0.0	0.0	1,247.6	1,245.4	30.4	23.2	56.5	49.5	56.5	49.5
Mississippi	0.0	0.0	218.1	160.6	0.0	0.0	0.0	0.0	302.4	302.4	0.0	0.0	520.5	463.0	9.2	6.9	227.3	167.5	227.3	167.5
Tennessee	29.1	29.1	180.5	177.8	0.0	0.0	2,616.6	2,616.6	196.2	196.2	0.0	0.0	3,022.4	3,019.7	58.8	56.7	239.3	234.5	239.3	234.5
West South Central	36,228.2	32,257.9	2,591.7	2,080.4	0.0	0.0	2,991.4	2,991.4	1,164.4	1,310.6	0.0	0.0	42,975.7	38,640.3	855.8	636.9	3,447.5	2,717.3	3,447.5	2,717.3
Arkansas	0.0	0.0	112.2	100.0	0.0	0.0	1,265.8	1,265.8	264.7	331.3	0.0	0.0	1,642.7	1,697.1	25.3	15.3	137.5	115.3	137.5	115.3
Louisiana	0.0	0.0	1.1	1.1	0.0	0.0	192.0	192.0	422.1	490.1	0.0	0.0	615.2	683.2	147.4	139.7	148.5	140.8	148.5	140.8
Oklahoma	8,168.7	8,070.7	30.5	30.5	0.0	0.0	863.6	863.6	76.2	76.2	0.0	0.0	9,139.0	9,041.0	12.6	7.3	43.1	37.8	43.1	37.8
Texas	28,059.5	24,187.2	2,447.9	1,948.8	0.0	0.0	670.0	670.0	401.4	413.0	0.0	0.0	31,578.8	27,219.0	670.5	474.7	3,118.4	2,423.5	3,118.4	2,423.5
Mountain	9,846.9	9,565.8	6,563.9	5,799.3	474.1	473.9	10,652.9	10,650.0	179.1	174.3	656.7	645.6	28,373.6	27,308.9	2,743.4	2,327.7	9,307.3	8,127.0	9,781.4	8,600.9
Arizona	267.3	267.3	1,865																	

Table 4.7.C. Net Summer Capacity of Utility Scale Units Using Primarily Fossil Fuels and by State, 2019 and 2018 (Megawatts)

Census Division and State	Natural Gas Fired Combined Cycle		Natural Gas Fired Combustion Turbine		Other Natural Gas		Coal		Petroleum Coke		Petroleum Liquids		Other Gases		Total Fossil Fuels	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	14,271.6	13,675.0	1,776.0	1,056.6	1,525.7	1,112.6	917.3	917.3	0.0	0.0	5,736.9	6,262.6	0.0	0.0	24,227.5	23,024.1
Connecticut	3,984.2	3,442.7	580.4	563.0	883.3	875.0	383.4	383.4	0.0	0.0	2,034.9	2,026.5	0.0	0.0	7,866.2	7,290.6
Maine	1,281.6	1,284.3	322.3	144.3	12.5	12.5	0.0	0.0	0.0	0.0	878.9	1,037.7	0.0	0.0	2,495.3	2,478.8
Massachusetts	5,960.6	5,902.8	857.1	333.1	204.3	199.7	0.0	0.0	0.0	0.0	2,576.4	2,599.2	0.0	0.0	9,598.4	9,034.8
New Hampshire	1,258.0	1,258.0	3.8	3.8	400.2	0.0	533.9	533.9	0.0	0.0	94.0	494.2	0.0	0.0	2,289.9	2,289.9
Rhode Island	1,787.2	1,787.2	12.4	12.4	25.4	25.4	0.0	0.0	0.0	0.0	7.1	7.1	0.0	0.0	1,832.1	1,832.1
Vermont	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	145.6	97.9	0.0	0.0	145.6	97.9
Middle Atlantic	34,419.5	31,831.4	7,894.3	7,909.1	14,142.8	14,505.4	11,183.7	13,776.7	11.6	11.6	5,363.5	5,499.1	115.9	130.7	73,131.3	73,664.0
New Jersey	8,579.0	8,529.9	2,844.3	2,826.3	68.5	46.9	463.0	609.0	11.6	11.6	246.1	385.0	29.0	29.0	12,241.5	12,437.7
New York	8,927.9	8,922.6	3,177.6	3,173.0	9,739.1	9,665.2	1,336.5	1,631.5	0.0	0.0	3,550.1	3,558.8	0.0	0.0	26,731.2	26,951.1
Pennsylvania	16,912.6	14,378.9	1,872.4	1,909.8	4,335.2	4,793.3	9,384.2	11,536.2	0.0	0.0	1,567.3	1,555.3	86.9	101.7	34,158.6	34,275.2
East North Central	21,711.8	21,661.3	26,681.0	26,654.4	5,615.4	5,563.6	51,488.3	54,908.0	247.6	247.6	2,347.8	2,452.6	1,084.9	1,092.9	109,176.8	112,580.4
Illinois	3,577.7	3,580.2	10,530.4	10,504.8	1,626.7	1,633.6	10,615.5	12,826.0	0.0	0.0	672.9	674.2	36.5	36.5	27,059.7	29,055.3
Indiana	3,866.0	3,836.0	3,287.3	3,353.4	741.0	730.0	15,245.7	15,291.4	0.0	0.0	98.3	98.3	619.3	619.3	23,857.6	23,928.4
Michigan	4,451.9	4,413.6	3,852.9	3,874.0	2,412.1	2,375.5	8,590.3	9,190.4	47.2	47.2	464.8	463.5	250.0	250.0	20,069.2	20,614.2
Ohio	7,037.8	7,020.4	5,636.7	5,559.2	205.5	185.1	11,496.0	12,246.0	142.0	142.0	531.5	581.1	179.1	187.1	25,228.6	25,920.9
Wisconsin	2,778.4	2,811.1	3,373.7	3,363.0	630.1	639.4	5,540.8	5,554.2	58.4	58.4	580.3	635.5	0.0	0.0	12,961.7	13,061.6
West North Central	7,019.1	6,640.9	11,587.5	11,737.3	3,748.6	3,807.2	32,957.1	33,054.1	32.0	39.5	3,849.5	3,868.8	8.4	8.4	59,202.2	59,156.2
Iowa	1,829.0	1,779.8	1,226.8	1,260.4	591.3	540.5	5,343.8	5,371.7	32.0	39.5	819.7	814.5	0.0	0.0	9,842.6	9,806.4
Kansas	266.0	266.0	2,158.1	2,156.8	1,185.6	1,367.9	4,678.5	4,670.2	0.0	0.0	557.9	564.5	0.0	0.0	8,846.1	9,025.4
Minnesota	2,496.0	2,172.0	2,544.8	2,667.9	401.2	381.6	4,180.5	4,157.9	0.0	0.0	767.1	768.1	0.0	0.0	10,389.6	10,147.5
Missouri	1,794.9	1,794.9	3,390.7	3,400.6	869.5	871.1	10,464.5	10,470.9	0.0	0.0	1,105.5	1,112.5	0.0	0.0	17,625.1	17,650.0
Nebraska	338.2	338.2	1,148.4	1,149.0	521.7	525.8	3,867.0	3,867.0	0.0	0.0	321.0	322.0	0.0	0.0	6,196.3	6,202.0
North Dakota	0.0	0.0	414.0	408.0	167.0	111.6	3,948.8	4,042.4	0.0	0.0	63.2	63.2	8.4	8.4	4,601.4	4,633.6
South Dakota	295.0	290.0	704.7	694.6	12.3	8.7	474.0	474.0	0.0	0.0	215.1	224.0	0.0	0.0	1,701.1	1,691.3
South Atlantic	61,366.0	59,181.2	32,167.0	31,914.2	7,250.4	7,334.2	51,483.1	53,994.3	142.8	142.8	8,892.5	8,957.3	135.0	135.0	161,436.8	161,659.0
Delaware	1,604.0	1,511.0	272.0	317.2	842.0	843.1	410.0	410.0	0.0	0.0	158.5	114.1	135.0	135.0	3,321.5	3,330.4
District of Columbia	0.0	0.0	20.6	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6	9.0
Florida	31,717.2	29,345.7	7,825.7	7,759.2	2,503.2	2,419.2	7,782.0	7,804.0	59.0	59.0	3,296.6	3,301.0	0.0	0.0	53,183.7	50,688.1
Georgia	8,009.5	7,989.0	7,803.2	7,791.0	842.9	842.9	8,416.0	9,398.5	83.8	83.8	945.4	945.4	0.0	0.0	26,100.8	27,050.6
Maryland	2,709.1	2,849.1	2,084.2	1,899.9	1,416.1	1,494.2	4,270.0	4,327.0	0.0	0.0	1,171.3	1,276.9	0.0	0.0	11,650.7	11,847.1
North Carolina	5,373.2	5,068.0	6,050.4	6,045.1	1.0	0.0	10,389.2	10,504.8	0.0	0.0	502.0	502.6	0.0	0.0	22,315.8	22,120.5
South Carolina	3,185.0	3,185.0	2,772.2	2,757.9	950.0	546.0	4,769.0	5,212.0	0.0	0.0	466.9	463.4	0.0	0.0	12,143.1	12,164.3
Virginia	8,868.0	9,233.4	4,245.3	4,245.3	579.7	1,073.3	2,878.9	3,780.0	0.0	0.0	2,340.8	2,342.9	0.0	0.0	18,912.7	20,674.9
West Virginia	0.0	0.0	1,093.4	1,089.6	115.5	115.5	12,568.0	12,558.0	0.0	0.0	11.0	11.0	0.0	0.0	13,787.9	13,774.1
East South Central	21,772.2	21,746.2	12,678.3	12,626.1	4,285.8	4,592.8	23,855.4	25,490.8	0.0	0.0	106.7	117.0	19.8	19.8	62,718.2	64,592.7
Alabama	9,729.8	9,699.0	2,575.8	2,532.2	1,957.8	2,028.1	5,284.3	6,338.7	0.0	0.0	42.6	42.6	19.8	19.8	19,610.1	20,660.4
Kentucky	1,763.0	1,763.0	4,931.2	4,976.6	260.0	260.0	11,281.8	11,862.8	0.0	0.0	11.9	11.9	0.0	0.0	18,247.9	18,874.3
Mississippi	7,824.3	7,829.1	1,338.8	1,336.8	2,001.8	2,238.5	1,444.0	1,444.0	0.0	0.0	9.0	19.3	0.0	0.0	12,617.9	12,867.7
Tennessee	2,455.1	2,455.1	3,832.5	3,780.5	66.2	66.2	5,845.3	5,845.3	0.0	0.0	43.2	43.2	0.0	0.0	12,242.3	12,190.3
West South Central	61,694.7	60,239.5	14,548.7	14,419.5	30,540.5	30,856.3	30,119.1	31,564.1	878.9	954.7	169.1	175.6	810.3	825.8	138,761.3	139,035.5
Arkansas	4,609.8	4,603.4	702.8	702.8	796.0	796.0	5,163.4	5,105.3	0.0	0.0	9.0	12.2	0.0	0.0	11,281.0	11,219.7
Louisiana	8,654.2	7,474.6	2,415.1	2,349.6	6,090.1	6,057.6	2,837.1	2,833.7	815.1	890.9	43.2	43.1	407.4	407.4	21,262.2	20,056.9
Oklahoma	7,321.2	7,263.6	1,630.9	1,686.9	5,706.1	4,773.6	3,246.0	4,303.5	0.0	0.0	74.4	74.4	0.0	0.0	17,978.6	18,102.0
Texas	41,109.5	40,897.9	9,799.9	9,680.2	17,948.3	19,229.1	18,872.6	19,321.6	63.8	63.8	42.5	45.9	402.9	418.4	88,239.5	89,656.9
Mountain	22,545.0	22,510.8	9,137.3	8,625.6	3,540.9	3,832.4	24,339.5	26,765.5	52.0	52.0	349.9	349.9	103.5	103.5	60,068.1	62,239.7
Arizona	9,908.6	9,879.6	2,899.0	2,367.6	1,190.1	1,478.6	3,329.0	5,579.0	0.0	0.0	90.5	90.5	0.0	0.0	17,417.2	19,395.3
Colorado	3,249.5	3,249.5	2,538.0	2,568.1	639.0	639.0	4,340.0	4,440.0	0.0	0.0	166.4	166.4	0.0	0.0	10,932.9	11,063.0
Idaho	547.7	547.7	552.0	552.0	8.2	13.5	8.5	8.5	0.0	0.0	5.4	5.4	0.0	0.0	1,121.8	1,127.1
Montana	0.0	0.0	315.8	321.6	72.2	72.2	2,297.6	2,297.6	52.0	52.0	0.0	0.0	1.5	1.5	2,739.1	2,744.9
Nevada	5,445.0	5,445.0	1,185.6	1,185.6	444.6	444.6	740.4	740.4	0.0	0.0	6.0	6.0	0.0	0.0	7,821.6	7,821.6
New Mexico	1,470.2	1,465.0	957.0	956.9	847.7	843.4	2,640.0	2,640.0	0.0	0.0	48.0	48.0	0.0	0.0	5,962.9	5,953.3
Utah	1,830.0	1,830.0	536.3	520.2	328.2	328.2	4,581.0	4,654.0	0.0	0.0	27.8	27.8	0.0	0.0	7,303.3	7,360.2
Wyoming	94.0	94.0	153.6	153.6	10.9	12.9	6,403.0	6,406.0	0.0	0.0	5.8	5.8	102.0	102.0	6,769.3	6,774.3
Pacific Contiguous	25,908.9	25,897.1	12,009.9	12,066.7	5,445.2	6,959.0	1,982.0	1,982.0	20.0	17.0	469.8	471.4	221.4	221.4	46,057.2	47,614.6
California	19,901.3	19,878.6	11,156.9	11,213.5	5,189.2	6,703.0	57.0	57.0	20.0	17.0	454.6	456.2	221.4	221.4	37,000.4	38,546.7
Oregon	3,372.0	3,382.9	133.8	133.8	224.4	224.4	585.0	585.0	0.0	0.0	0.0	0.0	0.0	0.0	4,315.2	4,326.1
Washington	2,635.6	2,635.6	719.2	719.4	31.6	31.6	1,340.0	1,340.0	0.0	0.0	15.2	15.2	0.0	0.0	4,741.6	4,741.8
Pacific Noncontiguous	477.2	479.2	631.1	626.3	175.0	175.0	331.9	332.8	0.0	0.0	2,730.7	2,598.7	0.0	6.4	4,345.9	4,218.4
Alaska	477.2	479.2	631.1	626.3	175.0	175.0	151.9	152.8	0.0	0.0	739.4	726.8	0.0	0.0	2,174.6	2,160.1
Hawaii	0.0	0.0	0.0	0.0	0.0	0.0	180.0	180.0	0.0	0.0	1,991.3	1,871.9	0.0	6.4	2,171.3	2,058.3
U.S. Total	271,186.0	263,862.6	129,111.1	127,635.8	76,270.3	78,738.5	228,657.4	242,785.6	1,384.9	1,465.2	30,016.4	30,753.0	2,499.2	2,543.9	739,125.3	747,784.6

NM = Not meaningful due to large relative standard error.
Values are final.

NOTES:
Capacity from facilities with a total generator nameplate capacity less than 1 MW are excluded from this report. This exclusion may represent a significant portion of existing or planned capacity for some technologies such as solar photovoltaic generation.

Sources: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels

Year/Month	Coal		Natural Gas								Petroleum					
			Combined Cycle		Gas Turbine		Steam Turbine		Internal Combustion		Steam Turbine		Gas Turbine		Internal Combustion	
	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor
Annual Data																
2009	312,091.2	64.2%	200,546.1	43.9%	117,120.3	6.8%	80,357.5	10.9%	2,360.1	6.6%	32,621.3	15.0%	19,812.2	1.7%	5,002.0	2.4%
2010	313,393.9	67.1%	202,404.4	44.3%	116,426.0	7.8%	80,233.7	11.1%	2,543.0	6.5%	29,871.2	13.6%	19,565.5	2.0%	5,016.0	2.1%
2011	314,056.1	62.8%	210,518.7	44.3%	119,144.1	7.9%	78,898.6	11.7%	2,822.5	8.4%	26,683.0	12.6%	18,397.7	1.3%	4,986.0	2.2%
2012	304,974.9	56.2%	217,938.2	52.2%	119,319.4	8.9%	74,200.2	13.3%	2,988.8	7.3%	22,483.7	13.7%	17,773.5	1.3%	4,942.5	2.0%
2013	302,604.4	59.4%	219,902.9	48.8%	123,025.6	8.3%	75,810.5	11.2%	2,996.2	8.8%	20,022.9	12.6%	17,224.1	0.9%	4,999.4	2.1%
2014	299,064.7	60.5%	224,183.2	48.6%	124,736.9	8.3%	75,049.1	10.3%	3,026.7	10.8%	18,057.0	13.0%	16,791.5	1.2%	5,011.3	2.1%
2015	286,082.7	54.3%	231,467.5	55.8%	123,444.3	9.8%	80,348.0	11.3%	3,507.8	11.9%	14,965.4	14.0%	16,122.8	1.3%	5,075.2	2.1%
2016	269,477.1	52.8%	236,442.8	55.4%	125,148.4	11.0%	81,225.1	12.3%	3,684.3	11.5%	13,993.7	12.2%	15,114.0	1.3%	5,082.8	2.3%
2017	259,930.2	53.1%	242,839.1	51.2%	125,806.6	9.6%	79,149.4	10.7%	4,225.5	11.6%	13,290.9	13.7%	14,275.3	1.0%	5,153.3	2.1%
2018	246,866.8	53.6%	254,403.3	55.0%	126,763.4	11.9%	76,177.8	12.6%	4,446.6	13.0%	13,300.1	14.2%	14,234.9	1.3%	5,289.7	1.9%
2019	235,089.3	47.5%	266,846.5	57.3%	128,832.5	11.3%	72,797.3	14.1%	4,848.3	15.3%	11,214.7	12.8%	14,009.7	1.0%	5,287.8	2.0%
Year 2017																
January	262,832.9	59.2%	238,604.9	47.1%	125,758.5	8.2%	79,997.2	5.0%	3,984.2	10.8%	13,545.9	11.5%	14,360.0	0.9%	5,165.1	2.3%
February	262,623.9	49.4%	238,711.5	44.7%	125,637.1	8.3%	79,997.2	4.6%	4,151.9	9.5%	13,545.9	10.9%	14,360.0	0.9%	5,162.5	1.9%
March	262,179.7	45.8%	239,783.7	44.8%	125,636.3	9.4%	79,980.6	7.6%	4,198.4	9.5%	13,545.9	13.7%	14,336.4	1.1%	5,153.8	2.2%
April	260,949.7	43.3%	239,783.7	42.6%	125,704.3	8.4%	79,618.6	9.0%	4,218.8	9.6%	13,545.9	10.5%	14,336.4	0.8%	5,159.8	1.8%
May	260,949.7	47.9%	242,325.8	45.6%	125,668.3	8.9%	79,584.1	9.4%	4,239.0	9.8%	13,545.9	16.0%	14,336.4	1.0%	5,158.8	1.9%
June	259,190.0	57.8%	242,355.4	55.5%	125,748.3	10.4%	78,791.5	14.1%	4,240.1	12.0%	13,110.9	16.4%	14,286.4	1.0%	5,149.4	2.0%
July	259,190.0	66.3%	244,634.3	66.3%	125,748.3	12.2%	78,791.5	20.4%	4,240.6	15.3%	13,110.9	17.0%	14,238.4	1.1%	5,149.0	2.0%
August	259,190.0	62.2%	245,481.9	64.9%	125,797.8	11.3%	78,697.5	16.0%	4,246.9	14.5%	13,110.9	15.5%	14,238.4	1.1%	5,137.2	2.2%
September	259,006.0	53.2%	245,481.9	53.2%	125,887.8	10.5%	78,645.7	13.2%	4,297.0	12.7%	13,110.9	14.6%	14,238.4	1.3%	5,144.8	2.3%
October	258,429.0	47.2%	245,521.9	48.1%	125,894.8	9.5%	78,643.7	12.5%	4,297.0	12.0%	13,110.9	12.0%	14,238.4	1.1%	5,148.9	2.1%
November	258,278.0	49.0%	245,521.9	45.8%	126,098.8	8.6%	78,551.6	7.6%	4,297.0	11.5%	13,110.9	12.8%	14,191.8	0.9%	5,144.3	1.9%
December	256,530.0	55.8%	245,520.9	52.3%	126,089.8	9.4%	78,543.2	9.0%	4,293.0	12.0%	13,110.9	13.5%	14,149.8	1.4%	5,165.9	2.2%
Year 2018																
January	251,730.8	64.0%	247,709.0	51.4%	126,362.3	11.7%	78,615.1	10.9%	4,280.9	11.8%	13,440.4	19.9%	14,336.6	3.5%	5,330.8	2.5%
February	250,522.8	49.1%	247,709.0	51.6%	126,189.1	9.3%	78,185.1	5.8%	4,292.9	12.0%	13,440.4	12.1%	14,336.6	0.8%	5,333.5	1.8%
March	249,781.8	43.8%	247,709.0	49.1%	126,170.5	10.3%	77,411.2	7.5%	4,288.5	11.9%	13,440.4	10.9%	14,336.6	0.9%	5,326.9	1.8%
April	248,603.8	41.5%	248,199.0	45.6%	126,338.5	10.5%	77,369.9	8.5%	4,372.4	10.9%	13,440.4	12.9%	14,336.6	1.0%	5,317.8	2.0%
May	248,603.8	46.7%	252,604.7	49.8%	126,690.5	11.3%	76,359.3	15.3%	4,372.4	12.0%	13,440.4	10.0%	14,336.6	1.1%	5,319.2	1.8%
June	245,407.8	58.0%	255,100.3	58.7%	126,881.1	12.4%	75,658.1	16.3%	4,362.4	13.1%	13,440.4	15.0%	14,166.6	1.4%	5,275.1	1.8%
July	245,407.8	63.8%	256,721.3	69.8%	126,878.6	16.3%	75,658.1	23.3%	4,369.0	18.3%	13,440.4	16.6%	14,166.6	1.5%	5,276.5	1.8%
August	245,407.8	63.6%	257,487.3	69.3%	127,267.4	15.0%	75,658.1	20.3%	4,594.6	16.9%	13,440.4	15.6%	14,166.6	1.3%	5,277.8	2.1%
September	245,113.4	55.3%	258,463.3	63.2%	127,146.3	13.8%	75,650.6	15.6%	4,594.3	13.8%	13,440.4	16.9%	14,166.6	1.3%	5,274.0	2.0%
October	244,837.5	48.5%	258,836.7	52.9%	127,104.0	11.6%	75,120.6	12.6%	4,595.0	12.4%	13,440.4	13.7%	14,166.6	1.1%	5,269.0	2.0%
November	244,426.5	53.2%	260,948.0	48.8%	126,977.7	10.5%	74,758.6	8.7%	4,613.6	11.7%	13,440.4	13.4%	14,154.6	1.1%	5,240.4	1.8%
December	242,785.6	55.9%	260,868.5	48.9%	127,108.3	9.1%	73,841.6	6.3%	4,613.6	11.0%	11,788.4	12.6%	14,154.6	1.0%	5,237.9	1.7%
Year 2019																
January	241,507.5	56.6%	261,918.1	54.6%	128,218.2	9.6%	73,728.3	8.4%	4,620.8	12.9%	11,347.1	12.8%	14,037.5	1.4%	5,285.8	2.0%
February	239,252.5	50.4%	261,918.1	55.8%	128,218.2	9.9%	73,730.3	6.9%	4,695.3	14.2%	11,347.1	12.5%	14,037.5	0.9%	5,287.8	1.9%
March	238,021.5	45.0%	261,601.1	51.0%	128,164.0	9.3%	73,188.3	9.3%	4,695.3	12.8%	11,347.1	11.8%	14,018.5	0.6%	5,287.4	1.7%
April	236,625.1	35.7%	264,436.4	45.8%	128,276.4	9.7%	73,191.0	10.9%	4,878.7	12.5%	11,201.1	10.9%	14,018.5	0.8%	5,283.2	1.7%
May	235,815.1	41.7%	265,631.1	49.2%	128,705.3	10.2%	73,191.0	13.7%	4,881.2	12.4%	11,201.1	16.4%	14,018.5	1.0%	5,290.0	1.9%
June	235,767.5	46.9%	268,823.5	59.9%	128,828.7	11.2%	72,899.9	16.7%	4,881.2	14.4%	11,201.1	15.6%	14,008.2	1.1%	5,289.2	1.9%
July	234,785.0	58.3%	269,658.1	70.5%	129,173.4	15.0%	72,853.9	24.9%	4,903.2	20.1%	11,201.1	17.5%	14,008.2	1.1%	5,293.9	2.1%
August	234,785.0	54.6%	269,658.1	71.6%	129,318.4	14.9%	72,853.9	26.1%	4,903.2	20.4%	11,201.1	16.7%	14,002.5	1.3%	5,292.1	2.2%
September	233,847.0	51.4%	269,658.1	64.2%	129,278.4	12.9%	72,853.9	19.8%	4,903.2	17.4%	11,134.1	14.4%	14,002.5	1.2%	5,292.6	2.4%
October	233,086.4	39.3%	269,110.5	54.5%	129,348.4	11.6%	72,211.9	14.6%	4,903.2	15.5%	11,134.1	8.8%	14,002.5	1.2%	5,292.1	2.3%
November	229,164.4	46.0%	269,670.1	52.2%	129,314.4	10.9%	72,038.9	8.7%	4,903.2	16.1%	11,134.1	7.6%	14,002.5	0.8%	5,292.9	2.0%
December	228,657.4	43.3%	269,766.0	57.4%	129,098.3	10.2%	70,909.4	8.4%	5,001.6	14.1%	11,134.1	8.6%	13,962.5	0.8%	5,267.4	2.1%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels

	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Gas		Solar				Wind		Wood	
Year/Month											Photovoltaic		Thermal					
	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor	Time Adjusted Capacity	Capacity Factor
Annual Data																		
2009	2,278.0	73.0%	78,500.4	39.6%	101,003.7	90.3%	4,183.9	65.0%	1,752.2	43.4%	81.9	20.0%	468.2	23.6%	28,996.9	28.1%	6,936.4	61.7%
2010	2,392.1	71.6%	78,810.3	37.5%	101,167.4	91.1%	4,298.7	64.2%	1,929.0	50.5%	206.8	20.2%	473.0	24.5%	35,702.6	29.7%	6,991.5	61.5%
2011	2,407.9	71.5%	78,564.7	45.8%	101,265.1	89.1%	4,469.8	64.2%	1,902.7	54.1%	537.0	19.0%	485.3	23.9%	42,019.2	32.1%	7,000.3	59.6%
2012	2,531.8	68.3%	78,296.6	39.6%	101,166.0	86.6%	4,639.7	63.3%	1,802.8	59.6%	1,527.1	20.4%	476.0	23.6%	49,458.0	31.8%	7,089.1	61.3%
2013	2,509.5	71.8%	78,873.5	38.8%	99,006.8	90.8%	4,949.7	62.3%	2,171.6	55.9%	3,525.2	24.5%	552.1	17.4%	59,175.6	32.4%	7,887.9	59.0%
2014	2,513.3	72.0%	79,582.8	37.2%	98,569.3	91.7%	5,114.6	62.7%	1,994.0	54.0%	6,555.6	25.6%	1,445.3	18.3%	60,587.8	34.0%	8,319.7	60.0%
2015	2,523.0	71.9%	79,650.8	35.7%	98,614.6	92.3%	5,104.5	62.6%	2,527.7	60.8%	9,521.6	25.5%	1,697.3	21.7%	67,106.2	32.2%	9,024.5	59.3%
2016	2,516.6	71.6%	79,806.0	38.2%	99,364.8	92.3%	5,099.5	62.7%	2,458.8	64.8%	14,161.4	25.0%	1,757.9	22.1%	74,162.7	34.5%	8,979.8	58.3%
2017	2,460.4	73.2%	79,698.8	43.0%	99,619.5	92.3%	5,125.6	61.8%	2,375.8	62.8%	21,940.9	25.6%	1,757.9	21.8%	83,355.6	34.6%	8,807.5	60.2%
2018	2,391.5	76.0%	79,771.9	41.9%	99,605.2	92.5%	5,059.0	61.8%	2,543.9	65.4%	27,143.3	25.1%	1,757.9	23.6%	89,228.5	34.6%	8,760.2	60.6%
2019	2,535.2	69.6%	79,838.0	41.2%	98,836.7	93.4%	4,786.5	62.5%	2,504.1	67.4%	31,840.8	24.3%	1,758.1	21.2%	97,564.8	34.4%	8,485.0	59.0%
Year 2017																		
January	2,511.1	74.9%	79,657.2	44.9%	99,609.9	98.7%	5,095.1	64.2%	2,375.8	63.8%	20,249.8	14.6%	1,757.9	7.3%	81,337.2	34.2%	8,748.6	61.4%
February	2,511.1	73.0%	79,657.2	44.6%	99,609.9	95.0%	5,097.3	63.2%	2,375.8	65.4%	20,603.7	18.6%	1,757.9	11.6%	81,713.0	40.2%	8,748.6	61.6%
March	2,451.1	73.8%	79,657.2	50.0%	99,609.9	87.8%	5,097.3	61.1%	2,375.8	64.8%	20,792.6	26.7%	1,757.9	22.9%	81,962.1	41.8%	8,741.6	60.0%
April	2,451.1	75.6%	79,660.1	51.3%	99,609.9	79.2%	5,105.7	60.0%	2,375.8	61.8%	21,177.9	29.6%	1,757.9	24.8%	83,041.4	42.4%	8,789.1	56.4%
May	2,451.1	71.0%	79,660.1	55.0%	99,609.9	82.8%	5,122.7	62.5%	2,375.8	58.1%	21,700.6	33.1%	1,757.9	30.9%	83,182.1	37.2%	8,796.6	55.0%
June	2,451.1	72.4%	79,660.1	53.3%	99,609.9	93.5%	5,126.7	62.8%	2,375.8	59.1%	22,006.1	35.4%	1,757.9	37.9%	83,313.5	33.4%	8,802.9	60.6%
July	2,451.1	74.9%	79,667.4	44.8%	99,628.9	96.2%	5,145.2	61.7%	2,375.8	58.9%	22,242.6	31.5%	1,757.9	25.3%	83,498.6	25.8%	8,802.9	62.1%
August	2,451.1	74.4%	79,614.2	37.1%	99,628.9	97.7%	5,147.3	62.0%	2,375.8	65.0%	22,356.4	29.9%	1,757.9	27.5%	83,980.6	22.2%	8,856.4	63.3%
September	2,451.1	75.1%	79,761.5	33.3%	99,628.9	95.0%	5,147.2	59.4%	2,375.8	61.8%	22,547.7	28.7%	1,757.9	29.1%	83,980.6	29.5%	8,856.4	58.6%
October	2,451.1	66.2%	79,797.5	29.8%	99,628.9	89.0%	5,147.2	58.2%	2,375.8	62.1%	22,762.8	25.2%	1,757.9	24.1%	84,229.8	38.7%	8,856.4	57.4%
November	2,451.1	73.5%	79,797.1	34.6%	99,628.9	92.9%	5,143.9	62.3%	2,375.8	65.1%	23,095.3	18.1%	1,757.9	10.3%	84,483.3	36.6%	8,856.4	61.2%
December	2,446.3	74.2%	79,794.4	37.5%	99,628.9	99.4%	5,129.5	63.9%	2,375.8	67.4%	23,660.0	15.6%	1,757.9	9.0%	85,431.2	34.2%	8,830.9	65.3%
Year 2018																		
January	2,387.5	75.3%	79,771.8	42.2%	99,730.6	100.6%	5,108.5	62.2%	2,543.9	66.2%	25,311.1	16.3%	1,757.9	10.0%	87,552.6	38.7%	8,813.0	65.3%
February	2,403.5	78.9%	79,771.8	46.4%	99,730.6	96.7%	5,083.1	64.6%	2,543.9	66.6%	25,968.4	20.9%	1,757.9	16.1%	88,563.2	38.8%	8,813.0	62.5%
March	2,382.2	76.8%	79,785.3	43.6%	99,730.6	90.3%	5,086.1	62.0%	2,543.9	63.3%	26,067.6	24.3%	1,757.9	19.2%	88,787.7	40.1%	8,780.5	61.7%
April	2,392.2	69.0%	79,792.3	48.9%	99,730.6	82.4%	5,086.1	60.9%	2,543.9	61.6%	26,591.3	29.7%	1,757.9	24.4%	88,789.2	41.3%	8,780.5	55.6%
May	2,392.2	77.7%	79,753.3	51.3%	99,730.6	90.7%	5,083.5	59.4%	2,543.9	63.2%	26,859.7	31.8%	1,757.9	32.9%	89,086.2	36.0%	8,761.5	58.0%
June	2,392.2	75.5%	79,753.8	48.1%	99,730.6	97.1%	5,006.9	63.0%	2,543.9	64.1%	27,291.3	34.9%	1,757.9	41.7%	89,078.2	38.4%	8,775.5	61.7%
July	2,392.2	77.0%	79,751.6	42.3%	99,730.6	97.7%	5,050.2	62.3%	2,543.9	65.8%	27,451.7	31.1%	1,757.9	30.1%	89,227.2	24.7%	8,767.2	63.7%
August	2,392.2	76.8%	79,751.6	37.1%	99,730.6	97.4%	5,042.5	62.6%	2,543.9	68.7%	27,590.1	30.5%	1,757.9	32.5%	89,387.5	29.8%	8,748.7	62.2%
September	2,392.2	77.1%	79,751.6	33.4%	99,277.9	90.3%	5,042.5	58.3%	2,543.9	67.2%	27,674.0	27.7%	1,757.9	34.8%	89,469.5	28.6%	8,748.7	58.5%
October	2,392.2	71.5%	79,753.6	32.9%	99,277.9	80.4%	5,041.4	61.0%	2,543.9	64.3%	27,989.5	22.4%	1,757.9	20.7%	89,941.8	31.5%	8,748.7	56.5%
November	2,392.2	77.3%	79,753.6	38.1%	99,432.9	89.3%	5,039.0	62.3%	2,543.9	67.4%	28,158.3	17.3%	1,757.9	13.3%	90,282.8	33.8%	8,694.6	60.4%
December	2,387.9	79.4%	79,870.8	38.4%	99,432.9	96.9%	5,038.6	63.2%	2,543.9	67.0%	28,690.2	13.7%	1,757.9	7.0%	90,534.1	34.8%	8,694.6	61.4%
Year 2019																		
January	2,527.5	73.9%	79,881.1	41.7%	99,440.4	99.6%	4,894.7	63.2%	2,509.0	68.2%	30,238.8	15.2%	1,758.1	8.4%	94,361.8	34.4%	8,716.6	62.0%
February	2,527.5	76.1%	79,883.6	42.6%	99,440.4	96.8%	4,894.7	62.3%	2,509.0	64.8%	30,911.4	17.7%	1,758.1	10.9%	95,284.6	35.3%	8,716.6	60.7%
March	2,527.5	75.6%	79,897.2	44.3%	99,440.4	88.0%	4,796.3	61.4%	2,509.0	61.6%	31,124.1	24.1%	1,758.1	19.8%	95,776.4	36.0%	8,565.9	57.6%
April	2,535.4	68.7%	79,897.2	48.4%	99,595.4	84.5%	4,785.1	59.9%	2,514.0	62.1%	31,355.0	28.4%	1,758.1	25.5%	96,608.9	41.6%	8,553.5	52.8%
May	2,535.4	71.1%	79,874.5	53.8%	98,921.8	90.8%	4,783.7	61.5%	2,514.0	67.6%	31,466.6	29.1%	1,758.1	25.7%	96,610.5	35.7%	8,538.5	54.1%
June	2,535.4	72.8%	79,878.4	48.8%	98,921.8	96.6%	4,764.2	64.2%	2,499.2	67.5%	31,528.4	32.9%	1,758.1	35.5%	96,840.0	31.9%	8,469.0	58.2%
July	2,535.4	72.9%	79,879.9	41.9%	98,921.8	98.1%	4,765.8	63.8%	2,499.2	68.5%	31,803.5	32.4%	1,758.1	31.4%	98,084.1	30.1%	8,498.4	61.4%
August	2,535.4	73.9%	79,776.1	38.0%	98,921.8	97.7%	4,765.9	64.4%	2,499.2	68.0%	32,079.8	31.0%	1,758.1	32.0%	98,359.7	27.1%	8,498.4	62.7%
September	2,535.4	74.9%	79,775.9	32.3%	98,119.0	93.1%	4,754.4	62.6%	2,499.2	72.4%	32,302.5	27.4%	1,758.1	24.3%	98,668.1	34.1%	8,409.1	59.2%
October	2,535.4	60.5%	79,772.0	30.8%	98,119.0	85.0%	4,754.4	61.5%	2,499.2	64.4%	32,556.1	23.3%	1,758.1	23.0%	99,662.8	37.2%	8,305.5	57.0%
November	2,535.4	53.3%	79,772.0	35.2%	98,119.0	90.8%	4,751.2	61.5%	2,499.2	71.6%	33,001.5	17.4%	1,758.1	11.3%	99,618.3	34.9%	8,305.5	60.2%
December	2,555.4	61.5%	79,772.0	36.2%	98,119.0	100.1%	4,735.4	63.7%	2,499.2	72.2%	33,658.4	12.8%	1,758.1	5.4%	100,729.8	34.9%	8,258.5	62.7%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Capacity factors are a comparison of net generation with available capacity. See the technical note for an explanation of how capacity factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.08.C. Usage Factors for Utility Scale Storage Generators

Year/Month	Battery		Pumped Storage	
	Time Adjusted Capacity	Usage Factor	Time Adjusted Capacity	Usage Factor
Annual Data				
2013	126.7	0.7%	22,389.3	9.8%
2014	155.1	1.7%	22,477.9	10.2%
2015	206.8	3.6%	22,568.9	10.2%
2016	423.0	3.8%	22,752.7	11.2%
2017	632.8	6.8%	22,791.7	11.4%
2018	713.6	5.2%	22,815.4	10.8%
2019	949.8	5.4%	22,754.7	10.4%
Year 2017				
January	562.8	6.9%	22,753.4	10.2%
February	573.8	7.1%	22,753.4	8.0%
March	581.8	8.1%	22,753.4	8.5%
April	611.8	7.7%	22,753.4	9.5%
May	627.7	6.6%	22,810.4	11.7%
June	641.2	7.0%	22,810.4	14.2%
July	643.2	6.5%	22,810.4	16.9%
August	645.4	6.7%	22,810.4	16.2%
September	678.2	6.2%	22,810.4	12.9%
October	679.4	6.4%	22,810.4	10.2%
November	681.4	6.9%	22,810.4	9.0%
December	663.4	6.5%	22,810.4	9.1%
Year 2018				
January	643.7	5.2%	22,785.2	9.8%
February	663.5	5.1%	22,785.2	9.6%
March	667.1	5.2%	22,785.2	7.9%
April	681.1	5.0%	22,785.2	8.2%
May	690.6	5.2%	22,830.2	11.0%
June	696.1	4.9%	22,830.2	13.2%
July	742.1	5.6%	22,830.2	15.5%
August	740.1	5.6%	22,830.2	16.1%
September	746.4	5.6%	22,830.2	12.2%
October	748.9	5.0%	22,830.2	9.4%
November	768.9	5.3%	22,830.2	8.2%
December	770.7	5.1%	22,830.2	7.7%
Year 2019				
January	864.8	5.5%	22,721.3	9.3%
February	877.1	5.7%	22,721.3	9.2%
March	901.9	6.3%	22,721.3	8.3%
April	931.0	5.9%	22,721.3	10.2%
May	934.7	5.9%	22,721.3	11.8%
June	939.7	5.2%	22,778.3	11.7%
July	962.9	5.2%	22,778.3	15.1%
August	983.9	5.0%	22,778.3	13.7%
September	990.8	5.8%	22,778.3	12.4%
October	998.7	4.5%	22,778.3	8.3%
November	1,001.2	5.2%	22,778.3	7.2%
December	1,006.2	5.0%	22,778.3	7.8%

Values are final.

Time adjusted capacity for month rows is the summer capacity of generators in operation for the entire month; units that began operation during the month or that retired during the month are excluded. Time adjusted capacity for year rows is a time weighted average of the month rows.

Usage factors are a comparison of gross generation with available capacity. See the technical note for an explanation of how usage factors are calculated.

Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report; U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report' and Form EIA-860M, 'Monthly Update to the Annual Electric Generator Report.'

Table 4.9.A. Total Capacity of Distributed and Dispersed Generators by Technology Type, 2009 through 2015 (Table Discontinued)

	Capacity (MW)										
	Internal Combustion	Combustion Turbine	Steam Turbine	Hydro	Wind	Photovoltaic	Storage	Other	Wind and Other	Total	Number of Generators
Year											
Distributed Generators											
2009	4,339.0	4,147.0	4,621.0	1,166.0	--	--	--	--	1,729.0	16,002.0	13,006
2010	886.8	186.0	109.9	97.4	98.9	236.3	--	372.7	--	1,988.0	15,630
2011	791.1	115.5	64.9	97.9	36.7	314.8	0.2	264.3	--	1,685.4	20,941
2012	756.1	105.8	60.2	119.9	252.9	543.7	15.2	324.4	--	1,990.6	28,252
2013	981.3	106.4	31.1	103.9	78.3	556.0	2.0	89.0	--	1,947.4	196,141
2014	813.8	81.3	12.9	108.2	33.7	692.0	7.2	101.0	--	1,855.5	203,099
2015	797.6	49.3	10.5	121.2	26.7	876.4	24.4	88.4	--	1,994.6	215,825
Dispersed Generators											
2009	9,751.0	329.0	204.0	81.0	--	--	--	--	108.0	10,475.0	13,928
2010	2,771.2	64.4	13.8	8.4	6.3	95.2	7.0	17.9	--	2,984.2	16,874
2011	2,916.9	40.3	14.6	6.0	3.2	2.7	8.0	7.9	--	2,999.6	14,123
2012	3,180.9	49.8	--	2.2	3.1	8.5	7.7	13.5	--	3,265.5	14,557
2013	3,249.7	159.8	17.0	1.9	4.5	21.6	8.7	25.8	--	3,489.0	17,929
2014	3,479.3	169.7	16.7	0.7	3.7	14.3	6.6	5.7	--	3,696.8	22,599
2015	3,160.9	199.1	16.7	0.7	4.7	17.6	7.2	5.7	--	3,412.6	23,665
Distributed and Dispersed Generators											
2009	14,090.0	4,476.0	4,825.0	1,247.0	--	--	--	--	1,837.0	26,477.0	26,934
2010	3,658.0	250.4	123.7	105.8	105.2	331.5	7.0	390.6	--	4,972.2	32,504
2011	3,708.0	155.8	79.5	103.9	39.9	317.5	8.2	272.2	--	4,685.0	35,064
2012	3,937.0	155.6	60.2	122.1	256.0	552.2	22.9	337.9	--	5,256.1	42,809
2013	4,231.0	266.2	48.1	105.8	82.8	577.6	10.7	114.8	--	5,436.4	214,070
2014	4,293.1	251.0	29.6	108.9	37.5	706.3	13.8	106.7	--	5,552.2	225,698
2015	3,958.5	248.5	27.2	121.9	31.4	893.9	31.6	94.1	--	5,407.1	239,490

Starting in 2013, the residential sector is now included and all net metering units are excluded.

Distributed and Dispersed generator data in 2005 include a significant number of generators reported by one respondent, which may be for residential applications.

Prior to 2010, data contains generators over and under 1 MW, from 2010 forward, data contains only generators under 1 MW.

Distributed generators are commercial and industrial generators which are connected to the grid. Dispersed generators are commercial and industrial generators which are not connected to the grid. Both types may be installed at or near a customer's site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 4.9.B Total Capacity of Non Net Metered Distributed Generators by Technology Type and Sector, 2010 through 2019

Year	Residential	Generators by Technology and Sector				Total
		Commercial	Industrial	Transportation	Direct Connected	
Internal Combustion						
2010	--	--	--	--	--	886.800
2011	--	--	--	--	--	791.100
2012	--	--	--	--	--	756.100
2013	--	--	--	--	--	981.311
2014	--	--	--	--	--	813.847
2015	--	--	--	--	--	797.595
2016	46.974	679.239	223.037	--	69.217	1,018.467
2017	86.766	851.363	306.305	--	78.180	1,322.614
2018	69.428	909.278	336.970	--	91.159	1,406.835
2019	76.934	955.455	263.507	0.275	111.981	1,408.152
Combustion Turbine						
2010	--	--	--	--	--	186.000
2011	--	--	--	--	--	115.500
2012	--	--	--	--	--	105.800
2013	--	--	--	--	--	106.385
2014	--	--	--	--	--	81.325
2015	--	--	--	--	--	49.329
2016	0.233	62.127	24.415	--	2.728	89.503
2017	11.750	56.187	25.069	--	5.893	98.899
2018	0.070	75.151	24.568	--	3.488	103.277
2019	0.077	76.695	22.128	--	4.488	103.388
Steam Turbine						
2010	--	--	--	--	--	109.900
2011	--	--	--	--	--	64.900
2012	--	--	--	--	--	60.200
2013	--	--	--	--	--	31.050
2014	--	--	--	--	--	12.925
2015	--	--	--	--	--	10.531
2016	--	2.995	0.524	--	0.431	3.950
2017	1.250	1.920	1.254	--	0.431	4.855
2018	--	4.626	0.539	--	2.581	7.746
2019	--	8.439	0.539	--	2.581	11.559
Hydroelectric						
2010	--	--	--	--	--	97.400
2011	--	--	--	--	--	97.900
2012	--	--	--	--	--	119.900
2013	--	--	--	--	--	103.935
2014	--	--	--	--	--	108.235
2015	--	--	--	--	--	121.234
2016	6.140	39.930	8.533	--	101.146	155.749
2017	5.915	30.763	8.033	--	103.607	148.318
2018	5.422	36.048	5.503	--	113.592	160.565
2019	7.482	37.818	5.503	--	113.910	164.713
Wind						
2010	--	--	--	--	--	98.900
2011	--	--	--	--	--	36.700
2012	--	--	--	--	--	252.900
2013	--	--	--	--	--	78.299
2014	--	--	--	--	--	33.727
2015	--	--	--	--	--	26.658
2016	2.616	15.742	1.366	--	8.828	28.552
2017	2.632	16.453	1.044	--	8.988	29.117
2018	2.579	15.527	1.441	--	9.071	28.618
2019	2.437	15.707	1.452	--	9.918	29.514
Photovoltaic						
2010	--	--	--	--	--	236.300
2011	--	--	--	--	--	314.800
2012	--	--	--	--	--	543.700
2013	--	--	--	--	--	555.965
2014	--	--	--	--	--	692.034
2015	--	--	--	--	--	876.351
2016	80.577	388.911	132.970	--	112.922	715.380
2017	186.910	513.251	177.192	--	120.946	998.299
2018	289.151	594.877	188.874	--	126.793	1,199.698
2019	437.911	688.600	202.899	--	131.391	1,460.800
Storage						
2010	--	--	--	--	--	--
2011	--	--	--	--	--	0.200
2012	--	--	--	--	--	15.200
2013	--	--	--	--	--	1.950
2014	--	--	--	--	--	7.227
2015	--	--	--	--	--	24.443
2016	0.070	32.678	8.714	--	1.246	42.708
2017	3.916	42.884	12.271	--	1.444	60.515
2018	6.935	79.042	10.674	--	7.276	103.927
2019	14.308	113.788	15.519	--	15.929	159.544
Fuel Cell						
2010	--	--	--	--	--	--
2011	--	--	--	--	--	--
2012	--	--	--	--	--	--
2013	--	--	--	--	--	--
2014	--	--	--	--	--	--
2015	--	--	--	--	--	--
2016	0.161	6.229	3.700	--	0.225	10.315
2017	0.167	7.953	6.336	--	0.625	15.081
2018	0.150	12.793	3.959	--	0.625	17.527
2019	0.150	19.943	3.601	--	0.625	24.319
Other						
2010	--	--	--	--	--	372.700
2011	--	--	--	--	--	264.300
2012	--	--	--	--	--	324.400
2013	--	--	--	--	--	89.000
2014	--	--	--	--	--	100.995
2015	--	--	--	--	--	88.423
2016	0.753	34.050	10.389	--	6.050	51.242
2017	1.139	33.093	12.729	--	4.950	51.911
2018	0.629	36.452	16.209	--	3.310	56.600
2019	0.464	37.306	14.954	--	3.579	56.303
Total						
2010	--	--	--	--	--	1,988.000
2011	--	--	--	--	--	1,685.400
2012	--	--	--	--	--	1,990.600
2013	--	--	--	--	--	1,947.394
2014	--	--	--	--	--	1,855.455
2015	--	--	--	--	--	1,994.564
2016	137.524	1,261.901	413.648	--	302.793	2,115.866
2017	300.445	1,553.867	550.233	--	325.064	2,729.609
2018	374.368	1,763.792	588.737	--	357.895	3,084.792
2019	539.763	1,953.751	530.102	0.275	394.402	3,418.292
Total Number of Generators						
2010	--	--	--	--	--	15,630
2011	--	--	--	--	--	20,941
2012	--	--	--	--	--	28,252
2013	--	--	--	--	--	196,141
2014	--	--	--	--	--	203,099
2015	--	--	--	--	--	215,825
2016	--	--	--	--	--	195,703
2017	--	--	--	--	--	215,889
2018	--	--	--	--	--	231,220
2019	--	--	--	--	--	251,357

Starting in 2016, Capacity is now collected by technology and sector.

Starting in 2013, the residential sector is now included and all net metering units are excluded.

Distributed generators are generators which are connected to the grid. They may be installed at or near a customer's site or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 4.10. Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2009 through 2019

Year	Capacity (MW)					Customers				
	Residential	Commercial	Industrial	Transportation	Total	Residential	Commercial	Industrial	Transportation	Total
Historical Data										
2009	N/A	N/A	N/A	N/A	N/A	88,205	7,365	919	--	96,489
Photovoltaic										
2010	697.890	517.861	243.051	--	1,458.802	137,618	11,897	1,225	--	150,740
2011	1,024.139	1,089.275	381.670	--	2,495.410	198,255	18,345	2,418	--	219,018
2012	1,542.226	1,741.821	395.328	--	3,679.630	294,437	27,611	1,317	--	323,365
2013	2,286.567	2,294.831	565.982	--	5,147.380	442,195	35,379	2,480	--	480,054
2014	3,452.987	2,933.122	710.719	--	7,096.828	642,276	43,335	3,131	--	688,742
2015	5,357.358	3,455.124	884.664	--	9,697.146	958,850	51,501	3,624	--	1,013,975
2016	7,487.643	3,975.813	1,078.607	--	12,542.064	1,321,277	60,456	4,391	--	1,386,124
2017	9,486.987	5,119.870	1,197.785	--	15,804.641	1,626,283	69,538	5,267	--	1,701,088
2018	11,356.711	6,173.324	1,378.863	--	18,908.896	1,911,892	78,912	5,844	--	1,996,648
2019	13,863.288	7,181.594	1,613.248	--	22,658.129	2,283,702	86,552	6,499	--	2,376,753
Storage										
2016	4.489	7.575	11.698	--	23.762	793	79	31	--	903
2017	13.276	15.356	12.328	--	40.960	2,316	137	34	--	2,487
2018	65.199	40.141	24.526	--	129.866	10,633	303	61	--	10,997
2019	153.282	48.397	40.441	--	242.120	24,007	427	93	--	24,527
Virtual PV (1 MW and over)										
2016	15.171	194.318	--	--	209.489	5,193	322	--	--	5,515
2017	11.115	287.440	2.000	--	300.555	3,611	535	2	--	4,148
2018	19.719	360.749	2.603	--	383.071	6,045	2,037	17	--	8,099
2019	19.883	401.179	4.212	--	425.274	5,939	2,164	22	--	8,125
Virtual PV (under 1 MW)										
2016	27.482	73.116	3.168	--	103.766	8,705	1,506	11	--	10,222
2017	42.005	129.547	5.136	--	176.689	11,337	2,372	17	--	13,726
2018	49.232	163.228	5.466	--	217.926	13,071	2,959	16	--	16,046
2019	57.609	223.409	6.472	--	287.489	14,814	3,744	18	--	18,576
Wind										
2010	83.797	26.106	6.392	--	116.295	3,467	583	37	--	4,087
2011	28.063	44.373	9.932	--	82.368	4,456	905	50	--	5,411
2012	33.484	74.620	17.495	--	125.599	4,796	1,143	48	--	5,987
2013	38.987	92.818	14.659	--	146.464	5,265	1,308	92	--	6,665
2014	37.918	101.622	25.426	--	164.966	5,379	1,351	94	--	6,824
2015	34.893	103.086	29.137	--	167.116	5,387	1,434	109	--	6,930
2016	37.030	108.726	41.454	--	187.210	5,759	1,470	113	--	7,342
2017	35.005	119.651	49.507	--	204.163	5,258	1,429	111	--	6,798
2018	33.625	133.856	52.386	--	219.867	5,368	1,452	110	--	6,930
2019	33.668	148.594	52.580	--	234.842	5,218	1,438	107	--	6,763
Other										
2010	11.455	34.752	24.835	--	71.042	767	271	56	--	1,094
2011	5.030	49.010	56.681	--	110.721	807	242	100	--	1,149
2012	7.539	65.821	83.170	--	156.530	862	314	122	--	1,298
2013	6.785	80.405	80.568	--	167.758	598	331	169	--	1,098
2014	7.633	102.797	98.277	--	208.707	857	397	201	--	1,455
2015	7.873	116.382	116.780	--	241.035	821	445	249	--	1,515
2016	7.952	155.889	149.608	--	313.449	862	592	325	--	1,779
2017	9.064	208.639	199.398	--	417.101	915	693	330	--	1,938
2018	6.351	258.601	241.416	--	506.368	692	826	347	--	1,865
2019	23.364	254.281	263.966	--	541.611	2,226	842	381	--	3,449
All Technologies										
2010	793.142	578.719	274.278	--	1,646.139	141,852	12,751	1,318	--	155,921
2011	1,057.232	1,182.658	448.283	--	2,688.173	203,518	19,492	2,568	--	225,578
2012	1,583.249	1,882.262	495.993	--	3,961.504	300,095	29,068	1,487	--	330,650
2013	2,332.339	2,468.054	661.209	--	5,461.602	448,058	37,018	2,741	--	487,817
2014	3,498.538	3,137.541	834.422	--	7,470.501	648,512	45,083	3,426	--	697,021
2015	5,400.124	3,674.592	1,030.581	--	10,105.297	965,058	53,380	3,982	--	1,022,420
2016	7,715.715	4,576.384	1,289.946	--	13,582.045	1,341,796	64,346	4,840	--	1,410,982
2017	9,584.177	5,865.147	1,453.826	--	16,903.148	1,647,404	74,567	5,727	--	1,727,698
2018	11,465.638	7,089.758	1,680.734	--	20,236.128	1,937,068	86,186	6,334	--	2,029,588
2019	13,997.811	8,209.056	1,940.478	--	24,147.345	2,311,899	94,740	7,027	--	2,413,666

N/A = Not Available.

Total customer count for the years 2007, 2009, and 2010 were revised based on requests from respondents.

Capacity and customer count was not collected by technology type before 2010.

Starting in 2013, there is no maximum capacity on installed units.

Starting in 2016, utilities have the option to report photovoltaic in DC or AC. Values have been converted to AC.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 4.11. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2019
(Megawatts, Percent)

		Fuel-Switchable Part of Total			
Producer Type	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Electric Utilities	247,018.9	81,920.1	33.2%	77,263.5	16,088.7
Independent Power Producers, Non-Combined Heat and Power Plants	187,715.6	45,039.8	24.0%	42,366.4	7,776.7
Independent Power Producers, Combined Heat and Power Plants	24,782.0	4,000.7	16.1%	3,835.1	298.1
Electric Power Sector Subtotal	459,516.5	130,960.6	28.5%	123,465.0	24,163.5
Commercial Sector	2,247.5	918.8	40.9%	864.4	97.2
Industrial Sector	14,803.4	920.7	6.2%	885.2	89.2
All Sectors	476,567.4	132,800.1	27.9%	125,214.6	24,349.9

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.12. Fuel-Switching Capacity of Operable Generators Reporting Petroleum Liquids as the Primary Fuel, by Producer Type, 2019 (Megawatts, Percent)

		Fuel-Switchable Part of Total		
Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum Liquids as the Primary Fuel	Net Summer Capacity of Petroleum Liquids-Fired Generators Reporting the Ability to Switch to Natural Gas	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Natural Gas
Electric Utilities	17,287.3	2,292.9	13.3%	2,273.8
Independent Power Producers, Non-Combined Heat and Power Plants	11,378.8	2,775.2	24.4%	1,911.6
Independent Power Producers, Combined Heat and Power Plants	246.8	--	0.0%	--
Electric Power Sector Subtotal	28,912.9	5,068.1	17.5%	4,185.4
Commercial Sector	856.7	5.9	0.7%	5.6
Industrial Sector	245.8	29.0	11.8%	25.0
All Sectors	30,015.4	5,103.0	17.0%	4,215.9

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.
Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.13. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Type of Prime Mover, 2019 (Megawatts, Percent)

Prime Mover Type	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Steam Generator	174	26,091.0	7,309.3
Combined Cycle	379	48,106.6	5,391.7
Internal Combustion	312	1,230.0	386.2
Gas Turbine	876	57,372.5	11,262.7
All Fuel Switchable Prime Movers	1,741	132,800.1	24,349.9

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 4.14. Fuel-Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel,

by Year of Initial Commercial Operation, 2019 (Megawatts, Percent)

Year of Initial Commercial Operation	Number of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Pre-1970	265	10,584.0	3,258.7
1970-1974	258	14,024.6	4,206.3
1975-1979	95	10,371.5	2,473.4
1980-1984	38	822.8	199.3
1985-1989	84	2,738.5	195.3
1990-1994	193	11,645.8	1,359.8
1995-1999	128	9,070.7	1,656.6
2000-2004	396	37,734.2	6,345.5
2005-2009	118	15,505.8	1,729.6
2010-2014	99	11,409.8	241.2
2015-2019	67	8,892.4	2,684.2
Total	1,741	132,800.1	24,349.9

Notes: Petroleum liquids include distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, waste oil, and propane.

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Chapter 5

Consumption of Fossil Fuels

**Table 5.1.A. Coal: Consumption for Electricity Generation,
by Sector, 2009 - 2019 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	934,683	695,615	234,077	317	4,674
2010	979,684	721,431	249,814	314	8,125
2011	934,938	689,316	239,541	347	5,735
2012	825,734	615,467	205,295	307	4,665
2013	860,729	638,327	217,219	513	4,670
2014	853,634	624,235	224,568	202	4,629
2015	739,594	539,506	195,927	163	3,999
2016	677,371	496,192	178,047	111	3,021
2017	663,911	484,389	176,643	95	2,783
2018	636,213	473,617	159,976	87	2,534
2019	537,620	399,545	135,838	76	2,161
Year 2017					
January	63,460	46,708	16,471	11	270
February	47,985	35,491	12,240	9	245
March	48,840	35,655	12,926	9	250
April	44,279	31,403	12,656	6	214
May	50,897	37,373	13,294	6	224
June	58,852	43,744	14,881	6	221
July	69,769	51,971	17,560	7	230
August	65,761	48,954	16,574	7	227
September	54,713	39,390	15,098	8	218
October	50,015	36,190	13,591	7	227
November	50,882	35,778	14,873	8	222
December	58,457	41,733	16,479	9	236
Year 2018					
January	64,845	47,762	16,817	11	255
February	45,793	34,002	11,552	9	230
March	44,474	32,312	11,930	8	224
April	40,515	30,350	9,965	7	193
May	47,293	35,261	11,815	6	211
June	56,078	42,502	13,360	6	210
July	63,818	48,277	15,322	6	212
August	63,737	47,866	15,660	7	204
September	53,914	40,293	13,415	7	199
October	48,422	35,547	12,695	6	173
November	51,702	37,956	13,537	7	202
December	55,624	41,488	13,908	7	221
Year 2019					
January	55,834	41,306	14,305	8	214
February	45,025	33,349	11,471	8	197
March	43,976	31,666	12,133	9	168
April	33,353	24,495	8,691	6	161
May	40,015	30,285	9,547	6	178
June	44,218	33,558	10,482	4	174
July	55,863	42,319	13,345	5	193
August	52,349	39,741	12,412	5	190
September	47,188	35,453	11,554	6	175
October	37,431	27,150	10,119	6	157
November	41,907	30,453	11,274	6	173
December	40,461	29,769	10,505	7	180

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.B. Coal: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Thousand Tons)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	20,507	0	3,935	1,481	15,091
2010	21,727	0	3,808	1,406	16,513
2011	21,532	0	3,628	1,321	16,584
2012	19,333	0	2,790	1,143	15,400
2013	18,350	0	2,416	843	15,090
2014	18,107	978	1,821	861	14,448
2015	16,632	1,032	1,980	635	12,985
2016	16,586	2,979	1,336	572	11,700
2017	14,667	2,802	1,158	515	10,192
2018	13,813	2,268	1,356	490	9,700
2019	12,397	2,062	1,161	443	8,731
Year 2017					
January	1,470	300	117	59	995
February	1,198	213	104	48	832
March	1,293	238	106	57	892
April	1,128	221	78	36	793
May	1,137	209	75	34	819
June	1,152	211	84	34	823
July	1,203	254	96	40	813
August	1,215	256	100	36	824
September	1,102	207	86	38	771
October	1,223	223	94	35	871
November	1,261	263	98	44	856
December	1,285	208	119	56	903
Year 2018					
January	1,434	237	144	65	987
February	1,285	216	126	51	892
March	1,254	202	119	49	885
April	1,095	188	100	40	767
May	1,081	173	106	33	769
June	1,081	184	107	30	759
July	1,078	189	105	34	750
August	1,064	181	103	35	745
September	1,061	183	97	38	743
October	984	159	72	35	718
November	1,167	173	141	40	813
December	1,229	182	135	40	872
Year 2019					
January	1,312	198	158	51	905
February	1,158	189	114	47	808
March	1,112	189	110	49	764
April	1,009	141	102	34	732
May	941	123	90	33	695
June	950	161	95	23	671
July	950	171	97	30	653
August	974	190	88	32	664
September	914	168	73	34	640
October	985	174	81	31	699
November	1,019	174	76	38	731
December	1,072	184	76	42	770

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.C. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	955,190	695,615	238,012	1,798	19,766
2010	1,001,411	721,431	253,621	1,720	24,638
2011	956,470	689,316	243,168	1,668	22,319
2012	845,066	615,467	208,085	1,450	20,065
2013	879,078	638,327	219,635	1,356	19,761
2014	871,741	625,212	226,389	1,063	19,076
2015	756,226	540,538	197,906	798	16,984
2016	693,958	499,172	179,383	683	14,720
2017	678,578	487,192	177,801	610	12,975
2018	650,027	475,885	161,332	577	12,233
2019	550,017	401,607	136,998	519	10,892
Year 2017					
January	64,930	47,008	16,588	71	1,264
February	49,183	35,705	12,344	58	1,077
March	50,132	35,893	13,032	66	1,142
April	45,407	31,624	12,735	42	1,007
May	52,034	37,582	13,370	39	1,043
June	60,004	43,955	14,965	40	1,044
July	70,972	52,225	17,656	47	1,043
August	66,976	49,209	16,673	43	1,050
September	55,815	39,596	15,184	45	989
October	51,239	36,413	13,686	42	1,098
November	52,143	36,042	14,971	52	1,078
December	59,742	41,940	16,598	66	1,139
Year 2018					
January	66,279	47,999	16,961	76	1,242
February	47,079	34,219	11,679	59	1,122
March	45,728	32,513	12,049	57	1,109
April	41,610	30,538	10,065	47	960
May	48,374	35,435	11,921	39	979
June	57,159	42,687	13,467	36	969
July	64,895	48,467	15,427	40	962
August	64,801	48,047	15,763	42	949
September	54,975	40,475	13,512	45	943
October	49,406	35,706	12,768	42	891
November	52,868	38,129	13,677	47	1,015
December	56,853	41,670	14,043	47	1,093
Year 2019					
January	57,146	41,504	14,463	59	1,119
February	46,183	33,539	11,586	54	1,005
March	45,088	31,855	12,243	58	932
April	34,362	24,636	8,793	40	893
May	40,956	30,408	9,637	38	873
June	45,168	33,720	10,577	27	844
July	56,813	42,490	13,442	35	846
August	53,323	39,931	12,500	37	854
September	48,103	35,621	11,628	40	814
October	38,417	27,323	10,200	37	856
November	42,926	30,628	11,350	44	904
December	41,533	29,953	10,581	49	950

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.D. Coal: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	18,240,611	13,744,178	4,390,596	7,007	98,829
2010	19,196,315	14,333,496	4,709,686	6,815	146,318
2011	18,074,298	13,551,416	4,399,144	7,263	116,475
2012	15,867,141	11,995,971	3,767,011	6,383	97,775
2013	16,509,468	12,421,537	3,981,216	9,444	97,270
2014	16,472,004	12,217,628	4,154,134	4,344	95,898
2015	14,167,878	10,456,910	3,624,869	3,443	82,656
2016	12,979,911	9,641,625	3,274,103	2,293	61,889
2017	12,606,527	9,328,961	3,219,833	1,914	55,820
2018	12,037,444	9,041,357	2,944,321	1,736	50,029
2019	10,166,309	7,623,281	2,498,944	1,509	42,575
Year 2017					
January	1,200,949	894,562	300,722	238	5,428
February	907,774	677,464	225,239	194	4,876
March	934,820	690,256	239,313	187	5,064
April	849,821	613,913	231,356	117	4,435
May	970,719	724,208	241,926	112	4,473
June	1,125,322	850,061	270,677	127	4,458
July	1,336,227	1,009,439	322,063	148	4,577
August	1,249,577	943,848	301,025	137	4,567
September	1,029,569	752,508	272,541	157	4,363
October	941,498	695,389	241,428	139	4,542
November	950,247	676,718	268,997	162	4,370
December	1,110,004	800,595	304,546	195	4,667
Year 2018					
January	1,244,183	925,236	313,697	231	5,019
February	861,400	642,512	214,188	184	4,516
March	843,941	615,379	223,981	162	4,419
April	764,142	577,004	183,171	133	3,833
May	897,675	675,299	218,106	121	4,149
June	1,069,511	819,784	245,472	114	4,140
July	1,211,799	922,838	284,640	123	4,199
August	1,208,987	915,915	288,894	135	4,044
September	1,014,778	767,264	243,419	138	3,958
October	907,352	675,385	228,441	117	3,409
November	965,757	716,357	245,287	139	3,973
December	1,047,918	788,385	255,025	138	4,371
Year 2019					
January	1,058,823	786,243	268,166	166	4,248
February	838,849	624,443	210,371	154	3,881
March	828,164	600,433	224,131	185	3,415
April	629,315	466,253	159,689	123	3,250
May	763,488	588,629	171,298	105	3,456
June	829,510	636,160	189,866	74	3,409
July	1,063,468	810,341	249,251	98	3,778
August	991,865	759,041	229,009	98	3,717
September	901,139	683,373	214,211	117	3,439
October	705,106	520,520	181,422	118	3,046
November	792,714	583,352	205,856	126	3,380
December	763,869	564,494	195,673	146	3,556

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.1.E. Coal: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	462,674	0	90,867	32,651	339,156
2010	490,931	0	90,184	30,725	370,022
2011	479,822	0	84,855	28,056	366,911
2012	420,923	0	58,275	23,673	338,975
2013	401,108	0	47,677	18,535	334,897
2014	391,550	18,332	37,139	18,805	317,274
2015	356,895	18,640	37,815	13,483	286,956
2016	342,370	51,590	29,330	11,736	249,714
2017	297,521	48,745	24,682	10,284	213,810
2018	278,277	38,513	28,829	9,719	201,217
2019	247,251	33,559	25,686	8,571	179,436
Year 2017					
January	29,761	5,162	2,524	1,194	20,883
February	24,175	3,662	2,172	966	17,375
March	26,114	4,069	2,292	1,125	18,627
April	23,166	3,834	1,753	720	16,859
May	23,095	3,697	1,703	677	17,018
June	23,522	3,737	1,779	678	17,327
July	24,291	4,509	2,038	813	16,931
August	24,587	4,500	2,062	710	17,315
September	22,578	3,663	1,898	748	16,269
October	24,856	3,851	2,040	659	18,307
November	25,263	4,533	1,992	869	17,869
December	26,112	3,527	2,428	1,125	19,031
Year 2018					
January	29,072	4,032	3,117	1,353	20,569
February	25,883	3,681	2,508	1,019	18,675
March	25,351	3,449	2,553	979	18,371
April	22,087	3,256	2,109	800	15,923
May	21,807	3,009	2,249	633	15,916
June	21,792	3,174	2,288	596	15,734
July	21,795	3,202	2,298	663	15,632
August	21,520	3,063	2,255	691	15,512
September	21,039	3,042	1,864	741	15,392
October	19,687	2,697	1,579	682	14,730
November	23,428	2,861	3,081	784	16,702
December	24,814	3,047	2,929	778	18,060
Year 2019					
January	26,507	3,253	3,590	997	18,667
February	23,132	3,102	2,419	931	16,680
March	22,498	3,035	2,448	976	16,039
April	20,420	2,310	2,280	666	15,164
May	18,923	2,002	2,074	622	14,226
June	18,934	2,665	2,087	418	13,763
July	18,828	2,837	2,047	572	13,372
August	19,330	3,116	1,994	610	13,610
September	18,125	2,675	1,600	658	13,192
October	19,298	2,778	1,830	593	14,097
November	20,082	2,812	1,672	716	14,882
December	21,177	2,974	1,646	813	15,744

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.1.F. Coal: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	18,703,284	13,744,178	4,481,463	39,658	437,985
2010	19,687,246	14,333,496	4,799,870	37,540	516,341
2011	18,554,120	13,551,416	4,483,999	35,319	483,385
2012	16,288,063	11,995,971	3,825,286	30,056	436,750
2013	16,910,576	12,421,537	4,028,894	27,979	432,167
2014	16,863,554	12,235,960	4,191,273	23,149	413,173
2015	14,524,773	10,475,551	3,662,685	16,926	369,612
2016	13,322,281	9,693,215	3,303,433	14,029	311,604
2017	12,904,048	9,377,705	3,244,514	12,198	269,630
2018	12,315,720	9,079,870	2,973,150	11,455	251,245
2019	10,413,560	7,656,840	2,524,630	10,080	222,011
Year 2017					
January	1,230,710	899,723	303,245	1,432	26,310
February	931,949	681,127	227,411	1,160	22,251
March	960,934	694,325	241,606	1,312	23,691
April	872,987	617,747	233,109	837	21,294
May	993,814	727,905	243,630	790	21,490
June	1,148,844	853,799	272,456	804	21,785
July	1,360,518	1,013,948	324,101	961	21,508
August	1,274,165	948,348	303,087	847	21,883
September	1,052,147	756,171	274,439	905	20,632
October	966,354	699,240	243,468	798	22,849
November	975,510	681,251	270,989	1,031	22,239
December	1,136,115	804,122	306,975	1,320	23,698
Year 2018					
January	1,273,255	929,268	316,814	1,585	25,589
February	887,284	646,193	216,696	1,203	23,191
March	869,293	618,828	226,534	1,141	22,789
April	786,229	580,260	185,280	933	19,756
May	919,483	678,308	220,355	754	20,065
June	1,091,302	822,958	247,760	710	19,874
July	1,233,595	926,040	286,938	786	19,831
August	1,230,507	918,977	291,149	825	19,556
September	1,035,817	770,306	245,282	879	19,350
October	927,039	678,082	230,020	799	18,139
November	989,185	719,218	248,368	923	20,675
December	1,072,732	791,432	257,954	916	22,431
Year 2019					
January	1,085,331	789,496	271,757	1,163	22,915
February	861,980	627,545	212,790	1,085	20,561
March	850,662	603,468	226,579	1,161	19,453
April	649,735	468,563	161,969	788	18,414
May	782,411	590,631	173,372	726	17,682
June	848,443	638,825	191,954	492	17,173
July	1,082,295	813,178	251,298	669	17,150
August	1,011,195	762,157	231,002	708	17,327
September	919,264	686,047	215,811	775	16,631
October	724,403	523,298	183,252	710	17,143
November	812,796	586,163	207,528	842	18,263
December	785,046	567,469	197,319	959	19,299

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; synthetic coal and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.A. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	43,562	31,847	9,880	184	1,652
2010	40,103	30,806	8,278	164	855
2011	27,326	20,844	5,633	133	716
2012	22,604	17,521	4,110	272	702
2013	23,231	16,827	5,494	328	582
2014	31,531	19,652	10,689	451	739
2015	28,925	18,562	9,473	249	641
2016	22,405	16,137	5,624	108	536
2017	21,696	15,567	5,461	191	476
2018	28,614	18,345	9,467	269	534
2019	20,836	15,677	4,464	251	444
Year 2017					
January	1,901	1,410	425	20	45
February	1,536	1,137	347	12	40
March	1,677	1,342	281	15	38
April	1,508	1,173	288	10	37
May	1,711	1,285	376	15	36
June	1,742	1,296	398	13	35
July	1,600	1,179	371	16	34
August	1,704	1,260	392	18	35
September	1,633	1,205	376	14	39
October	1,706	1,325	328	13	40
November	1,617	1,183	374	15	45
December	3,360	1,772	1,505	31	52
Year 2018					
January	9,468	4,469	4,861	66	72
February	1,451	1,118	270	14	49
March	1,497	1,096	348	12	42
April	1,601	1,169	383	15	34
May	1,863	1,340	463	18	43
June	1,895	1,378	464	18	35
July	1,753	1,216	454	27	56
August	1,870	1,295	516	24	35
September	1,863	1,401	411	18	33
October	1,814	1,368	390	16	40
November	1,799	1,281	452	22	45
December	1,740	1,216	455	20	49
Year 2019					
January	2,506	1,672	755	32	46
February	1,482	1,099	327	15	42
March	1,476	1,159	263	16	38
April	1,417	1,046	313	15	44
May	1,702	1,305	346	17	33
June	1,747	1,369	328	17	33
July	1,818	1,328	436	24	30
August	1,868	1,473	340	21	34
September	1,669	1,305	302	27	35
October	1,709	1,305	347	23	34
November	1,626	1,228	339	23	37
December	1,816	1,388	369	22	37

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.B. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Barrels)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	8,128	0	1,301	293	6,534
2010	4,866	0	1,086	212	3,567
2011	3,826	0	1,004	168	2,654
2012	3,097	0	992	122	1,984
2013	3,456	0	1,050	498	1,908
2014	3,099	64	1,170	216	1,650
2015	3,142	62	1,155	282	1,643
2016	2,277	68	245	245	1,719
2017	2,012	72	220	238	1,482
2018	2,614	103	354	350	1,807
2019	2,162	71	226	419	1,446
Year 2017					
January	198	12	37	36	113
February	136	8	17	23	87
March	151	4	8	26	113
April	141	3	10	12	117
May	137	3	12	14	107
June	120	5	13	10	92
July	117	4	12	13	89
August	119	3	10	14	91
September	134	4	18	11	102
October	143	4	16	13	110
November	242	4	19	19	200
December	373	18	47	46	262
Year 2018					
January	701	58	132	109	402
February	179	4	12	25	138
March	156	3	13	21	118
April	136	3	12	17	104
May	147	4	18	16	109
June	162	5	14	15	128
July	156	3	11	28	114
August	143	4	12	23	104
September	130	7	15	15	93
October	190	5	16	16	153
November	228	3	20	30	174
December	287	3	80	35	169
Year 2019					
January	404	18	42	58	287
February	195	9	22	30	135
March	160	5	18	29	108
April	143	4	16	17	106
May	228	5	16	120	86
June	115	3	16	12	83
July	110	3	12	24	71
August	124	5	11	23	84
September	138	5	20	28	86
October	140	5	18	21	96
November	249	4	17	32	195
December	157	5	16	26	109

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.2.C. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Barrels)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	51,690	31,847	11,181	477	8,185	
2010	44,968	30,806	9,364	376	4,422	
2011	31,152	20,844	6,637	301	3,370	
2012	25,702	17,521	5,102	394	2,685	
2013	26,687	16,827	6,544	826	2,490	
2014	34,630	19,716	11,859	667	2,389	
2015	32,067	18,624	10,629	531	2,283	
2016	24,682	16,205	5,869	352	2,255	
2017	23,708	15,640	5,681	429	1,958	
2018	31,228	18,448	9,820	619	2,341	
2019	22,998	15,748	4,690	670	1,890	
Year 2017						
January	2,099	1,422	462	56	158	
February	1,672	1,146	364	35	127	
March	1,828	1,346	290	41	151	
April	1,650	1,176	298	22	154	
May	1,848	1,288	388	29	143	
June	1,862	1,301	411	23	127	
July	1,717	1,183	383	29	123	
August	1,823	1,263	402	33	125	
September	1,768	1,208	394	24	141	
October	1,849	1,329	344	26	150	
November	1,860	1,187	394	34	245	
December	3,734	1,790	1,552	78	314	
Year 2018						
January	10,169	4,527	4,993	175	474	
February	1,630	1,122	282	39	187	
March	1,653	1,099	361	33	160	
April	1,738	1,172	395	32	138	
May	2,010	1,343	480	34	152	
June	2,057	1,383	478	33	164	
July	1,909	1,219	465	55	170	
August	2,012	1,298	528	46	140	
September	1,993	1,407	426	34	127	
October	2,003	1,373	406	31	193	
November	2,027	1,284	472	52	219	
December	2,027	1,220	534	55	218	
Year 2019						
January	2,911	1,691	797	90	333	
February	1,678	1,108	349	44	177	
March	1,635	1,164	281	44	145	
April	1,560	1,049	329	32	150	
May	1,929	1,311	362	137	119	
June	1,862	1,372	344	29	117	
July	1,928	1,332	448	48	101	
August	1,992	1,478	352	44	118	
September	1,807	1,310	321	54	121	
October	1,848	1,309	365	44	130	
November	1,875	1,231	356	55	232	
December	1,972	1,393	385	48	146	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.D. Petroleum Liquids: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	266,508	196,346	59,277	1,101	9,784
2010	244,114	188,987	49,042	970	5,115
2011	163,954	125,755	33,166	801	4,233
2012	134,956	105,179	24,081	1,618	4,078
2013	139,139	101,217	32,504	2,038	3,380
2014	188,814	118,226	63,488	2,765	4,335
2015	172,884	111,808	55,979	1,482	3,616
2016	133,457	96,967	32,922	639	2,928
2017	128,649	92,975	31,895	1,125	2,654
2018	169,663	109,734	55,433	1,579	2,916
2019	122,591	93,088	25,678	1,466	2,359
Year 2017					
January	11,190	8,387	2,434	117	252
February	9,084	6,751	2,048	70	215
March	9,887	7,958	1,626	88	215
April	8,921	6,984	1,669	58	210
May	10,155	7,684	2,186	86	198
June	10,349	7,786	2,299	75	189
July	9,510	7,060	2,168	94	188
August	10,150	7,562	2,289	107	193
September	9,677	7,215	2,166	79	217
October	10,152	7,961	1,890	79	222
November	9,559	7,050	2,163	89	257
December	20,015	10,576	8,957	184	298
Year 2018					
January	56,277	26,582	28,891	387	416
February	8,576	6,672	1,557	84	263
March	8,849	6,526	2,027	69	227
April	9,497	6,984	2,242	88	183
May	11,024	8,040	2,653	105	226
June	11,266	8,316	2,652	107	191
July	10,412	7,314	2,661	156	280
August	11,110	7,771	3,005	139	196
September	11,112	8,453	2,362	107	190
October	10,729	8,200	2,220	92	217
November	10,637	7,650	2,606	130	251
December	10,173	7,225	2,556	114	278
Year 2019					
January	14,739	9,930	4,366	187	256
February	8,675	6,498	1,866	86	225
March	8,661	6,854	1,510	91	205
April	8,308	6,209	1,785	86	228
May	9,986	7,741	1,975	100	169
June	10,289	8,141	1,876	99	173
July	10,743	7,908	2,538	139	158
August	11,039	8,791	1,945	121	183
September	9,817	7,760	1,716	156	186
October	10,036	7,746	1,972	136	182
November	9,666	7,293	2,041	135	197
December	10,630	8,215	2,088	129	198

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.E. Petroleum Liquids: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	48,912	0	7,557	1,802	39,552
2010	29,243	0	6,402	1,297	21,545
2011	22,799	0	5,927	1,039	15,833
2012	18,233	0	5,871	746	11,616
2013	20,717	0	6,176	3,292	11,248
2014	18,181	395	6,802	1,311	9,672
2015	18,449	379	6,748	1,755	9,568
2016	13,164	395	1,391	1,496	9,882
2017	11,825	405	1,253	1,432	8,736
2018	15,163	598	1,951	2,082	10,533
2019	12,383	403	1,319	2,472	8,189
Year 2017					
January	1,136	70	194	217	654
February	774	36	102	143	493
March	894	23	49	156	666
April	829	17	56	73	683
May	798	19	72	86	622
June	695	27	73	61	533
July	681	19	73	75	514
August	693	18	62	85	528
September	791	20	104	65	603
October	837	22	94	78	643
November	1,471	22	116	114	1,219
December	2,227	111	259	279	1,578
Year 2018					
January	4,121	353	733	645	2,390
February	1,046	26	71	148	801
March	898	17	77	127	677
April	794	17	71	105	601
May	848	20	106	94	628
June	942	28	82	89	743
July	873	18	63	166	625
August	832	21	70	134	608
September	760	38	86	90	546
October	1,104	27	92	94	891
November	1,353	17	120	181	1,035
December	1,592	19	379	208	987
Year 2019					
January	2,342	107	229	341	1,664
February	1,123	50	130	179	764
March	923	28	109	171	614
April	806	20	97	100	589
May	1,299	31	95	700	473
June	649	17	95	74	462
July	626	18	70	142	396
August	699	30	67	134	467
September	786	26	117	164	479
October	800	25	109	121	544
November	1,432	22	103	187	1,121
December	899	29	97	158	615

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.2.F. Petroleum Liquids: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	315,420	196,346	66,834	2,903	49,336	
2010	273,357	188,987	55,444	2,267	26,660	
2011	186,753	125,755	39,093	1,840	20,066	
2012	153,189	105,179	29,952	2,364	15,695	
2013	159,855	101,217	38,681	5,330	14,628	
2014	206,995	118,621	70,291	4,076	14,008	
2015	191,333	112,186	62,727	3,236	13,184	
2016	146,621	97,363	34,313	2,135	12,810	
2017	140,474	93,380	33,148	2,557	11,389	
2018	184,826	110,332	57,383	3,661	13,449	
2019	134,974	93,491	26,998	3,937	10,548	
Year 2017						
January	12,326	8,457	2,628	334	906	
February	9,858	6,788	2,150	212	707	
March	10,781	7,981	1,675	244	881	
April	9,749	7,001	1,725	131	892	
May	10,953	7,703	2,258	172	820	
June	11,045	7,813	2,372	136	723	
July	10,190	7,080	2,241	168	702	
August	10,843	7,580	2,350	192	721	
September	10,468	7,235	2,270	144	819	
October	10,988	7,983	1,984	157	865	
November	11,030	7,072	2,279	203	1,476	
December	22,243	10,687	9,216	464	1,877	
Year 2018						
January	60,398	26,935	29,625	1,032	2,806	
February	9,622	6,697	1,628	232	1,064	
March	9,747	6,543	2,105	195	904	
April	10,291	7,002	2,313	193	784	
May	11,872	8,060	2,759	199	854	
June	12,208	8,344	2,734	196	934	
July	11,284	7,332	2,725	323	905	
August	11,942	7,792	3,074	273	804	
September	11,872	8,491	2,448	198	736	
October	11,834	8,227	2,312	186	1,107	
November	11,990	7,667	2,725	312	1,286	
December	11,765	7,244	2,935	322	1,264	
Year 2019						
January	17,081	10,038	4,595	527	1,921	
February	9,798	6,549	1,996	265	988	
March	9,584	6,883	1,619	263	819	
April	9,114	6,229	1,883	186	816	
May	11,285	7,772	2,070	801	643	
June	10,938	8,159	1,971	173	635	
July	11,369	7,926	2,609	281	554	
August	11,738	8,821	2,011	255	650	
September	10,603	7,786	1,833	319	665	
October	10,836	7,772	2,082	257	725	
November	11,099	7,315	2,144	322	1,318	
December	11,529	8,244	2,185	286	813	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.A. Petroleum Coke: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	4,821	2,761	1,724	1	335	
2010	4,994	3,325	1,354	2	313	
2011	5,012	3,449	1,277	1	286	
2012	3,675	2,105	756	1	812	
2013	4,852	3,409	779	1	662	
2014	4,412	3,440	599	2	371	
2015	4,044	3,120	669	2	253	
2016	4,253	3,427	591	2	233	
2017	3,490	2,731	542	3	214	
2018	3,623	2,740	704	2	177	
2019	2,724	2,067	478	1	177	
Year 2017						
January	368	301	51	0	15	
February	277	217	44	0	15	
March	265	214	31	0	20	
April	168	110	41	0	16	
May	329	264	49	0	16	
June	350	282	48	0	20	
July	344	271	51	0	22	
August	300	226	52	0	22	
September	276	209	50	0	16	
October	228	171	40	0	18	
November	293	234	40	0	18	
December	292	231	44	0	16	
Year 2018						
January	377	296	67	0	14	
February	305	234	60	0	11	
March	255	198	43	0	13	
April	271	193	63	0	15	
May	212	140	58	0	14	
June	338	269	51	0	18	
July	367	284	66	0	17	
August	352	272	66	0	15	
September	325	259	50	0	15	
October	229	158	54	0	16	
November	271	196	63	0	13	
December	321	241	65	0	16	
Year 2019						
January	326	258	54	0	13	
February	272	222	39	0	11	
March	235	193	28	0	13	
April	155	107	32	0	16	
May	294	219	60	0	14	
June	216	151	51	0	14	
July	309	227	58	0	24	
August	276	203	58	0	15	
September	231	183	33	0	15	
October	83	64	3	0	15	
November	129	101	15	0	14	
December	197	137	46	0	14	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.B. Petroleum Coke: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	1,007	0	126	8	873
2010	1,059	0	98	11	950
2011	1,080	0	112	6	962
2012	1,346	0	113	11	1,222
2013	1,486	0	96	11	1,379
2014	1,283	3	90	16	1,174
2015	1,144	9	109	16	1,010
2016	1,099	6	113	9	971
2017	977	11	115	15	836
2018	929	12	93	10	814
2019	839	17	93	6	724
Year 2017					
January	81	0	10	2	70
February	69	0	10	1	58
March	90	1	10	2	77
April	74	0	10	1	63
May	78	1	10	1	66
June	91	1	9	1	80
July	86	1	10	0	75
August	90	2	9	2	77
September	76	1	9	2	64
October	85	1	9	1	74
November	80	1	9	1	69
December	76	1	10	2	63
Year 2018					
January	88	1	9	2	76
February	78	1	8	2	67
March	72	1	9	1	61
April	83	1	10	1	71
May	70	1	6	0	63
June	75	1	1	0	73
July	81	1	9	0	71
August	77	1	9	0	66
September	74	1	7	1	65
October	77	0	9	1	67
November	71	1	8	2	61
December	83	1	8	2	72
Year 2019					
January	73	1	8	2	62
February	66	1	8	1	55
March	73	1	9	1	62
April	71	2	9	1	59
May	70	1	9	0	61
June	70	1	7	0	62
July	76	2	8	0	65
August	69	0	8	0	61
September	79	2	7	0	69
October	64	1	2	0	61
November	57	2	9	0	46
December	72	2	9	1	60

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.C. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector				
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector	
Annual Totals						
2009	5,828	2,761	1,850	9	1,209	
2010	6,053	3,325	1,452	12	1,264	
2011	6,092	3,449	1,388	6	1,248	
2012	5,021	2,105	869	13	2,034	
2013	6,338	3,409	875	12	2,041	
2014	5,695	3,443	689	18	1,545	
2015	5,188	3,128	779	18	1,263	
2016	5,352	3,433	705	10	1,204	
2017	4,467	2,742	657	17	1,050	
2018	4,552	2,752	797	12	991	
2019	3,563	2,083	571	7	900	
Year 2017						
January	449	301	61	2	85	
February	347	218	54	1	74	
March	355	215	41	2	97	
April	241	110	51	1	79	
May	406	265	59	1	82	
June	441	283	57	1	100	
July	430	272	60	0	98	
August	390	228	61	2	99	
September	352	211	60	2	80	
October	314	172	49	2	91	
November	373	235	49	1	87	
December	368	233	54	2	80	
Year 2018						
January	466	297	76	2	90	
February	382	235	68	2	78	
March	327	199	52	2	74	
April	354	195	72	1	86	
May	281	141	63	0	77	
June	413	270	52	0	91	
July	448	285	75	0	88	
August	429	273	75	0	81	
September	399	260	58	1	80	
October	306	159	63	1	83	
November	342	196	70	2	74	
December	404	242	73	2	88	
Year 2019						
January	399	260	62	2	75	
February	338	224	47	1	66	
March	308	194	37	2	75	
April	227	110	41	1	74	
May	364	220	69	0	75	
June	287	152	58	0	76	
July	385	230	66	0	89	
August	346	203	66	0	76	
September	310	185	40	0	84	
October	146	65	5	0	76	
November	186	102	24	0	60	
December	269	139	55	1	74	

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.3.D. Petroleum Coke: Consumption for Electricity Generation,
by Sector, 2009 - 2019 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	136,474	77,919	48,776	32	9,747
2010	141,774	94,331	38,235	44	9,165
2011	144,406	99,257	36,923	20	8,206
2012	105,488	60,862	21,643	39	22,944
2013	138,774	97,626	22,052	38	19,058
2014	123,736	95,642	17,032	59	11,003
2015	113,568	87,210	18,889	58	7,411
2016	118,303	94,892	16,591	47	6,774
2017	94,136	72,919	15,100	72	6,045
2018	100,362	73,895	21,327	57	5,083
2019	74,970	56,411	13,472	37	5,050
Year 2017					
January	9,816	7,962	1,411	9	434
February	7,611	5,942	1,225	6	439
March	7,257	5,813	864	8	573
April	4,481	2,859	1,154	3	466
May	8,922	7,123	1,351	4	444
June	9,520	7,640	1,338	3	539
July	9,185	7,140	1,420	2	623
August	8,115	6,024	1,461	9	620
September	7,540	5,658	1,418	9	455
October	6,092	4,478	1,114	6	494
November	7,861	6,242	1,111	4	504
December	7,735	6,038	1,234	9	454
Year 2018					
January	10,384	7,942	2,030	9	403
February	8,297	6,172	1,814	8	303
March	6,943	5,268	1,282	9	384
April	7,506	5,193	1,892	3	418
May	5,886	3,704	1,757	0	425
June	9,342	7,272	1,553	0	517
July	10,232	7,741	2,003	0	488
August	9,875	7,469	1,984	0	422
September	9,022	7,059	1,515	4	443
October	6,353	4,237	1,638	5	472
November	7,587	5,320	1,900	9	358
December	8,935	6,517	1,958	10	449
Year 2019					
January	8,808	6,917	1,522	10	359
February	7,433	6,030	1,079	7	316
March	6,367	5,167	810	8	382
April	4,444	3,063	904	7	469
May	8,002	5,898	1,688	0	416
June	6,199	4,342	1,448	0	409
July	8,365	6,078	1,623	0	664
August	7,657	5,605	1,626	0	427
September	6,427	5,076	941	0	411
October	2,236	1,716	98	0	422
November	3,682	2,867	433	0	382
December	5,350	3,653	1,299	4	394

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.E. Petroleum Coke: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	29,974	0	3,652	213	26,109
2010	31,303	0	2,855	296	28,152
2011	31,943	0	3,244	153	28,546
2012	38,777	0	3,281	315	35,181
2013	40,846	0	2,769	305	37,772
2014	36,602	90	2,597	449	33,467
2015	33,138	255	3,167	446	29,269
2016	32,473	159	3,255	241	28,817
2017	28,680	297	3,335	403	24,645
2018	27,398	332	2,693	284	24,088
2019	24,348	470	2,681	164	21,032
Year 2017					
January	2,369	5	279	53	2,032
February	2,059	11	273	31	1,744
March	2,628	17	298	46	2,268
April	2,201	3	288	15	1,895
May	2,295	20	295	20	1,960
June	2,638	24	274	14	2,326
July	2,528	32	275	10	2,211
August	2,676	56	270	55	2,295
September	2,244	31	265	52	1,896
October	2,534	26	276	35	2,197
November	2,320	35	257	21	2,007
December	2,187	36	286	50	1,815
Year 2018					
January	2,579	36	275	51	2,217
February	2,283	24	230	44	1,984
March	2,135	27	255	39	1,815
April	2,419	39	277	16	2,087
May	2,113	24	167	0	1,922
June	2,229	31	38	0	2,160
July	2,400	31	255	0	2,114
August	2,280	29	261	0	1,990
September	2,213	23	211	25	1,954
October	2,309	11	260	23	2,015
November	2,053	26	227	42	1,757
December	2,386	31	237	45	2,073
Year 2019					
January	2,121	33	224	48	1,815
February	1,906	37	235	27	1,607
March	2,129	27	249	37	1,817
April	2,108	73	257	33	1,746
May	2,059	15	248	0	1,796
June	2,056	24	209	0	1,822
July	2,178	72	221	0	1,885
August	1,985	6	239	0	1,740
September	2,277	64	208	0	2,005
October	1,842	17	61	0	1,764
November	1,641	43	263	0	1,335
December	2,045	60	268	18	1,699

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.3.F. Petroleum Coke: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	166,449	77,919	52,428	245	35,856
2010	173,078	94,331	41,090	340	37,317
2011	176,349	99,257	40,167	173	36,752
2012	144,266	60,862	24,925	353	58,126
2013	179,621	97,626	24,821	343	56,831
2014	160,338	95,731	19,629	508	44,470
2015	146,706	87,465	22,056	505	36,680
2016	150,776	95,051	19,846	288	35,591
2017	122,816	73,216	18,435	475	30,690
2018	127,760	74,227	24,020	341	29,171
2019	99,318	56,881	16,153	201	26,083
Year 2017					
January	12,185	7,967	1,690	63	2,466
February	9,671	5,953	1,498	37	2,183
March	9,885	5,829	1,161	54	2,841
April	6,682	2,862	1,442	18	2,361
May	11,217	7,144	1,646	24	2,404
June	12,158	7,664	1,612	17	2,865
July	11,712	7,172	1,695	11	2,834
August	10,791	6,080	1,731	65	2,915
September	9,784	5,690	1,683	61	2,350
October	8,626	4,503	1,390	41	2,691
November	10,181	6,276	1,368	26	2,511
December	9,922	6,074	1,521	58	2,269
Year 2018					
January	12,964	7,978	2,305	60	2,621
February	10,580	6,196	2,045	52	2,287
March	9,078	5,295	1,536	48	2,199
April	9,926	5,233	2,169	19	2,505
May	7,999	3,728	1,925	0	2,346
June	11,571	7,303	1,591	0	2,677
July	12,632	7,773	2,258	0	2,602
August	12,155	7,498	2,244	0	2,413
September	11,234	7,082	1,726	29	2,397
October	8,662	4,248	1,898	28	2,487
November	9,640	5,346	2,127	51	2,116
December	11,321	6,548	2,195	55	2,522
Year 2019					
January	10,929	6,950	1,746	59	2,174
February	9,339	6,067	1,315	34	1,924
March	8,496	5,194	1,058	46	2,198
April	6,552	3,136	1,161	41	2,215
May	10,060	5,913	1,936	0	2,211
June	8,255	4,366	1,657	0	2,232
July	10,543	6,150	1,844	0	2,549
August	9,642	5,611	1,864	0	2,167
September	8,704	5,139	1,148	0	2,416
October	4,078	1,733	159	0	2,187
November	5,323	2,910	696	0	1,717
December	7,395	3,712	1,567	23	2,093

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

See the Technical Notes for fuel conversion factors.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.4.A. Natural Gas: Consumption for Electricity Generation,
by Sector, 2009 - 2019 (Million Cubic Feet)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	7,121,069	2,911,279	3,655,712	34,279	519,799
2010	7,680,185	3,290,993	3,794,423	39,462	555,307
2011	7,883,865	3,446,087	3,819,107	47,170	571,501
2012	9,484,710	4,101,927	4,686,260	63,116	633,407
2013	8,596,299	3,970,447	3,917,131	66,570	642,152
2014	8,544,387	3,895,008	3,954,032	71,957	623,390
2015	10,016,576	4,745,255	4,576,683	70,092	624,545
2016	10,170,110	5,018,894	4,571,375	46,304	533,537
2017	9,508,062	4,754,893	4,161,984	50,060	541,126
2018	10,833,043	5,551,181	4,663,935	52,650	565,276
2019	11,601,600	5,969,422	4,958,798	55,575	617,805
Year 2017					
January	680,323	337,744	291,564	4,242	46,773
February	588,021	292,116	250,305	3,800	41,801
March	690,819	351,273	290,929	4,062	44,554
April	647,308	331,864	268,629	3,561	43,255
May	720,158	374,092	298,415	3,835	43,816
June	872,286	435,724	386,279	4,378	45,904
July	1,104,270	552,590	497,819	4,912	48,948
August	1,043,343	516,908	474,369	4,804	47,262
September	877,043	432,895	397,619	4,352	42,177
October	791,359	385,130	358,651	4,091	43,488
November	686,661	340,219	298,198	3,766	44,478
December	806,472	404,337	349,206	4,257	48,671
Year 2018					
January	805,929	425,891	327,351	4,145	48,542
February	706,517	363,824	296,296	3,886	42,511
March	772,448	395,826	329,151	4,071	43,400
April	722,667	372,401	303,383	3,616	43,268
May	868,518	459,568	359,038	4,201	45,712
June	973,956	520,305	402,054	4,633	46,963
July	1,245,648	639,299	549,546	5,518	51,285
August	1,208,900	605,610	546,123	5,593	51,575
September	1,051,922	530,570	468,776	4,838	47,737
October	909,338	457,374	400,338	4,290	47,335
November	784,673	395,480	337,321	3,760	48,112
December	782,527	385,034	344,559	4,098	48,836
Year 2019					
January	873,321	441,671	373,529	4,566	53,555
February	801,111	411,897	338,638	4,217	46,359
March	835,730	431,601	350,686	4,516	48,926
April	762,597	398,966	313,343	4,173	46,115
May	863,169	458,759	350,386	4,217	49,806
June	1,016,521	538,873	422,755	4,619	50,274
July	1,283,658	657,397	566,007	5,625	54,630
August	1,305,990	676,294	568,683	5,493	55,519
September	1,108,966	572,673	478,814	4,824	52,654
October	964,547	493,811	414,452	4,356	51,926
November	846,614	423,092	366,212	4,253	53,057
December	939,376	464,388	415,293	4,715	54,981

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.B. Natural Gas: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	816,787	0	305,542	41,275	469,970
2010	821,775	0	301,769	46,324	473,683
2011	839,681	0	308,669	39,856	491,155
2012	886,103	0	322,607	47,883	515,613
2013	882,385	0	303,177	51,057	528,151
2014	865,146	4,926	292,016	46,635	521,569
2015	935,098	8,060	283,372	46,287	597,379
2016	1,151,866	38,096	356,905	80,943	675,922
2017	1,168,544	38,740	309,949	104,324	715,532
2018	1,205,962	43,156	331,952	81,856	748,997
2019	1,196,025	42,645	317,231	79,734	756,415
Year 2017					
January	101,549	3,706	27,280	9,873	60,690
February	90,407	3,220	23,641	8,410	55,135
March	97,294	3,494	27,032	8,162	58,606
April	89,369	2,988	23,820	6,875	55,687
May	91,989	3,096	24,254	7,268	57,371
June	95,015	2,718	25,783	8,423	58,091
July	103,478	3,437	27,754	9,924	62,363
August	101,700	3,212	27,478	9,947	61,063
September	97,286	2,968	25,062	8,898	60,357
October	97,642	3,045	25,404	8,648	60,544
November	95,784	3,124	24,761	8,412	59,488
December	107,031	3,731	27,680	9,485	66,136
Year 2018					
January	107,213	3,929	28,934	7,417	66,933
February	94,793	3,366	26,629	6,706	58,093
March	100,213	3,557	28,088	6,844	61,724
April	92,932	2,942	25,265	6,133	58,592
May	94,707	3,306	26,238	6,099	59,064
June	97,016	3,642	26,642	6,537	60,196
July	107,003	4,484	30,339	7,649	64,531
August	105,929	4,079	29,861	7,691	64,297
September	99,289	3,479	27,089	6,581	62,140
October	99,045	3,013	27,218	6,411	62,402
November	101,846	3,185	27,080	6,829	64,751
December	105,976	4,174	28,570	6,959	66,273
Year 2019					
January	108,272	3,951	29,369	7,409	67,543
February	97,224	3,804	24,972	6,793	61,656
March	101,583	3,690	27,549	6,684	63,661
April	91,878	2,748	24,623	6,027	58,480
May	94,224	2,863	24,079	5,727	61,556
June	95,837	3,342	25,592	6,130	60,772
July	102,404	3,983	27,280	7,354	63,786
August	104,051	4,098	28,829	6,950	64,175
September	97,399	3,762	25,526	6,377	61,734
October	96,976	2,931	25,473	6,171	62,402
November	100,030	3,527	26,036	6,628	63,839
December	106,147	3,946	27,902	7,486	66,812

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.C. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	7,937,856	2,911,279	3,961,254	75,555	989,769
2010	8,501,960	3,290,993	4,096,192	85,786	1,028,990
2011	8,723,546	3,446,087	4,127,777	87,026	1,062,657
2012	10,370,812	4,101,927	5,008,867	110,999	1,149,020
2013	9,478,685	3,970,447	4,220,309	117,626	1,170,303
2014	9,409,532	3,899,934	4,246,048	118,591	1,144,959
2015	10,951,674	4,753,315	4,860,055	116,380	1,221,924
2016	11,321,975	5,056,990	4,928,280	127,246	1,209,459
2017	10,676,606	4,793,632	4,471,933	154,383	1,256,658
2018	12,039,005	5,594,338	4,995,888	134,507	1,314,273
2019	12,797,626	6,012,067	5,276,029	135,310	1,374,220
Year 2017					
January	781,872	341,450	318,844	14,114	107,463
February	678,428	295,336	273,946	12,210	96,936
March	788,112	354,767	317,961	12,224	103,160
April	736,677	334,851	292,448	10,435	98,942
May	812,147	377,189	322,669	11,102	101,187
June	967,301	438,443	412,062	12,802	103,994
July	1,207,748	556,028	525,573	14,836	111,310
August	1,145,043	520,120	501,847	14,751	108,326
September	974,328	435,863	422,681	13,250	102,535
October	889,001	388,175	384,055	12,739	104,032
November	782,445	343,343	322,959	12,177	103,966
December	913,503	408,068	376,887	13,742	114,807
Year 2018					
January	913,142	429,820	356,285	11,562	115,475
February	801,310	367,190	322,924	10,592	100,604
March	872,661	399,383	357,239	10,914	105,124
April	815,600	375,343	328,647	9,750	101,860
May	963,226	462,873	385,276	10,300	104,776
June	1,070,972	523,947	428,696	11,170	107,159
July	1,352,652	643,783	579,885	13,167	115,816
August	1,314,829	609,689	575,984	13,285	115,872
September	1,151,210	534,049	495,866	11,419	109,877
October	1,008,383	460,387	427,556	10,702	109,738
November	886,519	398,665	364,401	10,589	112,863
December	888,503	389,208	373,128	11,058	115,109
Year 2019					
January	981,593	445,621	402,898	11,975	121,099
February	898,335	415,700	363,610	11,010	108,015
March	937,313	435,291	378,235	11,200	112,587
April	854,475	401,714	337,966	10,200	104,595
May	957,393	461,622	374,465	9,944	111,362
June	1,112,358	542,215	448,347	10,749	111,046
July	1,386,062	661,380	593,287	12,979	118,416
August	1,410,041	680,392	597,512	12,443	119,694
September	1,206,364	576,435	504,340	11,201	114,389
October	1,061,523	496,742	439,925	10,527	114,328
November	946,645	426,619	392,248	10,881	116,896
December	1,045,523	468,333	443,195	12,201	121,793

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.4.D. Natural Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	7,301,522	2,981,285	3,750,080	35,046	535,111
2010	7,852,665	3,359,035	3,882,995	40,356	570,279
2011	8,052,309	3,511,732	3,906,484	48,509	585,584
2012	9,696,575	4,179,725	4,802,741	64,987	649,122
2013	8,813,288	4,059,838	4,026,793	67,918	658,740
2014	8,795,303	4,001,826	4,076,787	74,194	642,495
2015	10,360,990	4,905,009	4,739,438	71,929	644,615
2016	10,515,826	5,189,543	4,728,444	47,550	550,288
2017	9,827,794	4,911,629	4,308,241	51,592	556,331
2018	11,191,452	5,730,408	4,825,957	54,390	580,696
2019	11,996,976	6,166,728	5,137,826	57,028	635,394
Year 2017					
January	703,875	349,666	302,008	4,368	47,833
February	607,776	301,718	259,154	3,915	42,989
March	713,669	362,690	301,014	4,188	45,776
April	668,682	342,733	277,802	3,669	44,479
May	743,595	386,053	308,547	3,934	45,060
June	901,473	450,067	399,664	4,508	47,234
July	1,142,502	571,579	515,481	5,060	50,383
August	1,079,042	534,306	491,131	4,951	48,654
September	907,689	447,592	412,178	4,490	43,429
October	817,248	397,175	371,168	4,220	44,685
November	708,836	350,721	308,473	3,889	45,753
December	833,407	417,330	361,621	4,400	50,056
Year 2018					
January	832,763	439,632	338,891	4,297	49,943
February	729,643	375,307	306,626	4,024	43,685
March	798,583	408,805	341,003	4,213	44,562
April	745,888	383,881	313,808	3,744	44,456
May	896,969	474,489	371,190	4,322	46,968
June	1,005,861	536,851	415,986	4,775	48,249
July	1,286,597	660,362	567,947	5,689	52,598
August	1,248,419	625,212	564,433	5,775	52,999
September	1,087,420	548,304	485,082	5,011	49,023
October	939,342	471,956	414,310	4,446	48,630
November	810,660	407,831	349,539	3,876	49,415
December	809,307	397,779	357,144	4,217	50,168
Year 2019					
January	901,900	455,045	387,180	4,684	54,991
February	827,416	424,560	350,869	4,326	47,662
March	862,791	444,842	363,075	4,635	50,238
April	787,711	412,207	323,855	4,288	47,361
May	890,239	472,669	362,071	4,323	51,176
June	1,049,852	556,057	437,389	4,738	51,668
July	1,328,690	680,354	586,332	5,762	56,242
August	1,353,214	700,522	589,832	5,629	57,230
September	1,147,718	591,980	496,535	4,954	54,249
October	997,755	510,360	429,551	4,473	53,371
November	876,616	437,601	380,018	4,370	54,627
December	973,075	480,530	431,121	4,845	56,579

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.E. Natural Gas: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	836,863	0	312,553	42,032	482,279
2010	841,521	0	308,246	47,001	486,274
2011	861,006	0	315,411	40,976	504,619
2012	909,087	0	330,354	48,944	529,788
2013	905,583	0	311,058	51,939	542,587
2014	891,994	5,033	300,870	47,579	538,514
2015	965,573	8,254	292,629	47,573	617,118
2016	1,188,399	39,123	367,919	83,938	697,418
2017	1,204,582	39,828	318,611	107,987	738,156
2018	1,242,771	44,393	341,707	85,108	771,563
2019	1,232,925	43,862	327,203	82,455	779,405
Year 2017					
January	104,758	3,813	28,045	10,223	62,676
February	93,160	3,310	24,273	8,706	56,871
March	100,229	3,588	27,763	8,440	60,438
April	92,042	3,069	24,463	7,102	57,408
May	94,753	3,181	24,908	7,500	59,164
June	97,955	2,795	26,507	8,718	59,935
July	106,716	3,537	28,533	10,280	64,365
August	104,854	3,308	28,247	10,300	63,000
September	100,432	3,053	25,827	9,217	62,336
October	100,639	3,126	26,136	8,955	62,422
November	98,711	3,206	25,452	8,716	61,336
December	110,333	3,842	28,457	9,829	68,204
Year 2018					
January	110,628	4,042	29,790	7,723	69,074
February	97,708	3,459	27,364	6,975	59,910
March	103,291	3,651	28,924	7,105	63,610
April	95,684	3,016	25,979	6,378	60,311
May	97,553	3,393	26,998	6,338	60,824
June	99,927	3,741	27,426	6,796	61,964
July	110,227	4,625	31,245	7,946	66,410
August	109,218	4,214	30,755	7,989	66,261
September	102,279	3,587	27,861	6,855	63,976
October	102,003	3,095	27,963	6,679	64,267
November	104,969	3,272	27,893	7,097	66,706
December	109,284	4,299	29,508	7,228	68,250
Year 2019					
January	111,586	4,062	30,283	7,654	69,588
February	100,131	3,910	25,665	7,015	63,541
March	104,540	3,780	28,320	6,904	65,536
April	94,549	2,814	25,348	6,231	60,157
May	96,983	2,936	24,765	5,921	63,360
June	98,713	3,437	26,357	6,342	62,577
July	105,625	4,109	28,188	7,602	65,726
August	107,481	4,228	29,837	7,188	66,227
September	100,509	3,875	26,356	6,603	63,675
October	100,070	3,008	26,323	6,391	64,347
November	103,186	3,633	26,907	6,865	65,781
December	109,550	4,069	28,852	7,739	68,889

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.4.F. Natural Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	8,138,385	2,981,285	4,062,633	77,077	1,017,390
2010	8,694,186	3,359,035	4,191,241	87,357	1,056,553
2011	8,913,315	3,511,732	4,221,895	89,485	1,090,203
2012	10,605,661	4,179,725	5,133,095	113,932	1,178,910
2013	9,718,871	4,059,838	4,337,851	119,857	1,201,326
2014	9,687,297	4,006,859	4,377,657	121,773	1,181,009
2015	11,326,564	4,913,263	5,032,066	119,502	1,261,732
2016	11,704,224	5,228,667	5,096,363	131,489	1,247,706
2017	11,032,375	4,951,457	4,626,852	159,580	1,294,487
2018	12,434,223	5,774,801	5,167,665	139,498	1,352,259
2019	13,229,901	6,210,590	5,465,029	139,483	1,414,799
Year 2017					
January	808,633	353,479	330,054	14,591	110,509
February	700,936	305,028	283,427	12,621	99,860
March	813,898	366,278	328,777	12,628	106,215
April	760,724	345,802	302,264	10,771	101,886
May	838,347	389,234	333,454	11,435	104,225
June	999,428	452,862	426,171	13,226	107,168
July	1,249,218	575,116	544,014	15,340	114,748
August	1,183,897	537,613	519,378	15,251	111,654
September	1,008,121	450,644	438,005	13,706	105,765
October	917,888	400,301	397,304	13,175	107,108
November	807,547	353,926	333,925	12,606	107,089
December	943,740	421,172	390,078	14,229	118,260
Year 2018					
January	943,391	443,674	368,681	12,020	119,017
February	827,351	378,767	333,990	10,999	103,595
March	901,874	412,456	369,928	11,318	108,172
April	841,572	386,896	339,787	10,121	104,768
May	994,522	477,882	398,187	10,660	107,792
June	1,105,788	540,592	443,412	11,572	110,213
July	1,396,824	664,987	599,192	13,636	119,009
August	1,357,638	629,426	595,188	13,764	119,260
September	1,189,699	551,891	512,943	11,866	112,999
October	1,041,345	475,051	442,273	11,125	112,896
November	915,629	411,103	377,431	10,973	116,121
December	918,591	402,077	386,652	11,444	118,418
Year 2019					
January	1,013,486	459,106	417,463	12,338	124,578
February	927,548	428,469	376,534	11,341	111,203
March	967,331	448,623	391,394	11,540	115,774
April	882,261	415,021	349,203	10,518	107,518
May	987,221	475,605	386,836	10,244	114,536
June	1,148,565	559,494	463,746	11,080	114,245
July	1,434,315	684,463	614,520	13,363	121,968
August	1,460,694	704,751	619,669	12,817	123,457
September	1,248,228	595,855	522,891	11,557	117,924
October	1,097,826	513,369	455,874	10,864	117,718
November	979,802	441,234	406,924	11,235	120,409
December	1,082,625	484,600	459,973	12,584	125,468

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.5.D. Wood / Wood Waste Biomass: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	320,444	29,565	130,894	274	159,712
2010	349,530	40,167	137,072	274	172,016
2011	347,623	35,474	130,108	482	181,559
2012	390,342	32,723	138,217	478	218,924
2013	397,929	43,363	143,721	536	210,308
2014	431,285	45,643	174,513	961	210,167
2015	406,650	43,919	171,387	504	190,840
2016	359,983	41,036	149,516	473	168,959
2017	363,646	42,806	151,877	460	168,503
2018	361,703	45,856	143,288	520	172,039
2019	338,317	42,240	128,980	583	166,514
Year 2017					
January	31,076	4,492	12,650	56	13,878
February	28,393	3,584	11,989	50	12,771
March	31,265	4,210	13,446	26	13,584
April	27,467	3,136	11,064	34	13,232
May	28,262	2,799	11,620	43	13,800
June	30,235	3,180	12,595	38	14,422
July	32,592	3,942	13,504	41	15,105
August	33,309	3,803	14,250	41	15,214
September	28,549	2,090	13,002	15	13,442
October	28,927	3,387	11,786	33	13,720
November	30,409	3,608	12,597	41	14,163
December	33,163	4,575	13,373	43	15,172
Year 2018					
January	33,136	4,713	13,790	63	14,571
February	28,906	3,689	12,141	42	13,033
March	31,435	4,501	12,243	36	14,655
April	26,860	2,966	10,597	16	13,280
May	29,530	3,196	11,683	32	14,619
June	31,205	3,909	12,733	53	14,509
July	33,490	4,670	13,260	59	15,501
August	32,186	4,427	12,624	69	15,067
September	28,704	3,340	11,278	52	14,034
October	27,972	3,376	10,642	27	13,927
November	28,539	3,741	10,733	20	14,044
December	29,741	3,326	11,563	51	14,801
Year 2019					
January	31,330	4,132	12,533	52	14,613
February	26,761	3,408	10,117	57	13,179
March	28,083	3,232	10,362	72	14,418
April	23,804	2,677	8,499	24	12,604
May	26,723	3,451	10,257	18	12,997
June	27,518	2,894	10,815	31	13,778
July	31,373	4,740	11,694	101	14,838
August	31,913	5,205	11,694	63	14,951
September	28,163	3,594	11,078	51	13,440
October	26,246	2,962	9,729	42	13,513
November	26,964	2,194	11,052	35	13,684
December	29,438	3,751	11,151	37	14,500

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.5.E. Wood / Wood Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	816,285	0	19,587	1,135	795,563
2010	876,041	0	18,357	1,064	856,620
2011	893,314	0	16,577	1,022	875,716
2012	883,158	0	19,251	949	862,958
2013	919,631	0	20,342	950	898,339
2014	946,344	8,835	22,262	3,766	911,481
2015	943,962	9,351	19,200	3,714	911,697
2016	969,841	10,950	22,905	4,520	931,465
2017	939,633	11,656	22,986	4,522	900,469
2018	929,365	10,297	21,623	4,806	892,639
2019	907,420	3,564	25,740	4,969	873,147
Year 2017					
January	81,329	1,206	2,090	525	77,508
February	74,084	1,037	1,879	430	70,738
March	80,057	1,170	2,113	299	76,475
April	74,348	1,044	1,548	295	71,461
May	75,155	716	1,623	301	72,516
June	78,685	1,007	1,641	322	75,716
July	80,804	683	1,963	355	77,803
August	81,948	989	2,010	365	78,585
September	73,629	931	2,032	233	70,432
October	77,295	893	1,972	402	74,028
November	78,977	902	1,929	473	75,674
December	83,321	1,079	2,186	524	79,532
Year 2018					
January	81,175	844	2,115	454	77,762
February	73,007	878	2,141	474	69,514
March	78,989	948	1,966	493	75,583
April	73,967	869	1,533	339	71,225
May	77,198	673	1,679	319	74,528
June	75,544	655	1,683	402	72,805
July	80,237	991	1,899	382	76,964
August	79,868	854	1,930	417	76,667
September	73,254	655	1,676	336	70,587
October	76,266	1,005	1,607	329	73,326
November	76,373	891	1,635	343	73,503
December	83,486	1,033	1,759	518	80,175
Year 2019					
January	81,039	449	2,361	544	77,685
February	73,341	412	2,142	478	70,309
March	77,242	410	2,134	436	74,262
April	72,647	421	2,095	344	69,788
May	74,589	127	2,256	356	71,850
June	73,406	186	2,365	342	70,512
July	76,941	286	2,031	403	74,220
August	77,355	190	2,179	398	74,588
September	72,370	117	2,067	394	69,791
October	74,506	233	1,711	423	72,140
November	75,571	346	2,122	442	72,662
December	78,415	386	2,277	410	75,342

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.5.F. Wood / Wood Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	1,136,729	29,565	150,481	1,408	955,276
2010	1,225,571	40,167	155,429	1,338	1,028,637
2011	1,240,937	35,474	146,684	1,504	1,057,275
2012	1,273,500	32,723	157,468	1,427	1,081,882
2013	1,317,560	43,363	164,063	1,486	1,108,647
2014	1,377,629	54,478	196,775	4,727	1,121,648
2015	1,350,612	53,269	190,587	4,219	1,102,537
2016	1,329,824	51,986	172,421	4,993	1,100,424
2017	1,303,279	54,462	174,862	4,982	1,068,972
2018	1,291,068	56,153	164,911	5,326	1,064,678
2019	1,245,737	45,804	154,720	5,552	1,039,661
Year 2017					
January	112,404	5,698	14,740	581	91,385
February	102,477	4,621	13,868	480	83,508
March	111,322	5,380	15,559	325	90,059
April	101,815	4,180	12,612	328	84,694
May	103,417	3,515	13,243	344	86,316
June	108,920	4,187	14,235	360	90,138
July	113,396	4,625	15,468	395	92,908
August	115,257	4,792	16,260	406	93,800
September	102,178	3,021	15,034	249	83,874
October	106,222	4,281	13,758	435	87,748
November	109,386	4,509	14,526	514	89,837
December	116,483	5,654	15,558	566	94,705
Year 2018					
January	114,312	5,557	15,905	517	92,333
February	101,913	4,567	14,282	516	82,547
March	110,425	5,449	14,209	528	90,238
April	100,826	3,835	12,131	356	84,505
May	106,728	3,869	13,362	351	89,146
June	106,749	4,564	14,416	455	87,314
July	113,727	5,661	15,160	441	92,465
August	112,054	5,281	14,554	486	91,733
September	101,958	3,995	12,954	388	84,621
October	104,238	4,381	12,248	356	87,253
November	104,912	4,633	12,368	363	87,548
December	113,227	4,360	13,322	569	94,976
Year 2019					
January	112,369	4,581	14,894	596	92,297
February	100,102	3,820	12,259	535	83,488
March	105,325	3,641	12,496	508	88,680
April	96,451	3,098	10,594	368	82,392
May	101,311	3,578	12,513	374	84,847
June	100,924	3,081	13,179	373	84,291
July	108,314	5,026	13,725	505	89,058
August	109,267	5,395	13,873	461	89,539
September	100,533	3,712	13,145	446	83,230
October	100,752	3,195	11,441	464	85,652
November	102,536	2,540	13,174	477	86,345
December	107,853	4,138	13,428	447	89,841

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.A. Landfill Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	206,792	19,583	180,689	5,931	589
2010	218,331	19,975	192,428	5,535	393
2011	232,795	22,086	180,856	29,469	384
2012	256,376	25,193	201,965	26,672	2,545
2013	271,967	27,259	211,942	28,143	4,623
2014	285,982	25,819	228,447	27,038	4,678
2015	282,530	25,257	227,381	25,250	4,642
2016	273,557	24,280	224,993	20,445	3,839
2017	278,112	25,074	229,050	20,121	3,866
2018	270,235	23,580	223,513	19,790	3,352
2019	257,494	22,726	214,819	16,874	3,075
Year 2017					
January	24,099	2,197	19,771	1,785	346
February	21,927	2,063	17,956	1,570	337
March	24,031	2,237	19,679	1,754	361
April	22,649	2,155	18,538	1,627	330
May	23,637	2,240	19,409	1,696	292
June	23,095	1,955	19,137	1,666	336
July	23,176	1,905	19,286	1,705	280
August	23,354	2,006	19,340	1,702	306
September	22,287	1,901	18,440	1,654	293
October	22,352	2,047	18,534	1,450	321
November	23,123	2,141	18,950	1,706	327
December	24,383	2,228	20,011	1,806	338
Year 2018					
January	23,568	2,389	19,205	1,673	301
February	22,069	2,186	17,993	1,576	314
March	23,672	2,377	19,280	1,692	324
April	22,281	2,159	18,159	1,633	330
May	22,748	2,125	18,722	1,609	291
June	21,854	1,777	18,189	1,607	281
July	22,507	1,817	18,773	1,651	266
August	23,061	1,739	19,377	1,696	249
September	20,472	1,604	17,004	1,643	222
October	22,360	1,779	18,634	1,687	259
November	22,405	1,812	18,708	1,630	255
December	23,237	1,815	19,468	1,695	259
Year 2019					
January	22,792	2,043	18,790	1,704	255
February	20,542	1,803	16,998	1,508	233
March	22,380	2,008	18,459	1,642	271
April	20,457	1,890	17,249	1,057	261
May	20,947	1,952	17,959	778	258
June	21,359	1,857	17,889	1,360	254
July	21,932	1,873	18,326	1,493	240
August	21,963	1,898	18,295	1,518	253
September	20,789	1,811	17,246	1,477	256
October	21,252	1,843	17,705	1,436	268
November	20,712	1,807	17,237	1,419	248
December	22,369	1,942	18,665	1,482	280

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.B. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Million Cubic Feet)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	793	0	545	176	72
2010	1,623	0	1,195	370	58
2011	3,195	0	2,753	351	91
2012	3,189	0	2,788	340	61
2013	831	0	261	423	147
2014	1,710	176	525	674	335
2015	1,522	2	644	515	362
2016	4,163	3	2,339	1,034	788
2017	3,940	2	1,948	1,099	891
2018	3,621	0	1,867	911	843
2019	3,570	5	1,933	820	812
Year 2017					
January	352	0	171	94	86
February	332	0	159	92	81
March	351	0	174	92	84
April	346	0	153	107	87
May	296	0	131	85	80
June	329	0	165	89	75
July	313	0	177	85	51
August	351	0	175	98	78
September	330	0	170	98	62
October	319	0	170	93	56
November	296	0	138	85	74
December	324	0	166	81	77
Year 2018					
January	321	0	176	68	77
February	320	0	165	79	77
March	340	0	175	82	83
April	335	0	164	85	86
May	285	0	140	71	74
June	259	0	146	46	68
July	278	0	139	76	64
August	302	0	157	82	63
September	290	0	150	82	58
October	334	0	170	95	69
November	276	0	134	73	68
December	280	0	152	71	57
Year 2019					
January	331	0	181	84	66
February	301	0	175	67	58
March	357	0	203	80	73
April	362	0	184	102	75
May	250	0	112	64	74
June	283	0	146	77	59
July	282	0	166	42	73
August	267	0	128	73	65
September	264	0	125	74	65
October	317	0	168	77	71
November	284	0	155	59	70
December	273	0	190	21	62

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.C. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Million Cubic Feet)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	207,585	19,583	181,234	6,106	661
2010	219,954	19,975	193,623	5,905	451
2011	235,990	22,086	183,609	29,820	474
2012	259,564	25,193	204,753	27,012	2,606
2013	272,798	27,259	212,203	28,566	4,770
2014	287,692	25,995	228,971	27,713	5,013
2015	284,052	25,259	228,024	25,765	5,004
2016	277,720	24,283	227,332	21,479	4,626
2017	282,051	25,076	230,998	21,220	4,757
2018	273,856	23,580	225,380	20,701	4,196
2019	261,064	22,731	216,753	17,694	3,887
Year 2017					
January	24,451	2,197	19,942	1,880	432
February	22,259	2,063	18,116	1,662	418
March	24,382	2,237	19,853	1,846	445
April	22,995	2,155	18,690	1,734	417
May	23,933	2,240	19,539	1,781	372
June	23,423	1,955	19,302	1,754	411
July	23,489	1,905	19,463	1,789	331
August	23,704	2,006	19,515	1,800	383
September	22,617	1,901	18,609	1,752	355
October	22,670	2,047	18,704	1,543	377
November	23,419	2,141	19,088	1,791	400
December	24,707	2,228	20,176	1,887	415
Year 2018					
January	23,890	2,389	19,382	1,741	378
February	22,390	2,186	18,158	1,655	390
March	24,012	2,377	19,455	1,774	407
April	22,616	2,159	18,323	1,718	416
May	23,033	2,125	18,862	1,680	366
June	22,113	1,777	18,335	1,652	349
July	22,785	1,817	18,912	1,726	330
August	23,363	1,739	19,534	1,778	313
September	20,763	1,604	17,154	1,725	280
October	22,694	1,779	18,804	1,783	328
November	22,681	1,812	18,842	1,703	324
December	23,516	1,815	19,620	1,766	316
Year 2019					
January	23,123	2,043	18,971	1,788	321
February	20,843	1,804	17,173	1,576	291
March	22,737	2,008	18,662	1,722	344
April	20,819	1,891	17,433	1,159	336
May	21,197	1,952	18,072	842	332
June	21,642	1,857	18,035	1,438	313
July	22,214	1,874	18,492	1,535	313
August	22,230	1,898	18,423	1,591	317
September	21,053	1,811	17,371	1,550	321
October	21,569	1,843	17,873	1,514	339
November	20,996	1,807	17,392	1,478	319
December	22,642	1,942	18,855	1,503	342

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.D. Landfill Gas: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	99,821	9,748	86,773	2,999	301
2010	105,835	10,029	92,763	2,837	205
2011	112,538	11,146	89,857	11,332	203
2012	124,297	12,721	99,938	10,356	1,282
2013	132,766	13,819	105,330	11,290	2,327
2014	140,779	13,132	114,333	10,937	2,377
2015	138,085	12,846	112,911	10,023	2,304
2016	135,365	12,294	112,770	8,374	1,927
2017	137,635	13,071	114,131	8,508	1,926
2018	133,957	12,395	111,769	8,104	1,689
2019	127,540	11,794	107,100	7,086	1,560
Year 2017					
January	11,915	1,146	9,852	745	172
February	10,857	1,074	8,953	665	165
March	11,881	1,161	9,798	743	180
April	11,204	1,119	9,242	681	162
May	11,718	1,153	9,694	725	146
June	11,460	1,044	9,532	715	169
July	11,493	1,023	9,598	729	142
August	11,554	1,055	9,620	724	154
September	11,014	987	9,190	689	147
October	11,096	1,062	9,257	620	157
November	11,430	1,102	9,451	715	162
December	12,013	1,145	9,944	756	168
Year 2018					
January	11,667	1,237	9,582	699	150
February	10,937	1,129	8,994	657	157
March	11,740	1,237	9,638	704	161
April	11,060	1,150	9,069	676	165
May	11,319	1,142	9,368	664	146
June	10,808	938	9,079	650	141
July	11,116	957	9,354	671	134
August	11,416	914	9,683	690	128
September	10,140	845	8,524	658	113
October	11,091	941	9,333	685	132
November	11,142	948	9,404	660	131
December	11,522	958	9,742	690	131
Year 2019					
January	11,250	1,062	9,360	697	130
February	10,167	936	8,493	620	118
March	11,055	1,043	9,204	671	137
April	10,195	982	8,612	469	132
May	10,504	1,017	8,987	371	129
June	10,673	964	8,953	629	127
July	10,857	971	9,141	621	124
August	10,838	984	9,092	633	129
September	10,247	939	8,571	608	129
October	10,514	956	8,839	585	135
November	10,218	934	8,577	579	128
December	11,022	1,006	9,273	600	143

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

**Table 5.6.E. Landfill Gas: Consumption for Useful Thermal Output,
by Sector, 2009 - 2019 (Billion Btus)**

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	440	0	313	91	37
2010	847	0	643	174	30
2011	1,635	0	1,422	165	48
2012	1,630	0	1,441	156	32
2013	414	0	132	206	76
2014	852	88	266	326	173
2015	756	1	326	250	179
2016	2,236	1	1,266	589	380
2017	2,196	1	1,066	698	431
2018	1,964	0	966	594	403
2019	1,960	2	1,034	531	394
Year 2017					
January	192	0	94	56	42
February	181	0	88	55	39
March	193	0	95	57	40
April	197	0	84	72	42
May	163	0	72	52	38
June	184	0	90	58	36
July	178	0	96	56	26
August	195	0	95	63	37
September	184	0	92	62	30
October	181	0	93	61	27
November	167	0	76	56	35
December	181	0	91	51	39
Year 2018					
January	169	0	91	42	36
February	172	0	85	50	36
March	185	0	91	55	39
April	183	0	86	56	41
May	151	0	73	43	35
June	135	0	77	26	33
July	153	0	73	50	30
August	166	0	82	54	31
September	161	0	78	55	28
October	185	0	87	65	33
November	152	0	69	49	34
December	151	0	74	50	27
Year 2019					
January	184	0	96	56	32
February	165	0	93	44	28
March	194	0	108	52	35
April	197	0	99	62	36
May	137	0	63	39	35
June	158	0	80	50	29
July	151	0	89	24	37
August	150	0	69	49	32
September	150	0	67	51	31
October	176	0	89	52	34
November	160	0	82	42	36
December	138	0	97	10	30

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.6.F. Landfill Gas: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	100,261	9,748	87,086	3,089	337
2010	106,681	10,029	93,405	3,011	236
2011	114,173	11,146	91,279	11,497	251
2012	125,927	12,721	101,379	10,512	1,315
2013	133,180	13,819	105,462	11,497	2,403
2014	141,632	13,220	114,599	11,263	2,550
2015	138,841	12,847	113,238	10,273	2,483
2016	137,600	12,295	114,036	8,963	2,307
2017	139,831	13,072	115,197	9,206	2,357
2018	135,921	12,395	112,736	8,698	2,092
2019	129,500	11,795	108,134	7,617	1,954
Year 2017					
January	12,107	1,146	9,946	801	214
February	11,039	1,074	9,041	720	204
March	12,074	1,161	9,894	800	220
April	11,401	1,119	9,325	753	204
May	11,881	1,153	9,766	777	184
June	11,644	1,044	9,621	773	205
July	11,670	1,023	9,695	785	167
August	11,749	1,055	9,715	787	192
September	11,198	987	9,282	751	177
October	11,278	1,062	9,350	681	184
November	11,597	1,102	9,527	771	197
December	12,194	1,145	10,035	807	207
Year 2018					
January	11,836	1,237	9,673	741	186
February	11,109	1,129	9,079	707	193
March	11,925	1,237	9,728	760	201
April	11,242	1,150	9,155	733	206
May	11,470	1,142	9,441	707	181
June	10,943	938	9,155	675	174
July	11,269	957	9,427	721	164
August	11,582	914	9,765	744	159
September	10,301	845	8,602	713	140
October	11,277	941	9,420	750	165
November	11,294	948	9,473	709	165
December	11,673	958	9,817	740	158
Year 2019					
January	11,434	1,062	9,456	753	162
February	10,332	936	8,586	664	146
March	11,249	1,043	9,312	723	172
April	10,393	982	8,711	531	168
May	10,641	1,017	9,050	410	164
June	10,832	965	9,033	679	155
July	11,008	972	9,231	645	161
August	10,988	984	9,161	683	160
September	10,396	939	8,638	659	160
October	10,690	956	8,929	637	169
November	10,378	934	8,659	621	164
December	11,159	1,006	9,370	610	173

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.A. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	19,669	465	17,048	2,155	0
2010	19,437	402	16,802	2,233	0
2011	16,972	388	14,625	1,955	4
2012	16,968	418	14,235	2,304	12
2013	17,007	456	14,057	2,485	8
2014	16,706	444	13,809	2,447	6
2015	16,631	452	13,797	2,375	8
2016	16,994	464	13,953	2,566	11
2017	16,348	422	13,381	2,537	8
2018	16,783	467	13,859	2,448	9
2019	15,559	297	12,941	2,310	10
Year 2017					
January	1,434	35	1,194	205	0
February	1,244	19	1,034	191	0
March	1,330	36	1,091	204	0
April	1,288	35	1,044	209	0
May	1,410	36	1,147	226	1
June	1,421	38	1,175	207	1
July	1,440	41	1,172	226	1
August	1,453	47	1,182	223	1
September	1,321	41	1,072	207	1
October	1,317	33	1,065	218	1
November	1,311	30	1,074	207	1
December	1,378	32	1,132	214	1
Year 2018					
January	1,370	28	1,147	195	0
February	1,297	26	1,090	180	1
March	1,398	40	1,153	204	1
April	1,356	38	1,117	200	1
May	1,419	43	1,158	217	1
June	1,476	42	1,218	214	1
July	1,479	48	1,224	207	1
August	1,483	47	1,220	215	1
September	1,334	36	1,097	199	1
October	1,387	43	1,140	205	0
November	1,369	39	1,127	202	0
December	1,416	37	1,169	210	0
Year 2019					
January	1,322	30	1,092	199	1
February	1,158	20	961	177	1
March	1,255	20	1,046	188	1
April	1,235	28	1,014	193	1
May	1,337	26	1,112	198	1
June	1,323	25	1,098	200	1
July	1,369	27	1,146	194	1
August	1,396	29	1,167	200	1
September	1,288	21	1,076	191	1
October	1,271	28	1,056	187	1
November	1,270	25	1,062	183	1
December	1,333	20	1,112	201	1

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.B. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	2,426	0	823	1,466	137
2010	2,287	0	819	1,316	152
2011	2,044	0	742	1,148	154
2012	1,986	0	522	1,273	190
2013	1,865	0	517	1,160	187
2014	1,955	0	650	1,104	200
2015	1,986	0	655	1,127	203
2016	2,232	0	885	1,134	213
2017	2,124	0	814	1,102	208
2018	2,050	0	752	1,109	189
2019	1,667	0	743	737	187
Year 2017					
January	203	0	72	111	20
February	171	0	64	94	12
March	187	0	75	93	19
April	173	0	69	86	18
May	182	0	69	96	18
June	185	0	68	101	16
July	185	0	72	97	17
August	196	0	77	97	22
September	154	0	63	74	17
October	155	0	59	78	18
November	166	0	64	88	15
December	168	0	63	88	17
Year 2018					
January	182	0	64	102	17
February	163	0	60	91	12
March	169	0	64	93	12
April	160	0	54	90	16
May	176	0	59	101	16
June	177	0	65	95	18
July	180	0	65	98	17
August	183	0	66	95	21
September	144	0	58	68	17
October	160	0	61	83	16
November	173	0	66	93	14
December	182	0	70	100	13
Year 2019					
January	173	0	66	92	15
February	155	0	63	77	15
March	153	0	67	70	16
April	115	0	56	43	17
May	127	0	64	52	12
June	137	0	64	59	15
July	136	0	67	53	16
August	139	0	62	56	21
September	124	0	53	56	15
October	130	0	57	58	15
November	139	0	63	61	15
December	139	0	61	62	15

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.C. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Thousand Tons)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	22,095	465	17,872	3,622	137
2010	21,725	402	17,621	3,549	152
2011	19,016	388	15,367	3,103	158
2012	18,954	418	14,757	3,577	203
2013	18,871	456	14,574	3,646	195
2014	18,661	444	14,459	3,551	206
2015	18,617	452	14,452	3,502	211
2016	19,226	464	14,838	3,700	224
2017	18,473	422	14,195	3,639	216
2018	18,833	467	14,611	3,557	197
2019	17,225	297	13,684	3,047	197
Year 2017					
January	1,637	35	1,266	316	20
February	1,415	19	1,098	286	12
March	1,517	36	1,165	297	19
April	1,461	35	1,113	295	18
May	1,592	36	1,215	322	19
June	1,606	38	1,243	309	17
July	1,625	41	1,244	323	18
August	1,649	47	1,259	320	23
September	1,475	41	1,135	281	18
October	1,472	33	1,124	295	19
November	1,477	30	1,138	295	15
December	1,546	32	1,195	301	18
Year 2018					
January	1,552	28	1,211	296	17
February	1,459	26	1,150	271	13
March	1,567	40	1,217	297	13
April	1,516	38	1,171	290	17
May	1,595	43	1,217	319	17
June	1,653	42	1,283	309	19
July	1,659	48	1,288	305	18
August	1,666	47	1,286	311	22
September	1,478	36	1,156	268	18
October	1,547	43	1,201	288	16
November	1,542	39	1,193	295	14
December	1,598	37	1,238	310	13
Year 2019					
January	1,495	30	1,158	291	16
February	1,313	20	1,024	254	16
March	1,408	20	1,114	258	17
April	1,350	28	1,069	235	18
May	1,465	26	1,176	249	13
June	1,461	25	1,162	258	15
July	1,504	27	1,213	247	17
August	1,535	29	1,229	256	22
September	1,412	21	1,129	246	16
October	1,401	28	1,113	245	16
November	1,409	25	1,125	244	15
December	1,472	20	1,173	263	16

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.D. Biogenic Municipal Solid Waste: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	146,971	3,989	126,649	16,333	0
2010	144,934	3,322	124,437	17,176	0
2011	135,241	3,433	115,841	15,933	34
2012	135,735	3,910	113,418	18,307	100
2013	135,764	4,459	111,430	19,811	64
2014	134,408	4,429	110,569	19,366	45
2015	133,117	4,295	109,691	19,068	63
2016	135,957	4,434	111,003	20,431	89
2017	130,942	4,172	106,382	20,320	67
2018	134,465	4,568	110,452	19,374	72
2019	115,114	2,454	95,638	16,946	76
Year 2017					
January	11,516	349	9,521	1,646	0
February	9,929	180	8,212	1,536	0
March	10,732	357	8,748	1,626	0
April	10,335	349	8,304	1,680	2
May	11,189	352	9,027	1,799	11
June	11,277	375	9,257	1,639	7
July	11,487	399	9,271	1,807	10
August	11,545	461	9,281	1,793	10
September	10,558	411	8,484	1,656	7
October	10,584	327	8,506	1,742	9
November	10,541	294	8,581	1,659	7
December	11,250	318	9,189	1,737	5
Year 2018					
January	11,104	278	9,239	1,583	4
February	10,426	253	8,728	1,439	7
March	11,332	400	9,296	1,628	8
April	10,904	377	8,952	1,568	7
May	11,349	431	9,212	1,702	5
June	11,807	420	9,689	1,687	10
July	11,815	477	9,677	1,651	9
August	11,828	449	9,676	1,695	8
September	10,577	348	8,681	1,540	7
October	11,083	408	9,062	1,610	3
November	10,921	371	8,955	1,595	0
December	11,319	356	9,285	1,676	2
Year 2019					
January	9,806	252	8,081	1,468	5
February	8,560	163	7,085	1,306	6
March	9,337	164	7,782	1,385	6
April	9,150	229	7,493	1,421	8
May	9,880	218	8,220	1,437	6
June	9,815	202	8,147	1,459	6
July	10,063	225	8,398	1,432	8
August	10,270	234	8,568	1,462	7
September	9,544	166	7,971	1,403	5
October	9,408	231	7,806	1,365	5
November	9,372	204	7,835	1,326	7
December	9,907	166	8,252	1,482	8

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.7.E. Biogenic Municipal Solid Waste: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	18,785	0	6,229	11,535	1,021
2010	17,502	0	6,031	10,333	1,138
2011	16,766	0	5,807	9,731	1,227
2012	16,310	0	4,180	10,615	1,515
2013	15,168	0	4,145	9,530	1,493
2014	15,783	0	5,140	9,046	1,597
2015	16,623	0	5,195	9,752	1,676
2016	18,259	0	6,877	9,665	1,717
2017	17,720	0	6,475	9,474	1,772
2018	16,724	0	5,887	9,312	1,524
2019	12,308	0	5,362	5,527	1,419
Year 2017					
January	1,779	0	585	1,007	187
February	1,457	0	514	837	106
March	1,573	0	601	811	161
April	1,451	0	535	759	157
May	1,437	0	540	749	148
June	1,491	0	523	842	126
July	1,522	0	571	811	140
August	1,629	0	612	825	191
September	1,291	0	499	649	143
October	1,305	0	470	686	150
November	1,375	0	511	743	121
December	1,409	0	512	754	143
Year 2018					
January	1,480	0	506	840	135
February	1,331	0	470	773	88
March	1,377	0	507	777	93
April	1,361	0	423	804	133
May	1,416	0	447	836	132
June	1,441	0	517	772	152
July	1,471	0	509	823	139
August	1,488	0	513	797	179
September	1,174	0	453	579	142
October	1,296	0	472	705	119
November	1,412	0	526	778	109
December	1,478	0	545	830	103
Year 2019					
January	1,306	0	476	715	115
February	1,158	0	458	590	111
March	1,136	0	491	529	116
April	842	0	396	318	128
May	914	0	444	380	90
June	994	0	455	430	109
July	974	0	471	385	119
August	1,071	0	454	449	167
September	908	0	385	411	113
October	967	0	428	417	121
November	1,009	0	456	443	110
December	1,028	0	448	460	119

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.7.F. Biogenic Municipal Solid Waste: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	165,755	3,989	132,877	27,868	1,021
2010	162,436	3,322	130,467	27,509	1,138
2011	152,007	3,433	121,648	25,664	1,262
2012	152,045	3,910	117,598	28,923	1,614
2013	150,932	4,459	115,574	29,342	1,557
2014	150,191	4,429	115,709	28,411	1,643
2015	149,740	4,295	114,886	28,821	1,739
2016	154,216	4,434	117,880	30,095	1,806
2017	148,662	4,172	112,857	29,794	1,839
2018	151,188	4,568	116,339	28,686	1,596
2019	127,422	2,454	101,000	22,473	1,495
Year 2017					
January	13,295	349	10,106	2,653	187
February	11,385	180	8,727	2,373	106
March	12,305	357	9,349	2,437	161
April	11,787	349	8,840	2,439	159
May	12,626	352	9,567	2,548	159
June	12,767	375	9,780	2,480	133
July	13,010	399	9,843	2,618	150
August	13,174	461	9,894	2,619	201
September	11,849	411	8,982	2,305	150
October	11,889	327	8,976	2,428	159
November	11,916	294	9,092	2,402	127
December	12,659	318	9,702	2,491	148
Year 2018					
January	12,585	278	9,745	2,423	139
February	11,757	253	9,198	2,211	95
March	12,709	400	9,802	2,405	102
April	12,265	377	9,375	2,372	140
May	12,765	431	9,659	2,538	137
June	13,248	420	10,206	2,459	162
July	13,286	477	10,186	2,474	148
August	13,316	449	10,189	2,492	187
September	11,751	348	9,134	2,119	149
October	12,379	408	9,534	2,315	122
November	12,332	371	9,480	2,372	109
December	12,797	356	9,830	2,506	105
Year 2019					
January	11,112	252	8,556	2,183	120
February	9,719	163	7,542	1,896	117
March	10,474	164	8,273	1,914	122
April	9,993	229	7,889	1,739	135
May	10,794	218	8,664	1,817	96
June	10,809	202	8,602	1,888	116
July	11,037	225	8,869	1,816	127
August	11,341	234	9,023	1,911	174
September	10,453	166	8,355	1,813	118
October	10,375	231	8,234	1,783	127
November	10,381	204	8,292	1,770	117
December	10,935	166	8,701	1,942	127

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.D. Other Waste Biomass: Consumption for Electricity Generation, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	24,847	3,679	13,231	3,760	4,177
2010	29,996	3,668	14,449	3,790	8,090
2011	30,771	4,488	16,115	3,816	6,352
2012	30,342	4,191	15,740	4,016	6,395
2013	29,385	2,432	13,671	4,979	8,303
2014	38,361	2,360	21,628	5,745	8,627
2015	41,785	2,853	25,058	5,935	7,939
2016	33,786	2,553	18,194	5,504	7,536
2017	35,755	1,845	22,517	5,288	6,105
2018	29,407	1,343	16,874	5,867	5,324
2019	23,947	1,133	12,606	5,668	4,540
Year 2017					
January	3,161	137	1,974	487	563
February	3,023	170	1,913	429	511
March	3,412	242	2,111	477	582
April	2,816	124	1,707	446	539
May	2,983	147	1,891	459	486
June	2,896	155	1,904	427	410
July	3,105	137	2,051	458	459
August	2,912	173	1,833	436	471
September	2,619	162	1,646	396	414
October	2,803	117	1,825	349	512
November	3,055	110	1,939	443	563
December	2,972	171	1,724	482	595
Year 2018					
January	3,130	201	1,896	507	527
February	2,990	123	1,915	474	477
March	2,880	103	1,751	495	531
April	2,858	130	1,785	479	465
May	2,721	66	1,728	475	451
June	2,431	59	1,565	481	325
July	2,025	122	1,040	486	377
August	2,036	95	1,060	495	385
September	1,833	103	934	475	322
October	2,184	125	1,090	506	463
November	2,140	112	1,041	490	496
December	2,179	102	1,069	504	504
Year 2019					
January	2,131	121	1,085	501	424
February	1,918	142	939	452	386
March	2,174	177	1,064	493	439
April	2,026	101	1,054	475	396
May	1,763	82	877	454	349
June	1,917	84	1,038	459	336
July	2,000	90	1,110	474	326
August	2,076	117	1,140	476	344
September	1,843	73	1,036	459	275
October	1,994	50	1,075	459	410
November	2,010	27	1,098	469	417
December	2,095	69	1,089	498	439

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

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Table 5.8.E. Other Waste Biomass: Consumption for Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	41,810	0	10,355	1,638	29,817
2010	47,153	0	8,436	1,648	37,070
2011	43,483	0	6,460	1,566	35,458
2012	46,863	0	6,914	1,796	38,153
2013	62,445	0	6,768	1,259	54,418
2014	65,201	15	6,930	1,543	56,712
2015	67,512	1	7,845	2,000	57,666
2016	57,123	18	11,252	3,569	42,284
2017	50,518	15	10,543	3,218	36,742
2018	50,338	14	10,753	3,673	35,898
2019	41,084	39	10,452	3,282	27,312
Year 2017					
January	5,626	2	1,280	346	3,999
February	4,894	0	1,002	271	3,621
March	5,352	0	1,192	291	3,869
April	4,627	7	779	256	3,586
May	3,644	2	692	264	2,686
June	2,834	0	772	276	1,785
July	3,009	0	616	235	2,158
August	3,059	1	552	269	2,238
September	2,657	2	466	226	1,963
October	4,233	0	846	221	3,166
November	5,205	1	1,125	291	3,788
December	5,379	0	1,221	274	3,884
Year 2018					
January	5,543	0	1,334	317	3,892
February	5,058	0	1,226	316	3,516
March	5,492	0	1,313	327	3,852
April	4,392	5	656	315	3,416
May	3,563	6	462	321	2,774
June	2,468	1	534	305	1,627
July	2,687	0	551	292	1,844
August	2,720	1	465	318	1,936
September	2,733	0	550	295	1,888
October	4,872	0	1,061	297	3,514
November	5,269	0	1,332	306	3,631
December	5,541	0	1,270	264	4,007
Year 2019					
January	4,576	12	1,166	288	3,109
February	4,339	11	1,149	238	2,941
March	4,299	6	1,178	335	2,780
April	3,245	7	945	268	2,024
May	2,579	0	630	252	1,697
June	2,729	1	510	262	1,957
July	2,259	0	519	253	1,486
August	2,361	0	552	278	1,532
September	2,009	0	451	275	1,283
October	3,987	0	1,092	300	2,595
November	4,289	0	1,151	256	2,883
December	4,413	0	1,109	278	3,026

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

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Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.8.F. Other Waste Biomass: Consumption for Electricity Generation and Useful Thermal Output, by Sector, 2009 - 2019 (Billion Btus)

		Electric Power Sector			
Period	Total (all sectors)	Electric Utilities	Independent Power Producers	Commercial Sector	Industrial Sector
Annual Totals					
2009	66,658	3,679	23,586	5,398	33,994
2010	77,150	3,668	22,884	5,438	45,159
2011	74,255	4,488	22,574	5,382	41,810
2012	77,205	4,191	22,654	5,812	44,548
2013	91,830	2,432	20,439	6,238	62,721
2014	103,561	2,375	28,558	7,289	65,339
2015	109,297	2,854	32,903	7,935	65,605
2016	90,909	2,571	29,446	9,073	49,820
2017	86,274	1,860	33,060	8,506	42,848
2018	79,745	1,357	27,627	9,540	41,221
2019	65,031	1,172	23,057	8,950	31,852
Year 2017					
January	8,787	138	3,254	833	4,562
February	7,917	171	2,915	699	4,132
March	8,764	242	3,303	769	4,451
April	7,443	131	2,485	701	4,125
May	6,627	149	2,584	723	3,172
June	5,730	155	2,677	702	2,196
July	6,113	137	2,667	692	2,617
August	5,972	174	2,385	705	2,709
September	5,275	164	2,111	622	2,377
October	7,035	117	2,671	569	3,678
November	8,260	111	3,064	734	4,351
December	8,351	172	2,945	756	4,479
Year 2018					
January	8,673	201	3,230	824	4,419
February	8,048	124	3,141	790	3,993
March	8,372	103	3,064	822	4,383
April	7,251	135	2,441	794	3,881
May	6,284	72	2,190	797	3,225
June	4,898	60	2,100	786	1,953
July	4,712	122	1,591	778	2,221
August	4,756	96	1,525	813	2,321
September	4,566	103	1,483	770	2,210
October	7,057	125	2,151	803	3,977
November	7,409	112	2,373	796	4,128
December	7,720	102	2,338	768	4,511
Year 2019					
January	6,706	133	2,251	788	3,533
February	6,257	153	2,088	689	3,327
March	6,473	183	2,242	828	3,219
April	5,270	108	1,999	743	2,420
May	4,343	83	1,508	707	2,046
June	4,646	85	1,548	721	2,293
July	4,258	90	1,629	727	1,812
August	4,438	117	1,691	753	1,876
September	3,852	73	1,487	734	1,558
October	5,981	51	2,166	759	3,005
November	6,300	27	2,249	724	3,299
December	6,508	69	2,198	776	3,465

Notes: Beginning with the collection of Form EIA-923 in January 2008, the methodology to allocate total fuel consumption for electricity generation and consumption for useful thermal output was changed.

The new methodology was retroactively applied to 2004-2007 data. See the Technical Notes (Appendix C) for further information. See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920

Combined Heat and Power Plant Report, and predecessor forms.

Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report.

Table 5.9. Consumption of Coal for Electricity Generation by State by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	224	531	-58.0%	159	294	61	233	0	0	4	4
Connecticut	48	221	-78.0%	0	0	48	221	0	0	0	0
Maine	17	16	3.1%	0	0	13	12	0	0	4	4
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	159	294	-46.0%	159	294	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	20,049	24,113	-17.0%	0	0	20,027	24,075	0	0	22	39
New Jersey	440	504	-13.0%	0	0	440	504	0	0	0	0
New York	187	276	-32.0%	0	0	187	272	0	0	0	4
Pennsylvania	19,422	23,334	-17.0%	0	0	19,400	23,299	0	0	22	35
East North Central	116,185	144,074	-19.0%	69,048	86,841	46,535	56,524	15	18	587	691
Illinois	29,617	36,013	-18.0%	1,923	2,254	27,230	33,239	4	9	460	511
Indiana	30,906	39,080	-21.0%	28,888	36,910	2,008	2,161	10	9	0	0
Michigan	21,257	24,235	-12.0%	21,056	23,991	192	212	0	0	9	33
Ohio	19,596	25,122	-22.0%	2,490	4,209	17,105	20,912	0	0	0	1
Wisconsin	14,809	19,624	-25.0%	14,692	19,477	0	0	0	0	117	147
West North Central	103,233	118,759	-13.0%	102,157	117,565	0	0	20	21	1,056	1,173
Iowa	12,710	16,187	-21.0%	12,190	15,673	0	0	17	19	502	495
Kansas	11,535	13,176	-12.0%	11,535	13,176	0	0	0	0	0	0
Minnesota	10,495	13,675	-23.0%	10,345	13,421	0	0	1	0	149	253
Missouri	32,663	36,978	-12.0%	32,661	36,976	0	0	2	2	0	0
Nebraska	13,517	14,834	-8.9%	13,149	14,443	0	0	0	0	367	391
North Dakota	20,682	22,457	-7.9%	20,645	22,423	0	0	0	0	37	34
South Dakota	1,631	1,453	12.0%	1,631	1,453	0	0	0	0	0	0
South Atlantic	69,979	85,873	-19.0%	62,386	75,137	7,422	10,538	10	12	161	186
Delaware	85	167	-49.0%	0	0	85	167	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	9,542	13,384	-29.0%	9,533	13,365	0	0	0	0	9	18
Georgia	13,591	16,996	-20.0%	13,552	16,953	0	0	0	0	39	43
Maryland	2,556	4,382	-42.0%	0	0	2,548	4,367	0	0	8	15
North Carolina	12,349	12,564	-1.7%	12,281	12,480	31	46	10	11	27	28
South Carolina	6,316	8,144	-22.0%	6,267	8,141	47	0	0	0	2	3
Virginia	1,781	4,565	-61.0%	1,658	4,200	45	284	1	1	76	79
West Virginia	23,760	25,671	-7.4%	19,094	19,996	4,666	5,675	0	0	0	0
East South Central	52,523	59,619	-12.0%	49,851	56,472	2,563	2,996	0	0	109	151
Alabama	14,250	16,249	-12.0%	14,245	16,235	0	0	0	0	5	14
Kentucky	24,974	28,368	-12.0%	24,974	28,368	0	0	0	0	0	0
Mississippi	3,833	4,506	-15.0%	1,271	1,510	2,563	2,996	0	0	0	0
Tennessee	9,466	10,496	-9.8%	9,362	10,359	0	0	0	0	104	137
West South Central	87,629	111,125	-21.0%	44,548	59,876	43,007	51,127	0	0	74	123
Arkansas	13,771	17,461	-21.0%	11,552	14,617	2,211	2,835	0	0	8	8
Louisiana	5,276	8,110	-35.0%	3,979	5,339	1,297	2,771	0	0	0	0
Oklahoma	5,271	9,656	-45.0%	5,206	8,348	0	1,193	0	0	66	114
Texas	63,311	75,899	-17.0%	23,812	31,572	39,499	44,327	0	0	0	0
Mountain	80,167	86,299	-7.1%	69,526	76,223	10,547	9,973	0	0	93	104
Arizona	12,875	16,814	-23.0%	12,875	16,814	0	0	0	0	0	0
Colorado	14,517	15,269	-4.9%	14,515	15,266	0	0	0	0	1	3
Idaho	4	4	1.0%	0	0	0	0	0	0	4	4
Montana	9,280	8,738	6.2%	261	233	9,014	8,500	0	0	5	5
Nevada	1,551	1,412	9.9%	945	816	606	596	0	0	0	0
New Mexico	8,148	7,262	12.0%	8,148	7,262	0	0	0	0	0	0
Utah	11,891	12,332	-3.6%	11,489	11,927	402	405	0	0	0	0
Wyoming	21,901	24,468	-10.0%	21,293	23,905	525	472	0	0	83	91
Pacific Contiguous	6,359	4,590	39.0%	1,499	898	4,804	3,628	0	0	55	63
California	49	57	-14.0%	0	0	0	0	0	0	49	57
Oregon	1,499	898	67.0%	1,499	898	0	0	0	0	0	0
Washington	4,811	3,635	32.0%	0	0	4,804	3,628	0	0	7	7
Pacific Noncontiguous	1,273	1,230	3.4%	370	312	872	882	32	36	0	0
Alaska	556	496	12.0%	370	312	155	148	32	36	0	0
Hawaii	717	734	-2.4%	0	0	717	734	0	0	0	0
U.S. Total	537,620	636,213	-15.0%	399,545	473,617	135,838	159,976	76	87	2,161	2,534

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.10. Consumption of Petroleum Liquids for Electricity Generation by State, by Sector, 2019 and 2018 (Thousand Barrels)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	390	2,109	-81.0%	55	345	284	1,713	38	36	14	16
Connecticut	79	601	-87.0%	9	9	64	588	3	3	2	1
Maine	53	317	-83.0%	0	0	36	298	8	6	10	13
Massachusetts	190	767	-75.0%	16	124	161	631	12	10	1	2
New Hampshire	49	298	-84.0%	26	201	10	82	13	15	0	0
Rhode Island	16	115	-86.0%	0	0	13	113	2	2	1	0
Vermont	4	10	-64.0%	4	10	0	0	0	0	0	0
Middle Atlantic	1,437	4,464	-68.0%	468	1,066	905	3,306	27	36	37	55
New Jersey	115	469	-75.0%	3	6	110	458	2	4	1	1
New York	896	2,596	-65.0%	464	1,057	403	1,485	14	20	15	35
Pennsylvania	426	1,398	-70.0%	0	3	392	1,364	11	12	22	19
East North Central	952	1,126	-15.0%	605	623	331	473	4	8	12	22
Illinois	97	106	-8.9%	16	16	81	90	0	0	0	0
Indiana	241	233	3.4%	234	214	0	1	NM	1	7	18
Michigan	185	254	-27.0%	182	247	0	0	2	6	1	1
Ohio	315	450	-30.0%	70	66	242	380	1	1	3	3
Wisconsin	114	83	38.0%	104	80	8	2	1	0	0	1
West North Central	796	697	14.0%	773	647	20	47	2	2	2	1
Iowa	135	129	4.2%	128	121	7	7	0	0	0	0
Kansas	175	118	48.0%	175	118	0	0	0	0	0	0
Minnesota	101	98	3.1%	85	56	13	39	2	2	1	1
Missouri	243	223	8.9%	243	223	0	0	0	0	0	0
Nebraska	41	34	21.0%	41	34	0	0	0	0	0	0
North Dakota	67	74	-9.6%	67	74	0	0	0	0	0	0
South Dakota	33	20	70.0%	33	20	0	0	0	0	0	0
South Atlantic	2,226	6,283	-65.0%	1,661	4,460	350	1,530	148	167	66	125
Delaware	35	333	-89.0%	1	12	35	321	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	547	1,031	-47.0%	506	983	26	27	0	0	16	21
Georgia	188	497	-62.0%	140	252	9	176	8	7	30	62
Maryland	173	549	-68.0%	4	11	166	533	1	2	1	3
North Carolina	355	1,231	-71.0%	335	1,128	9	77	2	5	9	21
South Carolina	154	609	-75.0%	140	586	7	11	0	0	8	12
Virginia	543	1,744	-69.0%	306	1,225	97	359	137	154	4	6
West Virginia	230	290	-20.0%	229	264	2	26	0	0	0	0
East South Central	500	603	-17.0%	481	520	8	69	0	0	10	13
Alabama	35	146	-76.0%	21	69	8	69	0	0	6	8
Kentucky	167	179	-6.8%	167	179	0	0	0	0	0	0
Mississippi	25	50	-49.0%	24	47	0	0	0	0	2	3
Tennessee	272	228	20.0%	269	225	1	0	0	0	2	2
West South Central	264	247	6.8%	197	191	56	47	1	1	10	8
Arkansas	81	59	38.0%	58	46	20	10	0	0	3	3
Louisiana	48	41	18.0%	39	41	9	0	0	0	0	0
Oklahoma	35	33	7.0%	33	31	0	0	0	0	2	2
Texas	100	115	-13.0%	66	74	27	37	1	1	5	3
Mountain	1,063	370	187.0%	1,025	326	37	44	0	0	0	0
Arizona	124	95	31.0%	124	95	0	0	0	0	0	0
Colorado	24	34	-30.0%	24	33	0	1	0	0	0	0
Idaho	0	0	132.0%	0	0	0	0	0	0	0	0
Montana	34	37	-7.4%	4	1	30	35	0	0	0	0
Nevada	25	21	16.0%	21	16	4	5	0	0	0	0
New Mexico	703	42	NM	703	42	0	0	0	0	0	0
Utah	70	64	9.5%	67	62	3	2	0	0	0	0
Wyoming	84	78	7.6%	83	78	0	0	0	0	0	0
Pacific Contiguous	147	164	-10.0%	85	80	39	35	2	2	21	47
California	101	120	-16.0%	67	64	20	17	1	1	13	38
Oregon	15	9	70.0%	14	9	0	0	0	0	0	0
Washington	31	35	-10.0%	3	7	19	18	0	0	9	9
Pacific Noncontiguous	13,059	12,552	4.0%	10,327	10,086	2,434	2,203	27	16	272	246
Alaska	1,608	1,454	11.0%	1,530	1,388	5	0	8	6	65	59
Hawaii	11,451	11,098	3.2%	8,797	8,698	2,429	2,203	19	10	207	187
U.S. Total	20,836	28,614	-27.0%	15,677	18,345	4,464	9,467	251	269	444	534

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.11. Consumption of Petroleum Coke for Electricity Generation by State, by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	12	20	-40.0%	0	0	0	0	0	0	12	20
New Jersey	8	7	12.0%	0	0	0	0	0	0	8	7
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	5	14	-65.0%	0	0	0	0	0	0	5	14
East North Central	773	1,160	-33.0%	389	558	316	550	0	0	68	52
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	418	564	-26.0%	350	513	0	0	0	0	68	51
Ohio	316	551	-43.0%	0	0	316	550	0	0	0	1
Wisconsin	39	45	-12.0%	39	45	0	0	0	0	0	0
West North Central	12	7	62.0%	0	0	0	0	1	2	10	5
Iowa	12	7	62.0%	0	0	0	0	1	2	10	5
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	466	594	-21.0%	433	559	0	0	0	0	33	35
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	433	559	-22.0%	433	559	0	0	0	0	0	0
Georgia	33	35	-5.6%	0	0	0	0	0	0	33	35
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	1,297	1,687	-23.0%	1,244	1,624	0	0	0	0	53	64
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,246	1,646	-24.0%	1,244	1,624	0	0	0	0	2	23
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	51	41	24.0%	0	0	0	0	0	0	51	41
Mountain	163	154	5.6%	0	0	163	154	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	163	154	5.6%	0	0	163	154	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	2,724	3,623	-25.0%	2,067	2,740	478	704	1	2	177	177

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.12. Consumption of Natural Gas for Electricity Generation by State, by Sector, 2019 and 2018 (Million Cubic Feet)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	351,302	371,172	-5.4%	1,540	2,658	334,916	353,979	5,891	5,862	8,956	8,673
Connecticut	149,034	141,310	5.5%	496	522	142,289	134,752	2,497	2,325	3,752	3,711
Maine	11,730	15,859	-26.0%	0	0	9,361	13,718	148	148	2,221	1,993
Massachusetts	111,604	133,263	-16.0%	952	1,724	106,334	127,086	2,964	3,118	1,353	1,334
New Hampshire	25,693	21,790	18.0%	79	400	25,381	21,163	45	32	188	195
Rhode Island	53,225	58,934	-9.7%	0	0	51,551	57,260	231	234	1,442	1,440
Vermont	17	16	8.1%	12	11	0	0	5	5	0	0
Middle Atlantic	1,317,087	1,210,777	8.8%	89,507	96,344	1,204,391	1,091,715	8,791	8,068	14,398	14,649
New Jersey	277,795	270,279	2.8%	1,582	1,602	272,204	265,520	1,734	1,094	2,276	2,063
New York	365,544	401,223	-8.9%	87,886	94,681	267,693	296,061	6,269	6,305	3,696	4,176
Pennsylvania	673,749	539,276	25.0%	38	62	664,495	530,134	789	670	8,427	8,410
East North Central	1,168,361	1,028,576	14.0%	404,987	379,177	725,680	615,520	7,650	7,958	30,043	25,922
Illinois	172,502	141,840	22.0%	11,739	10,478	155,078	125,035	1,823	2,094	3,862	4,233
Indiana	230,037	200,862	15.0%	101,345	90,971	111,896	96,367	1,028	870	15,768	12,653
Michigan	253,869	234,395	8.3%	97,842	91,603	149,348	136,240	3,167	3,195	3,512	3,358
Ohio	363,846	322,524	13.0%	62,285	72,293	299,079	247,949	1,102	1,218	1,379	1,064
Wisconsin	148,107	128,955	15.0%	131,775	113,832	10,280	9,929	530	580	5,522	4,614
West North Central	262,011	224,073	17.0%	216,875	194,749	39,189	24,193	1,806	1,604	4,140	3,527
Iowa	49,948	49,227	1.5%	46,716	46,478	0	76	616	492	2,616	2,181
Kansas	28,782	28,767	0.1%	28,232	28,281	0	0	0	0	550	486
Minnesota	86,011	61,174	41.0%	65,551	52,642	19,427	7,463	445	492	588	578
Missouri	62,142	56,961	9.1%	41,554	39,575	19,762	16,654	707	586	118	146
Nebraska	12,076	9,230	31.0%	12,037	9,196	0	0	38	34	0	0
North Dakota	13,817	9,615	44.0%	13,686	9,479	0	0	0	0	131	136
South Dakota	9,235	9,099	1.5%	9,099	9,099	0	0	0	0	136	0
South Atlantic	2,817,330	2,673,712	5.4%	2,300,179	2,164,942	474,308	471,691	12,952	10,387	29,890	26,693
Delaware	33,688	40,378	-17.0%	319	282	27,606	35,931	0	0	5,764	4,165
District of Columbia	1,511	614	146.0%	0	0	0	0	1,511	614	0	0
Florida	1,327,986	1,272,791	4.3%	1,262,062	1,201,253	57,158	63,351	107	151	8,659	8,036
Georgia	430,234	376,880	14.0%	327,045	284,254	99,660	88,999	1	0	3,528	3,626
Maryland	105,316	105,437	-0.1%	22,900	26,042	72,319	70,383	9,786	8,567	312	446
North Carolina	305,954	331,804	-7.8%	241,074	280,691	62,620	49,428	1,457	974	803	711
South Carolina	178,750	169,642	5.4%	168,922	143,129	8,941	25,704	3	2	884	807
Virginia	414,935	364,055	14.0%	273,670	227,378	133,755	129,086	87	79	7,423	7,512
West Virginia	18,955	12,112	56.0%	4,188	1,913	12,249	8,809	0	0	2,519	1,391
East South Central	1,017,088	1,010,560	0.6%	742,039	694,596	252,074	301,053	962	1,079	22,013	13,832
Alabama	414,117	421,586	-1.8%	156,800	155,114	247,450	259,291	0	0	9,866	7,181
Kentucky	113,334	113,487	-0.1%	107,944	105,040	4,426	7,616	0	0	965	831
Mississippi	361,588	368,214	-1.8%	358,718	331,487	51	34,009	0	40	2,819	2,678
Tennessee	128,049	107,273	19.0%	118,577	102,955	148	136	962	1,040	8,363	3,142
West South Central	2,878,287	2,637,243	9.1%	1,113,512	1,009,781	1,336,517	1,231,936	4,787	4,233	423,471	391,292
Arkansas	155,904	148,397	5.1%	147,395	139,217	6,476	7,221	479	431	1,554	1,528
Louisiana	500,639	442,731	13.0%	299,170	266,197	37,775	28,935	718	744	162,977	146,855
Oklahoma	341,019	320,293	6.5%	226,720	205,644	110,767	111,483	0	0	3,532	3,166
Texas	1,880,725	1,725,822	9.0%	440,226	398,722	1,181,500	1,084,297	3,590	3,058	255,409	239,744
Mountain	897,474	808,494	11.0%	725,201	654,483	158,146	138,452	2,252	2,173	11,876	13,386
Arizona	356,797	285,200	25.0%	273,400	226,923	82,798	57,666	598	611	0	0
Colorado	127,897	122,889	4.1%	107,650	100,913	19,856	21,648	35	5	356	322
Idaho	32,193	24,271	33.0%	19,222	12,610	12,187	11,073	168	170	616	419
Montana	5,510	5,153	6.9%	4,067	3,953	1,428	1,176	0	0	15	24
Nevada	191,553	198,627	-3.6%	173,486	180,440	15,166	15,129	262	258	2,639	2,800
New Mexico	104,014	99,161	4.9%	77,649	67,166	25,781	31,205	530	509	54	282
Utah	72,335	66,844	8.2%	66,472	60,620	914	541	658	619	4,291	5,063
Wyoming	7,175	6,350	13.0%	3,255	1,858	16	15	0	0	3,905	4,477
Pacific Contiguous	867,974	842,767	3.0%	351,183	329,059	433,576	435,397	10,484	11,284	72,731	67,028
California	615,344	646,381	-4.8%	209,860	220,039	326,983	349,196	10,226	10,995	68,275	66,150
Oregon	143,735	123,000	17.0%	69,066	60,935	73,945	61,412	227	211	497	442
Washington	108,895	73,386	48.0%	72,257	48,085	32,648	24,789	31	77	3,959	435
Pacific Noncontiguous	24,687	25,669	-3.8%	24,401	25,393	0	0	0	3	286	273
Alaska	24,687	25,669	-3.8%	24,401	25,393	0	0	0	3	286	273
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	11,601,600	10,833,043	7.1%	5,969,422	5,551,181	4,958,798	4,663,935	55,575	52,650	617,805	565,276

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.13. Consumption of Landfill Gas for Electricity Generation by State, by Sector, 2019 and 2018 (Million Cubic Feet)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	12,339	11,090	11.0%	1,410	0	10,711	10,850	217	240	0	0
Connecticut	169	266	-36.0%	0	0	169	266	0	0	0	0
Maine	682	688	-0.9%	0	0	682	688	0	0	0	0
Massachusetts	3,633	4,023	-9.7%	0	0	3,633	4,023	0	0	0	0
New Hampshire	1,958	1,699	15.0%	0	0	1,741	1,459	217	240	0	0
Rhode Island	4,229	4,133	2.3%	0	0	4,229	4,133	0	0	0	0
Vermont	1,668	281	494.0%	1,410	0	257	281	0	0	0	0
Middle Atlantic	48,526	51,470	-5.7%	0	0	46,743	49,791	673	537	1,110	1,142
New Jersey	6,693	7,398	-9.5%	0	0	6,510	7,243	183	155	0	0
New York	16,168	16,333	-1.0%	0	0	16,168	16,333	0	0	0	0
Pennsylvania	25,665	27,739	-7.5%	0	0	24,064	26,215	491	382	1,110	1,142
East North Central	61,921	62,210	-0.5%	10,372	9,596	50,982	52,076	321	283	246	255
Illinois	11,432	11,915	-4.1%	3,202	2,675	8,230	9,240	0	0	0	0
Indiana	8,317	8,124	2.4%	7,170	6,922	1,147	1,202	0	0	0	0
Michigan	21,180	20,083	5.5%	0	0	21,180	20,083	0	0	0	0
Ohio	10,990	11,338	-3.1%	0	0	10,990	11,338	0	0	0	0
Wisconsin	10,002	10,751	-7.0%	0	0	9,435	10,213	321	283	246	255
West North Central	8,716	9,885	-12.0%	3,008	3,204	5,708	6,681	0	0	0	0
Iowa	2,242	2,434	-7.9%	0	0	2,242	2,434	0	0	0	0
Kansas	1,390	1,501	-7.5%	0	0	1,390	1,501	0	0	0	0
Minnesota	1,694	2,413	-30.0%	671	683	1,024	1,730	0	0	0	0
Missouri	1,886	1,857	1.6%	833	841	1,052	1,016	0	0	0	0
Nebraska	1,504	1,680	-10.0%	1,504	1,680	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	50,216	53,351	-5.9%	3,785	4,154	43,366	45,449	1,708	2,139	1,358	1,609
Delaware	1,305	1,159	13.0%	0	0	1,220	1,048	0	0	86	111
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	10,573	11,366	-7.0%	1,575	1,693	8,998	9,672	0	0	0	0
Georgia	6,096	6,748	-9.7%	0	0	5,949	6,651	0	0	147	97
Maryland	2,251	2,666	-16.0%	0	0	1,471	1,777	780	889	0	0
North Carolina	11,378	11,313	0.6%	0	0	10,641	10,269	737	1,044	0	0
South Carolina	3,493	4,155	-16.0%	2,134	2,407	233	347	0	0	1,126	1,401
Virginia	15,120	15,943	-5.2%	75	54	14,854	15,684	191	205	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	5,405	5,292	2.1%	2,212	2,363	3,193	2,929	0	0	0	0
Alabama	1,045	824	27.0%	0	0	1,045	824	0	0	0	0
Kentucky	2,455	2,562	-4.2%	2,212	2,363	243	199	0	0	0	0
Mississippi	236	231	2.1%	0	0	236	231	0	0	0	0
Tennessee	1,669	1,675	-0.4%	0	0	1,669	1,675	0	0	0	0
West South Central	11,627	13,020	-11.0%	0	0	11,438	12,417	189	603	0	0
Arkansas	1,472	1,097	34.0%	0	0	1,472	1,097	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	453	470	-3.6%	0	0	453	470	0	0	0	0
Texas	9,702	11,453	-15.0%	0	0	9,513	10,850	189	603	0	0
Mountain	6,774	6,454	5.0%	332	327	5,720	5,573	721	554	0	0
Arizona	747	950	-21.0%	0	0	747	950	0	0	0	0
Colorado	1,283	1,360	-5.7%	0	0	1,283	1,360	0	0	0	0
Idaho	945	683	38.0%	332	327	113	157	500	199	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	1,716	1,504	14.0%	0	0	1,716	1,504	0	0	0	0
New Mexico	409	168	144.0%	0	0	409	168	0	0	0	0
Utah	1,674	1,789	-6.4%	0	0	1,453	1,435	221	354	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	51,258	56,662	-9.5%	1,606	3,936	36,959	37,747	12,332	14,634	361	346
California	44,573	48,145	-7.4%	108	920	32,125	32,654	11,980	14,225	361	346
Oregon	5,631	5,758	-2.2%	1,498	1,453	3,780	3,895	352	409	0	0
Washington	1,053	2,760	-62.0%	0	1,562	1,053	1,198	0	0	0	0
Pacific Noncontiguous	712	801	-11.0%	0	0	0	0	712	801	0	0
Alaska	712	801	-11.0%	0	0	0	0	712	801	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	257,494	270,235	-4.7%	22,726	23,580	214,819	223,513	16,874	19,790	3,075	3,352

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Table 5.14. Consumption of Biogenic Municipal Solid Waste for Electricity Generation by State, by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State				Electric Power Sector							
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	3,391,400	3,567,698	-4.9%	0	0	3,251,436	3,393,693	139,964	174,005	0	0
Connecticut	1,152,812	1,142,714	0.9%	0	0	1,152,812	1,142,714	0	0	0	0
Maine	247,953	286,752	-14.0%	0	0	107,989	112,747	139,964	174,005	0	0
Massachusetts	1,874,608	2,015,957	-7.0%	0	0	1,874,608	2,015,957	0	0	0	0
New Hampshire	116,027	122,275	-5.1%	0	0	116,027	122,275	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	5,092,928	5,448,704	-6.5%	0	0	3,952,827	4,292,063	1,140,101	1,156,641	0	0
New Jersey	1,280,530	1,431,562	-11.0%	0	0	950,747	1,087,763	329,783	343,799	0	0
New York	1,958,517	2,054,078	-4.7%	0	0	1,388,113	1,495,386	570,404	558,692	0	0
Pennsylvania	1,853,881	1,963,064	-5.6%	0	0	1,613,967	1,708,914	239,914	254,150	0	0
East North Central	179,378	233,587	-23.0%	35,106	34,080	0	0	144,272	199,507	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	18,485	19,959	-7.4%	0	0	0	0	18,485	19,959	0	0
Michigan	125,787	179,548	-30.0%	0	0	0	0	125,787	179,548	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	35,106	34,080	3.0%	35,106	34,080	0	0	0	0	0	0
West North Central	482,950	672,132	-28.0%	262,383	432,826	209,879	227,847	10,688	11,459	0	0
Iowa	0	0	--	0	0	0	0	0	0	0	0
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	482,950	672,132	-28.0%	262,383	432,826	209,879	227,847	10,688	11,459	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	5,297,915	5,700,696	-7.1%	0	0	4,876,934	5,248,306	420,981	452,390	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	3,545,259	3,878,338	-8.6%	0	0	3,545,259	3,878,338	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	610,344	648,455	-5.9%	0	0	610,344	648,455	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	1,142,312	1,173,903	-2.7%	0	0	721,331	721,513	420,981	452,390	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	10,086	8,805	15.0%	0	0	0	0	0	0	10,086	8,805
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	0	0	--	0	0	0	0	0	0	0	0
Oklahoma	10,086	8,805	15.0%	0	0	0	0	0	0	10,086	8,805
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	650,245	697,555	-6.8%	0	0	650,245	697,555	0	0	0	0
California	385,958	426,524	-9.5%	0	0	385,958	426,524	0	0	0	0
Oregon	114,155	112,909	1.1%	0	0	114,155	112,909	0	0	0	0
Washington	150,132	158,122	-5.1%	0	0	150,132	158,122	0	0	0	0
Pacific Noncontiguous	453,635	454,307	-0.1%	0	0	0	0	453,635	454,307	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	453,635	454,307	-0.1%	0	0	0	0	453,635	454,307	0	0
U.S. Total	15,558,537	16,783,484	-7.3%	297,489	466,906	12,941,321	13,859,464	2,309,641	2,448,309	10,086	8,805

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

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Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

Chapter 6

Fossil Fuel Stocks for Electricity Generation

Table 6.1. Stocks of Coal, Petroleum Liquids, and Petroleum Coke: Electric Power Sector, 2009 - 2019

Period	Electric Power Sector			Electric Utilities			Independent Power Producers		
	Coal (Thousand Tons)	Petroluem Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroluem Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)	Coal (Thousand Tons)	Petroluem Liquids (Thousand Barrels)	Petroleum Coke (Thousand Tons)
End of Year Stocks									
2009	189,467	38,604	1,394	154,815	25,205	1,194	34,652	13,399	201
2010	174,917	34,841	1,019	143,744	23,934	850	31,173	10,908	168
2011	172,387	33,742	508	142,103	24,544	404	30,284	9,198	104
2012	185,116	30,862	495	150,942	22,513	414	34,174	8,349	81
2013	147,884	30,387	390	120,792	21,208	303	27,092	9,179	86
2014	151,548	32,322	827	116,684	21,304	686	34,864	11,018	142
2015	195,548	31,694	1,340	153,226	20,253	1,163	42,322	11,441	177
2016	162,009	30,593	845	130,885	19,767	603	31,124	10,827	241
2017	137,687	28,089	864	114,782	19,047	692	22,905	9,041	171
2018	102,793	25,977	539	84,728	16,553	521	18,065	9,423	19
2019	128,176	25,960	471	104,265	16,435	428	23,911	9,525	43
Year 2017, End of Month Stocks									
January	156,214	30,536	768	125,221	19,681	540	30,994	10,855	228
February	160,502	30,293	756	128,051	19,517	544	32,451	10,776	212
March	161,815	30,939	785	128,645	20,342	558	33,170	10,597	227
April	163,937	30,688	844	130,461	20,268	622	33,475	10,420	221
May	162,542	30,326	772	129,300	19,893	562	33,242	10,433	210
June	158,014	29,974	742	126,564	19,823	535	31,450	10,151	207
July	145,811	29,798	724	117,584	19,686	544	28,228	10,111	180
August	141,204	29,533	749	114,228	19,491	569	26,976	10,042	181
September	139,571	29,123	798	113,247	19,319	624	26,324	9,805	173
October	141,463	28,976	862	114,939	19,119	683	26,524	9,857	179
November	143,424	29,227	859	117,758	19,397	677	25,666	9,830	182
December	137,687	28,089	864	114,782	19,047	692	22,905	9,041	171
Year 2018, End of Month Stocks									
January	123,235	25,853	720	103,761	17,653	579	19,474	8,200	141
February	120,526	26,831	692	101,532	18,213	561	18,994	8,618	131
March	126,008	26,763	736	106,377	18,301	612	19,631	8,462	124
April	128,571	26,608	731	107,870	18,236	647	20,701	8,372	84
May	127,982	26,794	709	107,176	18,315	648	20,806	8,479	61
June	121,041	26,494	591	101,498	17,964	526	19,544	8,530	65
July	110,348	25,912	668	93,099	17,412	614	17,249	8,500	53
August	103,744	24,815	625	87,944	16,602	580	15,800	8,213	45
September	100,384	24,595	608	84,696	16,378	557	15,688	8,217	51
October	104,855	24,591	541	87,394	16,183	511	17,461	8,409	30
November	104,075	24,720	557	86,252	16,114	540	17,823	8,606	16
December	102,793	25,977	539	84,728	16,553	521	18,065	9,423	19
Year 2019, End of Month Stocks									
January	99,145	25,791	528	81,550	16,464	518	17,595	9,327	9
February	98,637	26,154	505	81,171	16,781	494	17,467	9,373	11
March	96,932	26,202	503	79,482	16,870	482	17,450	9,332	21
April	108,072	26,330	513	88,197	16,994	500	19,875	9,336	13
May	115,700	26,407	444	93,461	17,063	434	22,239	9,344	10
June	116,861	26,185	388	93,750	16,862	381	23,111	9,323	7
July	110,661	25,827	354	89,490	16,598	347	21,171	9,230	8
August	110,268	25,208	380	89,041	16,128	372	21,227	9,080	8
September	110,615	25,448	292	89,616	16,352	281	20,998	9,096	11
October	118,566	25,413	292	96,194	16,359	277	22,372	9,055	16
November	122,357	25,720	464	99,459	16,480	407	22,898	9,240	57
December	128,176	25,960	471	104,265	16,435	428	23,911	9,525	43

Notes: See Glossary for definitions. Values are final.
See Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms. Totals may not equal sum of components because of independent rounding.
Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms.
Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following: Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report; and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

**Table 6.2 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by State, 2019 and 2018**

Census Division and State	Coal (Thousand Tons)			Petroleum Liquids (Thousand Barrels)			Petroleum Coke (Thousand Tons)		
	December 2019	December 2018	Percentage Change	December 2019	December 2018	Percentage Change	December 2019	December 2018	Percentage Change
New England	465	605	-23.2%	3,409	3,385	0.7%	0	0	--
Connecticut	W	W	W	1,202	1,227	-2.0%	0	0	--
Maine	0	0	--	231	197	17.3%	0	0	--
Massachusetts	0	0	--	1,386	1,354	2.4%	0	0	--
New Hampshire	W	W	W	345	374	-7.9%	0	0	--
Rhode Island	0	W	W	207	195	6.5%	0	0	--
Vermont	0	0	--	NM	39	NM	0	0	--
Middle Atlantic	4,612	3,511	31.4%	5,671	5,217	8.7%	0	0	--
New Jersey	W	W	W	764	644	18.6%	0	0	--
New York	W	W	W	3,504	3,234	8.3%	0	0	--
Pennsylvania	4,427	3,261	35.8%	1,404	1,338	4.9%	0	0	--
East North Central	28,377	21,289	33.3%	1,180	1,062	11.2%	116	W	W
Illinois	4,385	5,209	-15.8%	NM	69	NM	0	0	--
Indiana	8,900	6,033	47.5%	164	97	68.8%	W	W	W
Michigan	4,998	4,438	12.6%	NM	291	NM	W	W	W
Ohio	6,697	2,797	139.4%	480	411	16.8%	W	0	W
Wisconsin	3,397	2,812	20.8%	NM	194	NM	W	W	W
West North Central	22,810	21,125	8.0%	844	895	-5.6%	0	0	--
Iowa	4,659	3,798	22.7%	NM	130	NM	0	0	--
Kansas	3,227	3,465	-6.9%	110	119	-7.1%	0	0	--
Minnesota	3,743	2,748	36.2%	NM	103	NM	0	0	--
Missouri	7,070	7,177	-1.5%	326	366	-10.8%	0	0	--
Nebraska	2,597	2,218	17.1%	NM	105	NM	0	0	--
North Dakota	W	W	W	NM	27	NM	0	0	--
South Dakota	W	W	W	NM	46	NM	0	0	--
South Atlantic	23,185	16,726	38.6%	10,401	11,044	-5.8%	W	W	W
Delaware	W	W	W	524	550	-4.6%	0	0	--
District of Columbia	0	0	--	0	0	--	0	0	--
Florida	2,737	3,026	-9.6%	3,853	4,249	-9.3%	W	W	W
Georgia	5,045	3,194	58.0%	805	821	-2.0%	0	0	--
Maryland	1,723	1,536	12.2%	723	757	-4.5%	0	0	--
North Carolina	3,776	2,961	27.5%	1,214	1,234	-1.6%	0	0	--
South Carolina	2,398	1,850	29.6%	671	721	-6.9%	0	0	--
Virginia	W	582	W	2,456	2,573	-4.5%	0	0	--
West Virginia	6,263	W	W	154	139	10.8%	W	W	W
East South Central	12,837	9,721	32.1%	1,196	1,146	4.4%	0	0	--
Alabama	W	W	W	210	206	1.9%	0	0	--
Kentucky	6,582	4,881	34.9%	221	231	-4.5%	0	0	--
Mississippi	W	W	W	NM	33	NM	0	0	--
Tennessee	2,868	2,417	18.7%	756	675	11.9%	0	0	--
West South Central	18,248	13,146	38.8%	1,243	1,324	-6.1%	W	W	W
Arkansas	3,611	2,297	57.2%	163	168	-2.7%	0	0	--
Louisiana	2,588	1,867	38.6%	222	223	-0.4%	W	W	W
Oklahoma	2,578	2,988	-13.7%	93	95	-2.8%	0	0	--
Texas	9,471	5,994	58.0%	765	837	-8.6%	0	0	--
Mountain	16,447	15,671	5.0%	334	385	-13.3%	W	W	W
Arizona	3,325	2,525	31.7%	126	136	-7.6%	0	0	--
Colorado	3,581	3,964	-9.7%	118	127	-6.6%	0	0	--
Idaho	0	0	--	0	0	-36.8%	0	0	--
Montana	W	W	W	NM	36	NM	W	W	W
Nevada	W	W	W	2	2	21.6%	0	0	--
New Mexico	W	W	W	NM	28	NM	0	0	--
Utah	2,866	3,252	-11.9%	26	26	1.2%	0	0	--
Wyoming	4,644	3,783	22.8%	29	30	-4.1%	0	0	--
Pacific Contiguous	W	W	W	358	352	1.6%	0	0	--
California	0	0	--	177	176	0.8%	0	0	--
Oregon	W	W	W	80	80	0.2%	0	0	--
Washington	W	W	W	NM	96	NM	0	0	--
Pacific Noncontiguous	W	W	W	1,323	1,168	13.3%	0	0	--
Alaska	W	W	W	NM	245	NM	0	0	--
Hawaii	W	W	W	1,103	923	19.6%	0	0	--
U.S. Total	128,176	102,793	24.7%	25,960	25,977	-0.1%	471	539	-12.6%

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

NM = Not meaningful due to large relative standard error or excessive percentage change.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Negative generation denotes that electric power consumed for plant use exceeds gross generation.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report.

**Table 6.3 Stocks of Coal, Petroleum Liquids, and Petroleum Coke:
Electric Power Sector, by Census Divison, 2019 and 2018**

	Electric Power Sector			Electric Utilities		Independent Power Producers	
Census Division	December 2019	December 2018	Percentage Change	December 2019	December 2018	December 2019	December 2018
Coal (Thousand Tons)							
New England	465	605	-23.2%	W	W	W	W
Middle Atlantic	4,612	3,511	31.4%	0	0	4,612	3,511
East North Central	28,377	21,289	33.3%	18,492	W	9,885	W
West North Central	22,810	21,125	8.0%	22,810	21,125	0	0
South Atlantic	23,185	16,726	38.6%	20,619	14,437	2,567	2,289
East South Central	12,837	9,721	32.1%	12,837	9,721	0	0
West South Central	18,248	13,146	38.8%	13,016	9,738	5,232	3,407
Mountain	16,447	15,671	5.0%	W	W	W	W
Pacific Contiguous	W	W	W	W	W	W	W
Pacific Noncontiguous	W	W	W	W	W	W	W
U.S. Total	128,176	102,793	24.7%	104,265	84,728	23,911	18,065
Petroleum Liquids (Thousand Barrels)							
New England	3,409	3,385	0.7%	497	520	2,911	2,865
Middle Atlantic	5,671	5,217	8.7%	2,138	1,833	3,534	3,384
East North Central	1,180	1,062	11.2%	717	709	463	353
West North Central	844	895	-5.6%	819	868	NM	27
South Atlantic	10,401	11,044	-5.8%	8,271	8,803	2,130	2,241
East South Central	1,196	1,146	4.4%	1,104	1,061	92	85
West South Central	1,243	1,324	-6.1%	1,025	1,026	218	297
Mountain	334	385	-13.3%	306	338	28	47
Pacific Contiguous	358	352	1.6%	278	273	79	80
Pacific Noncontiguous	1,323	1,168	13.3%	1,280	1,123	43	44
U.S. Total	25,960	25,977	-0.1%	16,435	16,553	9,525	9,423
Petroleum Coke (Thousand Tons)							
New England	0	0	--	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0
East North Central	116	W	W	W	W	W	0
West North Central	0	0	--	0	0	0	0
South Atlantic	W	W	W	W	W	W	W
East South Central	0	0	--	0	0	0	0
West South Central	W	W	W	W	W	0	0
Mountain	W	W	W	0	0	W	W
Pacific Contiguous	0	0	--	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0
U.S. Total	471	539	-12.6%	428	521	43	19

W = Withheld to avoid disclosure of individual company data.

Notes: See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form-923.

Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form-923, 'Power Plant Operations Report.'

Table 6.4. Stocks of Coal by Coal Rank: Electric Power Sector, 2009 - 2019
(Thousand Tons)

		Electric Power Sector			
Period		Bituminous Coal	Subbituminous Coal	Lignite Coal	Total
End of Year Stocks					
	2009	91,922	92,448	5,097	189,467
	2010	81,108	86,915	6,894	174,917
	2011	82,056	85,151	5,179	172,387
	2012	86,437	93,833	4,846	185,116
	2013	73,113	69,720	5,051	147,884
	2014	72,771	72,552	6,225	151,548
	2015	82,004	108,614	4,931	195,548
	2016	67,241	90,376	4,393	162,009
	2017	56,140	77,875	3,672	137,687
	2018	41,507	58,247	3,039	102,793
	2019	54,843	69,942	3,124	128,176
Year 2017, End of Month Stocks					
	January	65,797	86,082	4,335	156,214
	February	67,752	88,326	4,424	160,502
	March	67,783	89,381	4,651	161,815
	April	68,195	90,736	5,005	163,937
	May	68,333	89,005	5,204	162,542
	June	66,591	86,722	4,701	158,014
	July	60,766	80,765	4,281	145,811
	August	59,208	77,758	4,238	141,204
	September	58,453	77,173	3,945	139,571
	October	59,122	78,821	3,519	141,463
	November	59,427	79,916	4,081	143,424
	December	56,140	77,875	3,672	137,687
Year 2018, End of Month Stocks					
	January	47,910	72,251	3,074	123,235
	February	47,658	69,960	2,909	120,526
	March	49,027	73,768	3,213	126,008
	April	50,499	74,747	3,324	128,571
	May	51,393	73,377	3,212	127,982
	June	48,411	69,439	3,191	121,041
	July	44,487	63,014	2,847	110,348
	August	42,359	58,570	2,816	103,744
	September	40,384	57,155	2,845	100,384
	October	42,588	59,252	3,016	104,855
	November	42,392	58,575	3,108	104,075
	December	41,507	58,247	3,039	102,793
Year 2019, End of Month Stocks					
	January	39,894	56,367	2,883	99,145
	February	41,235	54,664	2,738	98,637
	March	44,238	49,467	3,054	96,932
	April	48,923	55,805	3,344	108,072
	May	51,971	60,325	3,023	115,700
	June	53,689	60,294	2,551	116,861
	July	50,057	57,593	2,670	110,661
	August	49,610	57,934	2,409	110,268
	September	48,834	59,057	2,395	110,615
	October	51,573	64,046	2,590	118,566
	November	52,621	66,446	2,959	122,357
	December	54,843	69,942	3,124	128,176

Notes: See Glossary for definitions.

Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

and predecessor forms. Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-906, Power Plant Report; U.S. Energy Information Administration, Form EIA-920 Combined Heat and Power Plant Report, and predecessor forms. Beginning with 2008 data, the Form EIA-923, Power Plant Operations Report, replaced the following:

Form EIA-906, Power Plant Report; Form EIA-920, Combined Heat and Power Plant Report; Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report;

and Federal Energy Regulatory Commission, FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants.

Chapter 7

Receipts, Cost, and Quality of Fossil Fuels

Table 7.1. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 2009 through 2019

	Coal				Petroleum				Natural Gas		All Fossil Fuels
			Average Cost				Average Cost			Average Cost	Average Cost
Period	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	(Dollars per MMBtu)	(Dollars per Ton)	Receipts (Thousand Barrels)	Average Sulfur Percent by Weight	(Dollars per MMBtu)	(Dollars per Barrel)	Receipts (Thousand Mcf)	(Dollars per MMBtu)	(Dollars per MMBtu)
2009	981,477	1.01	2.21	43.74	88,951	2.14	7.02	41.64	8,118,550	4.74	3.04
2010	979,918	1.16	2.27	44.64	75,285	2.14	9.54	56.35	8,673,070	5.09	3.26
2011	956,538	1.19	2.39	46.65	66,058	2.49	12.48	73.29	9,056,164	4.72	3.29
2012	841,183	1.25	2.38	46.09	40,364	3.61	12.48	73.30	9,531,389	3.42	2.83
2013	823,222	1.29	2.34	45.33	43,714	3.54	11.57	68.09	8,503,424	4.33	3.09
2014	854,560	1.32	2.37	45.96	54,488	3.56	11.60	68.12	8,431,423	5.00	3.31
2015	782,929	1.29	2.22	42.86	48,804	3.38	6.74	39.51	9,842,581	3.23	2.65
2016	650,770	1.34	2.11	40.64	37,637	3.69	5.24	30.46	10,271,180	2.87	2.47
2017	642,364	1.28	2.06	39.27	32,672	3.59	7.10	41.23	9,628,733	3.37	2.65
2018	596,215	1.31	2.06	39.25	37,341	3.31	9.68	56.82	10,885,764	3.55	2.83
2019	560,153	1.31	2.02	38.70	24,556	3.03	9.07	53.55	11,693,486	2.89	2.50

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.
- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.2. Receipts and Quality of Coal Delivered for the Electric Power Industry, 2009 through 2019

Period	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
2009	418,688	1.77	10.5	484,007	0.34	5.8	64,966	0.95	14.0
2010	403,619	1.90	10.4	491,425	0.33	5.8	71,416	0.90	14.1
2011	380,184	2.01	10.5	488,366	0.33	5.8	75,675	0.90	14.4
2012	317,398	2.23	10.6	442,674	0.32	5.8	71,848	0.93	14.6
2013	312,821	2.33	10.5	429,283	0.32	5.8	71,191	0.92	14.3
2014	334,082	2.34	10.3	440,013	0.31	5.8	71,534	0.90	14.1
2015	289,093	2.40	10.4	421,127	0.32	5.8	65,826	0.89	14.1
2016	245,141	2.43	10.3	333,241	0.31	5.8	64,426	0.91	14.0
2017	224,500	2.45	10.3	350,580	0.31	5.6	59,665	0.96	14.0
2018	205,783	2.55	10.1	329,974	0.31	5.7	52,438	0.91	13.4
2019	198,016	2.52	10.0	309,029	0.32	5.7	46,781	0.90	13.3

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Bituminous coal includes anthracite and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

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- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.3. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 2009 through 2019

	Coal			Petroleum			Natural Gas
Period	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Cubic Foot
2009	9,902	1.01	8.9	141,321	2.14	0.2	1,025
2010	9,842	1.16	8.8	140,598	2.14	0.2	1,022
2011	9,762	1.19	8.8	139,795	2.49	0.4	1,021
2012	9,668	1.25	8.8	139,567	3.61	0.5	1,023
2013	9,661	1.29	8.7	139,671	3.54	0.5	1,026
2014	9,710	1.32	8.6	139,713	3.56	0.5	1,029
2015	9,634	1.29	8.6	139,681	3.38	0.5	1,034
2016	9,617	1.34	8.7	138,384	3.69	0.5	1,034
2017	9,544	1.28	8.4	138,324	3.59	0.4	1,034
2018	9,536	1.31	8.3	139,762	3.31	0.3	1,033
2019	9,592	1.31	8.3	140,549	3.03	0.3	1,034

* = Value is less than half of the smallest unit of measure. (e.g., for values with no decimals, the smallest unit is 1 then values under 0.5 are shown as *.)

NM = Not meaningful due to large relative standard error or excessive percentage change.

W = Withheld to avoid disclosure of individual company data.

Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- All values are final.

- See Glossary for definitions.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.

- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.4. Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 2009 through 2019

	Coal								Petroleum		Natural Gas		Total Fossil	
	Bituminous		Subbituminous		Lignite		All Coal Ranks							
Period	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)	Receipts (Trillion Btu)	Average Cost (Dollars per MMBtu)
2009	10,010	2.75	8,421	1.64	835	1.58	19,438	2.21	528	7.02	8,319	4.74	28,285	3.04
2010	9,652	2.81	8,545	1.73	925	1.62	19,290	2.27	445	9.54	8,867	5.09	28,602	3.26
2011	9,040	2.94	8,498	1.91	986	1.62	18,676	2.39	388	12.48	9,251	4.72	28,314	3.29
2012	7,502	2.89	7,722	1.97	931	1.80	16,266	2.38	237	12.48	9,747	3.42	26,249	2.83
2013	7,351	2.77	7,511	2.00	927	1.78	15,907	2.34	256	11.57	8,721	4.33	24,884	3.09
2014	7,883	2.74	7,681	2.06	934	1.77	16,595	2.37	320	11.60	8,679	5.00	25,594	3.31
2015	6,797	2.58	7,353	1.94	855	1.92	15,086	2.22	286	6.74	10,174	3.23	25,546	2.65
2016	5,770	2.40	5,818	1.89	840	1.74	12,516	2.11	219	5.24	10,619	2.87	23,354	2.47
2017	5,279	2.31	6,123	1.90	773	1.66	12,261	2.06	190	7.10	9,952	3.37	22,403	2.65
2018	4,838	2.31	5,765	1.90	677	1.71	11,371	2.06	219	9.68	11,244	3.55	22,834	2.83
2019	4,670	2.26	5,401	1.86	601	1.68	10,746	2.02	145	9.07	12,093	2.89	22,984	2.50

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Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - All coal ranks subtotal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

Bituminous coal includes anthracite coal and beginning in 2011, coal-derived synthesis gas.

PETROLEUM - includes petroleum liquids (distillate fuel oil and residual fuel oil) and petroleum coke which includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.5. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	14,402,019	719,253	2.22	44.47	0.99	103.4	202,598	32,959	10.44	64.18	0.51	103.5
2010	14,226,995	713,094	2.27	45.33	1.14	98.8	189,790	31,099	13.94	85.07	0.48	101.0
2011	13,871,559	699,353	2.40	47.67	1.16	101.5	144,255	23,859	20.30	122.72	0.53	114.5
2012	11,939,543	609,445	2.43	47.51	1.18	99.0	86,030	14,252	22.11	133.44	0.41	81.3
2013	11,595,328	592,772	2.38	46.51	1.23	92.9	78,101	12,814	21.09	128.57	0.43	76.2
2014	12,064,810	614,728	2.39	46.95	1.21	98.3	98,357	16,161	19.90	121.14	0.44	82.0
2015	11,088,631	571,707	2.25	43.71	1.17	105.8	90,041	14,747	11.32	69.13	0.46	79.2
2016	9,256,878	476,207	2.16	42.01	1.21	95.4	73,294	11,985	9.16	56.02	0.45	74.0
2017	9,011,629	467,595	2.12	40.81	1.16	96.0	70,422	11,640	11.60	70.19	0.47	74.4
2018	8,351,036	435,964	2.11	40.35	1.18	91.6	84,050	13,896	14.39	87.09	0.37	75.3
2019	7,970,069	413,915	2.08	39.99	1.18	103.1	66,789	11,010	13.40	81.29	0.46	69.9
Year 2017												
January	797,433	41,477	2.14	41.15	1.14	88.2	6,680	1,100	11.15	67.71	0.44	77.4
February	737,614	38,372	2.11	40.53	1.20	107.5	4,658	770	11.60	70.11	0.46	67.3
March	706,986	36,570	2.12	41.05	1.20	101.9	10,582	1,778	11.59	68.99	0.53	132.1
April	650,562	33,339	2.14	41.82	1.22	105.4	4,760	788	11.41	68.97	0.46	67.0
May	702,581	36,058	2.16	42.07	1.21	95.9	4,694	778	11.40	68.79	0.45	60.4
June	786,845	40,393	2.13	41.51	1.20	91.9	5,771	951	10.93	66.29	0.47	73.1
July	821,488	42,591	2.11	40.78	1.11	81.6	4,826	803	10.96	65.87	0.45	67.9
August	890,849	46,092	2.11	40.79	1.18	93.7	5,210	855	11.12	67.72	0.46	67.7
September	741,814	38,857	2.08	39.69	1.10	98.1	4,823	792	11.80	71.87	0.48	65.5
October	733,109	38,175	2.09	40.12	1.15	104.8	5,030	825	12.05	73.47	0.49	62.1
November	726,042	38,128	2.11	40.23	1.13	105.8	7,044	1,156	12.00	73.12	0.41	97.4
December	716,306	37,543	2.11	40.20	1.11	89.5	6,345	1,043	12.93	78.67	0.42	58.3
Year 2018												
January	689,121	36,230	2.08	39.57	1.11	75.5	16,449	2,762	14.38	85.73	0.43	61.0
February	637,294	33,294	2.10	40.18	1.17	97.3	8,657	1,413	12.58	77.10	0.46	126.0
March	696,264	36,224	2.09	40.20	1.18	111.4	5,472	906	13.38	80.86	0.36	82.4
April	600,033	31,096	2.12	40.93	1.23	101.8	5,321	875	13.78	83.81	0.36	74.7
May	654,477	33,757	2.09	40.57	1.24	95.3	6,739	1,108	14.37	87.44	0.29	82.5
June	689,040	35,857	2.10	40.33	1.21	84.0	6,566	1,085	14.63	88.49	0.28	78.5
July	738,864	38,675	2.10	40.13	1.15	79.8	5,620	920	14.34	87.60	0.27	75.5
August	802,045	41,889	2.11	40.43	1.19	87.2	5,016	826	15.26	92.68	0.34	63.6
September	695,648	36,530	2.12	40.31	1.15	90.3	5,665	940	15.53	93.63	0.35	66.8
October	713,410	37,228	2.10	40.20	1.21	104.3	6,170	1,011	15.78	96.34	0.39	73.6
November	691,145	36,346	2.10	39.90	1.17	95.3	5,383	896	15.89	95.50	0.41	69.8
December	743,694	38,838	2.17	41.48	1.17	93.2	6,991	1,155	13.83	83.69	0.44	94.7
Year 2019												
January	738,951	38,447	2.16	41.50	1.17	92.6	6,257	1,035	12.58	76.07	0.42	61.2
February	631,870	33,072	2.14	40.80	1.15	98.6	6,768	1,106	13.06	79.89	0.46	99.9
March	588,088	30,001	2.14	41.91	1.36	94.2	6,258	1,034	14.36	86.91	0.42	88.8
April	646,989	33,355	2.13	41.31	1.20	135.4	5,460	901	14.73	89.26	0.47	85.9
May	664,887	34,246	2.12	41.12	1.21	112.6	5,038	832	14.15	85.71	0.48	63.5
June	651,381	33,621	2.10	40.75	1.19	99.7	5,247	869	13.31	80.39	0.47	63.3
July	723,359	37,713	2.08	39.90	1.15	88.8	4,455	740	13.30	80.10	0.46	55.6
August	746,495	38,909	2.06	39.56	1.14	97.4	3,921	656	13.65	81.53	0.48	44.4
September	676,927	35,149	2.01	38.79	1.17	98.7	6,831	1,119	12.41	75.70	0.45	85.5
October	643,227	33,488	2.01	38.57	1.13	122.6	4,958	815	13.28	80.79	0.47	62.2
November	624,023	32,728	2.01	38.36	1.14	106.9	6,206	1,013	12.83	78.61	0.48	82.2
December	633,871	33,185	1.95	37.30	1.12	110.8	5,390	891	13.65	82.59	0.47	63.9

Displayed values of zero may represent small values that round to zero.
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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.6. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2009	109,126	3,833	1.68	47.84	5.02	138.8	3,033,133	2,962,640	5.50	5.63	101.8	2.87	
2010	103,152	3,628	2.38	67.65	5.03	109.1	3,395,962	3,327,919	5.43	5.54	101.1	2.99	
2011	99,208	3,445	3.08	88.73	5.17	99.9	3,571,348	3,507,613	5.00	5.09	101.8	3.08	
2012	72,782	2,521	2.30	66.40	5.46	119.8	4,083,579	4,003,457	3.74	3.81	97.6	2.86	
2013	99,088	3,463	2.11	60.30	5.34	101.6	3,939,408	3,851,241	4.49	4.59	97.0	2.99	
2014	123,793	4,349	1.89	53.77	5.56	126.3	3,876,549	3,772,596	5.17	5.31	96.7	3.16	
2015	115,929	4,069	1.77	50.44	5.23	130.1	4,717,748	4,565,040	3.52	3.64	96.0	2.67	
2016	99,706	3,538	1.52	42.85	5.38	103.1	5,075,337	4,907,538	3.15	3.26	97.0	2.54	
2017	90,481	3,224	2.15	60.31	5.55	117.6	4,794,383	4,640,827	3.62	3.74	96.8	2.68	
2018	83,211	2,940	2.56	72.34	5.74	106.8	5,553,558	5,379,459	3.68	3.80	96.2	2.80	
2019	54,266	1,896	1.92	54.88	5.50	91.0	6,026,974	5,831,134	3.03	3.13	97.0	2.53	
Year 2017													
January	7,058	251	2.14	60.16	5.67	83.3	337,934	326,650	4.31	4.46	95.7	2.82	
February	7,593	271	2.00	56.03	5.85	124.3	294,739	285,524	3.80	3.92	96.7	2.62	
March	8,628	309	2.06	57.51	5.29	143.9	355,327	344,045	3.53	3.64	97.0	2.67	
April	5,835	208	2.00	55.96	5.34	188.7	337,897	327,119	3.52	3.63	97.7	2.65	
May	6,776	242	2.05	57.46	5.57	91.5	383,048	371,448	3.68	3.80	98.5	2.73	
June	8,386	298	2.14	60.07	5.55	105.5	441,947	428,006	3.55	3.66	97.6	2.67	
July	8,245	292	2.11	59.61	5.49	107.5	554,753	536,355	3.45	3.57	96.5	2.68	
August	7,676	273	2.11	59.17	5.45	119.8	519,869	502,857	3.42	3.53	96.7	2.62	
September	7,658	274	2.12	59.07	5.42	130.2	434,880	420,328	3.54	3.66	96.4	2.65	
October	7,454	265	2.37	66.84	5.58	154.2	389,164	376,992	3.55	3.66	97.1	2.63	
November	7,084	252	2.52	70.93	5.66	107.1	342,125	331,573	3.64	3.76	96.6	2.66	
December	8,088	287	2.17	60.99	5.74	123.5	402,703	389,931	3.71	3.83	95.6	2.74	
Year 2018													
January	7,009	248	2.38	67.41	5.31	83.4	423,606	410,310	5.20	5.37	95.5	3.41	
February	7,769	277	2.43	68.09	5.49	117.9	359,760	348,729	3.81	3.93	95.0	2.79	
March	7,841	281	2.54	70.89	5.54	141.5	397,572	384,900	3.46	3.57	96.4	2.64	
April	6,564	232	2.56	72.38	6.09	119.0	377,302	365,948	3.30	3.40	97.5	2.63	
May	4,344	152	2.41	68.58	6.09	108.3	452,870	438,567	3.24	3.35	94.8	2.63	
June	7,382	260	2.73	77.61	5.97	96.2	525,751	509,192	3.28	3.39	97.2	2.67	
July	8,147	287	2.73	77.48	5.73	100.4	632,132	612,044	3.27	3.38	95.1	2.69	
August	8,183	288	2.82	80.03	5.67	105.4	607,246	588,293	3.33	3.44	96.5	2.68	
September	7,493	263	3.05	86.74	5.59	101.2	535,618	518,216	3.28	3.39	97.0	2.68	
October	5,415	191	2.55	72.24	5.80	120.4	464,777	450,302	3.57	3.68	97.8	2.74	
November	6,524	229	2.23	63.55	5.88	116.4	390,167	378,446	4.26	4.39	94.9	2.93	
December	6,541	232	2.04	57.52	5.91	96.0	386,756	374,513	4.92	5.08	96.2	3.16	
Year 2019													
January	5,447	192	2.08	59.13	5.93	73.8	446,581	432,740	4.13	4.26	97.1	2.94	
February	4,486	155	2.27	65.75	5.78	69.4	414,367	398,782	3.76	3.90	95.9	2.84	
March	3,725	130	2.43	69.63	6.15	66.9	432,758	419,315	3.63	3.74	96.3	2.84	
April	3,159	111	2.71	76.93	5.65	101.5	401,329	388,531	3.05	3.15	96.7	2.55	
May	4,631	162	2.24	63.78	5.41	73.8	471,417	457,391	2.92	3.01	99.1	2.50	
June	3,740	130	2.18	62.61	5.15	85.7	546,353	529,347	2.73	2.82	97.6	2.43	
July	5,723	199	2.01	57.76	5.22	86.8	662,600	640,466	2.63	2.72	96.8	2.38	
August	6,693	235	1.72	48.82	5.15	115.7	680,091	657,152	2.52	2.61	96.6	2.31	
September	3,034	105	1.68	48.71	5.58	56.6	577,988	559,208	2.75	2.84	97.0	2.40	
October	1,738	60	1.51	43.76	5.45	92.3	496,610	480,428	2.69	2.78	96.7	2.35	
November	6,654	232	1.46	41.78	5.38	227.7	427,761	413,977	3.13	3.24	97.0	2.52	
December	5,236	183	1.14	32.50	5.44	132.2	469,120	453,799	3.12	3.22	96.9	2.50	

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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.7 Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	4,563,080	240,687	2.11	39.94	1.06	101.1	68,030	11,408	10.02	59.76	0.37	102.0
2010	4,555,898	243,585	2.20	41.15	1.21	96.0	49,598	8,420	14.80	87.19	0.35	89.9
2011	4,292,284	233,295	2.28	41.95	1.25	95.9	41,599	7,096	20.30	119.01	0.50	106.9
2012	4,036,436	218,341	2.21	40.92	1.42	104.9	23,922	4,073	22.34	131.28	0.44	79.8
2013	4,032,431	217,572	2.20	40.95	1.48	99.1	43,432	7,205	19.71	118.88	0.45	110.1
2014	4,243,949	226,600	2.25	42.20	1.61	100.1	71,774	11,980	19.90	119.36	0.45	101.0
2015	3,731,508	198,982	2.10	39.39	1.66	100.5	55,248	9,189	11.69	70.36	0.46	86.5
2016	3,047,358	164,648	1.93	35.69	1.73	91.8	25,975	4,410	9.93	58.56	0.48	75.1
2017	3,056,215	165,567	1.85	34.19	1.64	93.1	24,704	4,190	12.67	74.73	0.46	73.8
2018	2,849,062	152,015	1.89	35.41	1.70	94.2	47,699	8,022	14.52	86.39	0.44	81.7
2019	2,629,405	139,141	1.81	34.16	1.74	101.6	20,188	3,425	14.40	84.89	0.50	73.0
Year 2017												
January	297,849	16,042	1.92	35.75	1.59	96.7	2,862	488	13.96	82.04	0.47	105.5
February	254,381	13,690	1.88	34.92	1.59	110.9	1,514	254	11.89	70.84	0.50	69.9
March	251,712	13,439	1.88	35.27	1.75	103.1	1,436	247	11.97	69.71	0.44	85.2
April	235,324	12,633	1.85	34.48	1.66	99.2	1,436	242	12.28	72.85	0.44	81.4
May	238,355	12,976	1.86	34.11	1.67	97.1	1,790	306	11.55	67.69	0.45	78.7
June	239,687	13,070	1.86	34.15	1.67	87.3	1,559	267	10.88	63.53	0.42	65.0
July	257,789	14,218	1.85	33.64	1.55	80.5	1,775	303	10.73	62.88	0.48	79.1
August	279,845	15,249	1.83	33.52	1.64	91.5	1,702	289	11.16	65.68	0.43	72.0
September	258,366	13,963	1.82	33.65	1.63	92.0	1,543	267	11.35	65.70	0.42	67.7
October	250,339	13,545	1.83	33.87	1.60	99.0	2,399	406	11.71	69.17	0.50	118.1
November	243,578	13,224	1.79	33.00	1.64	88.3	2,544	434	13.15	77.15	0.56	110.2
December	248,991	13,519	1.83	33.70	1.68	81.5	4,145	688	15.82	95.35	0.43	44.3
Year 2018												
January	250,209	13,549	1.99	36.82	1.60	79.9	19,101	3,180	13.71	82.73	0.46	63.7
February	200,760	10,859	1.93	35.69	1.58	93.0	3,249	550	13.53	79.99	0.43	195.1
March	229,355	11,974	1.84	35.33	1.83	99.4	2,273	388	14.17	82.79	0.43	107.3
April	202,887	10,815	1.88	35.20	1.61	107.5	1,427	242	14.45	84.93	0.44	61.3
May	223,521	11,725	1.87	35.68	1.78	98.4	2,731	459	14.46	86.28	0.46	95.4
June	227,121	12,009	1.84	34.83	1.84	89.2	2,614	444	15.89	93.43	0.40	92.9
July	235,760	12,666	1.87	34.83	1.73	82.1	1,775	301	16.08	94.43	0.45	64.8
August	260,087	13,942	1.86	34.73	1.68	88.4	1,864	315	15.92	93.84	0.42	59.8
September	235,579	12,761	1.82	33.63	1.56	94.5	2,082	351	15.17	89.90	0.39	82.5
October	274,139	14,529	1.89	35.60	1.72	113.8	3,039	517	15.83	92.93	0.41	127.4
November	248,768	13,265	1.92	35.95	1.73	97.0	3,328	566	15.95	93.64	0.42	119.9
December	260,878	13,920	1.94	36.42	1.68	99.1	4,215	709	14.20	84.15	0.46	132.8
Year 2019												
January	258,502	13,732	1.91	35.91	1.75	94.9	2,550	426	12.15	72.73	0.50	53.5
February	208,595	11,136	1.83	34.30	1.66	96.1	2,052	344	13.83	82.61	0.46	98.6
March	225,693	11,804	1.88	35.97	1.87	96.4	1,312	223	14.97	88.25	0.54	79.1
April	215,930	11,232	1.84	35.44	1.89	127.7	1,400	238	15.72	92.48	0.51	72.3
May	219,210	11,432	1.83	35.06	1.91	118.6	1,628	278	15.67	91.68	0.49	76.9
June	210,718	11,178	1.76	33.24	1.84	105.7	1,505	255	15.10	89.08	0.48	74.1
July	210,437	11,271	1.79	33.38	1.69	83.9	1,409	240	15.49	90.87	0.48	53.7
August	228,948	12,067	1.78	33.72	1.69	96.5	1,184	203	16.40	95.62	0.49	57.7
September	207,547	11,127	1.75	32.61	1.59	95.7	1,361	232	13.79	81.01	0.56	72.0
October	219,896	11,624	1.77	33.58	1.69	114.0	1,713	292	15.05	88.23	0.52	80.0
November	214,440	11,469	1.77	33.22	1.61	101.1	1,652	281	13.67	80.52	0.49	78.7
December	209,490	11,070	1.75	33.07	1.66	104.6	2,423	414	13.65	79.88	0.50	107.5

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Notes:
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COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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Table 7.8. Receipts, Average Cost, and Quality of Fossil Fuels: Independent Power Producers, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2009	49,619	1,732	1.31	37.63	3.87	93.6	4,087,573	3,987,721	4.30	4.41	100.7	3.18	
2010	30,079	1,050	1.74	49.80	3.84	72.3	4,212,611	4,119,103	4.94	5.05	100.6	3.57	
2011	33,643	1,175	2.54	72.85	4.55	84.6	4,252,040	4,158,617	4.62	4.72	100.8	3.52	
2012	23,024	801	0.82	23.98	5.49	92.1	4,810,553	4,696,637	3.17	3.25	93.8	2.74	
2013	16,150	575	W	W	5.39	65.6	4,025,263	3,917,898	4.25	4.36	92.8	W	
2014	13,781	488	2.48	70.31	5.33	70.9	4,054,540	3,934,672	4.90	5.05	92.7	3.52	
2015	14,550	524	2.45	68.22	5.26	67.3	4,683,291	4,530,195	2.94	3.04	93.2	2.57	
2016	13,573	492	2.50	68.88	5.44	69.9	4,791,729	4,634,518	2.54	2.63	94.0	2.29	
2017	0	0	--	--	--	0.0	4,346,156	4,201,573	3.08	3.19	94.0	2.54	
2018	0	0	--	--	--	0.0	4,889,212	4,727,692	3.40	3.52	94.6	2.84	
2019	0	0	--	--	--	0.0	5,242,547	5,062,877	2.70	2.80	96.0	2.40	
Year 2017													
January	0	0	--	--	--	0.0	308,468	297,985	3.99	4.13	93.5	2.92	
February	0	0	--	--	--	0.0	266,924	258,124	3.34	3.46	94.2	2.58	
March	0	0	--	--	--	0.0	309,192	299,108	3.22	3.33	94.1	2.58	
April	0	0	--	--	--	0.0	284,438	275,168	3.20	3.31	94.1	2.55	
May	0	0	--	--	--	0.0	315,966	305,806	3.21	3.32	94.8	2.58	
June	0	0	--	--	--	0.0	401,399	388,239	2.92	3.02	94.2	2.49	
July	0	0	--	--	--	0.0	510,043	492,821	2.88	2.98	93.8	2.50	
August	0	0	--	--	--	0.0	490,650	474,187	2.74	2.84	94.5	2.37	
September	0	0	--	--	--	0.0	410,946	396,673	2.66	2.75	93.9	2.30	
October	0	0	--	--	--	0.0	370,533	358,357	2.60	2.69	93.3	2.29	
November	0	0	--	--	--	0.0	310,914	300,784	3.03	3.13	93.1	2.47	
December	0	0	--	--	--	0.0	366,682	354,320	3.64	3.77	94.0	2.91	
Year 2018													
January	0	0	--	--	--	0.0	343,077	331,644	5.21	5.39	93.1	3.99	
February	0	0	--	--	--	0.0	312,835	302,657	3.38	3.49	93.7	2.80	
March	0	0	--	--	--	0.0	346,290	334,497	2.87	2.97	93.6	2.46	
April	0	0	--	--	--	0.0	319,774	309,352	2.96	3.06	94.1	2.51	
May	0	0	--	--	--	0.0	377,388	365,397	2.79	2.89	94.8	2.46	
June	0	0	--	--	--	0.0	422,237	408,330	2.89	2.98	95.3	2.53	
July	0	0	--	--	--	0.0	570,783	552,360	3.21	3.32	95.3	2.79	
August	0	0	--	--	--	0.0	565,773	547,533	3.22	3.33	95.1	2.76	
September	0	0	--	--	--	0.0	489,149	472,958	2.90	3.00	95.4	2.54	
October	0	0	--	--	--	0.0	419,722	405,657	3.20	3.31	94.9	2.68	
November	0	0	--	--	--	0.0	355,192	343,013	4.12	4.27	94.1	3.19	
December	0	0	--	--	--	0.0	366,993	354,294	4.49	4.65	95.0	3.39	
Year 2019													
January	0	0	--	--	--	0.0	398,896	385,014	3.88	4.02	95.6	3.05	
February	0	0	--	--	--	0.0	357,555	345,530	3.49	3.61	95.0	2.85	
March	0	0	--	--	--	0.0	371,920	359,394	3.30	3.41	95.0	2.73	
April	0	0	--	--	--	0.0	333,598	322,802	2.65	2.74	95.5	2.33	
May	0	0	--	--	--	0.0	372,853	360,800	2.53	2.61	96.4	2.28	
June	0	0	--	--	--	0.0	446,512	432,051	2.35	2.43	96.4	2.17	
July	0	0	--	--	--	0.0	592,358	572,083	2.43	2.51	96.4	2.26	
August	0	0	--	--	--	0.0	597,443	576,291	2.27	2.35	96.5	2.13	
September	0	0	--	--	--	0.0	504,061	486,741	2.38	2.47	96.5	2.19	
October	0	0	--	--	--	0.0	438,101	422,965	2.22	2.30	96.1	2.09	
November	0	0	--	--	--	0.0	388,489	374,471	2.77	2.88	95.5	2.41	
December	0	0	--	--	--	0.0	440,761	424,737	2.69	2.79	95.8	2.39	

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Notes:
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PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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Table 7.9. Receipts, Average Cost, and Quality of Fossil Fuels: Commercial Sector, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Average Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	41,182	1,876	2.90	63.68	1.67	104.3	3,517	583	10.82	65.26	0.45	122.1
2010	37,778	1,747	2.82	61.06	1.77	101.6	2,395	400	15.24	91.25	0.38	106.3
2011	35,892	1,686	2.92	62.24	1.78	101.1	1,959	325	19.67	118.66	0.55	108.0
2012	4,427	192	3.41	78.71	2.75	13.2	247	43	W	W	0.00	11.0
2013	3,507	151	W	W	3.05	11.2	0	0	--	--	--	0.0
2014	4,096	182	3.12	70.30	2.50	17.1	0	0	--	--	--	0.0
2015	2,439	109	2.85	63.90	2.55	13.6	0	0	--	--	--	0.0
2016	1,288	57	2.69	60.89	3.03	8.3	0	0	--	--	--	0.0
2017	548	24	2.78	63.31	2.99	3.9	0	0	--	--	--	0.0
2018	290	13	2.94	66.52	3.04	2.2	0	0	--	--	--	0.0
2019	193	8	2.92	66.55	3.01	1.6	0	0	--	--	--	0.0
Year 2017												
January	111	5	2.77	62.82	2.99	6.9	0	0	--	--	--	0.0
February	91	4	2.77	63.46	2.95	6.9	0	0	--	--	--	0.0
March	104	5	2.77	63.24	3.02	7.0	0	0	--	--	--	0.0
April	1	0	2.77	63.60	2.96	0.1	0	0	--	--	--	0.0
May	11	0	2.77	63.54	3.23	1.2	0	0	--	--	--	0.0
June	17	1	2.77	63.65	3.02	1.8	0	0	--	--	--	0.0
July	0	0	--	--	--	0.0	0	0	--	--	--	0.0
August	4	0	2.77	63.24	2.77	0.4	0	0	--	--	--	0.0
September	72	3	2.77	63.24	2.96	6.9	0	0	--	--	--	0.0
October	35	2	2.79	64.50	2.96	3.6	0	0	--	--	--	0.0
November	13	1	2.79	63.70	3.04	1.1	0	0	--	--	--	0.0
December	89	4	2.79	63.31	3.01	6.0	0	0	--	--	--	0.0
Year 2018												
January	95	4	2.92	66.58	3.11	5.5	0	0	--	--	--	0.0
February	31	1	2.92	66.05	3.19	2.3	0	0	--	--	--	0.0
March	5	0	2.92	66.20	3.16	0.4	0	0	--	--	--	0.0
April	0	0	--	--	--	0.0	0	0	--	--	--	0.0
May	0	0	--	--	--	0.0	0	0	--	--	--	0.0
June	0	0	--	--	--	0.0	0	0	--	--	--	0.0
July	0	0	--	--	--	0.0	0	0	--	--	--	0.0
August	0	0	--	--	--	0.0	0	0	--	--	--	0.0
September	0	0	--	--	--	0.0	0	0	--	--	--	0.0
October	52	2	2.94	66.53	2.87	5.5	0	0	--	--	--	0.0
November	62	3	2.94	66.44	2.99	5.8	0	0	--	--	--	0.0
December	46	2	2.97	66.83	3.05	4.4	0	0	--	--	--	0.0
Year 2019												
January	27	1	2.90	65.89	3.00	2.0	0	0	--	--	--	0.0
February	37	2	2.90	65.51	2.95	3.0	0	0	--	--	--	0.0
March	48	2	2.90	65.86	2.94	3.6	0	0	--	--	--	0.0
April	2	0	2.90	65.28	2.90	0.3	0	0	--	--	--	0.0
May	0	0	--	--	--	0.0	0	0	--	--	--	0.0
June	2	0	2.90	66.38	3.02	0.4	0	0	--	--	--	0.0
July	1	0	2.97	67.69	2.94	0.2	0	0	--	--	--	0.0
August	0	0	--	--	--	0.0	0	0	--	--	--	0.0
September	0	0	--	--	--	0.0	0	0	--	--	--	0.0
October	23	1	2.96	67.99	3.17	2.7	0	0	--	--	--	0.0
November	31	1	2.96	67.99	3.17	3.0	0	0	--	--	--	0.0
December	21	1	2.96	67.34	2.91	1.9	0	0	--	--	--	0.0

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.
PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commerical Sector, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas					All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)
Annual Totals												
2009	252	9	1.65	46.54	5.11	102.8	81,134	79,308	5.18	5.30	105.0	4.58
2010	410	15	2.19	60.59	5.67	122.5	92,055	90,130	5.39	5.51	105.1	4.83
2011	268	9	W	W	5.46	147.4	95,287	93,306	5.20	5.31	107.2	W
2012	0	0	--	--	--	0.0	18,315	18,008	5.88	5.98	16.2	W
2013	0	0	--	--	--	0.0	5,497	5,450	W	W	4.6	W
2014	0	0	--	--	--	0.0	5,849	5,795	5.42	5.47	4.9	4.47
2015	0	0	--	--	--	0.0	6,499	6,371	4.11	4.19	5.5	3.76
2016	0	0	--	--	--	0.0	8,005	7,766	3.85	3.97	6.1	3.69
2017	0	0	--	--	--	0.0	7,841	7,593	3.82	3.95	4.9	3.75
2018	0	0	--	--	--	0.0	9,090	8,823	3.49	3.59	6.6	3.47
2019	0	0	--	--	--	0.0	9,429	9,087	3.26	3.39	6.7	3.26
Year 2017												
January	0	0	--	--	--	0.0	662	639	4.02	4.17	4.5	3.84
February	0	0	--	--	--	0.0	646	624	4.01	4.15	5.1	3.86
March	0	0	--	--	--	0.0	680	662	3.96	4.06	5.4	3.80
April	0	0	--	--	--	0.0	502	490	3.90	3.99	4.7	3.89
May	0	0	--	--	--	0.0	497	483	3.92	4.04	4.4	3.90
June	0	0	--	--	--	0.0	615	595	3.82	3.95	4.7	3.79
July	0	0	--	--	--	0.0	636	613	3.64	3.77	4.1	3.64
August	0	0	--	--	--	0.0	809	778	3.70	3.85	5.3	3.70
September	0	0	--	--	--	0.0	707	685	3.72	3.84	5.2	3.63
October	0	0	--	--	--	0.0	605	588	3.77	3.88	4.6	3.72
November	0	0	--	--	--	0.0	749	725	3.72	3.84	6.0	3.70
December	0	0	--	--	--	0.0	734	711	3.77	3.89	5.2	3.67
Year 2018												
January	0	0	--	--	--	0.0	844	818	3.63	3.74	7.1	3.56
February	0	0	--	--	--	0.0	709	688	3.72	3.84	6.5	3.69
March	0	0	--	--	--	0.0	768	746	3.59	3.69	6.8	3.58
April	0	0	--	--	--	0.0	732	713	3.49	3.58	7.3	3.49
May	0	0	--	--	--	0.0	776	758	3.47	3.55	7.4	3.47
June	0	0	--	--	--	0.0	670	650	3.57	3.67	5.8	3.57
July	0	0	--	--	--	0.0	790	760	3.39	3.52	5.8	3.39
August	0	0	--	--	--	0.0	786	764	3.42	3.52	5.8	3.42
September	0	0	--	--	--	0.0	744	723	3.38	3.48	6.3	3.38
October	0	0	--	--	--	0.0	792	770	3.36	3.45	7.2	3.33
November	0	0	--	--	--	0.0	723	701	3.41	3.52	6.6	3.37
December	0	0	--	--	--	0.0	756	732	3.41	3.52	6.6	3.39
Year 2019												
January	0	0	--	--	--	0.0	778	751	3.40	3.52	6.3	3.38
February	0	0	--	--	--	0.0	772	745	3.37	3.50	6.8	3.35
March	0	0	--	--	--	0.0	839	812	3.36	3.47	7.3	3.33
April	0	0	--	--	--	0.0	775	748	3.30	3.41	7.3	3.29
May	0	0	--	--	--	0.0	811	782	3.26	3.38	7.9	3.26
June	0	0	--	--	--	0.0	807	776	3.23	3.36	7.2	3.22
July	0	0	--	--	--	0.0	721	701	3.17	3.26	5.4	3.17
August	0	0	--	--	--	0.0	838	808	3.13	3.25	6.5	3.13
September	0	0	--	--	--	0.0	747	717	3.15	3.28	6.4	3.15
October	0	0	--	--	--	0.0	766	734	3.24	3.38	7.0	3.23
November	0	0	--	--	--	0.0	743	713	3.30	3.43	6.6	3.28
December	0	0	--	--	--	0.0	832	801	3.26	3.39	6.6	3.25

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Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

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- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.11. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2009 - 2019

	Coal						Petroleum Liquids					
	Receipts		Average Cost				Receipts		Average Cost			
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Barrels)	(Dollars per MMBtu)	(Dollars per Barrel)	Sulfur Percent by Weight	Percentage of Consumption
Annual Totals												
2009	431,686	19,661	2.81	61.68	1.22	99.5	55,899	9,232	9.83	59.52	0.83	112.8
2010	468,991	21,492	2.75	60.08	1.26	87.2	33,276	5,554	13.21	79.15	0.93	125.6
2011	476,108	22,204	2.93	62.86	1.33	99.5	28,939	4,878	17.67	104.83	1.08	144.8
2012	285,172	13,206	3.02	65.24	1.33	65.8	6,739	1,095	W	W	1.52	40.8
2013	275,543	12,727	W	W	1.32	64.4	2,431	394	18.20	112.29	1.43	15.8
2014	281,867	13,050	2.97	64.15	1.33	68.4	2,290	373	17.91	109.99	1.43	15.6
2015	263,630	12,132	2.72	59.17	1.35	71.4	2,359	385	13.45	82.47	1.42	16.9
2016	210,749	9,859	2.67	57.01	1.30	67.0	2,541	412	10.51	64.79	1.27	18.3
2017	192,637	9,178	2.49	52.29	1.35	70.7	1,850	297	11.18	69.57	1.42	15.2
2018	170,730	8,224	2.47	51.38	1.30	67.2	2,319	372	13.46	83.97	1.35	15.9
2019	146,324	7,088	2.55	52.69	1.19	65.1	1,684	275	13.19	80.82	1.47	14.5
Year 2017												
January	15,758	742	2.51	53.37	1.38	58.7	128	21	11.64	72.27	1.06	13.0
February	15,865	744	2.57	54.74	1.18	69.1	121	19	11.56	72.24	1.36	15.2
March	17,861	858	2.48	51.66	1.34	75.2	178	29	10.66	66.36	1.22	18.9
April	16,089	759	2.62	55.59	1.23	75.4	160	26	11.82	74.12	1.27	16.6
May	16,329	796	2.44	50.13	1.16	76.3	155	25	11.19	69.26	1.21	17.6
June	15,911	757	2.41	50.55	1.37	72.5	142	23	10.34	64.95	1.11	17.7
July	15,852	763	2.46	51.07	1.30	73.2	95	15	10.75	66.88	1.30	12.4
August	16,644	784	2.51	53.36	1.36	74.6	110	18	10.55	65.94	1.55	14.0
September	14,897	715	2.52	52.38	1.17	72.3	151	24	11.07	69.03	1.51	17.2
October	15,687	741	2.52	53.40	1.36	67.5	149	24	11.43	71.09	1.58	15.9
November	15,335	734	2.46	51.43	1.43	68.1	199	32	11.67	72.03	1.71	13.2
December	16,408	785	2.40	50.09	1.89	68.9	263	42	11.14	69.14	1.79	13.5
Year 2018												
January	15,751	758	2.46	51.13	1.18	61.0	408	65	12.64	79.32	1.32	13.7
February	14,274	683	2.48	51.82	1.32	60.9	187	30	11.38	71.32	1.20	15.9
March	15,612	747	2.51	52.40	1.31	67.4	234	38	12.59	78.52	1.32	23.5
April	13,476	643	2.52	52.79	1.35	67.0	153	24	13.24	83.77	1.23	17.6
May	14,544	704	2.51	51.92	1.24	71.9	149	24	14.33	87.27	1.47	16.1
June	14,489	697	2.49	51.65	1.28	71.9	107	17	13.54	84.39	1.48	10.5
July	14,900	724	2.41	49.69	1.32	75.3	138	22	14.64	89.87	1.42	13.2
August	13,930	668	2.48	51.76	1.31	70.4	135	22	14.45	89.97	1.39	15.5
September	12,593	600	2.53	53.10	1.35	63.7	155	25	14.38	89.73	1.12	19.7
October	12,410	598	2.47	51.18	1.38	67.1	180	29	14.50	91.01	1.37	14.9
November	14,259	701	2.50	50.92	1.15	69.1	206	33	14.01	87.74	1.58	15.0
December	14,492	701	2.35	48.52	1.47	64.1	268	43	13.75	85.58	1.46	19.7
Year 2019												
January	12,678	629	2.49	50.14	1.13	56.2	154	25	12.98	80.23	1.24	7.5
February	12,842	617	2.61	54.43	1.16	61.4	199	33	13.77	82.99	1.45	18.7
March	13,424	629	2.68	57.20	1.49	67.5	126	21	13.43	82.27	1.63	14.2
April	11,765	561	2.64	55.30	1.25	62.8	223	36	12.89	79.74	1.54	24.0
May	12,720	623	2.51	51.21	0.97	71.3	92	15	14.12	86.68	1.48	12.6
June	11,705	567	2.49	51.38	1.22	67.2	131	21	13.04	79.96	1.55	18.3
July	11,385	551	2.45	50.57	1.32	65.1	80	13	11.99	74.33	1.41	12.7
August	10,876	530	2.39	49.14	1.23	62.0	112	18	12.56	77.49	1.66	15.4
September	11,131	539	2.48	51.28	1.24	66.3	154	25	13.15	80.17	1.58	20.8
October	11,889	586	2.59	52.47	1.21	68.4	136	22	13.01	79.34	1.42	17.2
November	13,255	645	2.59	53.19	1.05	71.3	137	22	13.67	83.44	1.46	9.7
December	12,654	612	2.67	55.16	1.07	64.4	141	23	13.33	81.47	1.25	15.8

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Notes:

Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:

COAL - includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas. Prior to 2011, synthesis gas was included in the category of Other Gases.

PETROLEUM LIQUIDS - includes distillate fuel oil and residual fuel oil. Prior to 2013, petroleum liquids included distillate fuel oil, residual fuel oil, kerosene, jet fuel, waste oil, and, beginning in 2011, propane. Prior to 2011, propane was included in the category of Other Gases.

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- See Glossary for definitions.

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- See the Technical Notes for fuel conversion factors.

- Totals may not equal the sum of components because of independent rounding.

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Table 7.12. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial Sector, 2009 - 2019 (continued)

	Petroleum Coke						Natural Gas						All Fossil Fuels
	Receipts		Average Cost				Receipts		Average Cost			Average Cost	
Period	(Billion Btu)	(Thousand Tons)	(Dollars per MMBtu)	(Dollars per Ton)	Average Sulfur Percent by Weight	Percentage of Consumption	(Billion Btu)	(Thousand Mcf)	(Dollars per MMBtu)	(Dollars per Mcf)	Percentage of Consumption	(Dollars per MMBtu)	
Annual Totals													
2009	38,924	1,381	1.80	50.82	4.51	114.2	1,117,489	1,088,880	4.27	4.38	110.0	4.02	
2010	35,866	1,269	2.46	69.38	4.90	100.5	1,166,768	1,135,917	4.64	4.77	110.4	4.24	
2011	37,981	1,351	W	W	5.03	108.3	1,331,977	1,296,628	4.28	4.40	122.0	W	
2012	23,861	858	2.62	72.96	5.86	42.2	834,245	813,288	2.97	3.05	70.8	W	
2013	17,236	623	W	W	5.82	30.5	750,946	728,835	W	W	62.3	W	
2014	9,736	358	2.56	69.67	5.83	23.2	742,347	718,360	4.54	4.69	62.7	4.12	
2015	8,189	304	1.73	46.72	5.50	24.1	765,964	740,975	2.83	2.93	60.6	2.82	
2016	3,664	135	2.00	54.12	5.84	11.2	744,034	721,358	2.65	2.74	59.6	2.68	
2017	2,356	85	1.59	44.08	5.84	8.1	803,435	778,741	3.18	3.28	62.0	3.06	
2018	1,911	71	1.75	47.47	5.74	7.1	792,297	769,790	3.39	3.49	58.6	3.25	
2019	2,028	73	1.69	46.99	5.81	8.1	814,483	790,388	2.82	2.91	57.5	2.80	
Year 2017													
January	0	0	--	--	--	0.0	69,097	66,861	3.62	3.75	62.2	3.43	
February	0	0	--	--	--	0.0	66,943	64,869	3.19	3.29	66.9	3.08	
March	0	0	--	--	--	0.0	69,912	67,776	2.90	3.00	65.7	2.83	
April	0	0	--	--	--	0.0	66,465	64,429	3.26	3.36	65.1	3.15	
May	0	0	--	--	--	0.0	66,784	64,714	3.30	3.41	64.0	3.15	
June	271	9	1.25	35.84	5.75	9.5	66,326	64,294	3.26	3.36	61.8	3.10	
July	253	9	1.25	34.50	5.85	9.4	67,649	65,606	3.21	3.31	58.9	3.07	
August	296	11	1.25	34.50	5.85	10.9	65,687	63,678	3.08	3.17	58.8	2.97	
September	257	9	1.77	48.91	5.85	11.7	62,978	61,019	3.10	3.20	59.5	3.00	
October	893	32	1.77	48.91	5.85	35.4	63,059	61,210	3.08	3.17	58.8	2.97	
November	386	14	1.77	48.91	5.85	16.1	66,896	64,844	3.01	3.11	62.4	2.93	
December	0	0	--	--	--	0.0	71,639	69,441	3.11	3.21	60.5	3.00	
Year 2018													
January	0	0	--	--	--	0.0	69,164	67,045	3.59	3.70	58.1	3.42	
February	0	0	--	--	--	0.0	60,810	58,990	3.41	3.52	58.6	3.26	
March	0	0	--	--	--	0.0	61,164	59,423	2.85	2.94	56.5	2.81	
April	0	0	--	--	--	0.0	61,184	59,457	2.92	3.01	58.4	2.87	
May	0	0	--	--	--	0.0	63,410	61,557	2.99	3.08	58.8	2.92	
June	0	0	--	--	--	0.0	65,879	64,032	3.14	3.23	59.8	3.03	
July	160	6	1.70	45.10	5.83	6.8	68,296	66,523	3.03	3.11	57.4	2.93	
August	260	10	1.78	46.99	5.55	12.2	69,386	67,341	3.12	3.21	58.1	3.03	
September	664	25	1.78	47.54	6.02	31.0	67,825	66,022	3.12	3.20	60.1	3.04	
October	477	17	1.76	48.96	5.45	20.6	66,419	64,687	3.75	3.85	59.0	3.56	
November	172	6	1.69	46.62	5.85	8.4	71,469	69,556	3.97	4.08	61.6	3.75	
December	178	6	1.70	47.00	5.53	7.3	67,289	65,157	4.70	4.85	56.6	4.31	
Year 2019													
January	0	0	--	--	--	0.0	73,583	71,442	3.76	3.87	59.0	3.59	
February	0	0	--	--	--	0.0	64,847	62,775	3.44	3.56	58.1	3.33	
March	0	0	--	--	--	0.0	66,748	64,830	3.13	3.22	57.6	3.07	
April	0	0	--	--	--	0.0	64,259	62,480	2.85	2.93	59.7	2.85	
May	0	0	--	--	--	0.0	66,202	64,348	2.75	2.83	57.8	2.73	
June	0	0	--	--	--	0.0	64,540	62,725	2.63	2.70	56.5	2.62	
July	43	2	1.71	46.96	5.81	1.7	69,836	67,819	2.49	2.56	57.3	2.49	
August	615	23	1.75	46.99	5.75	30.2	70,509	68,322	2.37	2.45	57.1	2.39	
September	743	26	1.63	47.00	5.56	30.6	66,121	64,014	2.56	2.65	56.0	2.57	
October	627	23	1.72	47.00	6.17	30.1	65,572	63,624	2.46	2.54	55.7	2.49	
November	0	0	--	--	--	0.0	69,632	67,560	2.77	2.86	57.8	2.76	
December	0	0	--	--	--	0.0	72,635	70,448	2.62	2.70	57.8	2.64	

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Beginning in January 2013, the threshold for reporting fuel receipts data was changed from 50 megawatts to 200 megawatts of nameplate capacity for plants primarily fueled by natural gas, petroleum coke, distillate fuel oil, and residual fuel oil. In addition, the requirement to report self-produced and minor fuels, i.e., blast furnace gas, other manufactured gases, kerosene, jet fuel, propane, and waste oils was eliminated. The threshold for coal plants remained at 50 megawatts. The following caveats for each fuel type should be noted:
PETROLEUM COKE - includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.
NATURAL GAS - includes natural gas only. Prior to 2011, includes Other Gases.

- Values are final.
- See Glossary for definitions.
- Starting in January 2013, there may have been a shift in the continuity of Chapter 7 tables due to changes in the sample design of Form EIA-923 and the imputation process.
- See the EIA-923 section of the Technical Notes for a discussion of the sample design for the Form EIA-923 and predecessor forms.
- See the Technical Notes for fuel conversion factors.
- Totals may not equal the sum of components because of independent rounding.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor forms including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 7.13. Receipts of Coal Delivered for Electricity Generation by State, 2019 and 2018
(Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	159	276	-42.0%	90	94	69	182	0	0	0	0
Connecticut	0	105	-100.0%	0	0	0	105	0	0	0	0
Maine	69	62	11.0%	0	0	69	62	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	90	94	-4.2%	90	94	0	0	0	0	0	0
Rhode Island	0	15	-100.0%	0	0	0	15	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	19,758	22,115	-11.0%	0	0	19,682	22,007	0	0	76	108
New Jersey	562	603	-6.8%	0	0	562	603	0	0	0	0
New York	105	356	-70.0%	0	0	105	347	0	0	0	9
Pennsylvania	19,091	21,156	-9.8%	0	0	19,015	21,057	0	0	76	99
East North Central	121,130	135,418	-11.0%	70,966	79,529	48,299	53,644	0	0	1,865	2,244
Illinois	34,332	42,205	-19.0%	6,705	7,544	25,845	32,505	0	0	1,781	2,156
Indiana	28,275	29,773	-5.0%	26,185	27,733	2,091	2,040	0	0	0	0
Michigan	21,214	22,395	-5.3%	20,965	22,146	247	241	0	0	2	9
Ohio	22,722	22,772	-0.2%	2,606	3,914	20,117	18,858	0	0	0	0
Wisconsin	14,587	18,272	-20.0%	14,505	18,193	0	0	0	0	82	80
West North Central	106,926	115,190	-7.2%	103,914	111,951	0	0	8	13	3,004	3,226
Iowa	15,988	15,309	4.4%	13,745	13,080	0	0	0	0	2,242	2,228
Kansas	11,291	12,592	-10.0%	11,291	12,592	0	0	0	0	0	0
Minnesota	11,460	12,904	-11.0%	11,460	12,725	0	0	0	0	0	178
Missouri	31,097	35,275	-12.0%	31,088	35,262	0	0	8	13	0	0
Nebraska	13,430	13,527	-0.7%	12,669	12,708	0	0	0	0	761	819
North Dakota	21,882	24,023	-8.9%	21,882	24,023	0	0	0	0	0	0
South Dakota	1,778	1,560	14.0%	1,778	1,560	0	0	0	0	0	0
South Atlantic	76,973	79,146	-2.7%	67,945	66,966	8,259	11,281	0	0	768	899
Delaware	71	35	100.0%	0	0	71	35	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	9,218	11,702	-21.0%	9,166	11,625	0	0	0	0	53	77
Georgia	15,353	14,953	2.7%	15,217	14,814	0	0	0	0	136	139
Maryland	2,881	4,637	-38.0%	0	0	2,788	4,450	0	0	92	188
North Carolina	12,803	11,130	15.0%	12,535	10,761	55	119	0	0	213	251
South Carolina	7,317	6,077	20.0%	7,099	6,067	198	0	0	0	19	11
Virginia	2,617	4,705	-44.0%	2,071	3,760	292	710	0	0	255	235
West Virginia	26,712	25,906	3.1%	21,857	19,939	4,855	5,967	0	0	0	0
East South Central	55,572	57,134	-2.7%	52,421	53,298	2,561	2,993	0	0	590	843
Alabama	15,107	14,648	3.1%	15,107	14,648	0	0	0	0	0	0
Kentucky	29,987	32,038	-6.4%	29,987	32,038	0	0	0	0	0	0
Mississippi	4,124	4,600	-10.0%	1,563	1,607	2,561	2,993	0	0	0	0
Tennessee	6,354	5,848	8.6%	5,763	5,005	0	0	0	0	590	843
West South Central	91,089	98,713	-7.7%	46,260	49,892	44,600	48,517	0	0	229	304
Arkansas	14,098	16,843	-16.0%	11,854	14,003	2,184	2,762	0	0	61	78
Louisiana	5,843	7,252	-19.0%	4,456	4,736	1,387	2,515	0	0	0	0
Oklahoma	4,833	8,774	-45.0%	4,665	7,436	0	1,112	0	0	169	226
Texas	66,315	65,845	0.7%	25,286	23,717	41,029	42,128	0	0	0	0
Mountain	80,585	82,404	-2.2%	70,392	73,210	10,192	9,194	0	0	0	0
Arizona	13,396	16,162	-17.0%	13,396	16,162	0	0	0	0	0	0
Colorado	13,935	14,505	-3.9%	13,935	14,505	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	8,917	7,971	12.0%	256	239	8,661	7,731	0	0	0	0
Nevada	1,697	1,167	45.0%	1,093	582	604	585	0	0	0	0
New Mexico	8,495	7,520	13.0%	8,495	7,520	0	0	0	0	0	0
Utah	11,481	10,975	4.6%	11,079	10,570	402	405	0	0	0	0
Wyoming	22,663	24,104	-6.0%	22,138	23,632	525	472	0	0	0	0
Pacific Contiguous	6,950	4,833	44.0%	1,599	764	4,795	3,469	0	0	555	600
California	555	600	-7.4%	0	0	0	0	0	0	555	600
Oregon	1,599	764	109.0%	1,599	764	0	0	0	0	0	0
Washington	4,795	3,469	38.0%	0	0	4,795	3,469	0	0	0	0
Pacific Noncontiguous	1,011	987	2.4%	327	260	683	727	0	0	0	0
Alaska	327	260	26.0%	327	260	0	0	0	0	0	0
Hawaii	683	727	-6.0%	0	0	683	727	0	0	0	0
U.S. Total	560,153	596,215	-6.0%	413,915	435,964	139,141	152,015	8	13	7,088	8,224

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Notes:
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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.14. Receipts of Petroleum Liquids Delivered for Electricity Generation by State, 2019 and 2018
(Thousand Barrels)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	357	1,724	-79.0%	21	238	336	1,486	0	0	0	0
Connecticut	10	395	-98.0%	0	0	10	395	0	0	0	0
Maine	152	298	-49.0%	0	0	152	298	0	0	0	0
Massachusetts	155	487	-68.0%	8	33	147	454	0	0	0	0
New Hampshire	13	365	-96.0%	13	206	0	160	0	0	0	0
Rhode Island	28	179	-85.0%	0	0	28	179	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	1,293	3,888	-67.0%	653	1,041	567	2,751	0	0	73	96
New Jersey	77	264	-71.0%	0	0	77	264	0	0	0	0
New York	823	2,437	-66.0%	653	1,041	168	1,375	0	0	1	21
Pennsylvania	393	1,187	-67.0%	0	0	321	1,112	0	0	72	75
East North Central	901	875	3.1%	555	497	313	347	0	0	33	30
Illinois	90	98	-8.6%	4	6	86	92	0	0	0	0
Indiana	215	208	3.0%	215	207	0	1	0	0	0	0
Michigan	153	159	-3.9%	140	151	0	0	0	0	13	8
Ohio	393	323	22.0%	153	58	220	244	0	0	20	21
Wisconsin	51	86	-40.0%	44	76	8	11	0	0	0	0
West North Central	617	575	7.2%	614	572	3	3	0	0	0	0
Iowa	115	117	-1.8%	115	117	0	0	0	0	0	0
Kansas	146	105	40.0%	146	105	0	0	0	0	0	0
Minnesota	76	51	49.0%	73	48	3	3	0	0	0	0
Missouri	177	206	-14.0%	177	206	0	0	0	0	0	0
Nebraska	19	9	112.0%	19	9	0	0	0	0	0	0
North Dakota	71	77	-8.1%	71	77	0	0	0	0	0	0
South Dakota	13	11	13.0%	13	11	0	0	0	0	0	0
South Atlantic	1,699	5,402	-69.0%	1,315	3,750	221	1,410	0	0	163	242
Delaware	7	331	-98.0%	0	0	7	331	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	423	495	-15.0%	387	445	0	0	0	0	36	51
Georgia	234	458	-49.0%	156	325	4	72	0	0	73	61
Maryland	186	628	-70.0%	0	0	186	628	0	0	0	0
North Carolina	243	1,130	-78.0%	207	1,023	4	48	0	0	32	59
South Carolina	110	623	-82.0%	99	580	2	0	0	0	9	43
Virginia	247	1,439	-83.0%	218	1,123	18	288	0	0	12	28
West Virginia	248	299	-17.0%	248	254	0	44	0	0	0	0
East South Central	287	511	-44.0%	267	427	14	79	0	0	7	5
Alabama	32	144	-78.0%	18	65	14	79	0	0	0	0
Kentucky	142	147	-3.2%	142	147	0	0	0	0	0	0
Mississippi	23	37	-38.0%	23	37	0	0	0	0	0	0
Tennessee	90	183	-51.0%	84	178	0	0	0	0	7	5
West South Central	230	188	22.0%	184	151	46	36	0	0	0	0
Arkansas	75	48	56.0%	53	35	22	13	0	0	0	0
Louisiana	37	27	36.0%	37	27	0	0	0	0	0	0
Oklahoma	35	30	14.0%	35	30	0	0	0	0	0	0
Texas	83	82	1.1%	59	59	24	23	0	0	0	0
Mountain	362	298	21.0%	337	266	25	32	0	0	0	0
Arizona	124	94	32.0%	124	94	0	0	0	0	0	0
Colorado	5	14	-62.0%	5	14	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	18	25	-26.0%	0	0	18	25	0	0	0	0
Nevada	25	20	23.0%	20	15	5	5	0	0	0	0
New Mexico	48	34	42.0%	48	34	0	0	0	0	0	0
Utah	69	56	24.0%	66	54	2	2	0	0	0	0
Wyoming	72	55	30.0%	72	55	0	0	0	0	0	0
Pacific Contiguous	28	20	41.0%	11	5	17	15	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	4	0	--	4	0	0	0	0	0	0	0
Washington	23	20	18.0%	6	5	17	15	0	0	0	0
Pacific Noncontiguous	8,937	8,810	1.4%	7,054	6,948	1,883	1,862	0	0	0	0
Alaska	27	14	94.0%	27	14	0	0	0	0	0	0
Hawaii	8,910	8,796	1.3%	7,027	6,935	1,883	1,862	0	0	0	0
U.S. Total	14,711	22,290	-34.0%	11,010	13,896	3,425	8,022	0	0	275	372

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Notes:
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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Petroleum Liquids includes distillate and residual fuel oils.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.15. Receipts of Petroleum Coke Delivered for Electricity Generation by State, 2019 and 2018
(Thousand Tons)

Census Division and State	Electric Power Sector										
	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	0	0	--	0	0	0	0	0	0	0	0
Connecticut	0	0	--	0	0	0	0	0	0	0	0
Maine	0	0	--	0	0	0	0	0	0	0	0
Massachusetts	0	0	--	0	0	0	0	0	0	0	0
New Hampshire	0	0	--	0	0	0	0	0	0	0	0
Rhode Island	0	0	--	0	0	0	0	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	0	0	--	0	0	0	0	0	0	0	0
New Jersey	0	0	--	0	0	0	0	0	0	0	0
New York	0	0	--	0	0	0	0	0	0	0	0
Pennsylvania	0	0	--	0	0	0	0	0	0	0	0
East North Central	325	599	-46.0%	325	599	0	0	0	0	0	0
Illinois	0	0	--	0	0	0	0	0	0	0	0
Indiana	0	0	--	0	0	0	0	0	0	0	0
Michigan	280	539	-48.0%	280	539	0	0	0	0	0	0
Ohio	0	0	--	0	0	0	0	0	0	0	0
Wisconsin	45	60	-25.0%	45	60	0	0	0	0	0	0
West North Central	73	71	3.5%	0	0	0	0	0	0	73	71
Iowa	73	71	3.5%	0	0	0	0	0	0	73	71
Kansas	0	0	--	0	0	0	0	0	0	0	0
Minnesota	0	0	--	0	0	0	0	0	0	0	0
Missouri	0	0	--	0	0	0	0	0	0	0	0
Nebraska	0	0	--	0	0	0	0	0	0	0	0
North Dakota	0	0	--	0	0	0	0	0	0	0	0
South Dakota	0	0	--	0	0	0	0	0	0	0	0
South Atlantic	429	784	-45.0%	429	784	0	0	0	0	0	0
Delaware	0	0	--	0	0	0	0	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	429	784	-45.0%	429	784	0	0	0	0	0	0
Georgia	0	0	--	0	0	0	0	0	0	0	0
Maryland	0	0	--	0	0	0	0	0	0	0	0
North Carolina	0	0	--	0	0	0	0	0	0	0	0
South Carolina	0	0	--	0	0	0	0	0	0	0	0
Virginia	0	0	--	0	0	0	0	0	0	0	0
West Virginia	0	0	--	0	0	0	0	0	0	0	0
East South Central	0	0	--	0	0	0	0	0	0	0	0
Alabama	0	0	--	0	0	0	0	0	0	0	0
Kentucky	0	0	--	0	0	0	0	0	0	0	0
Mississippi	0	0	--	0	0	0	0	0	0	0	0
Tennessee	0	0	--	0	0	0	0	0	0	0	0
West South Central	1,142	1,557	-27.0%	1,142	1,557	0	0	0	0	0	0
Arkansas	0	0	--	0	0	0	0	0	0	0	0
Louisiana	1,142	1,557	-27.0%	1,142	1,557	0	0	0	0	0	0
Oklahoma	0	0	--	0	0	0	0	0	0	0	0
Texas	0	0	--	0	0	0	0	0	0	0	0
Mountain	0	0	--	0	0	0	0	0	0	0	0
Arizona	0	0	--	0	0	0	0	0	0	0	0
Colorado	0	0	--	0	0	0	0	0	0	0	0
Idaho	0	0	--	0	0	0	0	0	0	0	0
Montana	0	0	--	0	0	0	0	0	0	0	0
Nevada	0	0	--	0	0	0	0	0	0	0	0
New Mexico	0	0	--	0	0	0	0	0	0	0	0
Utah	0	0	--	0	0	0	0	0	0	0	0
Wyoming	0	0	--	0	0	0	0	0	0	0	0
Pacific Contiguous	0	0	--	0	0	0	0	0	0	0	0
California	0	0	--	0	0	0	0	0	0	0	0
Oregon	0	0	--	0	0	0	0	0	0	0	0
Washington	0	0	--	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	--	0	0	0	0	0	0	0	0
Alaska	0	0	--	0	0	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	1,969	3,010	-35.0%	1,896	2,940	0	0	0	0	73	71

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.
Petroleum Coke includes petroleum coke-derived synthesis gas.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.16. Receipts of Natural Gas Delivered for Electricity Generation by State, 2019 and 2018
(Million Cubic Feet)

				Electric Power Sector							
Census Division and State	All Sectors			Electric Utilities		Independent Power Producers		Commercial Sector		Industrial Sector	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	338,041	357,295	-5.4%	646	1,348	337,395	355,948	0	0	0	0
Connecticut	140,794	132,334	6.4%	0	0	140,794	132,334	0	0	0	0
Maine	9,373	13,614	-31.0%	0	0	9,373	13,614	0	0	0	0
Massachusetts	110,879	132,566	-16.0%	567	947	110,313	131,619	0	0	0	0
New Hampshire	25,487	21,600	18.0%	79	400	25,408	21,199	0	0	0	0
Rhode Island	51,509	57,181	-9.9%	0	0	51,509	57,181	0	0	0	0
Vermont	0	0	--	0	0	0	0	0	0	0	0
Middle Atlantic	1,299,674	1,176,917	10.0%	88,480	92,273	1,201,102	1,074,141	0	0	10,092	10,503
New Jersey	285,788	278,523	2.6%	0	0	285,788	278,523	0	0	0	0
New York	358,271	382,447	-6.3%	88,480	92,273	262,557	282,569	0	0	7,234	7,605
Pennsylvania	655,615	515,948	27.0%	0	0	652,757	513,049	0	0	2,858	2,899
East North Central	1,140,342	980,851	16.0%	382,520	345,229	736,954	614,152	6,889	6,707	13,979	14,763
Illinois	159,869	128,983	24.0%	11,328	9,674	148,518	119,272	0	0	22	37
Indiana	211,990	182,600	16.0%	99,028	87,691	112,961	94,909	0	0	0	0
Michigan	258,751	231,528	12.0%	80,521	68,184	165,409	150,349	6,889	6,707	5,932	6,288
Ohio	365,929	316,263	16.0%	61,895	71,616	298,611	238,899	0	0	5,423	5,748
Wisconsin	143,803	121,477	18.0%	129,747	108,063	11,454	10,722	0	0	2,602	2,691
West North Central	267,715	225,291	19.0%	222,855	195,270	37,931	22,828	2,197	2,116	4,732	5,079
Iowa	67,408	64,610	4.3%	62,676	59,608	0	0	0	0	4,732	5,002
Kansas	23,307	23,736	-1.8%	23,307	23,736	0	0	0	0	0	0
Minnesota	83,832	55,926	50.0%	63,047	47,747	20,773	8,093	12	10	0	77
Missouri	59,690	54,787	8.9%	40,347	37,946	17,158	14,735	2,185	2,106	0	0
Nebraska	11,470	9,068	26.0%	11,470	9,068	0	0	0	0	0	0
North Dakota	14,877	9,873	51.0%	14,877	9,873	0	0	0	0	0	0
South Dakota	7,131	7,291	-2.2%	7,131	7,291	0	0	0	0	0	0
South Atlantic	2,775,146	2,622,122	5.8%	2,289,939	2,144,723	449,301	440,969	0	0	35,906	36,430
Delaware	25,354	33,332	-24.0%	0	0	25,354	33,332	0	0	0	0
District of Columbia	0	0	--	0	0	0	0	0	0	0	0
Florida	1,289,171	1,229,395	4.9%	1,243,206	1,178,822	41,287	46,251	0	0	4,677	4,322
Georgia	434,294	380,482	14.0%	328,913	284,740	96,900	86,922	0	0	8,482	8,821
Maryland	96,466	92,375	4.4%	23,002	22,077	72,313	67,520	0	0	1,151	2,778
North Carolina	308,738	331,999	-7.0%	240,733	280,625	65,194	48,593	0	0	2,812	2,781
South Carolina	178,437	169,867	5.0%	173,081	147,310	4,403	21,601	0	0	954	956
Virginia	419,047	367,368	14.0%	276,888	229,292	131,541	127,744	0	0	10,618	10,332
West Virginia	23,638	17,306	37.0%	4,117	1,858	12,309	9,007	0	0	7,212	6,440
East South Central	1,019,264	1,007,842	1.1%	737,878	685,293	256,884	302,245	0	0	24,502	20,304
Alabama	399,066	398,878	0.0%	146,717	138,322	252,349	260,556	0	0	0	0
Kentucky	113,295	112,670	0.6%	108,870	105,054	4,426	7,616	0	0	0	0
Mississippi	363,823	370,210	-1.7%	363,714	336,137	110	34,073	0	0	0	0
Tennessee	143,079	126,084	13.0%	118,577	105,779	0	0	0	0	24,502	20,304
West South Central	3,240,210	3,009,544	7.7%	1,082,072	980,145	1,485,951	1,376,247	0	0	672,187	653,152
Arkansas	158,293	150,505	5.2%	143,446	134,446	12,136	13,448	0	0	2,711	2,612
Louisiana	558,627	500,434	12.0%	289,838	256,687	43,595	34,679	0	0	225,194	209,068
Oklahoma	337,151	318,549	5.8%	220,793	204,417	110,846	109,692	0	0	5,511	4,440
Texas	2,186,139	2,040,056	7.2%	427,995	384,596	1,319,374	1,218,428	0	0	438,770	437,032
Mountain	828,014	740,594	12.0%	692,679	623,305	134,995	116,686	0	0	341	604
Arizona	348,973	278,303	25.0%	267,937	220,964	81,036	57,340	0	0	0	0
Colorado	122,200	118,141	3.4%	105,060	99,700	17,140	18,441	0	0	0	0
Idaho	25,908	19,987	30.0%	13,721	8,914	12,187	11,073	0	0	0	0
Montana	2,780	2,749	1.1%	2,749	2,737	31	12	0	0	0	0
Nevada	173,732	180,683	-3.8%	173,732	180,683	0	0	0	0	0	0
New Mexico	89,193	82,962	7.5%	64,609	53,157	24,584	29,805	0	0	0	0
Utah	62,078	55,974	11.0%	61,738	55,369	0	0	0	0	341	604
Wyoming	3,149	1,796	75.0%	3,133	1,782	16	15	0	0	0	0
Pacific Contiguous	769,534	748,670	2.8%	318,521	295,237	422,364	424,478	0	0	28,649	28,955
California	528,794	559,705	-5.5%	183,436	189,598	316,709	341,152	0	0	28,649	28,955
Oregon	143,846	123,735	16.0%	70,838	62,606	73,008	61,129	0	0	0	0
Washington	96,895	65,229	49.0%	64,247	43,033	32,648	22,197	0	0	0	0
Pacific Noncontiguous	15,546	16,636	-6.6%	15,546	16,636	0	0	0	0	0	0
Alaska	15,546	16,636	-6.6%	15,546	16,636	0	0	0	0	0	0
Hawaii	0	0	--	0	0	0	0	0	0	0	0
U.S. Total	11,693,486	10,885,764	7.4%	5,831,134	5,379,459	5,062,877	4,727,692	9,087	8,823	790,388	769,790

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Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.17. Average Cost of Coal Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	W	4.37	W	3.35	3.87	W	4.64
Connecticut	--	W	W	--	--	--	W
Maine	W	W	W	--	--	W	W
Massachusetts	--	--	--	--	--	--	--
New Hampshire	3.35	3.87	-13.0%	3.35	3.87	--	--
Rhode Island	--	W	W	--	--	--	W
Vermont	--	--	--	--	--	--	--
Middle Atlantic	1.88	2.15	-13.0%	--	--	1.88	2.15
New Jersey	W	W	W	--	--	W	W
New York	W	W	W	--	--	W	W
Pennsylvania	W	2.09	W	--	--	W	2.09
East North Central	1.98	1.99	-0.5%	2.11	2.11	1.80	1.82
Illinois	W	1.77	W	1.97	1.88	W	1.75
Indiana	W	W	W	2.12	2.11	W	W
Michigan	W	W	W	2.09	2.12	W	W
Ohio	1.79	W	W	1.82	1.77	1.79	W
Wisconsin	2.22	2.28	-2.6%	2.22	2.28	--	--
West North Central	1.63	1.71	-4.7%	1.63	1.71	--	--
Iowa	1.54	1.63	-5.5%	1.54	1.63	--	--
Kansas	1.62	1.71	-5.3%	1.62	1.71	--	--
Minnesota	2.02	2.19	-7.8%	2.02	2.19	--	--
Missouri	1.67	1.80	-7.2%	1.67	1.80	--	--
Nebraska	1.23	1.26	-2.4%	1.23	1.26	--	--
North Dakota	1.63	1.55	5.2%	1.63	1.55	--	--
South Dakota	1.78	1.87	-4.8%	1.78	1.87	--	--
South Atlantic	2.57	2.64	-2.7%	2.59	2.70	2.38	2.30
Delaware	W	W	W	--	--	W	W
District of Columbia	--	--	--	--	--	--	--
Florida	2.83	2.88	-1.7%	2.83	2.88	--	--
Georgia	2.69	2.75	-2.2%	2.69	2.75	--	--
Maryland	2.66	2.53	5.1%	--	--	2.66	2.53
North Carolina	W	3.15	W	2.80	3.15	W	3.97
South Carolina	W	3.33	W	3.20	3.33	W	--
Virginia	W	W	W	2.77	2.67	W	W
West Virginia	2.08	2.09	-0.5%	2.11	2.14	1.96	1.90
East South Central	W	W	W	2.06	2.08	W	W
Alabama	2.29	2.27	0.9%	2.29	2.27	--	--
Kentucky	1.91	1.96	-2.6%	1.91	1.96	--	--
Mississippi	W	W	W	2.94	2.69	W	W
Tennessee	2.14	2.16	-0.9%	2.14	2.16	--	--
West South Central	1.83	1.88	-2.7%	2.07	2.08	1.58	1.66
Arkansas	W	W	W	1.97	1.98	W	W
Louisiana	W	W	W	3.11	3.12	W	W
Oklahoma	1.73	W	W	1.73	1.77	--	W
Texas	W	1.76	W	1.99	2.04	W	1.60
Mountain	W	W	W	2.01	2.00	W	W
Arizona	2.56	2.43	5.3%	2.56	2.43	--	--
Colorado	1.74	1.64	6.1%	1.74	1.64	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	1.95	2.01	W	W
Nevada	W	W	W	2.76	3.07	W	W
New Mexico	2.49	2.48	0.4%	2.49	2.48	--	--
Utah	1.97	2.02	-2.5%	1.97	2.02	--	--
Wyoming	W	W	W	1.63	1.68	W	W
Pacific Contiguous	W	W	W	2.27	2.34	W	W
California	--	--	--	--	--	--	--
Oregon	2.27	2.34	-3.0%	2.27	2.34	--	--
Washington	W	W	W	--	--	W	W
Pacific Noncontiguous	W	W	W	3.51	3.28	W	W
Alaska	3.51	3.28	7.0%	3.51	3.28	--	--
Hawaii	W	W	W	--	--	W	W
U.S. Total	2.01	2.05	-2.0%	2.08	2.11	1.81	1.89

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Coal includes anthracite, bituminous, subbituminous, lignite, waste coal, and coal-derived synthesis gas.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.18. Average Cost of Petroleum Liquids Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	11.62	13.08	-11.0%	16.64	11.89	11.32	13.29
Connecticut	16.68	14.91	12.0%	--	--	16.68	14.91
Maine	W	9.78	W	--	--	W	9.78
Massachusetts	11.61	12.59	-7.8%	14.70	16.01	11.45	12.31
New Hampshire	17.80	W	W	17.80	11.29	--	W
Rhode Island	W	W	W	--	--	W	W
Vermont	--	--	--	--	--	--	--
Middle Atlantic	W	14.02	W	12.01	12.12	W	14.88
New Jersey	13.81	15.71	-12.0%	--	--	13.81	15.71
New York	12.64	13.16	-4.0%	12.01	12.12	15.20	14.00
Pennsylvania	W	16.08	W	--	--	W	16.08
East North Central	15.15	W	W	14.70	16.28	15.93	W
Illinois	W	16.82	W	15.71	16.39	W	16.84
Indiana	14.86	W	W	14.86	16.34	--	W
Michigan	13.95	15.72	-11.0%	13.95	15.72	--	--
Ohio	15.44	W	W	15.44	16.36	15.44	W
Wisconsin	W	17.16	W	13.68	17.16	W	--
West North Central	14.72	16.23	-9.3%	14.72	16.23	--	--
Iowa	14.56	16.27	-11.0%	14.56	16.27	--	--
Kansas	14.92	16.50	-9.6%	14.92	16.50	--	--
Minnesota	14.83	16.47	-10.0%	14.83	16.47	--	--
Missouri	14.73	16.15	-8.8%	14.73	16.15	--	--
Nebraska	14.87	17.36	-14.0%	14.87	17.36	--	--
North Dakota	14.49	15.56	-6.9%	14.49	15.56	--	--
South Dakota	14.19	17.17	-17.0%	14.19	17.17	--	--
South Atlantic	14.52	14.88	-2.4%	14.60	15.16	14.06	13.95
Delaware	W	W	W	--	--	W	W
District of Columbia	--	--	--	--	--	--	--
Florida	15.33	16.43	-6.7%	15.33	16.43	--	--
Georgia	W	15.64	W	14.98	15.66	W	15.56
Maryland	14.20	14.01	1.4%	--	--	14.20	14.01
North Carolina	W	W	W	14.67	17.12	W	W
South Carolina	W	17.22	W	15.13	17.22	W	--
Virginia	W	W	W	11.78	11.71	W	W
West Virginia	15.51	W	W	15.51	16.62	--	W
East South Central	W	W	W	14.55	15.98	W	W
Alabama	W	W	W	15.13	16.26	W	W
Kentucky	14.68	15.67	-6.3%	14.68	15.67	--	--
Mississippi	14.35	15.64	-8.2%	14.35	15.64	--	--
Tennessee	14.27	16.21	-12.0%	14.27	16.21	--	--
West South Central	W	W	W	14.71	15.96	W	W
Arkansas	W	W	W	14.74	16.48	W	W
Louisiana	14.61	15.18	-3.8%	14.61	15.18	--	--
Oklahoma	15.28	16.20	-5.7%	15.28	16.20	--	--
Texas	W	W	W	14.41	15.89	W	W
Mountain	16.89	W	W	16.96	18.21	15.98	W
Arizona	16.89	17.24	-2.0%	16.89	17.24	--	--
Colorado	17.67	16.41	7.7%	17.67	16.41	--	--
Idaho	--	--	--	--	--	--	--
Montana	W	W	W	--	--	W	W
Nevada	W	W	W	16.25	18.47	W	W
New Mexico	19.01	19.37	-1.9%	19.01	19.37	--	--
Utah	W	W	W	16.75	19.21	W	W
Wyoming	16.08	18.53	-13.0%	16.08	18.53	--	--
Pacific Contiguous	W	W	W	14.80	17.24	W	W
California	--	--	--	--	--	--	--
Oregon	12.45	--	--	12.45	--	--	--
Washington	W	W	W	16.52	17.24	W	W
Pacific Noncontiguous	W	W	W	12.87	13.91	W	W
Alaska	15.74	17.76	-11.0%	15.74	17.76	--	--
Hawaii	W	W	W	12.86	13.90	W	W
U.S. Total	13.63	14.44	-5.6%	13.40	14.39	14.40	14.52

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Petroleum Liquids includes distillate and residual fuel oils.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.19. Average Cost of Petroleum Coke Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	--	--	--	--	--	--	--
Connecticut	--	--	--	--	--	--	--
Maine	--	--	--	--	--	--	--
Massachusetts	--	--	--	--	--	--	--
New Hampshire	--	--	--	--	--	--	--
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
Middle Atlantic	--	--	--	--	--	--	--
New Jersey	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	--
Pennsylvania	--	--	--	--	--	--	--
East North Central	1.58	1.51	4.6%	1.58	1.51	--	--
Illinois	--	--	--	--	--	--	--
Indiana	--	--	--	--	--	--	--
Michigan	1.54	1.48	4.1%	1.54	1.48	--	--
Ohio	--	--	--	--	--	--	--
Wisconsin	1.86	1.79	3.9%	1.86	1.79	--	--
West North Central	--	--	--	--	--	--	--
Iowa	--	--	--	--	--	--	--
Kansas	--	--	--	--	--	--	--
Minnesota	--	--	--	--	--	--	--
Missouri	--	--	--	--	--	--	--
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	--
South Dakota	--	--	--	--	--	--	--
South Atlantic	2.52	3.14	-20.0%	2.52	3.14	--	--
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	2.52	3.14	-20.0%	2.52	3.14	--	--
Georgia	--	--	--	--	--	--	--
Maryland	--	--	--	--	--	--	--
North Carolina	--	--	--	--	--	--	--
South Carolina	--	--	--	--	--	--	--
Virginia	--	--	--	--	--	--	--
West Virginia	--	--	--	--	--	--	--
East South Central	--	--	--	--	--	--	--
Alabama	--	--	--	--	--	--	--
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	--	--	--	--
Tennessee	--	--	--	--	--	--	--
West South Central	1.79	2.65	-32.0%	1.79	2.65	--	--
Arkansas	--	--	--	--	--	--	--
Louisiana	1.79	2.65	-32.0%	1.79	2.65	--	--
Oklahoma	--	--	--	--	--	--	--
Texas	--	--	--	--	--	--	--
Mountain	--	--	--	--	--	--	--
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	--	--	--
Idaho	--	--	--	--	--	--	--
Montana	--	--	--	--	--	--	--
Nevada	--	--	--	--	--	--	--
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	--	--	--
Wyoming	--	--	--	--	--	--	--
Pacific Contiguous	--	--	--	--	--	--	--
California	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--
Washington	--	--	--	--	--	--	--
Pacific Noncontiguous	--	--	--	--	--	--	--
Alaska	--	--	--	--	--	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	1.92	2.56	-25.0%	1.92	2.56	--	--

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Petroleum Coke includes petroleum coke-derived synthesis gas.
See the Technical Notes for fuel conversion factors.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.20. Average Cost of Natural Gas Delivered for Electricity Generation by State, 2019 and 2018
(Dollars per MMBtu)

Census Division and State	Electric Power Sector			Electric Utilities		Independent Power Producers	
	Year 2019	Year 2018	Percentage Change	Year 2019	Year 2018	Year 2019	Year 2018
New England	W	4.62	W	3.84	4.76	W	4.62
Connecticut	3.51	4.67	-25.0%	--	--	3.51	4.67
Maine	W	W	W	--	--	W	W
Massachusetts	4.37	4.75	-8.0%	3.32	4.26	4.38	4.76
New Hampshire	W	W	W	7.51	5.95	W	W
Rhode Island	3.22	4.10	-21.0%	--	--	3.22	4.10
Vermont	--	--	--	--	--	--	--
Middle Atlantic	2.61	3.29	-21.0%	3.23	4.11	2.56	3.20
New Jersey	2.80	3.07	-8.8%	--	--	2.80	3.07
New York	2.96	3.76	-21.0%	3.23	4.11	2.85	3.62
Pennsylvania	2.35	3.06	-23.0%	--	--	2.35	3.06
East North Central	2.62	3.22	-19.0%	2.70	3.30	2.58	3.18
Illinois	W	3.37	W	2.94	3.61	W	3.35
Indiana	2.59	3.27	-21.0%	2.71	3.38	2.49	3.18
Michigan	2.60	3.25	-20.0%	2.72	3.48	2.55	3.15
Ohio	2.44	3.12	-22.0%	2.55	3.17	2.41	3.11
Wisconsin	W	3.19	W	2.74	3.19	W	--
West North Central	W	W	W	2.70	3.18	W	W
Iowa	2.48	2.93	-15.0%	2.48	2.93	--	--
Kansas	2.78	3.22	-14.0%	2.78	3.22	--	--
Minnesota	W	W	W	2.92	3.47	W	W
Missouri	W	W	W	2.47	3.30	W	W
Nebraska	2.93	3.54	-17.0%	2.93	3.54	--	--
North Dakota	3.07	2.83	8.5%	3.07	2.83	--	--
South Dakota	2.54	2.81	-9.6%	2.54	2.81	--	--
South Atlantic	3.42	4.22	-19.0%	3.52	4.32	2.79	3.53
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	3.72	W	W	3.73	4.38	3.40	W
Georgia	2.88	3.90	-26.0%	2.87	4.00	2.91	3.53
Maryland	3.11	3.86	-19.0%	3.54	3.64	2.98	3.93
North Carolina	3.58	4.31	-17.0%	3.79	4.41	2.79	3.73
South Carolina	3.17	4.17	-24.0%	3.17	4.17	--	--
Virginia	3.15	4.14	-24.0%	3.37	4.52	2.47	3.15
West Virginia	2.20	W	W	2.19	3.22	2.20	W
East South Central	2.84	3.31	-14.0%	2.85	3.30	2.80	3.34
Alabama	W	W	W	2.88	3.40	W	W
Kentucky	W	W	W	3.22	3.59	W	W
Mississippi	W	W	W	2.73	3.21	W	W
Tennessee	2.85	3.17	-10.0%	2.85	3.17	--	--
West South Central	2.40	3.09	-22.0%	2.38	3.07	2.42	3.11
Arkansas	W	W	W	2.61	3.30	W	W
Louisiana	W	W	W	2.70	3.31	W	W
Oklahoma	W	W	W	2.39	2.76	W	W
Texas	2.33	3.09	-25.0%	2.09	2.98	2.43	3.13
Mountain	2.62	W	W	2.58	3.08	3.02	W
Arizona	W	2.96	W	2.14	2.90	W	3.33
Colorado	W	W	W	3.07	3.62	W	W
Idaho	4.09	3.59	14.0%	4.09	3.59	--	--
Montana	W	W	W	1.59	1.30	W	W
Nevada	3.06	3.16	-3.2%	3.06	3.16	--	--
New Mexico	1.26	2.42	-48.0%	1.26	2.42	--	--
Utah	3.07	3.11	-1.3%	3.07	3.11	--	--
Wyoming	W	W	W	3.07	3.77	W	W
Pacific Contiguous	3.45	3.94	-12.0%	3.47	3.69	3.43	4.19
California	3.76	4.50	-16.0%	4.10	4.44	3.50	4.55
Oregon	W	W	W	2.21	2.23	W	W
Washington	W	W	W	3.32	2.94	W	W
Pacific Noncontiguous	6.95	6.72	3.4%	6.95	6.72	--	--
Alaska	6.95	6.72	3.4%	6.95	6.72	--	--
Hawaii	--	--	--	--	--	--	--
U.S. Total	2.89	3.56	-19.0%	3.03	3.68	2.70	3.40

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
See Glossary for definitions. Values are final.
See Technical Notes for a discussion of the sample design for the Form EIA-923.
Totals may not equal sum of components because of independent rounding. Percentage change is calculated before rounding.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.21. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Total (All Sectors) by State, 2019**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	159	1.36	7.4	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	69	0.77	7.9	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	90	1.84	7.0	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	14,879	2.72	9.2	0	--	--	0	--	--
New Jersey	562	1.73	7.7	0	--	--	0	--	--
New York	105	2.85	8.4	0	--	--	0	--	--
Pennsylvania	14,212	2.75	9.3	0	--	--	0	--	--
East North Central	60,981	3.23	10.3	60,149	0.24	4.7	0	--	--
Illinois	9,941	3.31	19.1	24,390	0.21	4.6	0	--	--
Indiana	25,962	2.86	9.0	2,313	0.22	4.5	0	--	--
Michigan	1,829	2.33	7.6	19,385	0.26	4.7	0	--	--
Ohio	22,655	3.67	9.1	68	0.29	5.2	0	--	--
Wisconsin	594	2.39	8.2	13,993	0.24	4.8	0	--	--
West North Central	1,060	3.04	9.2	83,985	0.27	5.0	21,882	0.76	9.8
Iowa	445	3.20	8.3	15,543	0.24	4.7	0	--	--
Kansas	128	3.43	12.8	11,163	0.31	5.0	0	--	--
Minnesota	0	--	--	11,460	0.34	6.0	0	--	--
Missouri	487	2.79	9.1	30,610	0.24	4.8	0	--	--
Nebraska	0	--	--	13,430	0.26	4.9	0	--	--
North Dakota	0	--	--	0	--	--	21,882	0.76	9.8
South Dakota	0	--	--	1,778	0.34	5.5	0	--	--
South Atlantic	66,998	2.36	9.6	9,047	0.32	4.7	0	--	--
Delaware	71	2.63	7.6	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	9,218	2.41	8.3	0	--	--	0	--	--
Georgia	6,305	2.51	8.2	9,047	0.32	4.7	0	--	--
Maryland	2,881	2.36	10.9	0	--	--	0	--	--
North Carolina	12,803	1.74	9.7	0	--	--	0	--	--
South Carolina	7,317	1.85	9.2	0	--	--	0	--	--
Virginia	2,617	1.02	15.5	0	--	--	0	--	--
West Virginia	25,784	2.87	9.9	0	--	--	0	--	--
East South Central	33,046	2.57	9.2	19,965	0.29	5.3	2,561	0.51	13.6
Alabama	4,270	0.99	10.7	10,838	0.31	5.3	0	--	--
Kentucky	22,900	2.93	9.2	7,087	0.25	5.2	0	--	--
Mississippi	379	0.43	8.0	1,184	0.32	5.2	2,561	0.51	13.6
Tennessee	5,498	2.34	8.3	856	0.27	5.2	0	--	--
West South Central	444	2.37	11.5	68,772	0.27	5.0	21,873	1.09	17.0
Arkansas	61	0.45	9.2	14,038	0.22	4.9	0	--	--
Louisiana	334	2.92	9.3	4,308	0.28	5.0	1,200	0.60	15.8
Oklahoma	50	0.95	34.4	4,784	0.22	4.6	0	--	--
Texas	0	--	--	45,642	0.29	5.1	20,673	1.12	17.1
Mountain	19,875	0.59	12.9	60,052	0.52	8.8	256	0.53	9.0
Arizona	4,025	0.51	10.3	9,371	0.66	10.3	0	--	--
Colorado	1,236	0.46	11.1	12,699	0.32	5.6	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	8,661	0.69	10.0	256	0.53	9.0
Nevada	646	0.41	11.0	1,051	0.38	7.0	0	--	--
New Mexico	3,128	0.87	23.8	5,367	0.84	20.4	0	--	--
Utah	10,839	0.57	11.4	240	0.91	9.0	0	--	--
Wyoming	0	--	--	22,663	0.43	6.9	0	--	--
Pacific Contiguous	555	0.45	9.4	6,394	0.35	7.6	0	--	--
California	555	0.45	9.4	0	--	--	0	--	--
Oregon	0	--	--	1,599	0.24	5.0	0	--	--
Washington	0	--	--	4,795	0.39	8.4	0	--	--
Pacific Noncontiguous	18	0.56	11.2	665	0.23	4.0	209	0.15	9.2
Alaska	0	--	--	0	--	--	209	0.15	9.2
Hawaii	18	0.56	11.2	665	0.23	4.0	0	--	--
U.S. Total	198,016	2.52	10.0	309,029	0.32	5.7	46,781	0.90	13.3

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.22. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Electric Utilities by State, 2019

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	90	1.84	7.0	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	90	1.84	7.0	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	30,966	2.85	8.9	40,000	0.25	4.7	0	--	--
Illinois	2,404	2.53	9.4	4,301	0.21	4.5	0	--	--
Indiana	23,872	2.82	9.0	2,313	0.22	4.5	0	--	--
Michigan	1,580	2.48	7.7	19,385	0.26	4.7	0	--	--
Ohio	2,598	3.66	9.0	8	0.21	4.5	0	--	--
Wisconsin	512	2.65	7.8	13,993	0.24	4.8	0	--	--
West North Central	607	2.92	9.9	81,426	0.27	5.0	21,882	0.76	9.8
Iowa	0	--	--	13,745	0.25	4.8	0	--	--
Kansas	128	3.43	12.8	11,163	0.31	5.0	0	--	--
Minnesota	0	--	--	11,460	0.34	6.0	0	--	--
Missouri	479	2.79	9.1	30,610	0.24	4.8	0	--	--
Nebraska	0	--	--	12,669	0.26	5.0	0	--	--
North Dakota	0	--	--	0	--	--	21,882	0.76	9.8
South Dakota	0	--	--	1,778	0.34	5.5	0	--	--
South Atlantic	58,898	2.36	9.7	9,047	0.32	4.7	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	9,166	2.43	8.3	0	--	--	0	--	--
Georgia	6,170	2.55	8.1	9,047	0.32	4.7	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	12,535	1.76	9.8	0	--	--	0	--	--
South Carolina	7,099	1.87	9.2	0	--	--	0	--	--
Virginia	2,071	1.09	18.1	0	--	--	0	--	--
West Virginia	21,857	2.87	10.1	0	--	--	0	--	--
East South Central	32,456	2.60	9.2	19,965	0.29	5.3	0	--	--
Alabama	4,270	0.99	10.7	10,838	0.31	5.3	0	--	--
Kentucky	22,900	2.93	9.2	7,087	0.25	5.2	0	--	--
Mississippi	379	0.43	8.0	1,184	0.32	5.2	0	--	--
Tennessee	4,908	2.52	8.5	856	0.27	5.2	0	--	--
West South Central	384	2.71	12.0	39,102	0.25	4.9	6,775	1.59	20.4
Arkansas	0	--	--	11,854	0.23	4.8	0	--	--
Louisiana	334	2.92	9.3	2,921	0.26	5.0	1,200	0.60	15.8
Oklahoma	50	0.95	34.4	4,615	0.22	4.6	0	--	--
Texas	0	--	--	19,711	0.27	5.1	5,575	1.84	21.6
Mountain	19,875	0.59	12.9	50,262	0.49	8.7	256	0.53	9.0
Arizona	4,025	0.51	10.3	9,371	0.66	10.3	0	--	--
Colorado	1,236	0.46	11.1	12,699	0.32	5.6	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	256	0.53	9.0
Nevada	646	0.41	11.0	447	0.45	9.0	0	--	--
New Mexico	3,128	0.87	23.8	5,367	0.84	20.4	0	--	--
Utah	10,839	0.57	11.4	240	0.91	9.0	0	--	--
Wyoming	0	--	--	22,138	0.43	6.9	0	--	--
Pacific Contiguous	0	--	--	1,599	0.24	5.0	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	1,599	0.24	5.0	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	209	0.15	9.2
Alaska	0	--	--	0	--	--	209	0.15	9.2
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	143,275	2.29	9.8	241,401	0.31	5.7	29,122	0.93	12.1

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.23. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Independent Power Producers by State, 2019**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	69	0.77	7.9	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	69	0.77	7.9	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	14,803	2.72	9.2	0	--	--	0	--	--
New Jersey	562	1.73	7.7	0	--	--	0	--	--
New York	105	2.85	8.4	0	--	--	0	--	--
Pennsylvania	14,136	2.76	9.3	0	--	--	0	--	--
East North Central	28,808	3.62	11.9	19,491	0.21	4.6	0	--	--
Illinois	6,413	3.64	26.2	19,432	0.21	4.6	0	--	--
Indiana	2,091	3.33	9.1	0	--	--	0	--	--
Michigan	247	1.16	6.4	0	--	--	0	--	--
Ohio	20,057	3.67	9.1	60	0.30	5.2	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	0	--	--	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	7,331	2.55	9.3	0	--	--	0	--	--
Delaware	71	2.63	7.6	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	2,788	2.37	10.6	0	--	--	0	--	--
North Carolina	55	0.70	6.2	0	--	--	0	--	--
South Carolina	198	1.19	9.2	0	--	--	0	--	--
Virginia	292	0.84	7.6	0	--	--	0	--	--
West Virginia	3,927	2.90	8.5	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	2,561	0.51	13.6
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	2,561	0.51	13.6
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	29,502	0.29	5.1	15,098	0.89	15.6
Arkansas	0	--	--	2,184	0.22	5.0	0	--	--
Louisiana	0	--	--	1,387	0.30	4.9	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	25,931	0.30	5.1	15,098	0.89	15.6
Mountain	0	--	--	9,790	0.65	9.5	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	8,661	0.69	10.0	0	--	--
Nevada	0	--	--	604	0.33	5.3	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	525	0.44	5.5	0	--	--
Pacific Contiguous	0	--	--	4,795	0.39	8.4	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	4,795	0.39	8.4	0	--	--
Pacific Noncontiguous	18	0.56	11.2	665	0.23	4.0	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	18	0.56	11.2	665	0.23	4.0	0	--	--
U.S. Total	51,029	3.18	10.7	64,244	0.33	5.8	17,659	0.85	15.4

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 7.24. Receipts and Quality of Coal by Rank Delivered for Electricity Generation: Commercial Sector by State, 2019

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	0	--	--	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	0	--	--	0	--	--	0	--	--
East North Central	0	--	--	0	--	--	0	--	--
Illinois	0	--	--	0	--	--	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	0	--	--	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	0	--	--	0	--	--	0	--	--
West North Central	8	3.01	8.2	0	--	--	0	--	--
Iowa	0	--	--	0	--	--	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	8	3.01	8.2	0	--	--	0	--	--
Nebraska	0	--	--	0	--	--	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	0	--	--	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	0	--	--	0	--	--	0	--	--
Georgia	0	--	--	0	--	--	0	--	--
Maryland	0	--	--	0	--	--	0	--	--
North Carolina	0	--	--	0	--	--	0	--	--
South Carolina	0	--	--	0	--	--	0	--	--
Virginia	0	--	--	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	0	--	--	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	0	--	--	0	--	--	0	--	--
West South Central	0	--	--	0	--	--	0	--	--
Arkansas	0	--	--	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	0	--	--	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	0	--	--	0	--	--	0	--	--
California	0	--	--	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	8	3.01	8.2	0	--	--	0	--	--

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

**Table 7.25. Receipts and Quality of Coal by Rank Delivered for Electricity Generation:
Industrial Sector by State, 2019**

Census Division and State	Bituminous			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Receipts (Thousand Tons)	Average Sulfur Percent by Weight	Average Ash Percent by Weight
New England	0	--	--	0	--	--	0	--	--
Connecticut	0	--	--	0	--	--	0	--	--
Maine	0	--	--	0	--	--	0	--	--
Massachusetts	0	--	--	0	--	--	0	--	--
New Hampshire	0	--	--	0	--	--	0	--	--
Rhode Island	0	--	--	0	--	--	0	--	--
Vermont	0	--	--	0	--	--	0	--	--
Middle Atlantic	76	2.28	8.1	0	--	--	0	--	--
New Jersey	0	--	--	0	--	--	0	--	--
New York	0	--	--	0	--	--	0	--	--
Pennsylvania	76	2.28	8.1	0	--	--	0	--	--
East North Central	1,208	3.31	8.8	658	0.25	5.5	0	--	--
Illinois	1,124	3.53	8.7	658	0.25	5.5	0	--	--
Indiana	0	--	--	0	--	--	0	--	--
Michigan	2	0.59	7.8	0	--	--	0	--	--
Ohio	0	--	--	0	--	--	0	--	--
Wisconsin	82	0.50	10.6	0	--	--	0	--	--
West North Central	445	3.20	8.3	2,559	0.21	4.4	0	--	--
Iowa	445	3.20	8.3	1,797	0.20	4.5	0	--	--
Kansas	0	--	--	0	--	--	0	--	--
Minnesota	0	--	--	0	--	--	0	--	--
Missouri	0	--	--	0	--	--	0	--	--
Nebraska	0	--	--	761	0.21	4.4	0	--	--
North Dakota	0	--	--	0	--	--	0	--	--
South Dakota	0	--	--	0	--	--	0	--	--
South Atlantic	768	0.89	9.1	0	--	--	0	--	--
Delaware	0	--	--	0	--	--	0	--	--
District of Columbia	0	--	--	0	--	--	0	--	--
Florida	53	0.71	6.8	0	--	--	0	--	--
Georgia	136	0.92	11.4	0	--	--	0	--	--
Maryland	92	1.73	21.9	0	--	--	0	--	--
North Carolina	213	0.81	6.7	0	--	--	0	--	--
South Carolina	19	0.69	6.7	0	--	--	0	--	--
Virginia	255	0.74	7.1	0	--	--	0	--	--
West Virginia	0	--	--	0	--	--	0	--	--
East South Central	590	1.00	7.3	0	--	--	0	--	--
Alabama	0	--	--	0	--	--	0	--	--
Kentucky	0	--	--	0	--	--	0	--	--
Mississippi	0	--	--	0	--	--	0	--	--
Tennessee	590	1.00	7.3	0	--	--	0	--	--
West South Central	61	0.45	9.2	169	0.20	4.6	0	--	--
Arkansas	61	0.45	9.2	0	--	--	0	--	--
Louisiana	0	--	--	0	--	--	0	--	--
Oklahoma	0	--	--	169	0.20	4.6	0	--	--
Texas	0	--	--	0	--	--	0	--	--
Mountain	0	--	--	0	--	--	0	--	--
Arizona	0	--	--	0	--	--	0	--	--
Colorado	0	--	--	0	--	--	0	--	--
Idaho	0	--	--	0	--	--	0	--	--
Montana	0	--	--	0	--	--	0	--	--
Nevada	0	--	--	0	--	--	0	--	--
New Mexico	0	--	--	0	--	--	0	--	--
Utah	0	--	--	0	--	--	0	--	--
Wyoming	0	--	--	0	--	--	0	--	--
Pacific Contiguous	555	0.45	9.4	0	--	--	0	--	--
California	555	0.45	9.4	0	--	--	0	--	--
Oregon	0	--	--	0	--	--	0	--	--
Washington	0	--	--	0	--	--	0	--	--
Pacific Noncontiguous	0	--	--	0	--	--	0	--	--
Alaska	0	--	--	0	--	--	0	--	--
Hawaii	0	--	--	0	--	--	0	--	--
U.S. Total	3,703	1.86	8.6	3,385	0.21	4.7	0	--	--

Displayed values of zero may represent small values that round to zero.
NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

Notes:
Bituminous coal includes anthracite coal and coal-derived synthesis gas.
See Glossary for definitions. Values are final. See Technical Notes for a discussion of the sample design for the Form EIA-923.

Source: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Chapter 8

Electric Power System Characteristics and Performance

**Table 8.1. Average Operating Heat Rate for Selected Energy Sources,
2009 through 2019 (Btu per Kilowatthour)**

Year	Coal	Petroleum	Natural Gas	Nuclear
2009	10,414	10,923	8,160	10,459
2010	10,415	10,984	8,185	10,452
2011	10,444	10,829	8,152	10,464
2012	10,498	10,991	8,039	10,479
2013	10,459	10,713	7,948	10,449
2014	10,428	10,814	7,907	10,459
2015	10,495	10,687	7,878	10,458
2016	10,493	10,811	7,870	10,459
2017	10,465	10,834	7,812	10,459
2018	10,481	11,095	7,821	10,455
2019	10,551	11,205	7,732	10,442

Coal includes anthracite, bituminous, subbituminous and lignite coal. Waste coal and synthetic coal are included starting in 2002.
Petroleum includes distillate fuel oil (all diesel and No. 1 and No. 2 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil, jet fuel, kerosene, petroleum coke, and waste oil.

Notes:

Included in the calculation for coal, petroleum, and natural gas average operating heat rate are electric power plants in the utility and independent power producer sectors.

Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations.

The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report."

Table 8.2. Average Tested Heat Rates by Prime Mover and Energy Source, 2009 - 2019
(Btu per Kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
2009				
Steam Generator	10,150	10,349	10,427	10,459
Gas Turbine	--	13,326	11,560	--
Internal Combustion	--	10,428	9,958	--
Combined Cycle	W	10,715	7,605	--
2010				
Steam Generator	10,142	10,249	10,416	10,452
Gas Turbine	--	13,386	11,590	--
Internal Combustion	--	10,429	9,917	--
Combined Cycle	W	10,474	7,619	--
2011				
Steam Generator	10,128	10,414	10,414	10,464
Gas Turbine	--	13,637	11,569	--
Internal Combustion	--	10,428	9,923	--
Combined Cycle	W	10,650	7,603	--
2012				
Steam Generator	10,107	10,359	10,385	10,479
Gas Turbine	--	13,622	11,499	--
Internal Combustion	--	10,416	9,991	--
Combined Cycle	W	10,195	7,615	--
2013				
Steam Generator	10,089	10,334	10,354	10,449
Gas Turbine	--	13,555	11,371	--
Internal Combustion	--	10,401	9,573	--
Combined Cycle	W	9,937	7,667	--
2014				
Steam Generator	10,080	10,156	10,408	10,459
Gas Turbine	--	13,457	11,378	--
Internal Combustion	--	10,403	9,375	--
Combined Cycle	W	9,924	7,658	--
2015				
Steam Generator	10,059	10,197	10,372	10,458
Gas Turbine	--	13,550	11,302	--
Internal Combustion	--	10,379	9,322	--
Combined Cycle	W	9,676	7,655	--
2016				
Steam Generator	10,045	10,189	10,382	10,459
Gas Turbine	--	13,535	11,214	--
Internal Combustion	--	10,331	9,179	--
Combined Cycle	W	9,860	7,652	--
2017				
Steam Generator	10,043	10,199	10,353	10,459
Gas Turbine	--	13,491	11,176	--
Internal Combustion	--	10,301	9,120	--
Combined Cycle	W	9,811	7,649	--
2018				
Steam Generator	10,015	10,270	10,334	10,455
Gas Turbine	--	13,352	11,138	--
Internal Combustion	--	10,326	9,009	--
Combined Cycle	W	9,663	7,627	--
2019				
Steam Generator	10,002	10,236	10,347	10,442
Gas Turbine	--	13,315	11,098	--
Internal Combustion	--	10,325	8,899	--
Combined Cycle	W	9,662	7,633	--

Notes: W = Withheld to avoid disclosure of individual company data.

Heat rate is reported at full load conditions for electric utilities and independent power producers.
The average heat rates above are weighted by Net Summer Capacity.
Coal Combined Cycle represents integrated gasification units.

Source: U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report.'

Table 8.3. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 2009 through 2019 (Million Dollars)

Description	2009	2010	2011	2012	2013	2014
Utility Operating Revenues	276,124	285,512	280,520	270,912	281,901	298,430
.....Electric Utility	249,303	260,119	255,573	249,166	257,718	271,832
.....Other Utility	26,822	25,393	24,946	21,745	24,183	26,598
Utility Operating Expenses	244,243	253,022	247,118	235,694	244,316	258,936
.....Electric Utility	219,544	234,173	228,873	220,722	227,483	240,643
.....Operation	154,925	166,922	161,460	152,379	156,077	165,989
.....Production	118,816	128,831	122,520	111,714	115,046	123,366
.....Cost of Fuel	40,242	44,138	42,779	38,998	41,127	42,545
.....Purchased Power	67,630	67,284	61,447	54,570	55,529	62,066
.....Other	10,970	17,409	18,294	18,146	18,390	18,755
.....Transmission	6,742	6,948	6,876	7,183	7,881	8,902
.....Distribution	3,947	4,007	4,044	4,181	4,197	4,331
.....Customer Accounts	5,203	5,091	5,180	5,086	5,107	5,255
.....Customer Service	3,857	4,741	5,311	5,640	5,906	6,396
.....Sales	178	185	185	221	203	208
.....Administrative and General	15,991	17,120	17,343	18,353	17,738	17,532
.....Maintenance	14,092	14,957	15,772	15,489	15,505	16,801
.....Depreciation	20,095	20,951	22,555	23,677	24,723	25,919
.....Taxes and Other	29,081	31,343	29,086	29,177	31,179	31,934
.....Other Utility	24,698	18,849	18,245	14,972	16,833	18,293
Net Utility Operating Income	31,881	32,490	33,402	35,218	37,585	39,494

Description	2015	2016	2017	2018	2019
Utility Operating Revenues	282,695	282,499	286,501	293,868	293,000
.....Electric Utility	260,121	261,047	263,265	268,421	266,876
.....Other Utility	22,574	21,451	23,235	25,447	26,124
Utility Operating Expenses	242,728	239,037	240,041	253,944	250,136
.....Electric Utility	228,366	226,457	226,110	238,526	234,892
.....Operation	149,939	145,077	142,000	163,479	157,265
.....Production	107,201	100,852	98,859	104,185	99,518
.....Cost of Fuel	34,711	32,621	32,165	33,592	29,614
.....Purchased Power	52,970	49,962	49,030	53,060	50,378
.....Other	19,521	18,269	17,664	17,533	19,526
.....Transmission	9,624	10,447	10,804	11,387	11,941
.....Distribution	4,406	4,734	4,358	4,806	5,218
.....Customer Accounts	5,184	5,077	4,789	4,969	4,978
.....Customer Service	6,445	6,187	5,961	6,019	6,156
.....Sales	201	205	213	203	204
.....Administrative and General	16,878	17,575	17,016	31,911	29,248
.....Maintenance	16,392	16,982	17,996	17,786	19,898
.....Depreciation	26,847	30,097	30,323	32,125	34,883
.....Taxes and Other	35,188	34,301	35,791	25,136	22,846
.....Other Utility	14,362	12,579	13,931	15,418	15,245
Net Utility Operating Income	39,968	43,462	46,460	39,924	42,864

Notes: Missing or erroneous respondent data may result in slight imbalances in some of the expense account subtotals.

Total may not equal sum of components due to independent rounding.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned

Electric Utilities, 2009 through 2019 (Mills per Kilowatthour)

	Operation				Maintenance			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2009	10.00	4.23	4.88	3.05	6.34	3.96	3.50	2.58
2010	10.50	4.04	5.33	2.79	6.80	3.99	3.81	2.73
2011	10.89	4.02	5.13	2.81	6.80	3.99	3.74	2.93
2012	12.49	4.38	6.71	2.46	7.32	4.48	4.63	2.76
2013	12.51	4.57	6.56	2.56	6.64	4.41	4.32	2.80
2014	12.41	4.55	7.30	2.63	6.67	5.11	4.59	2.90
2015	11.17	5.16	8.37	2.34	7.06	5.41	5.06	2.68
2016	10.90	5.05	6.65	2.49	7.01	5.53	4.34	2.74
2017	10.27	5.01	6.33	2.45	6.63	5.13	3.96	2.83
2018	10.78	5.19	6.69	2.37	5.93	5.27	3.96	2.71
2019	10.63	5.52	6.86	2.58	6.29	6.85	3.94	2.64

	Fuel				Total			
Year	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale	Nuclear	Fossil Steam	Hydro-electric	Gas Turbine and Small Scale
2009	5.35	32.30	--	51.93	21.69	40.48	8.38	57.55
2010	6.68	27.73	--	43.21	23.98	35.76	9.15	48.74
2011	7.01	27.08	--	38.80	24.70	35.09	8.88	44.54
2012	7.61	28.34	--	30.45	27.42	37.20	11.34	35.67
2013	8.14	28.94	--	32.56	27.29	37.92	10.88	37.92
2014	7.71	29.39	--	37.06	26.79	39.04	11.90	42.60
2015	7.48	26.70	--	28.22	25.71	37.26	13.42	33.24
2016	7.45	25.50	--	24.97	25.36	36.08	10.98	30.19
2017	7.47	25.27	--	26.48	24.38	35.41	10.29	31.76
2018	7.15	25.40	--	27.35	23.86	35.86	10.65	32.43
2019	6.81	24.28	--	23.11	23.73	36.66	10.80	28.33

Hydroelectric category consists of both conventional hydroelectric and pumped storage.

Gas Turbine and Small Scale category consists of gas turbine, internal combustion, photovoltaic, and wind plants.

Notes: Expenses are average expenses weighted by net generation. A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of one cent).

Total may not equal sum of components due to independent rounding.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

Chapter 9

Environmental Data

Table 9.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants 2009 through 2019 (Thousand Metric Tons)

Year	Carbon Dioxide (CO ₂)	Sulfur Dioxide (SO ₂)	Nitrogen Oxides (NO _x)
2009	2,269,508	5,970	2,395
2010	2,388,596	5,400	2,491
2011	2,287,071	4,845	2,406
2012	2,156,875	3,704	2,148
2013	2,173,806	3,609	2,163
2014	2,168,284	3,454	2,100
2015	2,031,452	2,548	1,824
2016	1,928,401	1,807	1,630
2017	1,849,750	1,657	1,506
2018	1,874,346	1,571	1,485
2019	1,724,396	1,267	1,342

Notes:

The emissions data presented include total emissions from both electricity generation and the production of useful thermal output.

See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates.

Source: Calculations made by the Office of Electricity, Renewables, and Uranium Statistics, U.S. Energy Information Administration.

Table 9.2. Quantity and Net Summer Capacity of Operable Environmental Equipment, 2009 - 2019

	Flue Gas Desulfurization Systems		Electrostatic Precipitators		Baghouses		Select Catalytic and Non-Catalytic Reduction Systems		Activated Carbon Injection Systems		Direct Sorbent Injection Systems	
Year	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2009	678	174,801	1,456	314,356	597	73,863	1,323	300,007	227	39,546	65	8,242
2010	717	201,079	1,410	310,486	610	83,407	1,360	315,222	262	54,183	66	8,721
2011	731	211,781	1,368	307,043	633	98,507	1,408	331,242	274	59,057	75	8,977
2012	727	219,359	1,291	298,425	629	101,593	1,453	345,257	287	63,709	83	10,618
2013	705	219,359	1,218	289,182	637	104,331	1,458	351,233	262	61,215	97	12,985
2014	702	223,835	1,172	283,940	621	105,990	1,472	358,426	280	69,287	104	16,777
2015	693	224,143	1,037	264,905	623	110,820	1,480	359,885	364	106,450	122	23,307
2016	696	228,504	943	252,904	613	112,581	1,484	362,522	482	153,800	125	26,679
2017	681	222,513	886	244,087	601	109,495	1,492	365,878	477	151,208	126	25,762
2018	662	214,082	840	229,403	582	105,282	1,484	364,743	455	143,471	119	26,261
2019	617	203,035	781	217,328	535	101,839	1,455	361,767	431	136,597	114	25,461

Note:

'Associated Net Summer Capacity' is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment.

In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Data for 2005 and earlier are based primarily on Form EIA-767 data. In 2006, the Form EIA-767 was suspended. Data for 2007 and later are based primarily on Form EIA-860 data. All data for 2006 are inferred based on submissions from subsequent years. Beginning in 2013 environmental data was collected at a more detailed level, which increases its accuracy and in some cases reduces the equipment counts.

Source: U.S. Energy Information Administration, Forms EIA-767, "Steam-Electric Plant Operation and Design Report" and Form EIA-860, "Annual Electric Generator Report."

Table 9.3. Quantity and Net Summer Capacity of Operable Cooling Systems, by Energy Source and Cooling System Type, 2009 - 2019

	Once-Through Cooling Systems		Recirculating Cooling Systems		Cooling Ponds		Dry Cooling Systems		Hybrid Wet and Dry Cooling Systems		Other Cooling System Types	
Energy Source	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)	Quantity	Associated Net Summer Capacity (MW)
2009												
Coal	445	129,350	370	161,312	100	47,960	1	335	--	--	8	3,036
Natural Gas	192	48,737	431	83,932	58	23,062	51	12,338	3	482	3	1,175
Petroleum	81	22,111	18	6,575	3	4,104	--	--	--	--	2	2,022
Other	16	1,160	25	2,316	2	344	4	356	--	--	1	33
2010												
Coal	437	129,554	371	162,953	101	48,929	2	435	1	766	9	3,086
Natural Gas	180	48,398	427	83,120	58	22,786	54	13,078	3	542	3	1,172
Nuclear	49	51,465	39	43,363	13	14,996	--	--	--	--	7	7,901
Petroleum	80	21,232	17	5,513	3	4,064	--	--	--	--	2	2,022
Other	17	1,190	26	2,546	2	344	4	356	--	--	2	63
2011												
Coal	415	127,412	369	165,958	104	50,476	3	840	1	766	9	3,090
Natural Gas	176	48,361	442	87,168	59	21,984	57	13,471	3	542	2	870
Nuclear	49	51,642	39	43,422	13	15,011	--	--	--	--	8	8,890
Petroleum	70	17,454	17	5,443	4	4,692	--	--	--	--	2	2,022
Other	18	1,318	20	1,641	--	--	1	26	--	--	2	63
2012												
Coal	372	124,589	366	166,915	88	39,933	4	1,412	1	766	15	6,918
Natural Gas	172	52,020	448	92,518	55	18,573	59	13,813	4	637	2	499
Nuclear	49	51,846	38	39,561	13	15,105	--	--	--	--	8	8,900
Petroleum	63	15,326	17	4,046	4	4,692	--	--	--	--	2	2,022
Other	15	1,258	27	2,167	--	--	1	53	--	--	2	63
2013												
Coal	345	120,340	357	164,826	77	39,482	4	1,422	1	750	11	4,797
Natural Gas	159	51,291	428	88,707	58	18,883	58	12,828	4	637	4	2,481
Nuclear	45	50,266	38	40,013	13	15,251	--	--	--	--	8	11,181
Petroleum	49	11,910	11	3,481	4	4,692	--	--	--	--	--	--
Solar Thermal	--	--	2	591	--	--	4	516	--	--	--	--
Other	15	1,301	31	2,561	1	66	--	--	--	--	1	128
2014												
Coal	328	115,930	340	160,534	74	38,906	4	1,422	1	750	22	8,322
Natural Gas	161	50,985	420	84,984	56	20,294	58	11,878	4	637	3	2,419
Nuclear	44	49,586	35	37,650	13	15,237	--	--	--	--	9	11,886
Petroleum	40	10,043	11	3,473	4	4,691	--	--	--	--	--	--
Solar Thermal	--	--	4	841	--	--	5	900	--	--	--	--
Other	16	1,332	31	2,756	1	66	1	72	--	--	1	128
2015												
Coal	259	93,180	313	153,917	77	45,026	4	1,422	1	750	25	9,883
Natural Gas	160	49,219	437	88,982	59	22,351	59	12,038	3	475	3	2,410
Nuclear	43	47,268	35	37,610	14	17,663	--	--	--	--	9	12,062
Petroleum	27	8,254	9	2,308	4	4,299	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,676	26	2,104	1	66	1	72	--	--	1	128
2016												
Coal	210	82,047	294	149,187	79	44,702	4	1,422	1	750	22	10,148
Natural Gas	168	49,664	440	88,509	58	21,970	64	14,128	3	475	3	2,359
Nuclear	42	47,029	35	38,745	14	17,660	--	--	--	--	9	13,298
Petroleum	25	7,771	8	2,222	3	3,904	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,689	24	2,035	1	66	1	72	--	--	1	128
2017												
Coal	197	76,492	281	142,578	75	44,341	4	1,422	1	750	19	9,581
Natural Gas	172	50,053	439	91,217	59	21,677	66	15,271	4	801	6	3,772
Nuclear	42	47,013	35	38,784	14	17,700	--	--	--	--	9	13,298
Petroleum	26	8,174	8	1,844	4	3,965	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,582	26	2,464	2	97	2	245	--	--	1	128
2018												
Coal	180	70,659	273	138,632	67	39,593	4	1,422	1	750	16	8,089
Natural Gas	161	47,653	445	92,897	59	21,549	77	18,613	4	801	7	4,478
Nuclear	41	46,723	35	38,805	14	17,759	--	--	--	--	9	13,608
Petroleum	27	8,575	8	1,844	3	2,304	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	17	1,931	25	2,161	1	31	1	72	--	--	1	128
2019												
Coal	163	67,142	246	129,998	63	37,807	4	1,432	1	750	14	7,629
Natural Gas	150	45,079	446	95,407	56	21,279	77	18,615	4	801	7	4,058
Nuclear	40	46,244	34	37,970	14	17,759	--	--	--	--	10	14,927
Petroleum	26	8,147	7	1,684	3	2,302	--	--	--	--	--	--
Solar Thermal	--	--	4	866	--	--	5	900	1	110	--	--
Other	18	1,962	25	2,161	--	--	1	72	--	--	1	128

Notes:

'Associated Net Summer Capacity' is defined as the net summer capacity of the generators that are associated with the operation of this environmental equipment.

In some cases respondents have reported equipment late. Counts and capacity may have changed from prior publications of this table because of late reporting.

Coal includes anthracite, bituminous, subbituminous, lignite, and waste coal; coal synfuel and refined coal; and beginning in 2011, coal-derived synthesis gas. Prior to 2011 coal-derived synthesis gas was included in Other Gases.

Petroleum Liquids includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and beginning in 2011, propane. Prior to 2011 propane was included in Other Gases.

Petroleum Coke includes petroleum coke-derived synthesis gas. Prior to 2011, petroleum coke-derived synthesis gas was included in Other Gases.

EIA did not collect cooling system data for nuclear units before 2010.

Other Energy Sources consists of wood and wood waste products, biomass, blast furnace gas and other gases.

Data for 2005 and earlier are based primarily on Form EIA-767 data. In 2006, the Form EIA-767 was suspended. Data for 2007 and later are based primarily on Form EIA-860 data. All data for 2006 are inferred based on submissions from subsequent years.

Source: U.S. Energy Information Administration, Forms EIA-767, "Steam-Electric Plant Operation and Design Report" and Form EIA-860, "Annual Electric Generator Report."

**Table 9.4. Average Costs of Existing Flue Gas Desulfurization Units
Operating in Electric Power Sector, 2009 - 2019**

Year	Average Operation and Maintenance Costs (Dollars per Megawatthour)	Average Installed Capital Costs (Dollars per Kilowatt)
2009	1.44	345.85
2010	1.52	340.18
2011	1.79	335.16
2012	1.87	266.40
2013	1.74	255.86
2014	1.84	186.45
2015	2.03	157.83
2016	1.96	303.32
2017	2.15	246.61
2018	2.08	--
2019	2.11	454.98

Notes: Average Installed Capital Costs reflect units which began operating in the specified year. Prior publications of this table reported the average installation cost of all units that were operating during each year; the new metric is intended to portray a more accurate understanding of how installation costs have changed over time.

Years in which no new Flue Gas Desulfurization units were installed a '--' is indicated in the Average Installed Capital Cost column.

Average Operation and Maintenance Costs are based on all units in operation during the specified year regardless of installation year.

Commercial and industrial facilities had significantly different costs than units used in the electric power sector. In order to give a more accurate reflection of the electric power sector, commercial and industrial facilities have been excluded from this publication table; prior publications of this table included commercial and industrial facilities when calculating average costs.

Sources:

U.S. Energy Information Administration, Form EIA-860, 'Annual Electric Generator Report'

Table 9.5. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, by State, 2018 and 2019 (Thousand Metric Tons)

Census Division and State	Carbon Dioxide (CO2)		Sulfur Dioxide (SO2)		Nitrogen Oxides (NOx)	
	Year 2019	Year 2018	Year 2019	Year 2018	Year 2019	Year 2018
New England	24,813	27,317	10	12	23	25
Connecticut	9,517	9,591	0	1	5	6
Maine	1,823	2,202	7	7	5	6
Massachusetts	8,519	9,976	2	3	8	8
New Hampshire	1,952	2,191	1	1	2	3
Rhode Island	2,996	3,348	0	0	2	2
Vermont	7	10	0	0	1	0
Middle Atlantic	121,032	123,879	62	81	82	86
New Jersey	18,869	18,912	3	3	10	10
New York	24,807	27,936	8	11	26	29
Pennsylvania	77,357	77,031	51	67	45	47
East North Central	301,403	345,080	309	346	218	251
Illinois	63,036	72,261	86	80	33	37
Indiana	77,844	91,554	44	63	62	75
Michigan	57,232	61,435	74	74	51	52
Ohio	68,113	78,051	88	106	50	61
Wisconsin	35,179	41,779	16	23	22	26
West North Central	188,298	213,156	202	249	153	176
Iowa	28,989	34,253	27	34	24	29
Kansas	20,884	23,748	4	5	15	17
Minnesota	25,291	29,805	16	24	21	27
Missouri	57,516	65,623	81	94	42	48
Nebraska	23,660	25,525	42	54	20	22
North Dakota	28,668	31,282	31	37	29	32
South Dakota	3,289	2,921	1	1	1	1
South Atlantic	325,159	355,895	203	235	215	245
Delaware	2,650	3,193	0	1	1	2
District of Columbia	110	43	0	0	1	0
Florida	98,945	107,792	40	53	51	59
Georgia	51,074	54,803	48	48	40	43
Maryland	13,109	17,839	9	18	7	12
North Carolina	47,372	49,642	37	37	46	49
South Carolina	25,110	28,874	21	18	13	15
Virginia	29,965	33,504	13	18	22	28
West Virginia	56,823	60,203	35	42	34	37
East South Central	161,993	177,867	115	129	93	104
Alabama	50,842	56,140	32	37	26	32
Kentucky	58,805	66,267	48	53	40	45
Mississippi	25,018	26,157	12	12	16	15
Tennessee	27,328	29,303	23	27	12	12
West South Central	326,425	353,672	237	401	262	297
Arkansas	32,514	38,349	48	59	22	26
Louisiana	48,116	50,770	37	106	59	76
Oklahoma	28,239	34,476	9	32	19	24
Texas	217,556	230,076	143	203	163	171
Mountain	197,936	203,854	80	83	163	172
Arizona	43,562	46,757	11	15	34	38
Colorado	33,912	34,713	10	11	20	19
Idaho	2,293	1,766	4	4	5	4
Montana	16,348	15,614	12	11	17	16
Nevada	13,921	14,005	4	3	11	10
New Mexico	20,386	18,442	4	3	15	16
Utah	28,316	28,544	8	8	31	31
Wyoming	39,199	44,014	26	28	32	37
Pacific Contiguous	66,530	63,039	27	18	95	93
California	40,874	43,579	1	1	63	67
Oregon	11,029	8,800	7	6	15	12
Washington	14,628	10,661	19	11	16	14
Pacific Noncontiguous	10,807	10,587	21	18	37	35
Alaska	3,470	3,390	3	3	20	19
Hawaii	7,337	7,197	18	15	17	16
U.S. Total	1,724,396	1,874,346	1,267	1,571	1,342	1,485

The emissions data presented include total emissions from both electricity generation and the production of useful thermal output.

See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Source: Calculations made by the Office of Electricity, Renewables, and Uranium Statistics, U.S. Energy Information

Chapter 10

Demand-Side Management and Advanced Metering

Table 10.1. Demand-Side Management Program Annual Effects by Program Category, 2009 through 2012

	Energy Efficiency		Load Management			Total	
Year	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Potential Peak Load Reduction (MW)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)
2009	76,912	19,761	1,027	26,310	11,972	77,939	31,732
2010	86,914	20,828	447	26,100	12,536	87,361	33,364
2011	120,659	26,314	556	26,596	12,126	121,214	38,439
2012	138,525	28,924	712	28,503	13,200	139,237	42,124

2012 was the last year this data was collected.

Previously, annual effects were reported for large respondents only. Now the annual effects include large and small respondents, combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.2. Demand-Side Management Program Annual Effects by Program

Category, by Sector, 2009 through 2012 (Table Discontinued)

Year	Residential	Commercial	Industrial	Transportation	Total
Energy Efficiency - Energy Savings (Thousand MWh)					
2009	27,395	34,831	14,610	76	76,912
2010	32,150	37,416	17,259	89	86,914
2011	46,790	50,732	23,061	76	120,659
2012	54,516	58,894	25,023	92	138,525
Energy Efficiency - Actual Peak Load Reduction (MW)					
2009	8,724	7,954	3,074	9	19,761
2010	9,404	8,046	3,368	10	20,828
2011	11,391	10,422	4,490	11	26,314
2012	12,821	11,743	4,348	12	28,924
Load Management - Energy Savings (Thousand MWh)					
2009	436	197	394	--	1,027
2010	215	113	118	--	447
2011	237	194	125	--	556
2012	257	368	87	--	712
Load Management - Potential Peak Load Reduction (MW)					
2009	7,308	6,460	12,462	81	26,310
2010	7,998	6,080	11,750	272	26,100
2011	7,882	6,023	12,380	311	26,596
2012	8,600	6,462	13,261	180	28,503
Load Management - Actual Peak Load Reduction (MW)					
2009	3,899	3,464	4,606	3	11,972
2010	4,726	2,854	4,819	137	12,536
2011	4,105	2,808	5,108	105	12,126
2012	4,152	3,208	5,732	108	13,200

2012 was the last year this data was collected.

Transportation data is not available before 2003.

Previously, annual data included only large respondents. Now it includes large and small respondents, combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.3. Demand-Side Management Program Incremental Effects by Program Category, 2009 through 2012 (Table Discontinued)

	Energy Efficiency		Load Management			Total	
Year	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Potential Peak Load Reduction (MW)	Actual Peak Load Reduction (MW)	Energy Savings (Thousand MWh)	Actual Peak Load Reduction (MW)
2009	12,907	3,721	65	6,042	2,224	12,972	5,945
2010	13,592	3,215	46	5,234	2,709	13,639	5,923
2011	21,421	3,974	135	4,043	2,062	21,556	6,036
2012	21,478	3,764	41	5,357	2,671	21,520	6,435

2012 was the last year this data was collected.

Previously, large and small respondents were published separately, now they are combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.4. Demand-Side Management Program Incremental Effects by Program

Category, by Sector, 2009 through 2012 (Table Discontinued)

Year	Residential	Commercial	Industrial	Transportation	Total
Energy Efficiency - Energy Savings (Thousand MWh)					
2009	5,030	4,959	2,918	1	12,907
2010	6,492	5,325	1,771	5	13,592
2011	9,989	8,166	3,261	6	21,421
2012	9,531	8,924	3,019	4	21,478
Energy Efficiency - Actual Peak Load Reduction (MW)					
2009	1,849	1,044	827	1	3,721
2010	1,378	1,053	783	1	3,215
2011	1,628	1,545	800	1	3,974
2012	1,775	1,562	426	1	3,764
Load Management - Energy Savings (Thousand MWh)					
2009	34	21	10	--	65
2010	13	21	12	--	46
2011	29	86	21	--	135
2012	20	14	7	--	41
Load Management - Potential Peak Load Reduction (MW)					
2009	1,922	1,971	2,127	22	6,042
2010	1,976	1,171	2,087	--	5,234
2011	1,324	1,327	1,392	--	4,043
2012	1,369	1,155	2,833	1	5,357
Load Management - Actual Peak Load Reduction (MW)					
2009	793	781	648	3	2,224
2010	666	948	1,095	--	2,709
2011	817	619	625	--	2,062
2012	686	737	1,248	*	2,671

2012 was the last year this data was collected.

Transportation data is not available before 2003.

Previously, large and small respondents were published separately, now they are combined.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.5. Demand-Side Management Program Direct and Indirect Costs,

2009 through 2012 (Thousand Dollars) (Table Discontinued)

Year	Energy Efficiency	Load Management	Direct Cost	Indirect Cost	Total Cost
2009	2,221,480	944,261	3,165,741	394,193	3,607,076
2010	2,906,906	1,048,356	3,955,262	275,158	4,230,420
2011	4,002,672	1,213,102	5,215,774	328,622	5,544,396
2012	4,397,635	1,270,391	5,668,026	332,440	6,000,466

2012 was the last year this data was collected.

Direct Costs reflect electric utility costs incurred during the year that are identified with Energy Efficiency and Load Management. Total Costs are the sum of Direct and Indirect Costs.

Previously, this table included only large respondents. Now it includes large and small respondents, combined.

For the total cost data, prior to 2010, both large and small respondents reported total costs, however small respondents did not break out the costs into direct and indirect. The direct and indirect costs were reported for large respondents only.

Therefore, prior to 2010 the total cost does not equal the sum of the direct and indirect costs.

Totals may not equal sum of components because of independent rounding.

Non-Utility DSM Administrators are included in the 2011 data. See technical notes for list.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 10.6. Energy Efficiency
Category, by Sector, 2013 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Incremental Annual Savings - Energy Savings (MWh)					
2013	11,020,468	10,461,718	3,141,044	29,894	24,653,124
2014	11,443,087	11,928,798	3,074,819	19,316	26,466,020
2015	11,012,627	12,285,000	2,818,448	13,414	26,129,489
2016	11,712,873	13,348,029	2,425,175	14,147	27,500,224
2017	13,199,995	14,095,101	2,592,155	11,776	29,899,028
2018	12,459,323	13,350,203	2,565,238	40,273	28,415,037
2019	13,283,024	12,706,234	2,538,169	35,103	28,562,529
Incremental Annual Savings - Peak Demand Savings (MW)					
2013	3,642	5,974	1,458	5	11,078
2014	3,000	2,889	563	2	6,453
2015	2,654	2,891	407	--	5,952
2016	2,698	2,556	401	3	5,658
2017	2,790	2,739	540	1	6,071
2018	2,775	3,072	459	4	6,309
2019	3,402	3,116	614	4	7,135
Incremental Costs - Customer Incentive (thousand dollars)					
2013	1,251,703	1,274,284	345,662	5	2,871,654
2014	1,522,205	1,561,358	327,227	64	3,410,854
2015	1,488,651	1,616,843	342,773	20	3,448,286
2016	1,541,458	1,733,170	296,321	--	3,570,950
2017	1,657,086	1,713,295	294,026	--	3,664,407
2018	1,602,723	1,608,369	273,676	--	3,484,767
2019	1,712,243	1,659,591	285,643	--	3,657,477
Incremental Costs - All Other Costs (thousand dollars)					
2013	1,015,135	749,710	179,719	33	1,944,597
2014	1,088,914	911,967	208,095	122	2,209,098
2015	1,152,224	938,021	193,015	40	2,283,300
2016	1,387,122	959,160	176,560	12	2,522,854
2017	1,221,072	900,291	176,585	10	2,297,957
2018	1,127,692	874,427	163,783	78	2,165,981
2019	1,209,389	910,039	168,567	33	2,288,028

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.7. Energy Efficiency - Life Cycle Category, by Sector, 2013 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Life Cycle Savings - Energy Savings (MWh)					
2013	83,729,903	127,269,038	38,493,282	448,421	249,940,645
2014	105,870,642	156,171,166	39,626,390	287,925	301,956,123
2015	99,512,487	160,045,443	36,589,144	199,328	296,346,403
2016	134,003,597	186,654,713	33,477,182	212,200	354,347,692
2017	137,297,599	204,102,657	33,249,999	176,636	374,826,892
2018	129,572,460	195,288,558	33,981,062	604,095	359,446,175
2019	134,474,216	186,931,400	33,284,347	526,549	355,216,512
Life Cycle Savings - Peak Demand Savings (MW)					
2013	3,782	5,876	1,293	6	10,956
2014	4,058	3,308	672	2	8,040
2015	3,492	3,104	500		7,096
2016	3,408	3,132	507	3	7,050
2017	2,668	2,698	584	1	5,951
2018	2,649	2,987	436	4	6,075
2019	3,322	2,993	613	4	6,931
Life Cycle Costs - Customer Incentive (thousand dollars)					
2013	2,698,135	2,875,483	455,343	5	6,028,810
2014	1,748,893	1,912,277	346,218	64	4,007,452
2015	1,844,246	1,997,677	413,416	30	4,255,368
2016	1,704,458	2,079,373	342,927		4,126,758
2017	2,194,049	2,359,255	296,498		4,849,803
2018	1,808,354	2,093,170	276,381		4,177,905
2019	1,911,197	2,000,492	440,237		4,351,926
Life Cycle Costs - All Other Costs (thousand dollars)					
2013	2,134,225	1,626,069	234,577	33	3,994,889
2014	1,555,433	1,348,672	216,673	122	3,120,898
2015	2,086,543	1,407,658	216,226	40	3,710,453
2016	1,964,832	1,265,765	202,112	12	3,432,717
2017	1,649,863	1,335,176	177,945	10	3,162,995
2018	2,605,135	1,409,483	164,623	78	4,179,320
2019	1,884,678	1,527,461	243,435	33	3,655,607

* = Value is less than half of the smallest unit of measure.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 10.8. Demand Response - Yearly Energy and Demand Savings
Category, by Sector, 2013 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Customers Enrolled					
2013	8,419,233	611,826	155,893	398	9,187,350
2014	8,603,402	605,094	57,129	4	9,265,629
2015	8,140,688	890,284	63,163	3	9,094,138
2016	8,739,535	1,033,649	66,170	1	9,839,355
2017	8,287,913	1,084,392	68,630	3	9,440,938
2018	8,700,669	986,816	64,753	--	9,752,238
2019	10,447,335	432,669	52,841	--	10,932,845
Energy Savings (MWh)					
2013	799,743	486,348	115,895	1	1,401,987
2014	881,563	462,337	92,549	--	1,436,449
2015	855,017	273,089	122,900	--	1,251,006
2016	1,005,144	225,174	105,818	--	1,336,136
2017	948,037	244,603	118,230	--	1,310,862
2018	1,099,179	221,502	105,536	--	1,426,211
2019	1,075,567	306,832	80,336	--	1,462,735
Potential Peak Demand Savings (MW)					
2013	7,003	5,124	14,800	168	27,095
2014	8,118	6,215	16,505	353	31,191
2015	8,703	6,989	17,169	14	32,875
2016	10,518	11,053	14,339	14	35,924
2017	8,996	6,995	15,512	5	31,508
2018	8,539	7,021	15,335	--	30,895
2019	8,867	6,907	15,246	--	31,020
Actual Peak Demand Savings (MW)					
2013	3,381	2,548	5,805	149	11,883
2014	3,147	2,652	6,883	1	12,683
2015	3,430	3,047	6,546	13	13,036
2016	3,608	3,598	4,632	4	11,841
2017	3,960	2,743	5,546	--	12,248
2018	3,788	2,694	6,040	--	12,522
2019	3,426	2,403	5,505	--	11,334

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 10.9. Demand Response - Program Costs
Category, by Sector, 2013 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Customer Incentives (thousand dollars)					
2013	398,598	286,057	421,208	6,919	1,112,782
2014	345,894	345,435	514,751	11,716	1,217,796
2015	320,683	338,153	461,271	339	1,120,446
2016	306,635	448,332	284,584	339	1,039,890
2017	292,443	345,226	365,451	--	1,003,124
2018	310,892	347,235	531,157	--	1,189,284
2019	306,152	322,611	490,119	--	1,118,882
All Other Costs (thousand dollars)					
2013	338,353	95,748	50,982	50	485,133
2014	301,389	101,127	45,028	115	447,659
2015	256,519	78,758	46,613	28	381,918
2016	253,180	66,084	60,443	--	379,707
2017	245,231	68,251	57,221	--	370,700
2018	235,159	66,024	59,534	--	360,718
2019	223,129	49,407	70,677	--	343,214

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 10.10. Advanced Metering Count by Technology Type, 2010 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Automated Meter Reading (AMR)					
2010	43,913,225	4,611,877	159,315	626	48,685,043
2011	41,451,888	4,341,105	172,692	77	45,965,762
2012	43,455,437	4,691,018	185,862	125	48,330,822
2013	42,491,242	4,632,744	196,132	1,202	47,321,320
2014	41,830,781	4,781,167	216,459	1,252	46,829,659
2015	42,326,302	5,049,978	226,908	1,023	47,604,211
2016	41,508,261	5,074,877	223,584	971	46,807,693
2017	39,325,014	4,813,029	230,099	707	44,368,849
2018	36,365,339	4,591,398	213,108	712	41,170,557
2019	32,750,506	4,160,628	207,286	861	37,119,281
Advanced Metering Infrastructure (AMI)					
2010	18,369,908	1,904,983	59,567	67	20,334,525
2011	33,453,548	3,682,159	154,659	7	37,290,373
2012	38,524,639	4,461,350	179,159	35	43,165,183
2013	47,321,995	5,770,067	248,515	845	53,341,422
2014	51,710,725	6,563,614	270,683	916	58,545,938
2015	57,107,785	7,324,345	310,889	813	64,743,832
2016	62,360,132	8,119,223	342,766	1,345	70,823,466
2017	69,474,626	9,060,128	365,447	1,389	78,901,590
2018	76,498,388	9,932,993	411,287	1,489	86,844,157
2019	83,539,594	10,850,886	446,871	1,504	94,838,855
Standard (non-AMR/AMI) Meters					
2010	--	--	--	--	--
2011	--	--	--	--	--
2012	--	--	--	--	--
2013	32,059,522	5,104,322	244,114	132	37,408,090
2014	32,995,176	5,642,247	254,621	1,331	38,893,375
2015	32,430,105	5,744,831	290,354	432	38,465,722
2016	28,491,094	4,929,344	280,406	416	33,701,260
2017	24,351,523	4,261,918	225,949	445	28,839,835
2018	21,982,727	3,884,695	186,001	414	26,053,837
2019	20,778,995	3,734,399	175,344	478	24,689,216
Total Number of Meters					
2010	--	--	--	--	--
2011	--	--	--	--	--
2012	--	--	--	--	--
2013	121,872,759	15,507,133	688,761	2,179	138,070,832
2014	126,536,682	16,987,028	741,763	3,499	144,268,972
2015	131,864,192	18,119,154	828,151	2,268	150,813,765
2016	132,359,487	18,123,444	846,756	2,732	151,332,419
2017	133,151,163	18,135,075	821,495	2,541	152,110,274
2018	134,846,454	18,409,086	810,396	2,615	154,068,551
2019	137,069,095	18,745,913	829,501	2,843	156,647,352

Prior to 2010, the count was the number of customers, not number of meters.

Starting in 2013 Standard (Non-AMR/AMI) meter data was collected on the EIA-861.

This data is not collected on the EIA-861S.

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

Chapter 11

U.S. Territories

**Table 11.1 Puerto Rico- Number of Ultimate Customers Served:
by Sector, 2009 through 2019**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	1,330,507	132,620	828	--	1,463,955
2010	1,339,703	133,029	790	--	1,473,522
2011	1,341,708	132,738	750	--	1,475,196
2012	1,349,750	131,264	721	--	1,481,735
2013	1,340,989	131,034	694	--	1,472,717
2014	1,328,546	129,122	662	--	1,458,330
2015	1,326,631	127,365	647	--	1,454,643
2016	1,332,152	127,179	633	--	1,459,964
2017	1,337,756	127,065	618	--	1,465,439
2018	1,346,102	126,527	602	--	1,473,231
2019	1,341,424	124,912	588	--	1,466,924
Year 2017					
January	1,336,481	127,251	627	--	1,464,359
February	1,337,101	127,229	626	--	1,464,956
March	1,335,413	127,147	620	--	1,463,180
April	1,337,164	127,086	620	--	1,464,870
May	1,337,956	127,048	618	--	1,465,622
June	1,339,373	127,119	616	--	1,467,108
July	1,338,891	127,049	614	--	1,466,554
August	1,337,758	127,026	615	--	1,465,399
September	1,338,973	127,056	615	--	1,466,644
October	1,337,261	126,948	615	--	1,464,824
November	1,338,117	126,941	613	--	1,465,671
December	1,338,583	126,877	612	--	1,466,072
Year 2018					
January	1,343,369	126,955	605	--	1,470,929
February	1,342,510	126,695	606	--	1,469,811
March	1,343,914	126,640	607	--	1,471,161
April	1,344,684	126,489	606	--	1,471,779
May	1,344,960	126,396	604	--	1,471,960
June	1,344,798	126,278	604	--	1,471,680
July	1,345,450	126,221	601	--	1,472,272
August	1,346,380	126,283	598	--	1,473,261
September	1,347,298	126,375	599	--	1,474,272
October	1,348,855	126,492	597	--	1,475,944
November	1,349,924	126,702	595	--	1,477,221
December	1,351,082	126,800	596	--	1,478,478
Year 2019					
January	1,343,649	125,945	594	--	1,470,188
February	1,344,627	125,872	593	--	1,471,092
March	1,345,398	125,610	595	--	1,471,603
April	1,344,357	125,225	590	--	1,470,172
May	1,343,442	125,067	589	--	1,469,098
June	1,341,453	124,798	588	--	1,466,839
July	1,341,100	124,692	588	--	1,466,380
August	1,339,811	124,550	587	--	1,464,948
September	1,338,804	124,409	584	--	1,463,797
October	1,338,280	124,254	583	--	1,463,117
November	1,338,174	124,157	582	--	1,462,913
December	1,337,987	124,366	581	--	1,462,934

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.2 Puerto Rico- Sales of Electricity to Ultimate Customers:
by Sector, 2009 through 2019 (Megawatthours)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	6,673,185	8,936,576	3,094,188	--	18,703,949
2010	6,975,149	9,041,424	2,967,817	--	18,984,390
2011	6,586,877	8,832,355	2,832,127	--	18,251,359
2012	6,770,865	8,879,105	2,500,360	--	18,150,330
2013	6,319,746	8,968,572	2,504,182	--	17,792,500
2014	6,218,352	8,761,182	2,376,022	--	17,355,556
2015	6,313,615	8,586,457	2,355,385	--	17,255,457
2016	6,524,304	8,568,874	2,251,095	--	17,344,273
2017	5,045,346	6,819,591	1,746,554	--	13,611,491
2018	6,102,980	8,202,893	2,128,354	--	16,434,227
2019	6,205,152	7,905,084	2,048,192	--	16,158,428
Year 2017					
January	507,862	649,624	159,232	--	1,316,718
February	395,440	575,493	153,949	--	1,124,883
March	490,439	697,879	191,188	--	1,379,507
April	494,072	628,330	184,098	--	1,306,500
May	525,030	675,349	181,797	--	1,382,176
June	595,232	692,079	184,358	--	1,471,669
July	590,447	709,863	200,197	--	1,500,507
August	631,851	718,603	186,937	--	1,537,392
September	519,910	372,458	127,184	--	1,019,551
October	16,339	224,180	11,110	--	251,630
November	41,829	569,484	28,062	--	639,375
December	236,894	306,249	138,441	--	681,584
Year 2018					
January	389,090	558,621	141,787	--	1,089,498
February	393,230	760,068	174,720	--	1,328,018
March	450,083	531,455	98,406	--	1,079,945
April	466,218	784,445	273,377	--	1,524,040
May	565,759	801,950	165,300	--	1,533,009
June	507,497	591,959	208,432	--	1,307,888
July	577,748	680,752	145,339	--	1,403,840
August	577,416	688,524	209,353	--	1,475,293
September	527,390	722,248	186,217	--	1,435,855
October	697,731	847,420	191,078	--	1,736,230
November	456,854	593,194	172,051	--	1,222,099
December	493,964	642,258	162,293	--	1,298,515
Year 2019					
January	446,630	572,906	154,093	--	1,173,629
February	367,258	487,108	145,670	--	1,000,036
March	448,373	650,652	179,999	--	1,279,023
April	465,255	681,472	164,587	--	1,311,314
May	512,020	655,330	188,520	--	1,355,870
June	567,550	692,815	170,676	--	1,431,041
July	618,052	687,926	181,218	--	1,487,197
August	594,230	718,690	175,077	--	1,487,997
September	585,897	712,800	165,757	--	1,464,454
October	587,379	712,597	195,722	--	1,495,698
November	503,846	677,555	161,844	--	1,343,245
December	508,662	655,234	165,029	--	1,328,925

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.3 Puerto Rico- Revenue from Sales of Electricity to Ultimate Customers:
by Sector, 2009 through 2019 (Thousand Dollars)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	1,313,102	1,868,381	517,578	--	3,699,061
2010	1,520,584	2,102,942	564,218	--	4,187,744
2011	1,748,433	2,483,175	662,537	--	4,894,145
2012	1,689,700	2,604,712	647,414	--	4,941,826
2013	1,633,328	2,474,088	570,210	--	4,677,626
2014	1,636,166	2,394,155	550,673	--	4,580,994
2015	1,282,008	1,850,101	417,158	--	3,549,267
2016	1,169,715	1,677,209	356,310	--	3,203,233
2017	1,123,005	1,549,337	344,034	--	3,016,376
2018	1,265,179	1,893,330	405,173	--	3,563,682
2019	1,329,706	1,810,611	420,178	--	3,560,495
Year 2017					
January	112,261	142,225	29,890	--	284,375
February	99,221	142,975	31,523	--	273,719
March	105,243	151,375	33,960	--	290,577
April	109,465	143,850	33,925	--	287,239
May	118,971	157,160	34,597	--	310,728
June	129,095	151,630	33,508	--	314,233
July	129,968	160,590	36,898	--	327,456
August	142,908	166,467	35,351	--	344,726
September	100,645	74,126	20,797	--	195,568
October	6,083	45,705	4,476	--	56,264
November	19,236	115,412	14,884	--	149,531
December	49,911	97,824	34,226	--	181,961
Year 2018					
January	86,018	159,397	31,640	--	277,056
February	75,989	170,895	32,231	--	279,115
March	109,809	148,653	22,060	--	280,522
April	84,357	161,256	54,292	--	299,904
May	103,994	165,295	22,768	--	292,057
June	107,787	132,963	40,090	--	280,839
July	122,329	165,585	28,750	--	316,664
August	114,400	148,958	38,757	--	302,114
September	109,452	162,472	33,858	--	305,781
October	136,653	181,005	35,721	--	353,379
November	101,917	142,385	33,635	--	277,937
December	112,475	154,467	31,372	--	298,314
Year 2019					
January	85,157	133,940	30,481	--	249,578
February	80,236	108,862	29,331	--	218,430
March	97,926	156,348	36,593	--	290,868
April	106,476	176,783	36,066	--	319,326
May	126,532	132,306	40,714	--	299,553
June	115,587	156,609	36,290	--	308,486
July	121,856	140,238	32,435	--	294,529
August	132,042	174,002	37,054	--	343,098
September	113,409	149,848	31,382	--	294,638
October	126,261	162,497	39,071	--	327,830
November	106,555	154,101	33,426	--	294,082
December	117,668	165,076	37,334	--	320,077

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.4 Puerto Rico- Average Price of Electricity to Ultimate Customers:
by Sector, 2009 through 2019 (Cents per Kilowatthour)**

Period	Residential	Commercial	Industrial	Transportation	All Sectors
Annual Totals					
2009	19.68	20.91	16.73	--	19.78
2010	21.80	23.26	19.01	--	22.06
2011	26.54	28.11	23.39	--	26.82
2012	24.96	29.34	25.89	--	27.23
2013	25.84	27.59	22.77	--	26.29
2014	26.31	27.33	23.18	--	26.39
2015	20.31	21.55	17.71	--	20.57
2016	17.93	19.57	15.83	--	18.47
2017	22.26	22.72	19.70	--	22.16
2018	20.73	23.08	19.04	--	21.68
2019	21.43	22.90	20.51	--	22.03
Year 2017					
January	22.10	21.89	18.77	--	21.60
February	25.09	24.84	20.48	--	24.33
March	21.46	21.69	17.76	--	21.06
April	22.16	22.89	18.43	--	21.99
May	22.66	23.27	19.03	--	22.48
June	21.69	21.91	18.18	--	21.35
July	22.01	22.62	18.43	--	21.82
August	22.62	23.17	18.91	--	22.42
September	19.36	19.90	16.35	--	19.18
October	37.23	20.39	40.29	--	22.36
November	45.99	20.27	53.04	--	23.39
December	21.07	31.94	24.72	--	26.70
Year 2018					
January	22.11	28.53	22.32	--	25.43
February	19.32	22.48	18.45	--	21.02
March	24.40	27.97	22.42	--	25.98
April	18.09	20.56	19.86	--	19.68
May	18.38	20.61	13.77	--	19.05
June	21.24	22.46	19.23	--	21.47
July	21.17	24.32	19.78	--	22.56
August	19.81	21.63	18.51	--	20.48
September	20.75	22.50	18.18	--	21.30
October	19.59	21.36	18.69	--	20.35
November	22.31	24.00	19.55	--	22.74
December	22.77	24.05	19.33	--	22.97
Year 2019					
January	19.07	23.38	19.78	--	21.27
February	21.85	22.35	20.14	--	21.84
March	21.84	24.03	20.33	--	22.74
April	22.89	25.94	21.91	--	24.35
May	24.71	20.19	21.60	--	22.09
June	20.37	22.60	21.26	--	21.56
July	19.72	20.39	17.90	--	19.80
August	22.22	24.21	21.16	--	23.06
September	19.36	21.02	18.93	--	20.12
October	21.50	22.80	19.96	--	21.92
November	21.15	22.74	20.65	--	21.89
December	23.13	25.19	22.62	--	24.09

Sources: U.S. Energy Information Administration, Form EIA-861M (formerly EIA-826), Monthly Electric Industry Power Report.
Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report;
Form EIA-861, Annual Electric Power Industry Report

**Table 11.5. American Samoa
By Sector, 2009 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2009	10,453	1,418	9	--	11,880
2010	10,475	1,404	5	--	11,884
2011	10,616	1,447	4	--	12,067
2012	10,736	1,437	4	--	12,177
2013	10,945	1,411	4	--	12,360
2014	11,561	1,386	4	--	12,951
2015	11,023	1,356	4	--	12,383
2016	10,916	1,363	6	--	12,285
2017	10,930	1,386	4	--	12,320
2018	10,866	1,395	4	--	12,265
2019	10,762	1,450	4	--	12,216
Sales of Electricity to Ultimate Customers (megawatthours)					
2009	43,398	77,754	36,613	--	157,765
2010	45,269	76,014	20,587	--	141,870
2011	41,144	72,785	22,352	--	136,281
2012	39,935	71,952	22,539	--	134,426
2013	40,719	71,069	23,724	--	135,512
2014	41,029	70,598	23,142	--	134,769
2015	43,306	72,007	25,974	--	141,287
2016	46,493	69,617	32,232	--	148,342
2017	49,538	71,173	26,699	--	147,410
2018	45,621	72,185	24,546	--	142,352
2019	47,127	75,151	25,415	--	147,693
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2009	13,185	23,273	9,786	--	46,244
2010	14,336	23,651	5,751	--	43,737
2011	16,459	26,981	7,457	--	50,898
2012	17,343	29,092	8,233	--	54,668
2013	15,809	27,905	8,339	--	52,053
2014	17,286	27,553	8,076	--	52,915
2015	15,035	22,981	7,695	--	45,710
2016	13,184	18,402	7,962	--	39,548
2017	15,020	20,626	7,294	--	42,940
2018	15,434	23,557	7,668	--	46,659
2019	16,617	25,328	8,211	--	50,155
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2009	30.38	29.93	26.73	--	29.31
2010	31.67	31.11	27.93	--	30.83
2011	40.00	37.07	33.36	--	37.35
2012	43.43	40.43	36.53	--	40.67
2013	38.82	39.26	35.15	--	38.41
2014	42.13	39.03	34.90	--	39.26
2015	34.72	31.91	29.63	--	32.35
2016	28.36	26.43	24.70	--	26.66
2017	30.32	28.98	27.32	--	29.13
2018	33.83	32.63	31.24	--	32.78
2019	35.26	33.70	32.31	--	33.96

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 11.6. Guam
By Sector, 2009 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2009	39,863	6,625	--	--	46,488
2010	40,633	6,700	--	--	47,333
2011	41,255	6,717	--	--	47,972
2012	41,612	6,908	--	--	48,520
2013	41,708	6,890	--	--	48,598
2014	41,999	6,925	--	--	48,924
2015	42,752	6,940	--	--	49,692
2016	43,943	6,956	--	--	50,899
2017	43,756	7,087	--	--	50,843
2018	44,006	7,366	--	--	51,372
2019	44,226	7,517	--	--	51,743
Sales of Electricity to Ultimate Customers (megawatthours)					
2009	471,385	1,152,841	--	--	1,624,226
2010	486,962	1,150,700	--	--	1,637,662
2011	487,230	1,130,580	--	--	1,617,810
2012	459,499	1,103,976	--	--	1,563,475
2013	462,163	1,104,247	--	--	1,566,410
2014	457,835	1,075,511	--	--	1,533,346
2015	463,990	1,078,018	--	--	1,542,008
2016	494,842	1,087,317	--	--	1,582,159
2017	516,682	1,103,757	--	--	1,620,439
2018	510,725	1,071,705	--	--	1,582,430
2019	514,829	1,071,513	--	--	1,586,342
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2009	103,972	284,032	--	--	388,004
2010	101,892	262,998	--	--	364,890
2011	112,320	279,555	--	--	391,875
2012	122,259	315,853	--	--	438,112
2013	122,463	315,369	--	--	437,832
2014	125,028	309,439	--	--	434,467
2015	106,057	260,652	--	--	366,709
2016	93,568	214,840	--	--	308,408
2017	103,327	230,472	--	--	333,799
2018	121,331	260,506	--	--	381,837
2019	128,641	275,267	--	--	403,908
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2009	22.06	24.64	--	--	23.89
2010	20.92	22.86	--	--	22.28
2011	23.05	24.73	--	--	24.22
2012	26.61	28.61	--	--	28.02
2013	26.50	28.56	--	--	27.95
2014	27.31	28.77	--	--	28.33
2015	22.86	24.18	--	--	23.78
2016	18.91	19.76	--	--	19.49
2017	20.00	20.88	--	--	20.60
2018	23.76	24.31	--	--	24.13
2019	24.99	25.69	--	--	25.46

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 11.7. Northern Mariana Islands
By Sector, 2011 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2011	11,010	3,673	--	--	14,683
2012	10,657	3,615	--	--	14,272
2013	11,138	3,524	--	--	14,662
2014	11,045	3,651	--	--	14,696
2015	11,318	3,612	--	--	14,930
2016	11,869	3,952	--	--	15,821
2017	12,106	3,952	--	--	16,058
2018	12,323	4,243	--	--	16,566
2019	11,525	3,983	--	--	15,508
Sales of Electricity to Ultimate Customers (megawatthours)					
2011	65,962	160,389	--	--	226,351
2012	57,490	157,247	--	--	214,737
2013	54,056	154,505	--	--	208,561
2014	57,532	153,959	--	--	211,491
2015	52,928	145,170	--	--	198,098
2016	70,404	177,766	--	--	248,170
2017	80,502	193,399	--	--	273,901
2018	75,128	182,533	--	--	257,661
2019	76,795	180,421	--	--	257,216
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2011	23,615	66,316	--	--	89,931
2012	20,209	66,437	--	--	86,646
2013	20,128	67,020	--	--	87,148
2014	20,714	66,034	--	--	86,749
2015	12,197	43,521	--	--	55,718
2016	12,657	42,870	--	--	55,527
2017	18,653	52,614	--	--	71,268
2018	20,530	58,788	--	--	79,318
2019	19,410	55,434	--	--	74,844
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2011	35.80	41.35	--	--	39.73
2012	35.15	42.25	--	--	40.35
2013	37.24	43.38	--	--	41.79
2014	36.01	42.89	--	--	41.02
2015	23.04	29.98	--	--	28.13
2016	17.98	24.12	--	--	22.37
2017	23.17	27.21	--	--	26.02
2018	27.33	32.21	--	--	30.78
2019	25.28	30.72	--	--	29.10

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

**Table 11.8. Virgin Islands
By Sector, 2009 through 2019**

Year	Residential	Commercial	Industrial	Transportation	Total
Number of Ultimate Customers					
2009	44,237	8,907	1,032	--	54,176
2010	44,711	8,320	1,038	--	54,069
2011	44,993	8,881	1,031	--	54,905
2012	44,780	8,826	1,023	--	54,629
2013	44,736	8,785	1,050	--	54,571
2014	45,066	8,808	1,043	--	54,917
2015	45,090	8,747	1,044	--	54,881
2016	49,559	9,951	1,089	--	60,599
2017	49,559	9,951	1,089	--	60,599
2018	46,721	7,491	2,238	--	56,450
2019	46,283	7,526	2,324	--	56,133
Sales of Electricity to Ultimate Customers (megawatthours)					
2009	248,227	127,325	348,725	--	724,277
2010	264,932	120,988	368,867	--	754,787
2011	266,721	151,424	337,652	--	755,797
2012	249,011	156,328	318,578	--	723,917
2013	231,148	123,234	326,158	--	680,540
2014	219,402	113,517	308,119	--	641,038
2015	211,753	109,530	299,598	--	620,881
2016	224,268	115,464	298,959	--	638,691
2017	174,208	85,273	201,822	--	461,303
2018	191,200	75,000	256,100	--	522,300
2019	217,003	87,000	257,313	--	561,316
Revenue from Sales of Electricity to Ultimate Customers (thousand dollars)					
2009	90,735	49,695	124,189	--	264,619
2010	112,891	42,486	132,097	--	287,474
2011	94,859	61,096	124,404	--	280,359
2012	109,441	57,856	150,636	--	317,932
2013	112,133	62,760	158,869	--	333,762
2014	108,204	58,361	153,232	--	319,797
2015	90,567	43,840	134,197	--	268,603
2016	76,907	45,969	101,434	--	224,310
2017	72,035	38,703	93,206	--	203,944
2018	66,093	36,220	83,192	--	185,505
2019	84,090	43,842	95,311	--	223,243
Average Price of Electricity to Ultimate Customers (cents per kilowatthour)					
2009	36.55	39.03	35.61	--	36.54
2010	42.61	35.12	35.81	--	38.09
2011	35.56	40.35	36.84	--	37.09
2012	43.95	37.01	47.28	--	43.92
2013	48.51	50.93	48.71	--	49.04
2014	49.32	51.41	49.73	--	49.89
2015	42.77	40.03	44.79	--	43.26
2016	34.29	39.81	33.93	--	35.12
2017	41.35	45.39	46.18	--	44.21
2018	34.57	48.29	32.48	--	35.52
2019	38.75	50.39	37.04	--	39.77

Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Appendix

Table A.1. Sulfur Dioxide Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration						
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons	Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Tangential Firing Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Distillate Fuel Oil*	DFO	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Jet Fuel*	JF	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Kerosene*	KER	Assumed to have emissions similar to DFO.	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Other Biomass Liquids*	OBL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Residual Fuel Oil*	RFO	Source: 2, Table 1.3-1; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	157.00	15.70	157.00	157.00	157.00	140.00	140.00
Wood Waste Liquids*	WDL	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	142.00	14.20	142.00	142.00	142.00	140.00	140.00
Waste Oil*	WO	Source: 2, Table 1.11-2; Combustion turbines and internal combustion engines assumed to have emissions similar to DFO.	Lbs per MG	147.00	14.70	147.00	147.00	147.00	140.00	140.00
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Landfill Gas	LFG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Natural Gas	NG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other Gases	OG	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Propane Gas	PG	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Coal-Derived Synthesis Gas	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Synthesis Gas from Petroleum Coke	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60
Agricultural Byproducts	AB	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	N/A	N/A
Bituminous Coal*	BIT	Source: 2, Table 1.1-3	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Lignite Coal*	LIG	Source: 2, Table 1.7-1	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	1.70	0.17	1.70	1.70	1.70	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	N/A	N/A
Petroleum Coke*	PC	Source: 1	Lbs per ton	39.00	3.90	39.00	39.00	39.00	N/A	N/A
Refined Coal*	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Subbituminous Coal*	SUB	Source: 2, Table 1.1-3	Lbs per ton	35.00	3.50	35.00	35.00	35.00	N/A	N/A
Tire-Derived Fuel*	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	38.00	3.80	38.00	38.00	38.00	N/A	N/A
Waste Coal*	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	30.00	3.00	30.00	30.00	30.00	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	0.29	0.08	0.08	0.29	0.29	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	7.00	0.70	7.00	7.00	7.00	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.80	0.28	2.80	2.80	2.80	N/A	N/A

Notes:

* For these fuels, emissions are estimated by multiplying the emissions factor by the physical volume of fuel and the sulfur percentage of the fuel (other fuels do not require the sulfur percentage in the calculation). Note that EIA data do not provide the sulfur content of TDF. The value used (1.56 percent) is from U.S. EPA, Control of Mercury Emissions from Coal-Fired Electric Utility Boilers, April 2002, EPA-600/R-01-109, Table A-11 (available at:<http://www.epa.gov/appcdwww/aptb/EPA-600-R-01-109A.pdf>).

** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., Documentation for the 2002 Electric Generating Unit National Emissions Inventory, Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park
2. U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources); available at: <http://www.epa.gov/ttn/chief/ap42/>

Table A.2. Nitrogen Oxides Uncontrolled Emission Factors

Fuel, Code, Source and Emission Units				Combustion System Type / Firing Configuration								
							Tangential Boiler		All Other Boiler Types			
Fuel	EIA Fuel Code	Source and Tables (As Appropriate)	Emissions Units Lbs = Pounds MMCF = Million Cubic Feet MG = Thousand Gallons	Cyclone Firing Boiler	Fluidized Bed Firing Boiler	Stoker Boiler	Dry-Bottom Boilers	Wet-Bottom Boilers	Dry-Bottom Boilers	Wet-Bottom Boilers	Combustion Turbine	Internal Combustion Engine
Distillate Fuel Oil	DFO	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	122.00	443.80
Jet Fuel	JF	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Kerosene	KER	Source: 2, Tables 1.3-1, 3.1-1, & 3.4-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	24.00	118.80	432.00
Other Biomass Liquids	OBL	Source: 1 (including footnote 3 within source); EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	112.30	408.30
Residual Fuel Oil	RFO	Source: 2, Table 1.3-1; EIA estimates	Lbs per MG	47.00	47.00	47.00	32.00	32.00	47.00	47.00	131.70	479.00
Wood Waste Liquids	WDL	Source: 1 (including footnote 16 within source); EIA estimates	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	5.43	230.50	838.10
Waste Oil	WO	Source: 2, Table 1.11-2; EIA estimates	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	19.00	92.20	335.20
Blast Furnace Gas	BFG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40	15.40	30.40	256.55
Landfill Gas	LFG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	72.44	72.44	72.44	72.44	72.44	72.44	72.44	144.00	1,215.22
Natural Gas	NG	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Other Biomass Gas	OBG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	112.83	313.60	2,646.48
Other Gases	OG	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	152.82	152.82	152.82	152.82	152.82	152.82	152.82	263.82	2,226.41
Other	OTH	Assumed to have emissions similar to Natural Gas.	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Propane Gas	PG	Sources: 3; EIA estimates	Lbs per MMCF	522.26	522.26	522.26	522.26	522.26	522.26	522.26	803.36	6,779.57
Synthesis Gas from Petroleum Coke	SGC	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Coal-Derived Synthesis Gas	SGP	Assumed to have emissions similar to Natural Gas	Lbs per MMCF	280.00	280.00	280.00	170.00	170.00	280.00	280.00	328.00	2,768.00
Agricultural Byproducts	AB	Source: 1	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20	1.20	N/A	N/A
Bituminous Coal	BIT	Source: 2, Table 1.1-3	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Lignite Coal	LIG	Source: 2, Table 1.7-1	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Municipal Solid Waste	MSW	Source: 1	Lbs per ton	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A
Other Biomass Solids	OBS	Source: 1 (including footnote 11 within source)	Lbs per ton	2.00	2.00	2.00	2.00	2.00	2.00	2.00	N/A	N/A
Petroleum Coke	PC	Source: 1 (including footnote 8 within source)	Lbs per ton	21.00	5.00	21.00	21.00	21.00	21.00	21.00	N/A	N/A
Refined Coal	RC	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Subbituminous Coal	SUB	Source: 2, Table 1.1-3	Lbs per ton	17.00	5.00	8.80	7.20	7.20	7.40	24.00	N/A	N/A
Tire-Derived Fuel	TDF	Source: 1 (including footnote 13 within source)	Lbs per ton	33.00	5.00	11.00	10.00	14.00	12.00	31.00	N/A	N/A
Waste Coal	WC	Source: 1 (including footnote 20 within source)	Lbs per ton	15.00	3.60	5.80	7.10	7.10	6.30	6.30	N/A	N/A
Wood Waste Solids	WDS	Source: 1	Lbs per ton	2.51	2.00	1.50	2.51	2.51	2.51	2.51	N/A	N/A
Black Liquor	BLQ	Source: 1	Lbs per ton **	1.50	1.50	1.50	1.50	1.50	1.50	1.50	N/A	N/A
Sludge Waste	SLW	Source: 1 (including footnote 11 within source)	Lbs per ton **	5.00	5.00	5.00	5.00	5.00	5.00	5.00	N/A	N/A

Notes:
** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Sources:
1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., Documentation for the 2002 Electric Generating Unit National Emissions Inventory, Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park
2. U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources); available at: <http://www.epa.gov/ttn/chief/ap42/>
3. U.S. Environmental Protection Agency, Factor Information Retrieval (FIRE) Database, Version 6.25; available at: <http://www.epa.gov/ttn/chief/software/fire/index.html>

Table A.3. Carbon Dioxide Uncontrolled Emission Factors

Fuel	EIA Fuel Code	Factor (Kilograms of CO2 Per Million Btu)**	Notes
Bituminous Coal	BIT	93.30	
Distillate Fuel Oil	DFO	73.16	
Geothermal	GEO	7.71	
Jet Fuel	JF	70.90	
Kerosene	KER	72.30	
Lignite Coal	LIG	97.70	
Municipal Solid Waste	MSW	41.69	
Natural Gas	NG	53.07	
Petroleum Coke	PC	102.10	
Propane Gas	PG	63.07	
Refined Coal	RC	93.30	Assumed to have emissions similar to Bituminous Coal.
Residual Fuel Oil	RFO	78.79	
Synthesis Gas Derived from Coal	SGC		* Factor is based on the fuel source used to produce the synthesis gas
Synthesis Gas Derived from Petroleum Coke	SGP		* Factor is based on the fuel source used to produce the synthesis gas
Subbituminous Coal	SUB	97.20	
Tire-Derived Fuel	TDF	85.97	
Waste Coal	WC	93.30	Assumed to have emissions similar to Bituminous Coal.
Waste Oil	WO	95.25	

Notes:

* Factors for synthesis gas derived from coal and synthesis gas derived from petroleum coke are based on the fuel source used to produce the synthesis gas.

** CO2 factors do not vary by combustion system type or boiler firing configuration.

Source: Energy Information Administration estimates:
http://www.eia.gov/environment/emissions/co2_vol_mass.cfm

Table A.4. Nitrogen Oxides Control Technology Emissions Reduction Factors

		Reduction Factor							
Nitrogen Oxides Control Technology	EIA Code	Coal	Residual Fuel Oil and Distallate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Gases	Other Fuels
Burner Out of Service	BO	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Low Excess Air	LA	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Biased Firing (Alternative Burners)	BF	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Overfire Air	OV	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Advanced Overfire Air	AA	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Low NOx Burners	LN	45.00%	45.00%	50.00%	45.00%	45.00%	45.00%	50.00%	45.00%
Fuel Reburning	FU	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%	55.00%
Selective Noncatalytic Reduction	SN	45.00%	32.50%	32.50%	55.00%	45.00%	32.50%	32.50%	45.00%
Selective Catalytic Reduction	SR	80.00%	80.00%	85.00%	80.00%	80.00%	80.00%	85.00%	80.00%
Ammonia Injection	NH3	62.50%	56.25%	58.75%	67.50%	62.50%	56.25%	58.75%	62.50%
Flue Gas Recirculation	FR	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Water Injection	H2O	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Steam Injection	STM	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Other	OT	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%

		Source of Selected Reduction Factor							
Nitrogen Oxides Control Technology	EIA Code	Coal	Residual Fuel Oil and Distallate Fuel Oil	Natural Gas	Wood	Other Solids	Other Liquids	Other Gases	Other Fuels
Burner Out of Service	BO	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low Excess Air	LA	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Biased Firing (Alternative Burners)	BF	Source: 1	Source: 2	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Overfire Air	OV	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Advanced Overfire Air	AA	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Low NOx Burners	LN	Source: 1	Source: 2	Source: 3	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Fuel Reburning	FU	Source: 1	Source: 9	Source: 9	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Selective Noncatalytic Reduction	SN	Source: 1	Source: 2	Source: 4	Source: 5	Source: 9	Source: 10	Source: 11	Source: 9
Selective Catalytic Reduction	SR	Source: 1	Source: 2	Source: 4	Source: 9	Source: 9	Source: 10	Source: 11	Source: 9
Ammonia Injection	NH3	Source: 6	Source: 6	Source: 6	Source: 6	Source: 9	Source: 10	Source: 11	Source: 9
Flue Gas Recirculation	FR	Source: 10	Source: 2	Source: 10	Source: 10	Source: 9	Source: 10	Source: 11	Source: 9
Water Injection	H2O	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Steam Injection	STM	Source: 8	Source: 8	Source: 8	Source: 8	Source: 9	Source: 10	Source: 11	Source: 9
Other	OT	Source: 7	Source: 7	Source: 7	Source: 7	Source: 9	Source: 10	Source: 11	Source: 9

Source: U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources); available at: <http://www.epa.gov/ttn/chief/ap42/>

- Source 1: AP-42, Table 1.1-2
Source 2: AP-42, Section 1.3.4.3 Text
Source 3: AP-42, Table 1.4-1
Source 4: AP-42, Section 1.4.4 Text
Source 5: AP-42, Section 1.6.4 Text
Source 6: Average of Selective Catalytic Reductiona and Selective Noncatalytic Reduction
Source 7: Minimum of other technologies for fuel group
Source 8: Matches Other selection
Source 9: Assumed to have reduction similar to coal
Source 10: Assumed to have reduction similar to Residual Fuel Oil and Distallate Fuel Oil
Source 11: Assumed to have reduction similar to natural gas

Notes:
Coal reduction factors are applied to Bituminous Coal, Subbituminous Coal, Lignite Coal, and Waste Coal.
Wood reduction factors are applied to Wood Waste Solids, Black Liquor, and Wood Waste Liquids.
Other Solids reduction factors are applied to Petroleum Coke, Mincipal Solid Waste, Tire-Derived Fuels, Sludge Waste, Agricultural Biproducts, and Other Biomass Solids.
Other Liquids reduction factors are applied to Jet Fuel, Kerosene, Waste Oil, and Other Biomass Liquids.
Other Gases reduction factors are applied to Blast Furnace Gas, Landfill Gas, Propane Gas, Coal-Derived Synthesis Gas, Synthesis Gas from Petroleum Coke, Other Biomass Gas, and Other Gas.

Table A.5. Unit of Measure Equivalents

Unit	Equivalent
Kilowatt (kW)	1,000 (One Thousand) Watts
Megawatt (MW)	1,000,000 (One Million) Watts
Gigawatt (GW)	1,000,000,000 (One Billion) Watts
Terawatt (TW)	1,000,000,000,000 (One Trillion) Watts
Gigawatt	1,000,000 (One Million) Kilowatts
Thousand Gigawatts	1,000,000,000 (One Billion) Kilowatts
Kilowatthours (kWh)	1,000 (One Thousand) Watthours
Megawatthours (MWh)	1,000,000 (One Million) Watthours
Gigawatthours (GWh)	1,000,000,000 (One Billion) Watthours
Terawatthours (TWh)	1,000,000,000,000 (One Trillion) Watthours
Gigawatthours	1,000,000 (One Million) Kilowatthours
Thousand Gigawatthours	1,000,000,000 (One Billion) Kilowatthours
U.S. Dollar	1,000 (One Thousand) Mills
U.S. Cent	10 (Ten) Mills
Barrel of Oil	42 Gallons

Source: U.S. Energy Information Administration

Technical Notes

This appendix describes how the U.S. Energy Information Administration collects, estimates, and reports electric power data in the Electric Power Annual.

Data Quality and Submission

The Electric Power Annual (EPA) is prepared by the Office of Electricity, Renewables, and Uranium Statistics (ERUS), U.S. Energy Information Administration (EIA), U.S. Department of Energy (DOE). ERUS performs routine reviews of the data collection respondent frames, survey forms, and reviews the quality of the data received.

Data are entered directly by respondents into the ERUS Internet Data Collection (IDC) system. A small number of hard copy forms are keyed into the system by ERUS personnel. All data are subject to review via interactive edits built into the IDC system, internal quality assurance reports, and review by ERUS subject matter experts. Questionable data values are verified through contacts with respondents, and survey non-respondents are identified and contacted.

IDC edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, must either be corrected by the respondent or the respondent must enter an explanation as to why the data are correct. If these explanations are unsatisfactory the respondent is contacted by EIA for clarification or corrected data.

Those respondents unable to use the electronic reporting method provide the data in hard copy, typically via fax and email. These data are manually entered into the computerized database and are subjected to the same data edits as those performed during e-filing by the respondent.

Reliability of Data

Annual survey data have non-sampling errors. Non-sampling errors can be attributed to many sources: (1) inability to obtain complete information about all cases (i.e., non-response); (2) response errors; (3) definitional difficulties; (4) differences in the interpretation of questions; (5) mistakes in recording or coding the data; and (6) other errors of collection, response, coverage, and estimation for missing data.

Although no direct measurement of the biases due to non-sampling errors can be obtained, precautionary steps were taken in all phases of the frame development and data collection, processing, and tabulation processes to minimize their influence.

Imputation: If the reported values appear to be in error and the data issue cannot be resolved with the respondent, or if the facility is a non-respondent, a regression methodology is used to impute for the facility. The regression methodology relies on other data to make estimates for erroneous or missing responses. The basis for the current methodology involves a 'borrowing of strength' technique for small domains.¹

Data Revision Procedure

The EPA presents the most current and complete data available to the EIA. The statistics may differ from those published previously in EIA publications due to corrections, revisions, or other adjustments to the data subsequent to its original release.

After data are disseminated as final, revisions will be considered if a correction would make a difference of 1 percent or greater at the national level. Revisions for differences that do not meet the 1 percent or greater threshold will be determined by the Office Director. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.

Sensitive Data (Formerly Identified as Data Confidentiality): Most of the data collected on the electric power surveys are not considered business sensitive. However, the data that are classified as sensitive are handled by ERUS consistent with EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 Federal Register 59812 (1980)).

Rounding and Percent Change Calculations

Rounding Rules for Data: To round a number to n digits (decimal places), add one unit to the n th digit if the $(n+1)$ digit is 5 or larger and keep the n th digit unchanged if the $(n+1)$ digit is less than 5. The symbol for a number rounded to zero is (*).

Percent Change: The following formula is used to calculate percent changes:

$$\text{Percent Change} = \left(\frac{x(t_2) - x(t_1)}{x(t_1)} \right) \times 100,$$

where $x(t_1)$ and $x(t_2)$ denote the quantity at period t_1 and subsequent period t_2 .

Data Sources for Electric Power Annual

Data published in the EPA are compiled from forms filed annually or aggregated to an annual basis from monthly forms (see figure on EIA Electric Industry Data Collection in Appendix A). The respondents to these forms include electric utilities, other generators and sellers of electricity, and North American Electric Reliability Corporation (NERC) reliability entities. The EIA forms used are:

- Form EIA-411, "Coordinated Bulk Power Supply Program Report;"
- Form EIA-860, "Annual Electric Generator Report;"
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-861M, "Monthly Electric Power Industry Report;"
- Form EIA-861S, "Annual Electric Power Industry Report (Short Form);"
- Form EIA-923, "Power Plant Operations Report."

These forms can be found on the EIA Internet website at:

<http://www.eia.gov/cneaf/electricity/page/forms.html>.

Survey data from other Federal sources are also utilized for this publication. They include:

- FERC Form 1, “Annual Report of Major Electric Utilities, Licensees, and Others;”
- U. S. Department of Agriculture (USDA) Rural Utility Service Form 7, “Financial and Statistical Report;” and
- USDA Rural Utility Service Form 12, “Operating Report – Financial.”

In addition to the above-named forms, the historical data published in the EPA are compiled from the following inactive forms:

- Form EIA-412, “Annual Electric Industry Financial Report,” FERC Form 423, “Cost and Quality of Fuels for Electric Plants;”
- Form EIA-423, “Monthly Cost and Quality of Fuels for Electric Plants Report;”
- Form EIA-759, “Monthly Power Plant Report;”
- Form EIA-767, “Steam-Electric Plant Operation and Design Report;”
- Form EIA-826, “Monthly Electric Utility Sales and Revenues with State Distributions Report;”
- Form EIA-860A, “Annual Electric Generator Report–Utility;”
- Form EIA-860B, “Annual Electric Generator Report–Nonutility;”
- Form EIA-867, “Annual Nonutility Power Producer Report;”
- Form EIA-900, “Monthly Nonutility Power Report;”
- Form EIA-906, “Power Plant Report;” and
- Form EIA-920, “Combined Heat and Power Plant Report.”

Additionally, some data reported in this publication were acquired from public reports of the National Energy Board of Canada on electricity imports and exports.

Meanings of Symbols Appearing in Tables: The following symbols have the meaning described below:

- * The value reported is less than half of the smallest unit of measure, but is greater than zero.
- P Indicates a preliminary value.
- W Withheld to avoid disclosure of individual company data.
- NM Data value is not meaningful, either (1) when compared to the same value for the previous time period, or (2) when a data value is not meaningful due to having a high Relative Standard Error (RSE).
- (*) Usage of this symbol indicates a number rounded to zero.

Form EIA-411

The information reported on the mandatory Form EIA-411 includes: (1) actual energy and peak demand for the preceding year and five additional years; (2) existing and future generating capacity and capacity reserve margins; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) power flow cases; and (6) bulk power system maps. The data is collected for EIA by NERC from NERC regional reliability entities, which in turn aggregate reports from regional members. Non-member data is also included. The compiled data is reviewed and edited by

NERC and submitted to EIA annually on July 15. The data undergoes additional review by EIA. EIA resolves any quality issues with NERC.

Instrument and Design History: The Form EIA-411 program was initiated under the Federal Power Commission (FPC) Docket R-362, Reliability and Adequacy of Electric Service, and Orders 383-2, 383-3, and 383-4. The DOE, established in October 1977, assumed the responsibility for this activity. The responsibility for collecting these data was delegated to the Office of Emergency Planning and Operations within the DOE and was transferred to EIA for the reporting year 1996. Until 2008, this form was voluntary. The data are collected under the authority of the Federal Power Act (Public Law 88-280), the Federal Energy Administration Act of 1974 (Public Law 93-275), and the DOE Organization Act (Public Law 95-91).

Issues within Historical Data Series: The Florida Reliability Coordinating Council (FRCC) separated itself from the Southeastern Electric Reliability Council (SERC) in the mid-1990s and all time-series data have been adjusted. In 1998, several utilities realigned from Southwest Power Pool (SPP) to SERC. Adjustments were made to the information to account for the separation and to address the tracking of shared reserve capacity that was under long-term contracts with multiple members. Name changes altered the Mid-Continent Area Power Pool (MAPP) to the Midwest Reliability Organization (MRO) and the Western Systems Coordinating Council (WSCC) to the Western Electricity Coordinating Council (WECC). The MRO membership boundaries have altered over time, but WECC membership boundaries have not. The utilities in the associated regional entity identified as the Alaska System Coordination Council (ASCC) dropped their formal participation in NERC. (Alaska and, obviously, Hawaii are not electrically interconnected with the coterminous 48 States).

At the close of calendar year 2005, the following reliability regional councils were dissolved: East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-America Interconnected Network (MAIN). On January 1, 2006, the ReliabilityFirst Corporation (RFC) came into existence as a new regional reliability council. Individual utility membership in the former ECAR, MAAC, and MAIN councils mostly shifted to RFC. However, adjustments in membership, as utilities joined or left various reliability councils, impacted MRO, SERC, and SPP. The Texas Regional Entity (TRE) was formed to handle the regional reliability responsibilities of the Electric Reliability Council of Texas (ERCOT). The revised delegation agreements covering all the regions were approved by the FERC on March 21, 2008. Reliability Councils that are unchanged include: Florida Reliability Coordinating Council (FRCC), Northeast Power Coordinating Council (NPCC), and the Western Electricity Coordinating Council (WECC). The historical time series have not been adjusted to account for individual membership shifts.

The current NERC regional entity names are as follows:

- Florida Reliability Coordinating Council (FRCC),
- Midwest Reliability Organization (MRO),
- Northeast Power Coordinating Council (NPCC),
- ReliabilityFirst Corporation (RFC),
- Southeastern Electric Reliability Council (SERC),

- Southwest Power Pool (SPP),
- Texas Regional Entity (TRE), and
- Western Energy Coordinating Council (WECC).

Changes Introduced in 2011: Starting in 2011, NERC modified the bulk power system reporting regions (in contrast to regional reliability entity organizational boundaries) to align them with electric market operations. Consequently, reliability data will be reported for the PJM and MISO regional transmission organization areas and the MAPP area rather than for the MRO and RFC regional areas. This new framework, along with the other NERC regions, now forms the bulk power system reliability assessment areas.

Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. In published EIA reports the historical data series for these regions have not been adjusted. Instead, starting in 2011, EIA has introduced the Balance of Eastern Region category to provide a consistent trend for the Eastern interconnection.

Concept of Demand within the EIA-411: The EIA-411 uses the following categorization of electricity demand:

- **Net Internal Demand:** Internal Demand less Direct Control Load Management and Interruptible Demand.
- **Internal Demand:** To collect these data, NERC develops a Total Internal Demand that is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included nor are any requirement customer (utility) load or capacity found behind the line meters on the system.
- **Direct Control Load Management:** Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises; it does not include Interruptible Demand.
- **Interruptible Demand:** The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator.

For additional information on demand, refer to the NERC's Long-Term Reliability Assessments at <http://www.nerc.com/page.php?cid=4> | 61.

Sensitive Data: Power flow cases and maps are considered business sensitive.

Form EIA-412 (Terminated)

The Form EIA-412 was used annually to collect accounting, financial, and operating data from publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had

150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the two previous years. Data was collected annually.

Beginning with the 2001 data collection, the plant statistics reported on Schedule 9 were also collected from unregulated entities that own plants with a nameplate capacity of 10 megawatts or greater. Beginning with the 2003 collection, the transmission data reported in Schedules 10 and 11 were collected from each generation and transmission cooperative owning transmission lines having a nominal voltage of 132 kilovolts or greater.

Instrument and Design History: The FPC created the FPC Form 1M in 1961 as a mandatory survey. It became the responsibility of the EIA in October 1977 when the FPC was merged with DOE and renamed the Federal Energy Regulatory Commission (FERC). In 1979, the FPC Form 1M was superseded by the Economic Regulatory Administration (ERA) Form ERA-412 and in January 1980 by the Form EIA-412.

The criteria used to select the respondents for this survey fit approximately 500 publicly owned electric utilities. Federal electric utilities were required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault Ste. Marie, Michigan); the U.S. Department of Interior, Bureau of Reclamation; and the U.S. International Boundary and Water Commission were collected on the Form EIA-412 from the Federal power marketing administrations. The form was terminated after the 2003 data year.

Issues within Historical Data Series: For 2001 - 2003, the California Department of Water Resources (CDWR) Electric Energy Fund data were included in the EIA-412 data tables. In response to the energy shortfall in California, in 2001 the California State legislature authorized the CDWR, using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail customers effective on January 17, 2001 and for the period ending December 31, 2002. Their 2001 revenue collected was \$5,501,000,000 with purchased power costs of \$12,055,000,000. Their 2002 revenue collected was \$4,210,000,000 with purchased power costs of \$3,827,749,811. Their 2003 revenue collected was \$4,627,000,000 with purchased power costs of \$4,732,000,000. The California Public Utility Commission was required by statute to establish the procedures for retail revenue recovery mechanisms for their purchase power costs in the future.

Sensitive Data: The nonutility data collected on Schedule 9 "Electric Generating Plant Statistics" for "Cost of Plant" and "Production Expenses," are considered business sensitive. .

Form EIA-423 (Replaced in 2008 by the Form EIA-923)

The Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," collected the cost and quality of fossil fuels delivered to nonutility plants to produce electricity. These plants included independent power producers (including those facilities that formerly reported on the FERC Form 423) and commercial and industrial combined heat and power (CHP) producers whose total fossil-fueled nameplate generating capacity was 50 or more megawatts (MW). (CHP plants are sometimes referred to as co-generators. They produce heat, such as steam for use in a manufacturing process, along with electricity).

Instrument and Design History: The Form EIA-423² was implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. It was terminated on January 1, 2008, and replaced by the Form EIA-923, "Power Plant Operations Report."

Issues within Historical Data Series: Natural gas values do not include blast furnace gas or other gas.

Sensitive Data: Plant fuel cost data collected on the survey are considered business sensitive. State- and national-level aggregations are published if sufficient data are available to avoid disclosure of individual company and plant level costs.

FERC Form 423 (Replaced in 2008 by Form EIA-923)

The FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," was administered by FERC. The data were downloaded from the Commission's website into an EIA database. The Form was filed by approximately 600 regulated plants. To meet the criteria for filing, a plant must have had a total steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity of 50 or more megawatts. Only fuel delivered for use in steam-turbine and combined-cycle units was reported. Fuel received for use in gas-turbine or internal-combustion units that was not associated with a combined-cycle operation was not reported. The FERC Form 423 was replaced after 2007 by the Form EIA-923.

Instrument and Design History: On July 7, 1972, the FPC issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, creating the FPC Form 423. Originally, the form was used to collect data only on fossil steam plants, but was amended in 1974 to include data on internal-combustion and combustion-turbine units. When DOE was formed in 1977, most of FPC became FERC. The FERC Form 423 replaced the FPC Form 423 in January 1983. The FERC Form 423 dropped stand-alone combustion turbines. In addition, the generator nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All historical FPC Form 423 data in this publication were revised to reflect the new generator-nameplate-capacity threshold of 50 or more megawatts reported on the FERC Form 423. In January 1991, the collection of data on the FERC Form 423 was extended to include combined cycle units. Historical data have not been revised to include these units. On January 1, 2008, EIA assumed responsibility for collection of these data and both the utility and nonutility plants began to report their cost and quality of fuels information on Schedule 2 of Form EIA-923, "Power Plant Operations Report."

Issues within Historical Data Series: These data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 survey. The data were quality reviewed by EIA and when possible quality issues were resolved with FERC.

Natural gas values for 2001 forward do not include blast furnace gas or other gas.

Due to the estimation procedure described below in the discussion of the Form EIA-923, 2003 and later data cannot be directly compared to previous years' data.

Sensitive Data: Data collected on FERC Form 423 are not business sensitive.

Form EIA-767 (Replaced by Forms EIA-860 and EIA-923)

The Form EIA-767 was used to collect data annually on plant operations and equipment design, including boiler, generator, cooling system, air pollution control equipment, and stack characteristics. Data were collected from a mandatory restricted-universe census of all electric power plants with a total existing or planned organic-fueled or combustible renewable steam-electric generator nameplate rating of 10 or more megawatts. The entire form was filed by approximately 800 power plants with a nameplate capacity of 100 or more megawatts. An additional 600 power plants with a nameplate capacity under 100 megawatts submitted information only on fuel consumption and quality, boiler and generator configuration, and nitrogen oxides, mercury, particulate matter, and sulfur dioxide controls.

Instrument and Design History: The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, "Steam-Electric Plant Air and Water Quality Control Data," was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and re-titled Form EIA-767, "Steam-Electric Plant Operation and Design Report." In 1986, the respondent universe of 700 plants was increased to 900 plants to include plants with nameplate capacity from 10 megawatts to 100 megawatts. In 2002, the respondent universe was increased by almost 1,370 plants with the addition of nonutility plants.

Collection of data via the form was suspended for the 2006 data year. Starting with the collection of 2007 calendar year data, most of the Form EIA-767 information is now collected on either the revised Form EIA-860, "Annual Electric Generator Report" or the new Form EIA-923, "Power Plant Operations Report."

Estimation of EIA-767 Data: No estimation of Form EIA-767 data was performed. Normally the survey had no non-response.

Issues within Historical Data Series: As noted above, no data were collected for calendar year 2006.

Sensitive Data: Latitude and longitude data collected on the Form EIA-767 were considered business sensitive.

Form EIA-861M (Formerly the EIA-826)

The Form EIA 861M, "Monthly Electric Power Industry Report," is a monthly collection of data from a sample of approximately 520 of the largest electric utilities (primarily investor and publicly owned) as well as a census of energy service providers with sales to ultimate consumers in deregulated States. Form EIA-861 (see below), with approximately 3,300 respondents, serves as a frame from which the Form 826 sample is drawn. Based on this sample, a model is used to estimate for the entire universe of U.S. electric utilities on a monthly basis.

Instrument and design history: The collection of electric power sales data and related information began in the early 1940's and was established as FPC Form 5 by FPC Order 141 in 1947. In 1980, the report was revised with only selected income items remaining and became the FERC Form 5. The Form

EIA 826, “Electric Utility Company Monthly Statement,” replaced the FERC Form 5 in January 1983. In January 1987, the “Electric Utility Company Monthly Statement” was changed to the “Monthly Electric Utility Sales and Revenue Report with State Distributions.” The title was changed again in January 2002 to “Monthly Electric Utility Sales and Revenues with State Distributions Report” to become consistent with other EIA report titles. The Form EIA 826 was revised in January 1990, and some data elements were eliminated.

In 1993, EIA for the first time used a model sample for the Form EIA 826. A stratified random sample, employing auxiliary data, was used for each of the four previous years. The sample for the Form EIA 826 was designed to obtain estimates of electricity sales and average retail price of electricity at the State level by end use sector.

Starting with data for January 2001, the restructuring of the electric power industry was taken into account by forming three schedules on the Form EIA-826. Schedule 1, Part A is for full service utilities that operate as in the past. Schedule 1, Part B is for electric service providers only, and Schedule 1, Part C is for those utilities providing distribution service for those on Schedule 1, Part B. In addition, Schedule 1 Part D is for those retail energy providers or power marketers that provide bundled service. Also, the Form EIA-826 frame was modified to include all investor-owned electric utilities and a sample of companies from other ownership classes. A new method of estimation was implemented at this same time. (See Electric Power Monthly, April 2001, p.1.)

With the October 2004 issue of the Electric Power Monthly (EPM), EIA published for the first time preliminary electricity sales data for the Transportation Sector. These data are for electricity delivered to and consumed by local, regional, and metropolitan transportation systems. The data being published for the first time in the October EPM included July 2004 data as well as year-to-date. EIA’s efforts to develop these new data have identified anomalies in several States and the District of Columbia. Some of these anomalies are caused by issues such as: 1) Some respondents have classified themselves as outside the realm of the survey. The Form EIA-826 collects retail data from those respondents providing electricity and other services to the ultimate end users. EIA has experienced specific situations where, although the respondents’ customers are the ultimate end users, particular end users qualify under wholesale rate schedules. 2) The Form EIA-826 is a cutoff sample and not intended to be a census.

Data processing and data system editing: Monthly Form EIA-861M submission is available via an Internet Data Collection (IDC) system. The completed data are due to EIA by the last calendar day of the month following the reporting month. Nonrespondents are contacted to obtain the data. The data are edited and additional checks are completed. Following verification, imputation is run, and tables and text of the aggregated data are produced for inclusion in the EPM.

Imputation: Regression prediction, or imputation, is done for entities not in the monthly sample and for any nonrespondents. Regressor data for Schedule 1, Part A is the average monthly sales or revenue from the most recent finalized data from survey Form EIA-861. Beginning with January 2008 data and the finalized 2007 data, the regressor data for Schedule 1 Parts B and C is the prior month’s data.

Formulas and methodologies: The Form EIA 861M data are collected by end-use sector (residential, commercial, industrial, and transportation) and State. Form EIA 861 (see below) data are used as the

frame from which the sample is selected and in some instances also as regressor data. Updates are made to the frame to reflect mergers that affect data processing.

With the revised definitions for the commercial and industrial sectors to include all data previously reported as 'other' data except transportation, and a separate transportation sector, all responses that would formerly have been reported under the "other" sector are now to be reported under one of the sectors that currently exist. This means there is probably a lower correlation, in general, between, say, commercial Form EIA-826 data for 2004 and commercial Form EIA-861 data for 2003 than there was between commercial Form EIA-826 data for 2003 and commercial Form EIA-861 data for 2002 or earlier years, although commercial and industrial definitions have always been somewhat nebulous due to power companies not having complete information on all customers.

Data submitted for January 2004 represent the first time respondents were to provide data specifically for the transportation end-use sector.

During 2003 transportation data were collected annually through Form EIA-861. Beginning in 2004 the transportation data were collected on a monthly basis via Form EIA-826. In order to develop an estimate of the monthly transportation data for 2003, values for both sales of electricity to ultimate customers and revenue from sales of electricity to ultimate customers were estimated using the 2004 monthly profile for the sales and revenues from the data collected via Form EIA-826. All monthly non-transportation data for 2003 (i.e. street lighting, etc.), which were previously reported in the "other" end-use sector on the Form EIA-826 have been prorated into the Commercial and Industrial end-use sectors based on the 2003 Form EIA-861 profile.

A monthly distribution factor was developed for the monthly data collected in 2004 (for the months of January through November). The transportation sales and revenues for December 2004 were assumed to be equivalent to the transportation sales and revenues for November 2004. The monthly distribution factors for January through November were applied to the annual values for transportation sales and revenues collected via Form EIA-861 to develop corresponding 2003 monthly values. The eleven month estimated totals from January through November 2003 were subtracted from the annual values obtained from Form EIA-861 in order to obtain the December 2003 values.

Data from the Form EIA-861M are used to determine estimates by sector at the State, Census division, and national level. State level sales and revenues estimates are first calculated. Then the ratio of revenue divided by sales is calculated to estimate retail price of electricity at the State level. The estimates are accumulated separately to produce the Census division and U.S. level estimates³.

Some electric utilities provide service in more than one State. To facilitate the estimation, the State service area is actually used as the sampling unit. For each State served by each utility, there is a utility State part, or "State service area." This approach allows for an explicit calculation of estimates for sales, revenue, and average retail price of electricity by end use sector at State, Census division, and national level. Estimation procedures include imputation to account for nonresponse. Non-sampling error must also be considered. The non-sampling error is not estimated directly, although attempts are made to minimize the non-sampling error.

Average retail price of electricity represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector.

The electric revenue used to calculate the average retail price of electricity is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric utility operating revenues also include State and Federal income taxes and taxes other than income taxes paid by the utility.

The average retail price of electricity reported in this publication by sector represents a weighted average of consumer revenue and sales within sectors and across sectors for all consumers, and does not reflect the per kWh rate charged by the electric utility to the individual consumers. Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric utility for providing electrical service.

Adjusting monthly data to annual data: As a final adjustment based on our most complete data, use is made of final Form EIA-861 data, when available. The annual totals for Form EIA-826 data by State and end-use sector are compared to the corresponding Form EIA-861 values for sales and revenue. The ratio of these two values in each case is then used to adjust each corresponding monthly value.

Sensitive data: Most of the data collected on the Form EIA-861M are not considered business sensitive. However, monthly revenue, sales, and customer data collected from energy service providers (Schedule 1, Part B), which do not also provide energy delivery, are considered business sensitive and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45Federal Register 59812 (1980)).

Form EIA-860

The Form EIA-860 is a mandatory annual census of all existing and planned electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The survey is used to collect data on existing power plants and 10 year plans for constructing new plants, as well as generating unit additions, modifications, and retirements in existing plants. Data on the survey are collected at the individual generator level. Certain power plant environmental-related data are collected at the boiler level. These data include environmental equipment design parameters and boiler air emission standards and boiler emission controls.

Instrument and Design History: The Form EIA-860 was originally implemented in January 1985 to collect plant data on electric utilities as of year-end 1984. It was preceded by several Federal Power Commission (FPC) forms including the FPC Form 4, Form 12 and 12E, Form 67, and Form 411. In January 1999, the Form EIA-860 was renamed the Form EIA-860A and was implemented to collect data as of January 1, 1999.

In 1989, the Form EIA-867, "Annual Nonutility Power Producer Report," was initiated to collect plant data on unregulated entities with a total generator nameplate capacity of 5 or more megawatts. In

1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. In 1998, the Form EIA-867, was renamed Form EIA-860B, "Annual Electric Generator Report – Nonutility." The Form EIA-860B was a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts.

Beginning with data collected for the year 2001, the infrastructure data collected on the Form EIA-860A and the Form EIA-860B were combined into the new Form EIA-860 and the monthly and annual versions of the Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Starting with 2007, design parameters data formerly collected on Form EIA-767 were collected on Form EIA-860. These include design parameters associated with certain steam-electric plants' boilers, cooling systems, flue gas particulate collectors, flue gas desulfurization units, and stacks and flues.

Estimation of EIA-860 Data: No imputation was required for EIA-860 data.

Issues within Historical Data Series Regarding Categorization of Capacity by Business Sector: There are a small number of electric utility CHP plants, as well as a small number of industrial and commercial generating facilities that are not CHP. For the purposes of this report the data for these plants are included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and "Combined Heat and Power, Commercial."

Some capacity in 2001 through 2004 is classified based on the operating company's classification as an electric utility or an independent power producer. Starting in the EPA 2006, capacity by producer type was determined at the power plant level for 2005 and all subsequent data collections. This change required revisions to the original published 2005 data.

Issues within Historical Data Series Regarding Planned Capacity: Delays and cancellations may have occurred subsequent to respondent data reporting as of December 31 of the data year.

Issues within Historical Data Series Regarding Capacity by Energy Source: Prior to the EPA 2005, the capacity for generators for which natural gas or petroleum was the most predominant energy source was presented in the following three categories: petroleum only, natural gas only, and dual-fired. The dual-fired category, which was EIA's effort to infer which generators could fuel-switch between natural gas and fuel oil, included only the capacity of generators for which the most predominant energy source and second most predominant energy source were reported as natural gas or petroleum. Beginning in 2005, capacity is assigned to energy source based solely on the most predominant (primary) energy source reported for a generator. The "dual-fired" category was eliminated. Separately, summaries of capacity associated with generators with fuel-switching capability are presented for 2005 and later years. These summaries are based on data collected from new questions added to the Form EIA-860 survey that directly address the ability of generators to switch fuels and co-fire fuels.

In the EPA 2005, certain petroleum-fired capacity was misclassified as natural gas-fired capacity for 1995 – 2003. This was corrected in the EPA 2006. Corrections were noted as revised data.

Prime Movers: The Form EIA-860 sometimes represents a generator's prime mover by using the abbreviations in the table below.

Prime Mover Code	Prime Mover Description
BA	Energy Storage, Battery
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
FW	Energy Storage, Flywheel
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
ES	Energy Storage, Other
ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)
GT	Combustion (Gas) Turbine (including jet engine design)
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	Combined Cycle Steam Part
CT	Combined Cycle Combustion Turbine Part
CS	Combined Cycle Single Shaft
CC	Combined Cycle Total Unit
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other
HY	Hydroelectric Turbine (including turbines associated with delivery of water by pipeline)
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore
FC	Fuel Cell
OT	Other

Energy Sources: The Form EIA-860 sometimes represents the energy sources associated with generators by using the abbreviations and/or groupings in the table below.

Energy Source Grouping	Energy Source	
	Code	Energy Source Description
Coal	ANT	Anthracite Coal
	BIT	Bituminous Coal
	LIG	Lignite Coal
	SUB	Subbituminous Coal
	SGC	Coal-Derived Synthesis Gas
	WC	Waste/Other Coal (including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
Petroleum Products	DFO	Distillate Fuel Oil (including diesel, No. 1, No. 2, and No. 4 fuel oils)
	JF	Jet Fuel
	KER	Kerosene
	PC	Petroleum Coke
	PG	Gaseous Propane
	RFO	Residual Fuel Oil (including No. 5, and No. 6 fuel oils, and bunker C fuel oil)
	SG	Synthesis Gas from Petroleum Coke
	WO	Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)
Natural Gas and Other Gases	BFG	Blast Furnace Gas
	NG	Natural Gas
	OG	Other Gas
Nuclear	NUC	Nuclear (including Uranium, Plutonium, and Thorium)
Hydroelectric Conventional	WAT (Prime Mover = HY)	Water at a Conventional Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology
Hydroelectric Pumped Storage	WAT (Prime Mover = PS)	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
Wood and Wood-Derived Fuels	WDS	Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
	WDL	Wood Waste Liquids (excluding Black Liquor but including red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
	BLQ	Black Liquor
Other Biomass	AB	Agricultural By-Products
	MSW	Municipal Solid Waste
	OBG	Other Biomass Gas (including digester gas, methane, and other biomass gases)
	OBL	Other Biomass Liquids
	OBS	Other Biomass Solids
	LFG	Landfill Gas
	SLW	Sludge Waste
	SUN	Solar (including solar thermal)
Other Renewable Energy Sources	WND	Wind
Other Energy Sources	GEO	Geothermal
	PUR	Purchased Steam
	WH	Waste heat not directly attributed to a fuel source
	TDF	Tire-Derived Fuels
	MWH	Electricity used for energy storage
	OTH	Other

Sensitive Data: The tested heat rate data collected on the Form EIA-860 are considered business sensitive.

Form EIA-861

The Form EIA-861 is a mandatory annual census of electric power industry participants in the United States. Prior to data year 2012, the survey was used to collect information on power sales and revenue data from approximately 3,300 respondents. About 3,100 are electric utilities, and the remainders are nontraditional entities such as energy service providers or the unregulated subsidiaries of electric utilities and power marketers.

For data year 2012 and forward, EIA modified the frame of the Form EIA-861, “Annual Electric Power Industry Report,” from a census to a sample, and EIA is using model-based methods to estimate the sales, revenues, and customer counts by sector and state for those respondents that have been removed from the frame. EIA created a new Form EIA-861S, “Annual Electric Power Industry Report (Short Form),” for the respondents that have been removed from the Form EIA-861 frame. Respondents removed from the EIA-861 frame and placed on the EIA-861S tend to be smaller utilities with annual sales volumes not exceeding 100,000 megawatthours (MWhs). Form EIA-861S with fewer data elements compared to the EIA-861, collects limited data on total sales, revenues, and customer counts by state. Every eighth data year, EIA-861S respondents are required to fill out the full EIA-861 form. For data year 2019, EIA-861S respondents were required to complete the full EIA-861 form.

Transportation Sector: Prior to 2003, sales of electric power for transportation (e.g., city subway systems) were included in the Other Sector, along with sales to customers for public buildings, traffic signals and public street lighting. Beginning with the 2003 data collection, sales to the Transportation Sector were collected separately. The balance of the Other Sector was reclassified as Commercial Sector.

On the Form EIA-861, the Transportation Sector is defined as electrified rail, primarily urban transit, light rail, automated guideway, and other rail systems whose primary propulsive energy source is electricity. Electricity sales to Transportation Sector consumers whose primary propulsive energy source is not electricity (i.e., gasoline, diesel fuel, etc.) are not included.

Benchmark statistics were reviewed from outside surveys, most notably the U.S. Department of Transportation (DOT) Federal Transit Administration’s National Transportation Database, a source previously used by EIA to estimate electricity transportation consumption. The DOT survey indicated the State and City locations of expected respondents. The Form EIA-861 survey methodology assumed that sales, revenue, and customer counts associated with these mass transit systems would be provided by the incumbent utilities in these areas, relying on information drawn routinely from rate schedules and classifications designed to serve the sector separately and distinctly. In 2010, 64 respondents reported transportation data in 28 States.

Data Reconciliation: The Electric Power Annual reports total sales volumes (megawatthours) of electricity to ultimate consumers and customer counts in States with deregulated markets as the sum of bundled sales reported by full-service providers and delivery reported by transmission and distribution utilities. ERUS has concluded that the sales of electricity to ultimate consumers data reported by delivery utilities are more reliable than data reported by power marketers and Energy Service Providers (ESPs).

The reporting methodology change uses sales volumes and a customer count reported by distribution utilities, and modifies only an incremental revenue value, representing revenue associated with misreported sales assumed to be attributable to the ESPs that were under-represented in the survey frame.

Instrument and Design History: The Form EIA-861 was implemented in January 1985 for collection of data as of year-end 1984. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Average Retail Price of Electricity: This value represents the average cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector.

The electric revenue used to calculate the average retail price of electricity is the operating revenue reported by the electric power industry participant. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric power industry participant operating revenues also include ratepayer reimbursements for State and Federal income taxes and other taxes paid by the utility.

This computed average retail price of electricity reported in this publication by is a weighted average of consumer revenue and sales and does not equal the per kWh rate charged by the electric power industry participant to the individual consumers. Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs of the electric power industry participant for providing electrical service.

Issues within Historical Data Series: Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. The number of ultimate customers is an average of the number of customers at the close of each month. Also see the discussion of the Transportation Sector, above.

Net-Metering: This section was expanded in 2011. Previously, customer count by sector was the only data collected and published. In 2010, the EIA-861 started collecting the capacity of the net-metered installations by sector and technology. The technology types are: photovoltaic (PV), wind and other.

Starting with the 2016 data collection year, storage and virtual net metering were added to the PV section.

Demand-Side Management (DSM): Prior to 2011, DSM data was separated into two categories, large and small utilities. Some tables contained data for just large utilities and others contained both categories, published separately. Starting in 2011, there is no longer a division in the data. All tables now include all DSM data from utilities; this change is also reflected in the historical data.

Starting in 2011, a new category of respondents were added to the EIA-861, non-utility DSM administrators: Efficiency Maine Trust, Energy trust of Oregon, Focus on Energy, NYSERDA and Vermont Energy Investment Corporation.

The following definitions are supplied to assist in interpreting DSM data. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that used to support DSM programs.

- **Actual Peak Load Reduction** is the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (potential peak load reduction). Actual peak load reduction is reported by large utilities only.
- **Energy Savings** is the change in aggregate electricity use (measured in megawatthours) for consumers that participate in a utility DSM program. These savings represent changes at the consumer's meter (i.e., exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility.
- **Large Utilities** are those electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2009 and, for years prior, the threshold was set at 120 million kilowatthours.
- **Potential Peak Load Reduction** is the potential peak load reduction that may occur if all demand response is called and/or participates.

Advanced Metering: New in 2011, Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI), including historical data back to 2007. From 2007-2009, the count by sector is for number of customers, for 2010-2011, the count is the actual number of meters. For example; if an industrial customer had 12 meters, in 2007-2009 the count would have been 1, in 2010-2011, the count would be 12.

In 2013, the number of standard meters (non AMR/AMI) was added to this schedule.

Sensitive Data: None.

Forms EIA-906 and EIA-920 (Replaced in 2008 by Form EIA-923)

The Form EIA-906 was used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities. Data were collected monthly from a model-based sample of approximately 1,700 utility and nonutility electric power plants. The form was also used to

collect these statistics from another 2,667 plants (i.e., all other generators 1 MW or greater) on an annual basis. The form was ended after the 2007 data collection and replaced by the Form EIA-923.

Instrument and Design History: The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the FPC assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982. In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities. In 1998, the Form EIA-900 was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data. In 2000, the form was modified to include data on the production of useful thermal output (typically process steam) by combined heat and power (CHP) plants.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as CHP plants; all other plants that generated electricity continued to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93 275) defines the legislative authority to collect these data. In January 2008, the Form EIA-923 superseded this form.

Issues within Historical Data Series: A relatively small number electric commercial- and industrial-only plants are, for the purposes of this report, are included in the CHP data categories. The small number of electric utility plants that are CHP units are reported together with other utility plants. No information on the production of useful thermal output (UTO) or fuel consumption for UTO was collected or estimated for the electric utility CHP plants.

Sensitive Data: The only business sensitive data element collected on the Forms EIA-906 and EIA-920 was fuel stocks at the end of the reporting period.

Form EIA-923

Form EIA-923, “Power Plant Operations Report,” is used to collect information on receipts and cost of fossil fuels, fuel stocks, generation, consumption of fuel for generation, nonutility source and disposition of electricity, combustion by-product collection and disposal, and cooling systems, as well as operational data for flue gas desulfurization, particulates, and nitrous oxide controls. Data are collected from a monthly sample of approximately 2,150 plants, which includes a census of nuclear and pumped-storage hydroelectric plants. The plants in the monthly sample report their receipts, cost and stocks of fossil fuels, electric power generation, and the total consumption of fuels for both electric power generation and, at combined heat and power (CHP) plants, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), operational data for air emissions controls and cooling systems, and the collection and disposal of combustion by-products on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 7,800 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report applicable data on the entire form annually. In addition to electric power generating plants, respondents include fuel storage terminals without

generating capacity that receive shipments of fossil fuel for eventual use in electric power generation. The monthly data are due by the last day of the month following the reporting period.

Receipts of fossil fuels, fuel cost and quality information, and fuel stocks at the end of the reporting period are all reported at the plant level. Fuel receipts and costs are collected from plants with a nameplate capacity of 50 MW or more and burn fossil fuels. Plants that burn organic fuels and have a steam turbine capacity of at least 10 megawatts report consumption at the boiler level and generation at the generator level for each month, regardless of whether the plant reports in the monthly sample or reports annually. For all other plants, consumption is reported at the prime-mover level and generation is reported at the prime-mover level or, for noncombustible sources (e.g., wind, nuclear), at the prime-mover and energy source levels (including generating units for nuclear only). The source and disposition of electricity are reported annually for nonutilities at the plant level, as is revenue from sales for resale. Operational data for air emissions equipment are collected annually from facilities that have a steam turbine capacity of at least 10 megawatts, and operational data on cooling systems and data on the collection and disposal of combustion by-products are collected from facilities that have a steam turbine capacity of at least 100 megawatts.

Instrument and Design History: See discussion of predecessor forms (EIA-906, -920, -767, and -423, and FERC Form 423).

Imputation: For data collected monthly, regression prediction, or imputation, is done for all missing data including non-sampled units and any non-respondents. For data collected annually, imputation is performed for non-respondents. For gross generation and total fuel consumption, multiple regression is used for imputation (see discussion, above). Approximately 0.02 percent of the national total generation for is imputed, although this will vary by State and energy source.

When gross generation is reported and net generation is not available, or vice versa, net or gross generation is estimated by using a fixed ratio of net to gross generation by prime-mover type and installed emissions equipment. These ratios are:

Net Generation = (Factor) x Gross Generation
<u>Prime Movers:</u>
Combined Cycle Steam - 0.97
Combined Cycle Single Shaft - 0.97
Combined Cycle Combustion Turbine - 0.97
Compressed Air - 0.97
Fuel Cell - 0.99
Gas Turbine - 0.98
Hydroelectric Turbine - 0.99
Hydroelectric Pumped Storage - 0.99
Internal Combustion Engine - 0.98
Other - 0.97
Photovoltaic - 0.99
Steam Turbine - 0.97
Wind Turbine - 0.99
<u>Environmental Equipment:</u>
Flue Gas Desulfurization - 0.97
Flue Gas Particulate 0.99
All Others - 0.97

For stocks, a linear combination of the prior month's ending stocks value and the current month's consumption and receipts values is used.

Receipts of Fossil Fuels: Receipts data, including cost and quality of fuels, are collected at the plant level from selected electric generating plants and fossil-fuel storage terminals in the United States. Power plants include independent power producers, electric utilities, and commercial and industrial CHP facilities with a total fossil-fueled nameplate capacity of 50 megawatts or more. The data on cost and quality of fuel shipments are used to produce aggregates and weighted averages for each fuel type at the State, Census division, and U.S. levels.

The units for receipts are: 1) coal and petroleum coke, tons and million Btu per ton; 2) petroleum, barrels and million Btu per barrel.; and gases, thousand cubic feet (Mcf) and million Btu per thousand cubic feet.

Net and Gross Generation and Fuel Consumption and Stocks: Generation data are collected in megawatthours from all power plants with a sum of nameplate capacity at least 1 MW. The fuels consumed are collected in tons (solids), barrels (liquids) and thousand cubic feet (gases). Fuels are grouped into coal, petroleum liquids, petroleum coke, natural gas, other gases, and other miscellaneous fuels. Energy consumption is not collected for nuclear, wind, solar, geothermal or other plants that do not burn fuels. For information on fuel groupings, see the instructions to the Form EIA-923 at http://www.eia.gov/survey/form/eia_923/instructions.pdf. **Combustion By-Product Collection and Disposal:** Data are collected in thousand tons. Associated financial data for by-products (O&M and capital expenses and revenue) are collected in thousand dollars.

Air Emissions Equipment: Operational efficiencies and emission rates are collected for flue gas desulfurization, particulate matter, and nitrous oxide control equipment for steam-electric units with at least 10 MW nameplate capacity.

Cooling Systems: Operational data on water use is collected from steam-electric plants, including nuclear plants, with at least 100 MW nameplate capacity.

Methodology to Estimate Biogenic and Non-biogenic Municipal Solid Waste:⁴ Municipal Solid Waste (MSW) consumption for generation of electric power is split into its biogenic and non-biogenic components beginning with 2001 data by the following methodology:

The tonnage of MSW consumed is reported on the Form EIA-923. The composition of MSW and categorization of the components were obtained from the Environmental Protection Agency (EPA) publication, *Municipal Solid Waste in the United States: 2005 Facts and Figures*. The Btu contents of the components of MSW were obtained from various sources.

In 2011, the components of MSW as a percentage of the total were updated. The updated values were applied to final 2011 data and to preliminary 2012 and 2013 data. Although updated component percentages for 2006 through 2010 were available, historical EIA data series for consumption of MSW and net generation were not revised for 2005 to 2010. The tables below are the percentages applied to the EIA data for each year.

The potential quantities of combustible MSW discards (which include all MSW material available for combustion with energy recovery, discards to landfill, and other disposal) were multiplied by their respective Btu contents. The EPA-based categories of MSW were then classified into renewable and non-renewable groupings. From this, EIA calculated how much of the energy potentially consumed from MSW was attributed to biogenic components and how much to non-biogenic components (see Table 1 and 2, below).⁵

These values are used to allocate consumption of municipal solid waste and net generation published in the Electric Power Monthly tables. The tons of biogenic and non-biogenic components were estimated with the assumption that glass and metals were removed prior to combustion. The average Btu/ton for the biogenic and non-biogenic components is estimated by dividing the total Btu consumption by the total tons. Published net generation attributed to biogenic MSW and non-biogenic MSW is classified under Other Renewables and Other, respectively.

Table 1. Btu consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogenic	57	56	55	55	56	56	56	56	56	56	51
Non-biogenic	43	44	45	45	44	44	44	44	44	44	49

Table 2. Tonnage consumption for biogenic and non-biogenic municipal solid waste (percent)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biogenic	77	77	76	76	75	75	75	75	75	75	64
Non-biogenic	23	23	24	24	25	25	25	25	25	25	36

Useful Thermal Output (UTO): With the implementation of the Form EIA-923, “Power Plant Operations Report,” in 2008, combined heat and power (CHP) plants were required to report total fuel consumed and electric power generation. Beginning with preliminary January 2008 data, EIA estimated the allocation of the total fuel consumed at CHP plants between electric power generation and UTO.

The estimated allocation methodology is summarized in the following paragraphs. The methodology was retroactively applied to 2004-2007 data. Prior to 2004, UTO was collected on the Form EIA-906 and an estimated allocation of fuel for electricity was not necessary.

First, an efficiency factor is determined for each plant and prime mover type. Based on data for electric power generation and UTO collected in 2003 (on Form EIA-906, “Power Plant Report”), efficiency was calculated for each prime mover type at a plant. The efficiency factor is the total output in Btu, including electric power and UTO, divided by the total input in Btu. Electric power is converted to Btu at 3,412 Btu per kilowatthour.

Second, to calculate the amount of fuel for electric power, the gross generation in Btu is divided by the efficiency factor. The fuel for UTO is the difference between the total fuel reported and the fuel for electric power generation. UTO is calculated by multiplying the fuel for UTO by the efficiency factor.

In addition, if the total fuel reported is less than the estimated fuel for electric power generation, then the fuel for electric power generation is equal to the total fuel consumed, and the UTO will be zero.

Beginning with 2016 Form EIA-923 data, reported efficiency factors by survey respondents replaced the previously EIA estimated efficiency factors used in the fuel allocation process. For the processing of 2016 CHP data, EIA used for each plant an average of the efficiency factors reported by the CHP plants on the 2013, 2014, and 2015 Form EIA-923, “Power Plant Operations Report” surveys. An average was used to smooth out variations in any one year’s data. Once efficiency of each plant was established, the value was input into the above methodology to allocate the consumption of fuel between electric power and UTO. This update applies to the 2016 data and going forward but was not retroactively applied to previous years.

Issues within Historical Data Series for Receipts and Cost and Quality of Fossil Fuels: Values for receipts of natural gas for 2001 forward do not include blast furnace gas or other gas.

Historical data collected on FERC Form 423 and published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. However, these data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 data. In 2003, EIA introduced a procedure to estimate for late

or non-responding entities that were required to report on the FERC Form 423. Due to the introduction of this procedure, 2003 and later data cannot be directly compared to previous years' data.

Prior to 2008, regulated plants reported receipts data on the FERC Form 423. These plants, along with unregulated plants, now report receipts data on Schedule 2 of Form EIA-923. Because FERC issued waivers to Form 423 filing requirements to some plants who met certain criteria, and because not all types of generators were required to report (only steam turbines and combined cycle units reported), a significant number of plants either did not submit fossil fuel receipts data or submitted only a portion of their fossil fuel receipts. Since Form EIA-923 does not have exemptions based on generator type, or reporting waivers, receipts data from 2008 and later cannot be directly compared to previous years' data for the regulated sector. Also beginning with January 2008 data, tables for total receipts included imputed quantities for plants with capacity one megawatt or more, to be consistent with other electric power data. Previous published receipts data were from plants at or over a 50 megawatt threshold, which was a legacy of their original collection as information for a regulatory agency, not as a survey to provide more meaningful estimates of totals for statistical purposes. Totals appeared to become smaller as more electric production came from unregulated plants, until the Form EIA-423 was created to help fill that gap. As a further improvement, estimation of all receipts for the universe normally depicted in the Electric Power Annual (i.e., one megawatt and above), with associated relative standard errors, provides a more complete assessment of the market.

Issues within Historical Data Series for Generation and Consumption: Beginning in 2008, a new method of allocating fuel consumption between electric power generation and UTO was implemented (see above). This new methodology evenly distributes a CHP plant's losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change causes the fuel for electric power to be lower while the fuel for UTO is higher as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power between periods.

Sensitive Data: The total delivered cost of fuel delivered to nonutilities, the commodity cost of fossil fuels, and fuel stocks are considered business sensitive.

Capacity Factors and Usage Factors

This section describes the methodology for calculating capacity factors and usages factors by fuel and technology type for operating electric power plants. Capacity factor is a measure (expressed as a percent) of how often an electric generator operates over a specific period of time, using a ratio of the actual output to the maximum possible output over that time period.

The monthly capacity factor calculation includes all operating electric generators which operated for the entire month using the net generation reported on the Form EIA-923 and the net summer capacity reported on the Form EIA-860. The capacity factor for a particular fuel/technology type is given by:

$$capacity\ factor = \frac{\sum_{x,m} net\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

where x represents generators of that fuel/technology combination and m represents individual months. Net generation and capacity are specific to a generator, and the generator is categorized by its primary fuel type as reported on the EIA-860. All generation from that generator is included, regardless of other fuels consumed. Net generation and capacity for a generator is excluded from the summations during the month that the generator initially began operation and if applicable during the month that the generator retired. Therefore, these published capacity factors will differ from a simple calculation using annual generation and capacity totals from the appropriate tables in this publication.

Usage factors are calculated for energy storage technologies using gross generation instead of net generation:

$$usage\ factor = \frac{\sum_{x,m} gross\ generation_{x,m}}{\sum_{x,m} capacity_{x,m} * hours\ in\ month_m}$$

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO₂) from electric generating plants for 1989 through the present, as well as the estimated emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from electric generating plants for 2001 through the present. For a description of the methodology used for other years, see the technical notes to the EPA 2003.

Methodology Overview: Initial estimates of uncontrolled SO₂ and NO_x emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA on the Form EIA-923. An emission factor is the average quantity of a pollutant released from a power plant when a unit of fuel is burned, assuming no use of pollution control equipment. The basic relationship is:

$$Emissions = Quantity\ of\ Fuel\ Consumed \times Emission\ Factor$$

Quantity is defined in physical units (e.g., tons of solid fuels, million cubic feet of gaseous fuels, and thousands of barrels of liquid fuels) for determining NO_x and SO₂ emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO₂ emissions.

For some fuels, the calculation of SO₂ emissions requires including in the formula the sulfur content of the fuel measured in percentage of weight. Examples include coal and fuel oil. In these cases the formula is:

$$Emissions = Quantity\ of\ Fuel\ Consumed \times Emission\ Factor \times Sulfur\ Content$$

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A.1., which lists the SO₂ emission factors used for this report.

In the case of SO₂ and NO_x emissions, the factor applied to a fuel can also vary with the combustion system: a steam-producing boiler, a combustion turbine, or an internal combustion engine. In the case of boilers, NO_x emissions can also vary with the firing configuration of a boiler and whether or not the boiler is a wet-bottom or dry-bottom design.⁶ These distinctions are shown in Tables A.1. and A.2.

For SO₂ and NO_x, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment are available from the historical Form EIA-767 survey (i.e., data for the years 2005 and earlier) and the EIA-860 and EIA-923 surveys for the years 2007 through 2010. A special case for removal of SO₂ is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO₂ emission factors shown in Table A.1. for fluidized bed boilers already account for 90 percent removal of SO₂ since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO₂ and NO_x emission estimates are made for all plants, in many cases the estimated emissions can be replaced with actual emissions data collected by the U.S. Environmental Protection Agency's (U.S. EPA's) Continuous Emissions Monitoring System (CEMS) program. (CEMS data for CO₂ are incomplete and are not used in this report.) The CEMS data account for the bulk of SO₂ and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO₂ and NO_x emissions are employed for the limited purpose of allocating emissions by fuel, since the CEMS data itself do not provide a detailed breakdown of plant emissions by fuel. For plants for which CEMS data are unavailable, the EIA-computed values are used as the final emissions estimates.

There are a number of reasons why the historical data are periodically revised. These include data revisions, revisions in emission and technology factors, and changes in methodology. For instance, the 2008 Electric Power Annual report features a revision in historic CO₂ values. This revision occurred due to a change in the accepted methodology regarding adjustments made for the percentage combustion of fuels.

The emissions estimation methodologies are described in more detail below.

CO₂ Emissions: CO₂ emissions are estimated using the information on fuel consumption in physical units and the heat content of fuel collected on the Form EIA-923 and predecessors. Heat content information is used to convert physical units to millions of Btu (MMBtu) consumed. To estimate CO₂ emissions, the fuel-specific emission factor from Table A.3. is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO₂ emissions. CO₂ control technologies are currently in the early stages of research and there are no commercial systems installed. Therefore, no estimates of controlled CO₂ emissions are made.

SO₂ and NO_x Emissions: To comply with environmental regulations controlling SO₂ emissions, many coal-fired generating plants have installed flue gas desulfurization (FGD) units. Similarly, NO_x control regulations require many fossil-fueled plants to install low-NO_x burners, selective catalytic reduction systems, or other technologies to reduce emissions. It is common for power plants to employ two or even three NO_x control technologies; accordingly, the NO_x emissions estimation approach accounts for the combined effect of the equipment (Table A.4.). However, control equipment information is available only for plants that reported on the Form EIA-923 and for historical data from the Form EIA-767. The Form EIA-860, EIA-923, and the historical EIA-767 surveys are limited to plants with boilers fired by combustible fuels⁷ with a minimum generating capacity of 10 megawatts (nameplate). Pollution control equipment data are unavailable from EIA sources for plants that did not report on the historical EIA-767 survey, or the Forms EIA-860 and EIA-923.

The following method is used to estimate SO₂ and NO_x emissions:

- For steam electric plants, uncontrolled emissions are estimated using the emission factors shown in Tables A.1. and A.2. as well as reported data on fuel consumption, sulfur content, and boiler firing configuration. Controlled emissions are then determined when pollution control equipment is present. Although information on control equipment was not collected in 2006, updates for new installations during this period were made based on EPA data. Beginning in 2007, these data were collected on the Forms EIA-860 and EIA-923. For SO₂, the reported efficiency of the plant's FGD units is used to convert uncontrolled to controlled emission estimates. For NO_x, the reduction percentages shown in Table A.4. are applied to the uncontrolled estimates.
- For plants and prime movers not reported on the historical Form EIA-767 survey or Forms EIA-860 and EIA-923, uncontrolled emissions are estimated using the Table A.1. and Table A.2. emission factors and the following data and assumptions:
 - Fuel consumption is taken from the Form EIA-923 and predecessors.
 - The sulfur content of the fuel is estimated from fuel receipts for the plant reported on the Form EIA-923. When plant-specific sulfur content data are unavailable, the national average sulfur content for the fuel, computed from the Form EIA-923 is applied to the plant.
 - As noted earlier, the emission factor for plants with boilers depends in part on the type of combustion system, including whether a boiler is wet-bottom or dry-bottom, and the boiler firing configuration. However, this boiler information is unavailable for steam electric plants that did not report on the historical Forms EIA-767 or EIA-860. For these cases, the plant is assumed to have a dry-bottom, non-cyclone boiler using a firing method that falls into the "All Other" category shown on Table A.1.⁸
For the plants that did not report on the historical Form EIA-767 or EIA-860, pollution control equipment data are unavailable and the uncontrolled estimates are not reduced.
- If actual emissions of SO₂ or NO_x are reported in the EPA's CEMS data, the EIA estimates are replaced with the CEMS values, using the EIA estimates to allocate the CEMS plant-level data by fuel. If CEMS data are unavailable, the EIA estimates are used as the final values.

Conversion Factors for Propane, Petroleum Coke, and Synthesis Gases.

The quantity conversion for petroleum coke is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds), propane is 1.53 thousand cubic feet per barrel, coal-derived synthesis gas is 98.06 thousand cubic feet per ton, and petroleum coke-derived synthesis gas is 107.31 thousand cubic feet per ton.

Relative Standard Error

The relative standard error (RSE) statistic, usually given as a percent, describes the magnitude of sampling error that might reasonably be incurred. The RSE is the square root of the estimated variance, divided by the variable of interest. The variable of interest may be the ratio of two variables, or a single variable.

The sampling error may be less than the non-sampling error. In fact, large RSE estimates found in preliminary work with these data have often indicated non-sampling errors, which were then identified and corrected. Non-sampling errors may be attributed to many sources, including response errors, definitional difficulties, differences in the interpretation of questions, mistakes in recording or coding data obtained, and other errors of collection, response, or coverage. These non-sampling errors also occur in complete censuses.

Using the Central Limit Theorem, which applies to sums and means such as are applicable here, there is approximately a 68 percent chance that the true total or mean is within one RSE of the estimated total. Note that reported RSEs are always estimates, themselves, and are usually, as here, reported as percents. As an example, suppose that a net generation from coal value is estimated to be 1,507 total million kilowatthours with an estimated RSE of 4.9 percent. This means that, ignoring any non-sampling error, there is approximately a 68 percent chance that the true million kilowatthour value is within approximately 4.9 percent of 1,507 million kilowatthours (that is, between 1,433 and 1,581 million kilowatthours). Also under the Central Limit Theorem, there is approximately a 95 percent chance that the true mean or total is within 2 RSEs of the estimated mean or total.

Note that there are times when a model may not apply, such as in the case of a substantial reclassification of sales, when the relationship between the variable of interest and the regressor data does not hold. In such a case, the new information represents only itself, and such numbers are added to model results when estimating totals. Further, there are times when sample data may be known to be in error, or are not reported. Such cases are treated as if they were never part of the model-based sample, and values are imputed.

Business Classification

Nonutility power producers consist of entities that own or operate electric generating units but are not subject to direct economic regulation of rates, such as by state utility commissions. Nonutility power producers do not have a designated franchised service area. In addition to entities whose primary business is the production and sale of electric power, entities with other primary business classifications can and do sell electric power. These can consist of, for example, manufacturing facilities and paper mills.

The EIA, in the Electric Power Annual and other data products, classifies nonutility power producers into the following categories:

- **Electric Utility (Sector 1):** All regulated plants with a primary purpose of selling electricity in the public markets (NAICS = 22).
- **Independent Power Producers (Sector 2):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with no ability to cogenerate heat and power.
- **Electric Power, Combined Heat and Power (Sector 3):** All non-regulated plants with a primary purpose of electric power generation and a primary purpose of selling electricity in the public markets (NAICS = 22) with the ability to cogenerate heat and power.
- **Commercial, Non-Combined Heat and Power (Sector 4):** All plants with a commercial primary purpose with no ability to cogenerate heat and power.

- **Commercial, Combined Heat and Power (Sector 5):** All plants with a commercial primary purpose with the ability to cogenerate heat and power.
- **Industrial, Non-Combined Heat and Power (Sector 6):** All plants with an industrial primary purpose with no ability to cogenerate heat and power.
- **Industrial, Combined Heat and Power (Sector 7):** All plants with an industrial primary purpose with the ability to cogenerate heat and power.

The following is a list of the North American Industry Classification System (NAICS) classifications used by EIA.

	Agriculture, Forestry, Fishing and Hunting
111	Crop Production
112	Animal Production
113	Forestry and Logging
114	Fishing, Hunting and Trapping
115	Support Activities for Agriculture and Forestry
	Mining, Quarrying, and Oil and Gas Extraction
211	Oil and Gas Extraction
2121	Coal Mining
2122	Metal Ore Mining
2123	Nonmetallic Mineral Mining and Quarrying
	Utilities
22	Electric Power Generation, Transmission and Distribution (other than 2212, 2213, 22131, 22132 or 22133)
2212	Natural Gas Distribution
22131	Water Supply and Irrigation Systems
22132	Sewage Treatment Facilities
22133	Steam and Air-Conditioning Supply
	Manufacturing
311	Food Manufacturing
312	Beverage and Tobacco Product Manufacturing
313	Textile Mills (Fiber, Yarn, Thread, Fabric, and Textiles)
314	Textile Product Mills
315	Apparel Manufacturing
316	Leather and Allied Product Manufacturing
321	Wood Product Manufacturing
322	Paper Manufacturing (other than 322122 or 32213)
322122	Newsprint Mills
32213	Paperboard Mills
323	Printing and Related Support Activities
324	Petroleum and Coal Products Manufacturing (other than 32411)
32411	Petroleum Refineries
325	Chemical Manufacturing (other than 32511, 32512, 325193, 325188, 3252 325211, 3253 or 325311)
32511	Petrochemical Manufacturing
32512	Industrial Gas Manufacturing
325193	Ethyl Alcohol Manufacturing (including Ethanol)
325188	Industrial Inorganic Chemicals

3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing (other than 325211)
325211	Plastics Material and Resin Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing (other than 325311)
325311	Nitrogenous Fertilizer Manufacturing
326	Plastics and Rubber Products Manufacturing
327	Nonmetallic Mineral Product Manufacturing (other than 32731)
32731	Cement Manufacturing
331	Primary Metal Manufacturing (other than 331111 or 331312)
331111	Iron and Steel Mills
331312	Primary Aluminum Production
332	Fabricated Metal Product Manufacturing
333	Machinery Manufacturing
334	Computer and Electronic Product Manufacturing
335	Electrical Equipment, Appliance, and Component Manufacturing
336	Transportation Equipment Manufacturing
337	Furniture and Related Product Manufacturing
339	Miscellaneous Manufacturing
421	Wholesale Trade
441	Retail Trade
	Transportation and Warehousing
481	Air Transportation
482	Rail Transportation
483	Water Transportation
484	Truck Transportation
485	Transit and Ground Passenger Transportation
486	Pipeline Transportation
487	Scenic and Sightseeing Transportation
488	Support Activities for Transportation (other than 4881, 4882, 4883 or 4884)
4881	Support Activities for Air Transportation (including Airports)
4882	Support Activities for Rail Transportation (including Rail Stations)
4883	Support Activities for Water Transportation (including Marinas)
4884	Support Activities for Road Transportation
491	Postal Service
492	Couriers and Messengers
493	Warehousing and Storage
	Information
511	Publishing Industries (except Internet)
512	Motion Picture and Sound Recording Industries
515	Broadcasting (except Internet)
517	Telecommunications
518	Data Processing, Hosting, and Related Services
519	Other Information Services
521	Finance and Insurance
53	Real Estate and Rental and Leasing (including Convention Centers and Office Buildings)
541	Professional, Scientific, and Technical Services

55	Management of Companies and Enterprises
	Administrative and Support and Waste Management and Remediation Services
561	Administrative and Support Services
562	Waste Management and Remediation Services (other than 562212 or 562213)
562212	Solid Waste Landfill
562213	Solid Waste Combustors and Incinerators
611	Educational Services
	Health Care and Social Assistance
621	Ambulatory Health Care Services
622	Hospitals
623	Nursing and Residential Care Facilities
624	Social Assistance
	Arts, Entertainment, and Recreation
711	Performing Arts, Spectator Sports, and Related Industries
712	Museums, Historical Sites, and Similar Institutions
713	Amusement, Gambling, and Recreation Industries
	Accommodation and Food Services
721	Accommodation
722	Food Services and Drinking Places
	Other Services (except Public Administration)
811	Repair and Maintenance
812	Personal and Laundry Services
813	Religious, Grantmaking, Civic, Professional, and Similar Organizations
814	Private Households
92	Public Administration (other than 921, 922, 92214 or 928)
921	Executive, Legislative, and Other General Government Services
922	Justice, Public Order and Safety Activities (other than 92214)
92214	Correctional Facilities
928	National Security and International Affairs (including Military Bases)

Multiple Survey Programs- Small Scale PV Solar Estimation of Generation

Monthly generation from small scale PV solar resources is an estimation of the generation produced from PV solar resources and not the results of a data collection effort for generation directly, with the exception of “Third Party Owned” or (TPO) solar installations which has direct data collection. TPO data however is not comprehensive. TPOs do not operate in every state, TPO collected data is not a large portion of the estimated amount, and the data has been collected for limited period of time. The generation estimate is based on data collected for PV solar capacity.

Capacity of PV solar resources is collected directly from respondents. These data are collected on several EIA forms and from several types of respondents. Monthly data for net-metered PV solar capacity is reported on the Form EIA-826. Form EIA-826 is a cutoff sample drawn from the annual survey Form EIA-861 which collects this data from all respondents. Using data from both of these surveys we have a regression model to impute for the non-sampled monthly capacity.

The survey instruments collect solar net metering capacity from reporting utilities by state and customer class. There are four customer classes: residential, commercial, industrial and transportation. However, the estimation process included only the residential, commercial and industrial customers.¹ Data for these customer classes were further classified by U.S. Census Regions, to ensure adequate number of customer observations in for each estimation group.

Estimation Model: The total PV capacity reported by utilities in the annual EIA-861 survey is the single primary input (regressor) to the monthly estimation of PV capacity by state. The model tested for each Census Region was of the form:

$$y_{i_{2015,m}} = \beta_1 x_{i_{2013}} + w_i^{-1/2} e_i, \text{ where}$$

$x_{i_{2013}}$ is the i^{th} utility's 2013 (or the last published year) solar PV capacity

$y_{i_{2015,m}}$ is the i^{th} utility's month m , 2015 (or the current year) reported solar PV capacity

w_i is the weight factor, which is the inverse of $x_{i_{2013}}$

β_1 is effectively the growth rate of reported month m solar PV capacity

e_i is the error term

The model checks for outliers and removes them from the regression equation inputs. The model calculates RSEs by sector, state, census region, and US total. Once we have imputed for all of the monthly net-metered PV solar capacity we add to total net metered capacity, the PV solar capacity collected on the Form EIA-861 for distributed and dispersed resources that are not net metered.

We use a second model to estimate the generation using this capacity as an input. The original methodology was developed for the "Annual Energy Outlook" based on our "NEMS" modelled projections several years ago. The original method underwent a calibration project designed to develop PV production levels for the NEMS projections consistent with simulations of a National Renewable Energy Laboratory model called PVWatts, which is itself embedded in PC software under the umbrella of the NREL's System Advisor Model (SAM).

The PVWatts simulations require, panel azimuth orientations and tilts, something that the NEMS projections do not include. Call the combinations of azimuths and tilts "orientations." The orientation and solar insolation (specific to a location) have a direct effect on the PV production level. The calibration project selected the 100 largest population Metropolitan Statistical Areas (MSAs) and relied on weights derived from orientation data from California Solar Initiative dataset to develop typical outputs for each of the 100 MSAs. It then was expanded from an annual estimate to a monthly estimate. A further description of this model is located here. A listing of the MSAs are included in Appendix 1.

Using Form EIA-861 data for service territories, which lists the counties that each electric distribution company (EDC) provides service, and NREL solar insolation data by county a simple average of insolation values by EDC is calculated.

Using the estimation model, we produce by utility, by state and by sector an estimate of generation. All the utilities' capacity and generation estimates are summed by state and sector and a KWh/KW rate by state and sector is calculated.

Capacity from the Form EIA-860 that is net metered is subtracted from the total capacity by state and sector as well as the capacity reported on the EIA-826 from TPOs, resulting in a new "net" capacity amount. This capacity amount is multiplied by the KWh/KW rate to produce the non-TPO generation estimate and then it is added to the TPO reported sales to ultimate customers from the EIA-826 to obtain a final estimate for generation and a blended KWh/KW rate is calculated. The estimate for generation is aggregated by US census regions and US totals. The RSEs for capacity are checked for level of error and if they pass, the summary data by state, US census region and US total are reported in the EPM.

Appendix 2 contains a flow diagram of the data inputs, data quality control checks and data analysis required to perform this estimation.

Appendix 1- MSAs

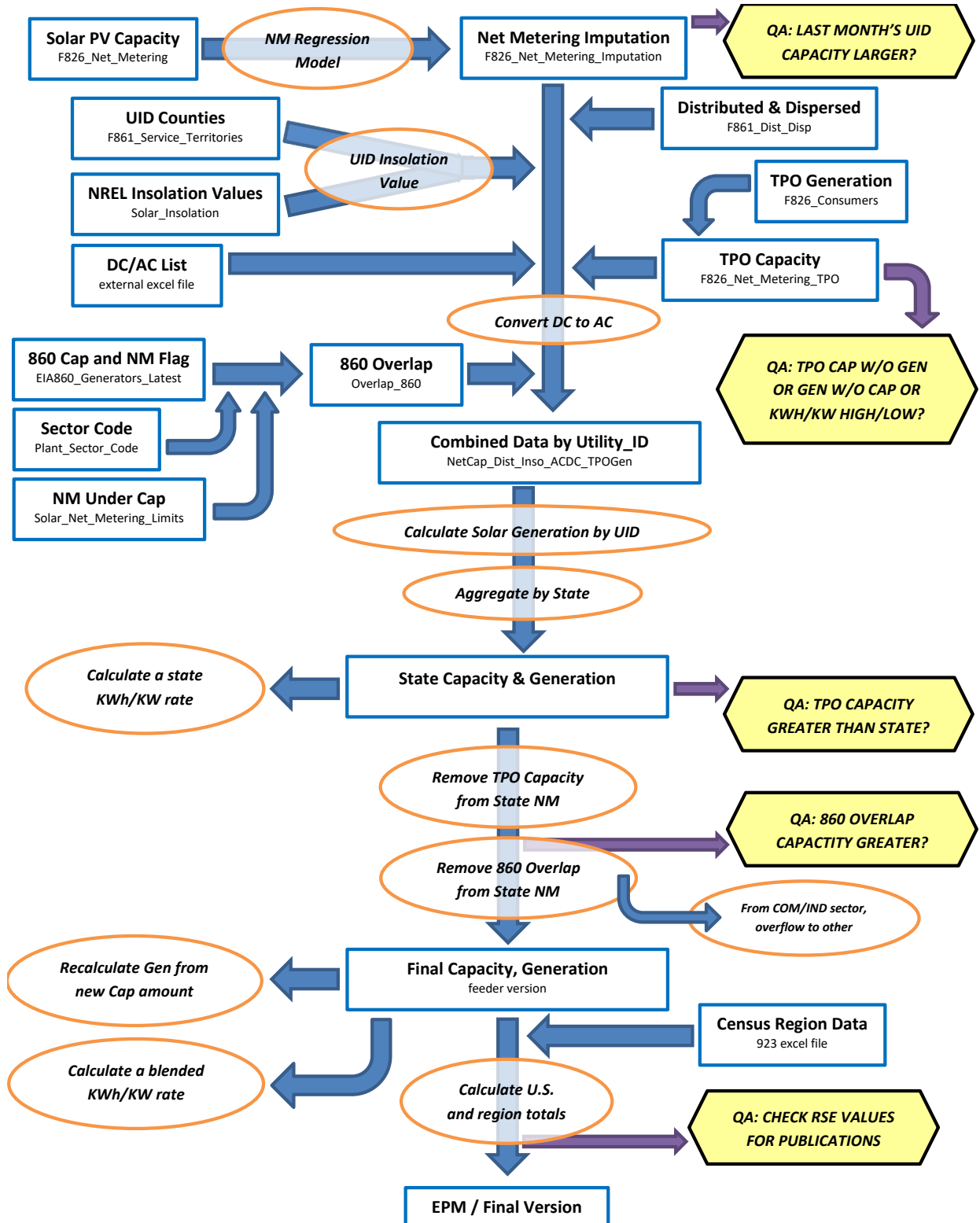
TMY3 (1991-2005) Weather Stations by MSA

Site	Weather Location	MSA
1	USA NY New York Central Park Obs.	New York-Newark-Jersey City, NY-NJ-PA MSA
2	USA CA Los Angeles Intl Airport	Los Angeles-Long Beach-Anaheim, CA MSA
3	USA IL Chicago Midway Airport	Chicago-Naperville-Elgin, IL-IN-WI MSA
4	USA TX Dallas-fort Worth Intl Airport	Dallas-Fort Worth-Arlington, TX MSA
5	USA TX Houston Bush Intercontinental	Houston-The Woodlands-Sugar Land, TX MSA
6	USA PA Philadelphia Int'l Airport	Philadelphia-Camden-Wilmington, PA-NJ-DE-MD MSA
7	USA VA Washington Dc Reagan Airport	Washington-Arlington-Alexandria, DC-VA-MD-WV MSA
8	USA FL Miami Intl Airport	Miami-Fort Lauderdale-West Palm Beach, FL MSA
9	USA GA Atlanta Hartsfield Intl Airport	Atlanta-Sandy Springs-Roswell, GA MSA
10	USA MA Boston Logan Int'l Airport	Boston-Cambridge-Newton, MA-NH MSA
11	USA CA San Francisco Intl Airport	San Francisco-Oakland-Hayward, CA MSA
12	USA AZ Phoenix Sky Harbor Intl Airport	Phoenix-Mesa-Scottsdale, AZ MSA
13	USA CA Riverside Municipal Airport	Riverside-San Bernardino-Ontario, CA MSA
14	USA MI Detroit City Airport	Detroit-Warren-Dearborn, MI MSA
15	USA WA Seattle Seattle-Tacoma Intl Airport	Seattle-Tacoma-Bellevue, WA MSA
16	USA MN Minneapolis-St. Paul Int'l Arp	Minneapolis-St. Paul-Bloomington, MN-WI MSA
17	USA CA San Diego Lindbergh Field	San Diego-Carlsbad, CA MSA
18	USA FL Tampa Int'l Airport	Tampa-St. Petersburg-Clearwater, FL MSA
19	USA MO St Louis Lambert Int'l Airport	St. Louis, MO-IL MSA
20	USA MD Baltimore-Washington Int'l Airport	Baltimore-Columbia-Towson, MD MSA
21	USA CO Denver Centennial [Golden - NREL]	Denver-Aurora-Lakewood, CO MSA
22	USA PA Pittsburgh Allegheny Co Airport	Pittsburgh, PA MSA
23	USA NC Charlotte Douglas Intl Airport	Charlotte-Concord-Gastonia, NC-SC MSA
24	USA OR Portland Hillsboro	Portland-Vancouver-Hillsboro, OR-WA MSA
25	USA TX San Antonio Intl Airport	San Antonio-New Braunfels, TX MSA
26	USA FL Orlando Intl Airport	Orlando-Kissimmee-Sanford, FL MSA
27	USA CA Sacramento Executive Airport	Sacramento-Roseville-Arden-Arcade, CA MSA
28	USA OH Cincinnati Municipal Airport	Cincinnati, OH-KY-IN MSA
29	USA OH Cleveland Hopkins Intl Airport	Cleveland-Elyria, OH MSA
30	USA MO Kansas City Int'l Airport	Kansas City, MO-KS MSA
31	USA NV Las Vegas McCarran Intl Airport	Las Vegas-Henderson-Paradise, NV MSA
32	USA OH Columbus Port Columbus Intl A	Columbus, OH MSA
33	USA IN Indianapolis Intl Airport	Indianapolis-Carmel-Anderson, IN MSA
34	USA CA San Jose Intl Airport	San Jose-Sunnyvale-Santa Clara, CA MSA
35	USA TX Austin Mueller Municipal Airport	Austin-Round Rock, TX MSA
36	USA TN Nashville Int'l Airport	Nashville-Davidson-Murfreesboro-Franklin, TN MSA

37	USA VA Norfolk Int'l Airport	Virginia Beach-Norfolk-Newport News, VA-NC MSA
38	USA RI Providence T F Green State	Providence-Warwick, RI-MA MSA
39	USA WI Milwaukee Mitchell Intl Airport	Milwaukee-Waukesha-West Allis, WI MSA
40	USA FL Jacksonville Craig	Jacksonville, FL MSA
41	USA TN Memphis Int'l Airport	Memphis, TN-MS-AR MSA
42	USA OK Oklahoma City Will Rogers	Oklahoma City, OK MSA
43	USA KY Louisville Bowman Field	Louisville/Jefferson County, KY-IN MSA
44	USA VA Richmond Int'l Airport	Richmond, VA MSA
45	USA LA New Orleans Alvin Callender	New Orleans-Metairie, LA MSA
46	USA CT Hartford Bradley Intl Airport	Hartford-West Hartford-East Hartford, CT MSA
47	USA NC Raleigh Durham Int'l	Raleigh, NC MSA
48	USA UT Salt Lake City Int'l Airport	Salt Lake City, UT MSA
49	USA AL Birmingham Municipal Airport	Birmingham-Hoover, AL MSA
50	USA NY Buffalo Niagara Intl Airport	Buffalo-Cheektowaga-Niagara Falls, NY MSA
51	USA NY Rochester Greater Rochester	Rochester, NY MSA
52	USA MI Grand Rapids Kent County Int'l Airport	Grand Rapids-Wyoming, MI MSA
53	USA AZ Tucson Int'l Airport	Tucson, AZ MSA
54	USA HI Honolulu Intl Airport	Urban Honolulu, HI MSA
55	USA OK Tulsa Int'l Airport	Tulsa, OK MSA
56	USA CA Fresno Yosemite Intl Airport	Fresno, CA MSA
57	USA CT Bridgeport Sikorsky Memorial	Bridgeport-Stamford-Norwalk, CT MSA
58	USA MA Worcester Regional Airport	Worcester, MA-CT MSA
59	USA NM Albuquerque Intl Airport	Albuquerque, NM MSA
60	USA NE Omaha Eppley Airfield	Omaha-Council Bluffs, NE-IA MSA
61	USA NY Albany County Airport	Albany-Schenectady-Troy, NY MSA
62	USA CA Bakersfield Meadows Field	Bakersfield, CA MSA
63	USA CT New Haven Tweed Airport	New Haven-Milford, CT MSA
64	USA TN Knoxville McGhee Tyson Airport	Knoxville, TN MSA
65	USA SC Greenville Downtown Airport	Greenville-Anderson-Mauldin, SC MSA
66	USA CA Oxnard Airport	Oxnard-Thousand Oaks-Ventura, CA MSA
67	USA TX El Paso Int'l Airport	El Paso, TX MSA
68	USA PA Allentown Lehigh Valley Intl	Allentown-Bethlehem-Easton, PA-NJ MSA
69	USA LA Baton Rouge Ryan Airport	Baton Rouge, LA MSA
70	USA TX McAllen Miller Intl Airport	McAllen-Edinburg-Mission, TX MSA
71	USA OH Dayton Int'l Airport	Dayton, OH MSA
72	USA SC Columbia Metro Airport	Columbia, SC MSA
73	USA NC Greensboro Piedmont Triad Int'l Airport	Greensboro-High Point, NC MSA
74	USA FL Sarasota Bradenton	North Port-Sarasota-Bradenton, FL MSA
75	USA AR Little Rock Adams Field	Little Rock-North Little Rock-Conway, AR MSA
76	USA SC Charleston Intl Airport	Charleston-North Charleston, SC MSA
77	USA OH Akron Akron-canton Reg. Airport	Akron, OH MSA
78	USA CA Stockton Metropolitan Airport	Stockton-Lodi, CA MSA

79	USA CO Colorado Springs Muni Airport	Colorado Springs, CO MSA
80	USA NY Syracuse Hancock Int'l Airport	Syracuse, NY MSA
81	USA FL Fort Myers Page Field	Cape Coral-Fort Myers, FL MSA
82	USA NC Winston-Salem Reynolds Airport	Winston-Salem, NC MSA
83	USA ID Boise Air Terminal	Boise City, ID MSA
84	USA KS Wichita Mid-continent Airport	Wichita, KS MSA
85	USA WI Madison Dane Co Regional Airport	Madison, WI MSA
86	USA MA Worcester Regional Airport	Springfield, MA MSA
87	USA FL Lakeland Linder Regional Airport	Lakeland-Winter Haven, FL MSA
88	USA UT Ogden Hinkley Airport	Ogden-Clearfield, UT MSA
89	USA OH Toledo Express Airport	Toledo, OH MSA
90	USA FL Daytona Beach Intl Airport	Deltona-Daytona Beach-Ormond Beach, FL MSA
91	USA IA Des Moines Intl Airport	Des Moines-West Des Moines, IA MSA
92	USA GA Augusta Bush Field	Augusta-Richmond County, GA-SC MSA
93	USA MS Jackson Int'l Airport	Jackson, MS MSA
94	USA UT Provo Muni	Provo-Orem, UT MSA
95	USA PA Wilkes-Barre Scranton Intl Airport	Scranton-Wilkes-Barre-Hazleton, PA MSA
96	USA PA Harrisburg Capital City Airport	Harrisburg-Carlisle, PA MSA
97	USA OH Youngstown Regional Airport	Youngstown-Warren-Boardman, OH-PA MSA
98	USA FL Melbourne Regional Airport	Palm Bay-Melbourne-Titusville, FL MSA
99	USA TN Chattanooga Lovell Field Airport	Chattanooga, TN-GA MSA
100	USA WA Spokane Int'l Airport	Spokane-Spokane Valley, WA MSA

Appendix 2 – Flow diagram of data sources and analysis



¹ The basic technique employed is described in the paper “Model-Based Sampling and Inference,” on the EIA website. Additional references can be found on the InterStat website (<http://interstat.statjournals.net/>). See the following sources: Knaub, J.R., Jr. (1999a), “Using Prediction-Oriented Software for Survey Estimation,” InterStat, August 1999, <http://interstat.statjournals.net/>; Knaub, J.R. Jr. (1999b), “Model-Based Sampling, Inference and Imputation,” EIA web site: <http://www.eia.gov/cneaf/electricity/forms/eiawebme.pdf>; Knaub, J.R., Jr. (2005), “Classical Ratio Estimator,” InterStat, October 2005, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2007a), “Cutoff Sampling and Inference,” InterStat, April 2007, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2008), “Cutoff Sampling.” Definition in Encyclopedia of Survey Research Methods, Editor: Paul J. Lavrakas, Sage, to appear; Knaub, J.R., Jr. (2000), “Using Prediction-Oriented Software for Survey Estimation - Part II: Ratios of Totals,” InterStat, June 2000, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2001), “Using Prediction-Oriented Software for Survey Estimation - Part III: Full-Scale Study of Variance and Bias,” InterStat, June 2001, <http://interstat.statjournals.net/>.

² Due to the restructuring of the electric power industry, many plants which had historically submitted this information for utility plants on the FERC Form 423 (see subsequent section) were being transferred to the nonutility sector. As a result, a large percentage of fossil fuel receipts were no longer being reported. The Form EIA-423 was implemented to fill this void and to capture the data associated with existing nonregulated power producers. Its design closely follows that of the FERC Form 423.

³ The basic technique employed is described in the paper “Model-Based Sampling and Inference,” on the EIA website. Additional references can be found on the InterStat website (<http://interstat.statjournals.net/>). See the following sources: Knaub, J.R., Jr. (1999a), “Using Prediction-Oriented Software for Survey Estimation,” InterStat, August 1999, <http://interstat.statjournals.net/>; Knaub, J.R. Jr. (1999b), “Model-Based Sampling, Inference and Imputation,” EIA web site: <http://www.eia.gov/cneaf/electricity/forms/eiawebme.pdf>; Knaub, J.R., Jr. (2005), “Classical Ratio Estimator,” InterStat, October 2005, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2007a), “Cutoff Sampling and Inference,” InterStat, April 2007, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2008), “Cutoff Sampling.” Definition in Encyclopedia of Survey Research Methods, Editor: Paul J. Lavrakas, Sage, to appear; Knaub, J.R., Jr. (2000), “Using Prediction-Oriented Software for Survey Estimation - Part II: Ratios of Totals,” InterStat, June 2000, <http://interstat.statjournals.net/>; Knaub, J.R., Jr. (2001), “Using Prediction-Oriented Software for Survey Estimation - Part III: Full-Scale Study of Variance and Bias,” InterStat, June 2001, <http://interstat.statjournals.net/>.

⁴ See the following sources: Bahillo, A. et al. Journal of Energy Resources Technology, “NOx and N2O Emissions During Fluidized Bed Combustion of Leather Wastes.” Volume 128, Issue 2, June 2006. pp. 99-103; U.S. Energy Information Administration. *Renewable Energy Annual 2004*. “Average Heat Content of Selected Biomass Fuels.” Washington, DC, 2005; Penn State Agricultural College Agricultural and Biological Engineering and Council for Solid Waste Solutions. Garth, J. and Kowal, P. Resource Recovery, Turning Waste into Energy, University Park, PA, 1993; Utah State University Recycling Center Frequently Asked Questions

⁵ Biogenic components include newsprint, paper, containers and packaging, leather, textiles, yard trimmings, food wastes, and wood. Non-biogenic components include plastics, rubber and other miscellaneous non-biogenic waste.

⁶ A boiler’s firing configuration relates to the arrangement of the fuel burners in the boiler, and whether the boiler is of conventional or cyclone design. Wet- and dry-bottom boilers use different methods to collect a portion of the ash that results from burning coal. For information on wet- and dry-bottom boilers, see the EIA Glossary at <http://www.eia.gov/glossary/index.html>. Additional information on wet- and dry-bottom boilers and on other aspects of boiler design and operation, including the differences between conventional and cyclone designs, can be found in Babcock and Wilcox, *Steam: Its Generation and Use*, 41st Edition, 2005.

⁷ Boilers that rely entirely on waste heat to create steam, including the heat recovery portion of most combined cycle plants, did not report on the historical Form EIA-767 or EIA-923.

⁸ The “All Other” firing configuration category includes, for example, arch firing and concentric firing. For a full list of firing method options for reporting on the historical Form EIA-767, see the form instructions, page xi, at http://www.eia.gov/survey/form/eia_767/instructions_form.pdf.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-108:
UT Austin Article



The University of Texas at Austin

energy institute

The Full Cost of Electricity (FCe-)



The History and Evolution of the U.S. Electricity Industry

PART OF A SERIES OF WHITE PAPERS



TEXAS

The University of Texas at Austin



THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FLe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FLe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website: energy.utexas.edu

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The History and Evolution of the U.S. Electricity Industry



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EXECUTIVE SUMMARY

Universally available, reliable, and affordable electricity is associated with a nation's improvements in quality of life for its citizens, increased productivity, and competitive advantage. The structure of the electricity industry – of generation, delivery, and use of electricity – over the past century has evolved significantly. For decades, scale economies associated with large centralized generation technologies encouraged vertical integration and drove down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region. Starting in the 1970s, higher fuel prices, environmental concerns, technological innovations and a desire for more economic efficiency led to the rethinking of this vertically-integrated, regional monopoly model.

Following the restructuring of the telecommunications industry and the natural gas industry, policy makers began to rethink the notion that power generation and sales are (or should be) a natural monopoly. In the 1980s policy makers chose to break up the telephone monopoly in the U.S., unleashing competitive and technological forces that have transformed the communications sector. In the late 1970s and 1980s a series of government decisions deregulating wellhead prices and the pipeline industry unleashed powerful market forces in the natural gas industry, ultimately making both natural gas and gas-fired power much less expensive. The increased competition from merchant generators encouraged restructuring of the electric power industry in many states, breaking down the vertical integration model.

During the same timeframe, innovations in finance were created that complemented these new technologies to help make them more cost competitive. An important example is the Power Purchase Agreement (PPA) for independent natural gas plant electricity production and, later, wind and solar plants. These agreements played a key role in financing non-utility owned

generating assets by enabling their owners, known as independent power producers (IPPs), to raise investment capital, employ tax-exempt bond financing, and capture Federal tax credits, enabling IPPs to provide renewable power at attractive long-term fixed prices to utilities. By the mid-1990s, policy makers began to restructure the electricity system, seeking to take advantage of these same technological and competitive forces in order to promote innovation and reduce electricity costs.

At the same time, policymakers incentivized alternative technologies, such as wind power. Both the federal and state governments implemented environmental regulations, tax credits, and other support programs for renewables. Solar technology, initially much more expensive than wind, did not benefit from these policies until the late 2000s and early 2010s when some states instituted programs that specifically supported solar installations. For both wind and solar, foreign government support for manufacturing has also been critical (e.g., Denmark for wind in its early days, and China for solar PV more recently). These technologies also enabled some customers to start generating some of their own electricity, competing with their local utility or competitive generators, and threatening the traditional utility business model as well as the competitive market structure as they exist today.

Several technologies will combine to drive changes in the electric industry: increasingly cost competitive wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, and electricity energy storage and demand response systems with progressively lower costs. These and other technological changes will continue to encourage the industry to adopt new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation that competes with traditional utilities in ways that may further de-stabilize the existing order. ■

1 | INTRODUCTION

The basic functions of the electric power industry, as historically structured, are electricity generation (production), transmission and distribution (T&D) to deliver electricity from the point of generation to the point of consumption, and customer relationship management.

There are various regulatory approaches for arranging the relationship between electricity generation and end-use consumption. Historically, a vertically integrated utility in the U.S. was an investor-owned utility (IOU) and was regulated by an independent public entity typically known as a public utility commission (PUC) or public service commission (PSC) (see Figure 3, Model 1). State-owned utilities in most of the world tended to also be vertically integrated (see Figure 4, Model 5). The customer relationship, where it mattered (primarily the U.S.) consisted primarily of monthly billing, outage management and advertising to encourage either conservation or consumption growth, depending on the situation.

The goal of this document is to summarize the history of the U.S. electric power industry, describe how the utility business model came to fruition, and introduce the more recent drivers

for changing that model. In many cases, the historical business structures and regulatory models have become challenged across the United States over the past few decades. Thus, with the background in this document, the reader can contextualize the drivers for recent and future changes within the electricity industry.

The rest of this document is organized as follows. Section 2 provides a history of the interplay between technology, finance, and regulation that formed the traditional regulated electric utility business model. Section 3 describes the major ownership (for-profit and non-profit), management, and regulatory models of modern electricity grids. Section 4 provides some future perspectives and technological drivers for continued regulatory and consumer changes before Section 5 provides a brief conclusion. ■

2 | FORMATION OF THE ELECTRIC UTILITY MODEL

OVERVIEW

The dominant model for delivering electricity to consumers was, and remains, large-scale, central generation facilities, and transmission and distribution networks at regulated prices (rates) (see Figure 3, Model 1). The traditional utility business model formed within the interplay of technology, finance, and regulation.

The business structure was created in the early 20th century as the industry pioneers like Samuel Insull realized that **technology** allowed for power plants to become larger (especially, using steam turbines) and to reach **economies of scale** that reduced the unit cost of power. Insull and other early electricity providers also realized that they could make money selling electricity to a more diverse set of customers throughout the day, rather than simply serving evening electricity demand (or “load”), which was the basis of the early electric systems. This realization led them to acquire more customers and to grow their service territories. These large power plants and networks necessitated **financing mechanisms**, via holding companies with multiple investors or later, access to low-cost financing via the debt markets. These progressively more advanced methods of equity and debt financing enabled new infrastructure (power plants, transmission and distribution lines) to be built and paid for over time, but without all the risk falling on a single company or investor. **Regulation** was considered necessary to allow electric companies to operate as monopolies to avoid waste of capital resources in duplicate infrastructure, create a regulatory compact that included an obligation to serve within the monopoly service area, stabilize the cost of capital by reducing risk, and provide affordable electricity service. To protect customers from monopolistic prices, electricity rates started to be regulated first by municipal, then by state governments. Federal regulation became relevant when grids grew larger across state borders, thus generating interstate commerce.

The traditional vertically integrated system persisted into the 1990s, when the federal government and some states decided to restructure the electricity industry, breaking vertically integrated utilities into generation and wires businesses, and introducing competition in the generation sector. In the late 1980s, Chile and the UK initiated a restructuring of their traditional vertically integrated electric power monopolies to introduce competition primarily at the wholesale or “bulk power” level where generators compete in a market. These efforts provided some guidance for restructuring in the U.S. Changes to the traditional model were also precipitated by a series of laws passed by the Congress between 1978 and 1992, which laid the foundation for the introduction of independent power producers (IPPs) into the market, the shift to market pricing of power, and the unbundling of electricity delivery from electricity sales. Today, the roles of both federal and state regulators in states with restructured electricity markets are more complex as they attempt to maintain grid reliability by managing robust and maturing competitive markets with more participants, increased integration of new sources of electricity generation, and increased demand-side participation into the system.

TECHNOLOGY

The modern electric utility industry in America began with Thomas Edison’s invention of the first practical light bulb in 1879. Within three years, Edison built the first “centralized” fossil fuel driven power plant at Pearl Street in New York City’s financial district. Adoption quickly followed in homes, factories, and in transportation to maximize the usefulness of this energy source. Entrepreneurs recognized the potential for electricity to revolutionize every aspect of American life from the home

to the factory, and they engaged government first at the local or municipal level to facilitate the construction of infrastructure.

Thomas Edison's original system design was based upon direct current (dc) and low voltages. Because of high dissipative power losses in wires, this limited the transmission distance from power plant to end use point for electric power, which in turn restricted interactions with government to the local level. The power was generated and consumed within only a few miles. However, technological advances soon extended the scale and reach of electricity generation, and simultaneously necessitated an expanded role for government.

The most significant technological advance was alternating current (ac) electricity. By 1896, in the famous "power wars", Westinghouse Electric (with the help from inventor Nikola Tesla) had introduced ac electricity, expanding the reach of power plants to dozens of miles (1000s of miles today) from the point of electric load. The shift from dc to ac technology made larger scale (e.g., larger power plants) systems possible. This shift was largely due to the fact that ac permitted the power to be transmitted at high voltage and low current, substantially reducing power losses relative to dc systems. In turn, the use of ac transmission permitted the *exploitation of the economies of scale* for power plants, reducing the unit cost of electricity, and making electricity progressively more affordable and available to ever more customers.

After this dc-to-ac transition, for decades the technology evolved along the lines of what has become the traditional electricity utility model: large scale centralized generation sending ac electricity over transmission and distribution lines to consumers. While the vast majority of transmission is high voltage ac, modern high voltage dc transmission lines have been selectively used primarily for point-to-point long distance connections to transfer large amounts of power with enhanced stability over an ac connection.

For the past century, scale economies associated with large centralized generation technologies encouraged vertical integration and drove

down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region.

The initial loads on these early power systems were mostly lighting, followed closely by electric motors, loads that were well suited for ac power. However, over the past few decades the explosion in the number of computers, microprocessors, and telecommunications systems provided loads that are inherently suited to dc. These devices require better power quality than lights and motors, while the rectifiers (that convert ac to dc) in the systems often produce power quality challenges. At the same time, distributed energy resources such as solar photovoltaic (PV) panels and batteries provide energy sources that are also inherently dc. In order to avoid losing the competition to serve this new kind of load, utilities may need to adapt by offering new energy delivery models, such as dc microgrid overlays on top of their existing ac distribution systems. Legislatures and utility regulators play an important, if not essential, role in redefining the regulatory environment that defines the incentives and structure for utility business models. The traditional vertically integrated structures that were appropriate for the 20th century may inhibit desired incentives, investments, or innovation of utilities.

FINANCING

During the very early years of distributing electricity, grids were local, and used small neighborhood power plants (combustion engines) to generate power. The amount of capital required was relatively modest and then-available financing resources were adequate. With the transition to large ac systems (e.g., 100+ MW thermal and hydroelectric power plants), however, it was obvious that larger-scale financing was required. Electric companies could issue bonds to build these plants, but the risk was becoming too great for the investors that participated in the debt market of the era.

To reduce both risk and financing costs, the concept of a **holding company** was developed to blend the bonds from existing as well as new power

plants and to also provide cash flow from one of the associated firms to finance further growth in another one of the held firms. Samuel Insull, a franchisee of Thomas Edison, recognized the potential for economies of scale and the role for the natural monopoly in electricity. He invested heavily in centralized power plants. By 1907, Insull had acquired twenty companies and formed Commonwealth Edison, beginning a cycle of centralization in the electric utility industry [1].

Despite growing state regulation (discussed in the next section), consolidation and private expansion continued in the electric sector through the 1910s and 20s, often using the financial innovation of holding companies. Applying this tool, Samuel Insull controlled businesses in 32 states with more than \$500 million in assets in 1930. By 1932, eight holding companies controlled three-fourths of the IOUs, with most of their operations exempt from state regulation due to the crossing of state lines [2].

Financial product innovations served to fuel the growth of the U.S. power system with minimal problems until the last quarter of the 20th century, when fuel prices increased and some utilities began losing money when regulators refused to allow them to charge rates that reflected these cost increases. Unprofitable operations, in turn, inhibited some utilities' ability to raise financing for new plants. Moreover, the scale of the new plants could sometimes be so large relative to the size of the utilities' assets or revenue that some smaller utilities could not afford to own and build a new large power plant without partners; meanwhile, regulators would not allow smaller utilities to take the risks associated with building such large facilities without historical precedent in their jurisdiction. This was particularly true with new nuclear construction and the reason why some nuclear power plants were owned by multiple companies in the 1970s and 80s.

Today, there is a corresponding struggle to finance large coal and nuclear power facilities (with capital costs of several billions of dollars each) in competitive wholesale markets. The vast majority of new generation capacity is relatively smaller natural gas, wind, and PV facilities (with capital costs of \$100s of millions). Today, the ability to add new generation capacity in smaller

sized increments can be attractive for utilities in an era of low load growth; it helps them to better manage cash flows, reduce capital demands and risk, and to simplify the project development, ownership, and operation structures.

REGULATION

In terms of the chronological development of electricity regulation, the electric power industry generally evolved from being unregulated, to being regulated first by municipalities, then states, and then the federal government. Today in the U.S., the states typically regulate the retail sale of electricity, while federal law authorizes the Federal Energy Regulatory Commission (FERC) to regulate wholesale markets that involve interstate commerce and interstate transmission of electricity.¹

The first progressive reformers in New York and Wisconsin expanded regulation of the industry to the state level at around the same time Samuel Insull was consolidating electric companies into what would become Commonwealth Edison. In 1905, Wisconsin's Governor Robert LaFollete established a state-level railroad commission to regulate railroad rates, schedules, service, and operations. Two years later, the Wisconsin legislature extended regulation to the state's electric companies, and New York State regulated its electric industry in the same year. Following the Progressives' lead, 45 states had established government oversight of electric utilities by 1914 [3].

The Federal Power Commission & Federal Energy Regulatory Commission

Congress first established the Federal Power Commission (FPC) by the Federal Water Power Act in 1920 to license hydroelectric dams on navigable waters or lands owned by the Federal Government. It later designated that the commission be comprised of five members, serving staggered terms, with no more than three from the same political party. This structure

¹ The ERCOT market in Texas does not include ac transmission of power across state lines, so it is mostly exempt from Federal Power Act regulation.

remains in place today within the Federal Energy Regulatory Commission (FERC), the subsequent federal agency that subsumed the FPC. Since the Federal Power Act of 1935, the FPC and now FERC has been charged with ensuring that wholesale power sales and transmission service be offered at rates that are “just and reasonable, and nondiscriminatory.” During the early decades of the FPC, the commission’s power to regulate interstate commerce in electricity and natural gas were further expanded or clarified.

After the Great Depression Progressive reformers began to warn of the dangers of monopolies combined with lax regulation, and to see electricity as an essential public good. Campaigning for President in 1932, Franklin Roosevelt (FDR) vowed to fight “the Ishmaels and Insulls, whose hand is against everyman’s [4].” Subsequent New Deal reforms established new regulatory frameworks for the electric industry as well as programs designed to bring electricity to rural America.

Electrification was seen to be an important technology to combat poverty and improve the quality of Americans’ lives. The formation of the Tennessee Valley Authority (TVA) in 1933 introduced public energy policy as a tool to fight rural poverty in America. By the 1930s, ninety-percent of urban households had electricity compared with only ten percent in rural areas. Private industry demonstrated little interest in serving rural America due to the high construction costs, low population density, and perceived lack of ability for customers (e.g., poor farmers) to pay for the electricity. In response, FDR followed TVA with an executive order establishing the Rural Electrification Administration in 1935 prior to Congress enacting the Rural Electrification Act (REA) in 1936. These federal actions stimulated the introduction of electric service in rural areas, substantially improving quality of life for Americans, and encouraging business to enter and drive further economic development.

By 1939, the REA had helped to establish 417 electric cooperatives in rural areas, serving 25% of rural households in America. At the time of FDR’s death in 1945, an estimated 90% of rural farms were electrified [5]. Rural electrification in the

period increased from 13% to 94% [6]. TVA then created the Electric Home and Farm Authority (EHFA) to increase the supply of electric ranges, refrigerators, and water heaters to rural areas and to provide low-cost financing for farmers to afford them. The REA and TVA made a significant contribution to the reduction in poverty in the U.S. In addition to rural co-ops, investor owned utilities have shown to be effective providing more than half of the electricity in the US.

The Public Utility Holding Company Act of 1935 (PUHCA) also had a lasting influence on the electric utility industry in America. Congress passed the PUHCA to facilitate the regulation of the electric utility sector by either confining their operations to a single state or limiting operations that cross state lines to a contiguous geographic service area, easing regulation. PUHCA also outlawed the highly leveraged and opaque multi-level pyramids of holding companies that contributed to the economic collapse during the Great Depression. Remaining interstate holding companies and most companies that delivered a substantial amount of electricity were forced to register with the new Securities and Exchange Commission (1935). Along with other public companies, these utility companies were now required to follow the more strict Securities and Exchange Commission (SEC) rules for financial reporting and to obtain approval to issue stock and bond securities [7]. ***In effect, PUHCA of 1935 established the framework for the traditional electric utility industry.***

National Electric Reform

The traditional regulated utility model, first formalized by the Public Utility Holding Company Act of 1935 and governed as a natural and technical monopoly, remained mostly unchanged until the energy shocks in the 1970s. The energy price spike following the 1973 Arab Oil Embargo set the expectation among utilities and regulators that energy prices would continue to increase in the decades to come. Utilities also expected continued growth of electricity demand driven by a growing population, the need to switch away from more expensive petroleum fuels for heating and power

generation, and continued supply disruptions from oil-exporting Arab nations or more specifically from the Organization of Petroleum Exporting Countries (OPEC). As a result of these expectations and the belief that natural gas supplies were limited, utilities developed ambitious plans for power plants based on coal and large-scale nuclear technologies, which turned out to have construction costs much higher than historic averages [8]. Some of these utility plans were influenced by the Power plant and Industrial Fuel Use Act (PIFUA) of 1978 (repealed in 1987) that, among other fuel use restrictions, prevented the use of natural gas by regulated utilities in power plants (except where it was necessary to reduce air pollution associated with burning coal or oil). By restricting the use of natural gas for electricity generation by utilities, PIFUA stimulated a large build-out of coal power plants during the 1970's and 1980's. While these coal plants contribute a significant portion of the emissions of the entire power generation sector, many of them are now uneconomic and being retired given low natural gas prices from the surge in gas supplies from hydraulic fracturing techniques, efficient combined-cycle gas plants, declining costs of wind and solar generation, in addition to implemented or proposed environmental regulations.

The perception of future energy shortfalls also created an opportunity for smaller scale plants such as small hydropower sites, industrial co-generation, burning of municipal waste, and renewable resources such as geothermal energy, wood, wind, and solar. With the traditional utilities mainly focused on large-scale and capital-intensive projects, the development of these new smaller and/or renewable resources was contingent upon the purchase of their output by utilities at favorable terms. To encourage the development of these new resources and to diversify the domestic electric power base, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 210 of this federal legislation created a new legal category of power plants known as qualifying facilities (QFs), with specific size and other characteristics, that enabled new market entrants such as non-utility generators, or NUGs (e.g., power producers that

BOX 1:

The Role of Natural Gas Industry Restructuring in Driving Changes in the Electric Power Industry

The Natural Gas Act of 1938 gave the FPC the power to regulate the sale and transportation of natural gas in interstate commerce. In 1940, amendments to the Natural Gas Act enabled the FPC to certify and regulate natural gas facilities, and the 1954 court ruling *Phillips Petroleum Co. v. Wisconsin* required the FPC to begin regulating natural gas wellhead prices. This action proved to be poorly conceived in that it eventually constrained gas exploration, and supply as well as technology innovation along the natural gas supply chain and by end-users. As part of the energy sector reforms in 1978, the Natural Gas Policy Act was passed along with PIFUA and PURPA that started the process of phasing out gas wellhead price regulation. Within a decade, rising market prices fostered new drilling and the development of new exploration and production techniques that led to significant new supplies and price declines.

Several orders by FERC in the 1980s and early 1990s, were designed to increase competition in the natural gas sector. The 1985 FERC Order No. 436 required that natural gas pipelines provide open access to transportation services, enabling gas consumers to negotiate prices directly with producers and contract separately for transportation. In 1992 FERC issued Order No. 636 (The Restructuring Rule) that mandated unbundling of sales services from transportation services, provided customers with a full choice of providers, and opened these markets to competition. In 2000, FERC Order No. 637 further addressed inefficiencies in the capacity release market. Together with PURPA and PIFUA, these changes in the natural gas industry fueled the emergence of the IPP sector, facilitating wholesale electricity competition.

There are many parallels between natural gas and electricity regulation. Both systems need to connect producers, via transmission and distribution infrastructure, to end-use consumers. The restructuring of the natural gas markets with the unbundling of services and open access to transmission provided a model for the subsequent restructuring of the electricity market.

were not utilities and did not own transmission lines) [9]. PURPA required local investor-owned utilities to purchase the output from QFs, at full avoided-cost (the cost utilities would incur if they were to generate the same amount themselves or purchase it from another source). Some states enacted laws and regulations specifying avoided-cost rates for power purchases from QFs. Initially, some states established avoided-cost rates that exceeded utilities' actual avoided-costs, until the Supreme Court struck down those laws in 1984.²

Congress responded to the 1970s' energy crises by reorganizing the FPC into the Federal Energy Regulatory Commission (FERC) in 1978 to streamline regulations, encourage greater energy security, and contain the increases in energy costs. An important aspect of these efforts was to wean U.S. power generation from oil (particularly imported oil) to domestic sources of energy.

Subsequently, in the 1980s and 1990s FERC finalized orders that significantly restructured natural gas markets (see Box 1). These orders enabled merchant developers of electricity generation plants to bypass local natural gas distribution companies and reduce their fuel costs by buying natural gas in the wholesale market and connecting to transmission pipelines directly.

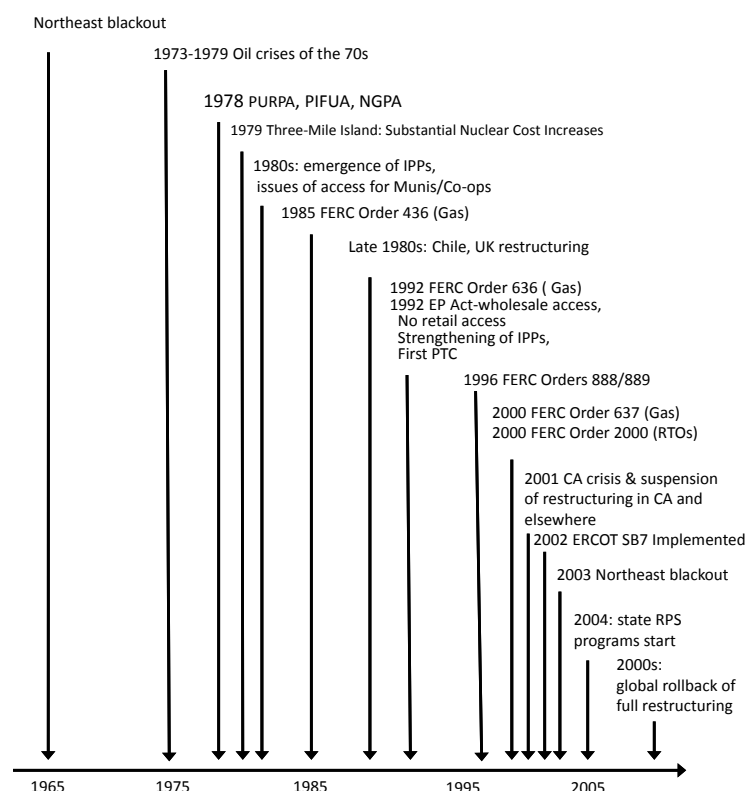
Wholesale electricity competition was further strengthened by the 1992 Energy Policy Act that authorized FERC to order "wheeling" (the transport of) of third party power over utility lines. This act also more broadly authorized new non-utility generation facilities to sell their electricity to utilities at market prices. Wholesale competition would not have been possible at the same pace and scale without the confluence of these laws and actions that allowed natural gas fired generation to become a key player from non-utility co-generation and CHP power plants. These non-utility generators sold their excess power to the utilities that could not legally burn natural gas in their own plants. Nowadays, these non-utility generators are commonly known as merchant

² Deregulation of the wellhead price of natural gas after 1978 rapidly increased gas supplies. Many of the QFs and NUGs built in the 1980s were gas-fired combined heat and power (CHP) facilities, sometimes also referred to as co-generation plants

FIGURE 1:

Milestones in U.S. electricity restructuring

Key Milestones in U.S. Electricity Restructuring

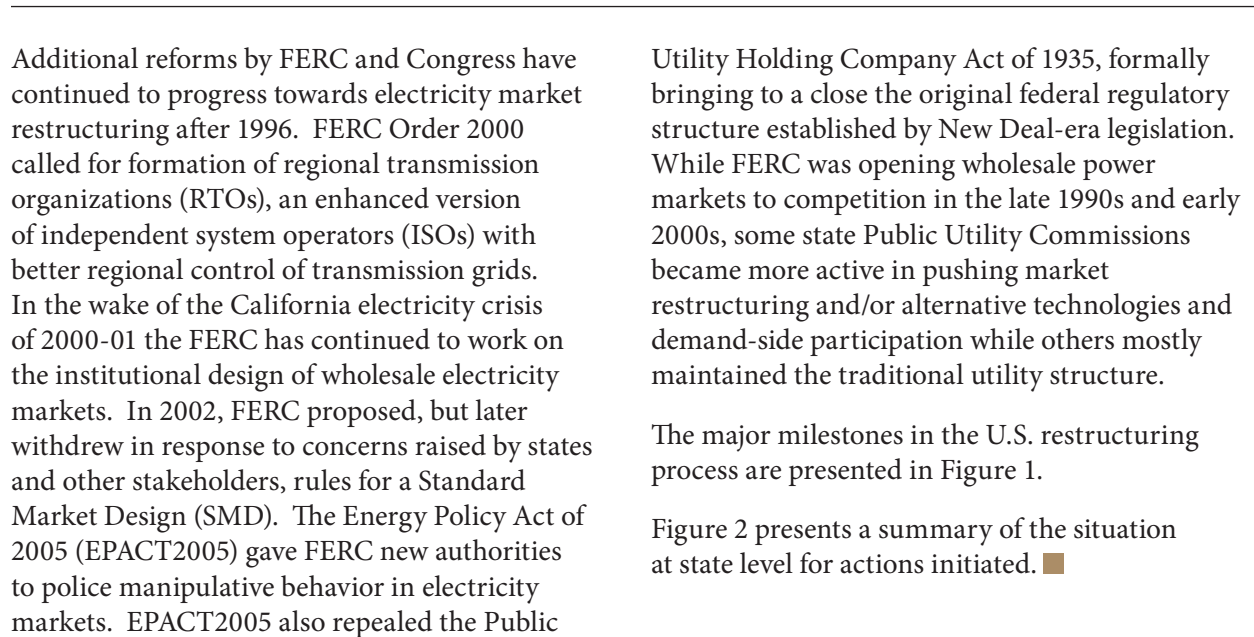


plants or independent power producers, or IPPs.

Using many of the concepts and lessons from the restructuring of the natural gas industry in the 1980s, FERC also pursued similar reforms in the electricity sector; Orders 888 and 889, issued on April 24, 1996, were particularly significant. These orders:

- Require transmission owners to offer nondiscriminatory, comparable transmission service to others seeking such services over its own facilities. This often is referred to as the "open access" rule;
- Ensure that potential suppliers of electricity have equal access to the market; and
- Encourage the creation of a separate Price Exchange to reveal market-clearing prices for electricity in the new competitive market [10].

Electricity Restructuring by state (Source EIA [11]). Restructuring implies that a monopoly system of electric utilities has been replaced with competing sellers.



3 | ELECTRICITY INDUSTRY ORGANIZATIONAL STRUCTURES

Now that we have provided an overview of the historical interplay of technology, finance, and regulation that has shaped the electricity industry, we now represent the various electric grid regulatory structures via a framework of six simplified models.

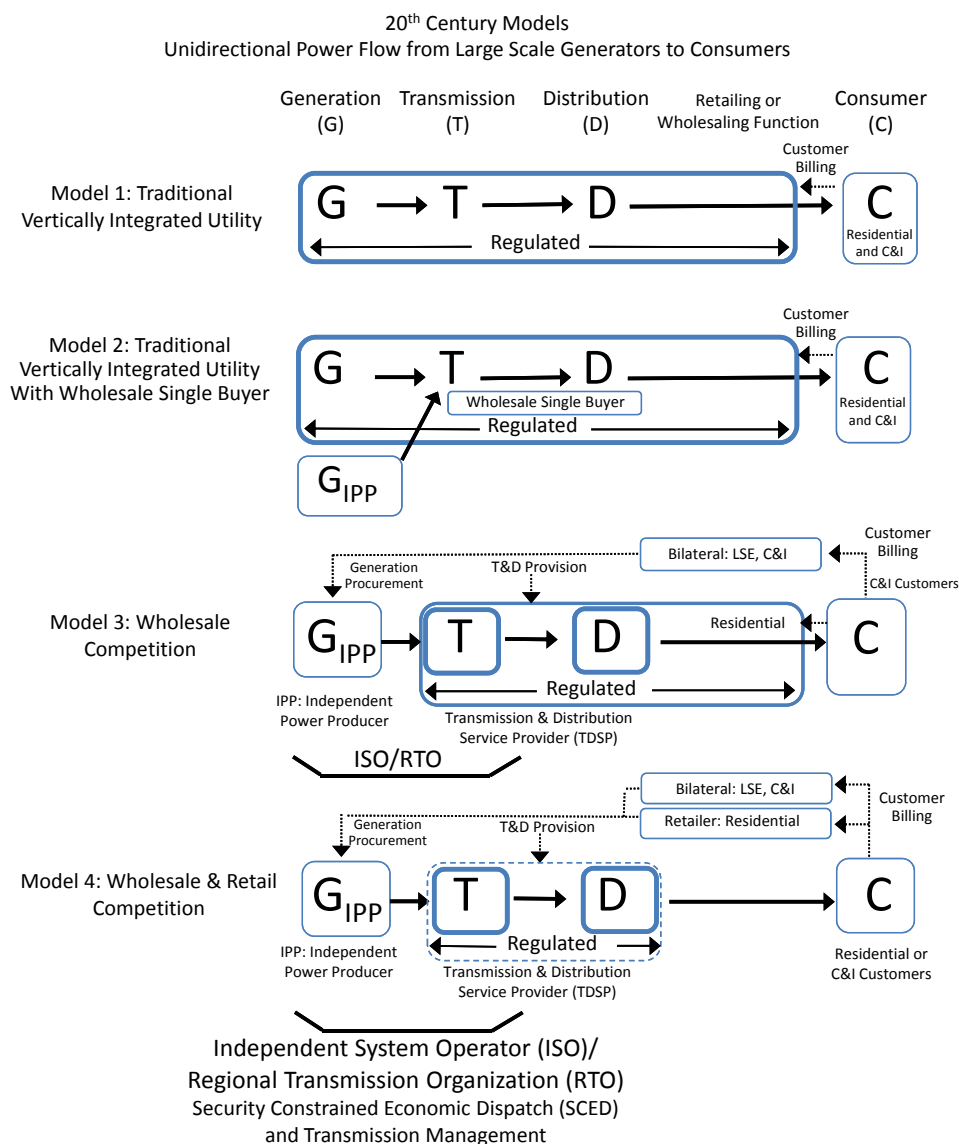
INVESTOR-OWNED UTILITIES (FOR PROFIT OWNERSHIP)

There are many ways to categorize the organization of electric utilities. From the point of view of investor owned utilities (IOUs) there are four

FIGURE 3:

Typical Investor Owned Utility (IOU) Electricity Market Structures

Different Structures of Electricity Markets



main ways of structuring the industry, although there are many possible variations on each.

Representations of each of these models are presented in Figure 3.

In the case of restructuring to competitive markets, the operation and control of the transmission (T) and distribution (D) system (in essence the grid) is still viewed as a natural monopoly, because of the requirement of central dispatch and the difficulty in building competing T&D systems given the costs and right-of-way barriers to entry. As such, the grid operations and T&D infrastructure have remained monopolies in almost all jurisdictions that experienced restructuring. Management of the grid to maintain reliability is handled by such entities as independent system operators (ISOs) or regional transmission organizations (RTOs), with oversight by regulators and other stakeholders.

Model 1 – Vertically Integrated (monopoly at all levels)

This is the traditional vertically integrated utility model. A single monopoly company handles the production of electricity and its delivery over its own transmission and distribution network to final consumers. Generation is not subject to competition and no commercial and industrial (C&I) or residential consumer has any choice of supplier (with the exception of self-generation).

State-owned electric companies around the world and many traditional IOUs fit this model. The state-owned utilities do not have the inherent conflict between owners and consumers since the consumers “own” the company (at least, in theory). For IOUs, there can be a conflict as the utility owners or debt holders (e.g., stock and bond holders) are not necessarily the utility’s customers. Even in restructured markets, one can find examples of this vertically integrated model with a monopoly service area (such as a municipally owned utility) selling electricity to its customers. There are more than 2,000 publicly owned utilities in the U.S., serving about 15% of the customers.

Model 2 – Single Buyer (limited competitive generation)

In restructured markets, different arrangements have been pursued to facilitate wholesale competition. One approach allows a single buyer, the purchasing agency, to choose from a number of different generators. Direct procurement of transmission service from competing generators to final customers is not permitted. The purchasing agency has a monopoly on transmission networks and sales to final consumers. This model allows for the integrated utility to introduce competition from independent power producers, or IPPs, that own power generation facilities. The Single Buyer model is most commonly associated with jurisdictions where a vertically integrated utility remains (often state-owned).

Model 3 – Wholesale Competition of Generation

Many countries prefer the model of Wholesale Competition to the single buyer model. This model allows Discos³ or load serving entities (LSEs) to buy wholesale electricity⁴ directly from competing producers on the transmission network and deliver this electricity over a distribution network to customers. Discos or LSEs may still have a monopoly over final consumers. There is open access to transmission lines for delivery of energy from any generator to carry power to any customer. A system operator manages the transmission system and generator dispatch. This system operator is independent of the other major market participants (generators, Discos, LSEs, and customers).

3 A “Disco” is a company that both owns the distribution wires and retails electricity. In Model 3, Discos continue to serve their captive customers at regulated rates. In Model 4, a retailer is a merchant who sells electricity to final customers, but does not own the wires over which the electricity is transported; this is the purest form of retail competition. In some regions, Discos are allowed to continue to serve as retailers in competition with non-wires retailers often driven by the problems of non-technical losses (i.e. theft). Sometimes, a retailer will be created as a separate company affiliated with a Disco, which is not ideal even if there are strong requirements for the two companies to not share information.

4 Wholesale electricity is the electricity after the point of generation, as it exists on the transmission network, before the electricity reaches final customers.

Model 3 is close to the UK system as it operated immediately after it was restructured in 1990, as well as some places in the U.S. and other restructured markets in Australia, New Zealand, Asia, and Latin America. It is probably the most common restructuring approach but with variations to reflect certain local political, socioeconomic, or technical peculiarities.

Model 4 – Retail and Wholesale Competition

This electricity market model allows all customers to choose their electricity supplier. There is open access to transmission and distribution wires, and as in the case of the Wholesale Competition model, transmission and distribution companies are usually still regulated as separate Transmission Service Providers (TSPs) and Distribution Service Provider (DSPs) or an integrated “Wires and Poles” Transmission and Distribution Service Provider (TDSP). Thus, the distribution (delivery) is separate from the retail activity, and the latter is competitive. A retailer is a merchant who sells electricity to final consumers but does not own any distribution wires.

The UK, Norway, Chile, Australia, and some U.S. states have systems that approximate to this

model, or are in a phased transition. The retail choice program in Electric Reliability Council of Texas (ERCOT) represents arguably the most competitive retail electricity market in the U.S. The market has been open since 2002, allowing even the residential customers to choose their electricity providers. However, municipally owned utilities and cooperatives have decided not to participate in retail choice. Still, there are tens of retail electricity providers (REPs) offering several hundred rate plans. In this model there are many possibilities. In the UK, most retailers sell bundled natural gas and electricity. Customers can choose and change retailers as contracts expire. This model is also expected to facilitate deployment of smart grid (e.g., smart thermostats, remote control of appliances, time-of-use pricing). However, the REPs in the ERCOT market have been slow to incorporate these technologies into their offers presumably because of uncertainty of return on investment.

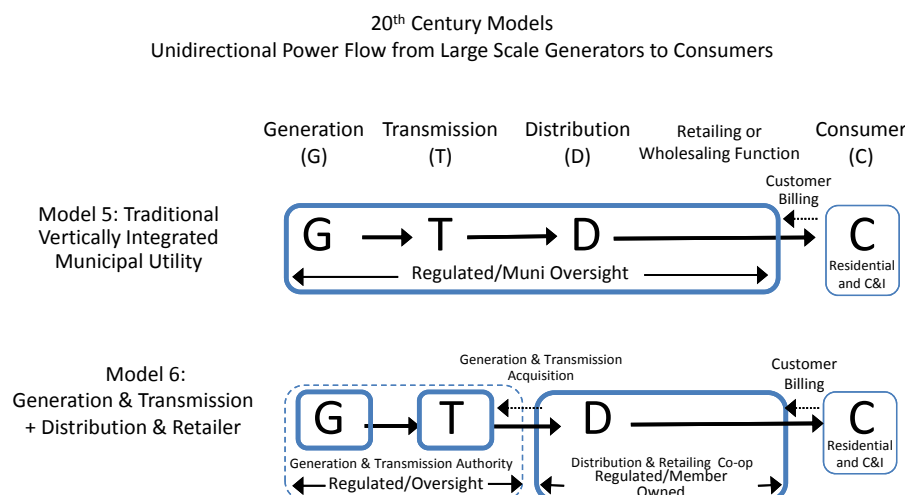
PUBLICLY-OWNED UTILITIES (NON-PROFIT OWNERSHIP)

Electric grid assets can be owned by non-profit entities, such as municipal and federal governments or member owned cooperatives

FIGURE 4:

Not-for-Profit Municipal Utilities, Generation & Transmission Authorities, Distribution & Retailing Co-ops

Different Structures of Electricity Markets



(see Figure 4). In these cases, the structure of the grid is similar to those models representing grids with for-profit ownership. In some cases, there is a mix of for-profit and non-profit ownership of assets on a single synchronized grid.

Model 5 – Vertically Integrated Municipally Owned Utilities

Some cities own their own electric utility. The municipally owned utility structure (Model 5) in Figure 4 is similar to the investor-owned, fully-integrated vertical Model 1, where the residential, commercial, or industrial consumer have no choice of supplier (with the exception of self-generation). Advantages to the electricity consumer can include the elimination of corporate income and property taxes that would be included in the cost of IOU-provided electricity service, a source of income for the municipal government, and local control. Disadvantages can include a lack of scale that may increase costs.

Model 6 – Administrations, Authorities, and Cooperatives (Co-Ops)

Figure 4 also shows the model successfully deployed in areas that did not have sufficient population density to attract service by investor or

nearby municipally owned utilities. These areas were without power until rural electrification efforts began in the 1930's. A few of these organizations also experienced significant growth in capacity to provide massive amounts of energy for critical World War II projects. Generation and transmission services can be provided by Federal Power Marketing Administrations (such as the Bonneville Power Administration), agencies such as the Tennessee Valley Authority (TVA), state created non-profit firms (e.g. Lower Colorado River Authority), or generation & transmission (G&T) co-ops. These G&T entities generate and transmit bulk power to rural co-ops or municipal utilities. Even with the separation of generation and transmission from distribution, the consumer has no choice of supplier (again, with the exception of self-generation) but possibly has the ability to influence investment decisions (e.g., as a co-owner of a cooperative or citizen of a city that owns its municipal utility). ■

4 | PERSPECTIVES ON THE FUTURE

A fundamental assumption that led to the initial regulatory model of the electric industry was that the provision of electricity was most economically achieved through scale economies that favored vertical integration and centralized generation. Accordingly, the regulatory model was based on the notion that regulatory commissions need to ensure that the consumers pay as little as possible for reliable and pervasively available electricity service. In order to achieve that main goal, regulators have sought to oversee the utilities to ensure that the utilities are investing in available technology to keep current prices low, allow the utilities to make sufficient profits so they can raise necessary funding in the capital markets, and monitor to ensure the utilities are operating in a manner that does not cause undue harm to public health and welfare. When it works well this is a political process that appropriately allocates costs and benefits in a complex, rapidly changing environment. When the structure does not function well, customers can suffer from increased costs and poor service.

The restructuring of the electricity industry has led to competition in wholesale markets, and, in some cases, retail markets. More efficient generation technologies, such as combined-cycle-gas-turbines, have benefited from and supported wholesale electricity competition. In most jurisdictions, including both restructured and traditionally regulated, policymakers have also been increasingly pursuing environmental goals. However, maximizing environmental performance and maximizing economic efficiency are distinct goals, and are sometimes in tension with one another.

Tax policies (federal and state), state renewable portfolio standards (RPS) programs, and environmental (air, land, water, climate) regulations have introduced technologies that compete with existing thermal generators. These include wind, solar (both distributed rooftop, and utility-scale PV, concentrated solar thermal), demand side management (energy efficiency,

demand response), and storage (batteries, flywheels, compressed air). Some communities promote these technologies for social and environmental reasons as well as reliability (e.g., community solar). It is interesting to note that RPS programs can be partially driven by state economic development goals as well as environmental considerations. State regulators have modified their rules to accommodate these technologies.

These trends pose continuing challenges for grid operators. Distributed resources and demand side participation can be particularly challenging with retail competition. The retail market structure may not encourage the investment required to exploit load that may be flexible. The relative ease for end-consumers to switch retail electricity providers can create disincentives for investments in intelligent distributed resources. The trend toward distributed energy resources represents an important departure from historical practice.

TECHNOLOGICAL CHANGE CONTINUES

Intermittent renewable electricity generation technologies do introduce some challenges for utilities, ISOs, and regulators. In competitive markets renewables enjoy certain advantages. The zero fuel costs, low operating costs, and low life-cycle emissions encourage deployment. However, the intermittency of these sources is forcing the grid operators to depend upon (and value) more flexible generation sources elsewhere on the grid to compliment the intermittent renewables in order to maintain reliable electric service. It is important to note that baseload power generation (e.g. nuclear and coal) with more constant output typically also needs to be complimented with flexible dispatchable generation to adjust the total power supply to match the constantly varying demand. Wind power fits the existing traditional electricity model fairly well because it is generally implemented as large-scale wind farms remote from the load, a typical scenario for a modern ac power system. The major challenge anticipated

in system dispatch by the grid system operator is to maintain stability and reliability by “firming” the renewable generation by simultaneously varying the output of traditional gas, coal, or hydro generation. To date, relatively modest levels of intermittency related to wind and solar power generation within major North American grids are handled via adjustments to existing system dispatch protocols that were already in existence to handle the intermittency related to unpredictability of loads and generator trip-outs. Improvements in wind and solar generation forecasting techniques have also helped. Despite the challenges of forecasting loads and renewable generation output, some small electric grids, such as on Oahu, Hawaii, have been able to reach high percentages of wind and solar generation relatively quickly, through the deployment of new technologies and regulatory adjustments.

Many believe that eventually solar photovoltaic (PV) power will be more widely adopted than wind power. Solar generation is becoming increasingly attractive. PV can be installed in smaller distributed applications or large utility scale solar farms (30-100MW+) as an IPP. Solar PV power output is inherently dc and appears to be relatively well matched to many modern load patterns. For example, peak solar PV generation occurs during the summer daytimes when air-conditioning loads are highest, though the exact hourly timing of the peak PV and air-conditioning load usually does not precisely match. More importantly, PV shows promise of becoming cost effective from large utility-scale installations, community level systems attached to neighborhood distribution circuits, and with smaller distributed rooftop installations on the home or business. Solar PV is a technology that brings back the initial concept of neighborhood dc power, but its integration can now be made even more robust by overlaying a dc microgrid with the existing ac transmission and distribution grid for those customers with the most demanding reliability requirements.

Wind and solar power show promise to be truly disruptive, as they might become (based on current cost trends) the least expensive ways to generate electricity in some regions on a levelized cost basis, not considering system costs such as

new transmission lines and balancing generation. Incremental transmission and balancing costs may or may not be consequential. The levelized cost of electricity (LCOE) is a commonly used metric for comparing different generation types. Typically expressed on a \$/kWh basis, it combines capital and operating costs to estimate the amount of money that it takes for a particular electricity generation plant to produce a kWh of electricity over its expected lifetime [12].

The impact of renewables is even more pronounced in dispatch decisions and spot markets for electricity, where the marginal cost of providing the next kWh is what matters. Since its marginal costs are effectively zero, wind can be dispatched at prices lower than conventional resources, even at negative prices at times, owing to federal tax credits and renewable energy trading credits. Such prices, driven by out-of-market subsidies provided to these generation technologies, can undermine energy price signals in competitive electricity markets. However, many of these subsidies expire over time. Renewable energy proponents sometimes argue that the competitive markets themselves are not complete since they do not fully internalize many important factors, such as health impacts from air emissions. Many emissions regulations have been implemented since the 1970s, helping to internalize some of these costs.

Renewable electricity generation output is both predictably variable with such factors as the time of day and sometimes intermittent with the changing of wind and cloud patterns. Grid operators have managed to incorporate significant amounts of wind power to date with little impact on reliability. However, as far larger amounts of renewables are installed, fast ramping thermal generation, energy storage, and more flexible load are likely to become more important. The electric industry will need to balance the grid using the legacy grid assets (e.g., natural gas power plants), even more advanced forecasting techniques, and perhaps eventually increased forms of energy storage. These options, however, are not mutually exclusive, and these technology changes are driving changes in both regulation, wholesale market structure, and financing of the electric sector.

Demand that is responsive to price signals (e.g., lower when prices are high) can reduce generator or utility revenues. Energy storage can be deployed in a number of places on the grid, including on the customer site that might enhance the level of demand response. Only a few of these storage configurations are financially attractive at this time. As storage prices decline, more regionally specific market applications for grid storage may become economic for various grid needs. Storage can be co-located near intermittent renewable generation to “firm” its output. Large-scale storage such as CAES, pumped hydro, or thermal storage could be attached to the transmission system. Local storage such as batteries could be installed at various interconnection points with the distribution network. “Behind the Meter” storage can be co-located with a customer’s load to reduce utility demand and energy charges.

There are other technologies that might impact the future of the electricity grid. Some have been around a long time but technology improvements and recent changes in market rules might render them more attractive. For example, micro-turbines that burn natural gas to generate electricity might make sense in some places as a distributed resource. Combined heat and power (CHP), which is one of the most efficient ways to utilize fuels, in large commercial and industrial applications may prove to be attractive for communities or municipalities. Batteries are not new either, but new material compositions may bring lower battery costs, in which case their deployment can be accelerated. Other technologies are relatively newer with a relatively small number of units deployed. Storage options such as compressed air energy storage (CAES) or thermal storage can find larger applications if they can be optimized to reduce costs. The storage of CO₂ through carbon capture and sequestration (CCS) might allow some traditional thermal capacity to remain as part of grids that might need to operate with lower CO₂ emissions. Small modular nuclear reactor (SMRs), the first “commercial” site of which might be built in the next few years, can be a game-changer if they prove to substantially reduce costs. Finally, there is significant activity in energy efficiency, conservation, and

flexible loads that can alter load profiles, and, hence, the way grids operate by changing the relevance of demand-side participation.

FINANCIAL CHALLENGES FOR UTILITIES

Utilities face increased affordability of distributed generation, particularly rooftop photovoltaic (PV) panels, and stagnant or declining electricity demand in the U.S. since 2007. These trends can lead to the underutilization of large, costly, and long-lived fixed utility assets (e.g., power plants, transmission, or distribution assets) compared to the expected utilization rates that were used in the original investment decision-making and regulatory approval. Thus, these assets are at risk of becoming a “stranded cost” or a cost that cannot be fully recovered. When markets were being restructured, utilities were concerned that their investments recently approved by the regulators would not recover their costs if the energy prices declined rapidly as a result of competition or new technology. Finding this concern legitimate in certain cases, policymakers granted ways to recover these stranded costs.

In restructured markets, new technologies can make large and long-lasting investments economically obsolete relatively quickly. The electric system includes transformers, transmission lines and power plants that are 50 years old or more, for example. The financial markets are reluctant to make these longer-term investments in an uncertain environment, at least not without a significant premium to cover the risk or without assurance that stranded costs will be recovered. The regulatory response can be to identify stranded costs that will be recovered independent of system evolution. Stranded cost recovery can in some circumstances shift the risk from the utility investors to the consumers by increasing the cost of electricity to customers. For example, if a utility is able to charge its customers for stranded assets (e.g., those retired early due to lack of economic operation), then the customers’ electric rates (e.g., \$/kWh charged on their bill) or fixed charges may increase even while the fuel costs of electricity generation decrease creating a customer backlash that may be of concern to regulators.

The issue of declining revenues, due to distributed generation and lower demand more generally, impacts the ability of electric utilities to access less expensive capital to fund new investments. As noted by Peter Kind in his report to the Edison Electric Institute, “Since practically all utilities have an ongoing need for capital to fund their capital expenditure programs, the industry has developed financial policies intended to support the access to relatively low-cost capital in (practically) all market environments. Under traditional cost-of-service ratemaking, customers benefit through lower cost of service and, therefore, lower rates” [13]. If future revenues become more in doubt for utilities, then they are pressured to raise their rates (e.g., \$/kWh charges) to pay existing debts, and future capital might come at a higher cost, again putting upward pressure on electricity rates. These upward pressures on electricity rates only enhance the incentives for further electricity conservation (or load defection to distributed generation) by consumers, a trend described as the “utility death spiral.” The extent to which this death spiral will play out is uncertain, but it is one of the many important motivations for understanding the Full Cost of Electricity. One of the policies that have been helpful to the expansion of rooftop solar PV around the country, net metering, has been under pressure. Utilities observed that there was a loss of revenues resulting from the expansion of rooftop solar while they are required to maintain the same infrastructure under rates approved by regulators for larger loads. At the time of writing, a couple of state utilities have revised their rules to address this concern deeming it legitimate from a ratemaking perspective. Other states and utilities are evaluating similar policies.

CUSTOMER ELECTRICITY COSTS

A customer’s electricity bill consists of different charges. In jurisdictions without competition, the rate will generally reflect generation and T&D costs but be set by the regulator or the government. In competitive markets, the regulated T&D charges are fixed over a relatively long period of time. These rates are fixed because the assets are long-lived (measured in decades) capital investments generally financed with long term debt and amortized over 20 to 30 years. The unregulated

cost of electricity (energy charges) will vary along with the wholesale price that varies over the course of days, seasons, or longer commodity price or technology cycle periods, but utility economists have become more expert at achieving an average cost due to the predictability of the average (not instantaneous) cost and load. The proportion of fixed charge related to long-term capital asset investments and variable energy generation related charges in a customer bill have varied over time and across jurisdictions.

In some states, ratemaking policies allow for some cross-subsidies between residential and larger commercial and industrial consumers. Block rates can be pursued to encourage conservation and efficiency (e.g., much higher rates above a certain level of consumption) despite sometimes-lower fixed cost amortization costs with higher volumetric energy sales. Fixed charges can increase meaningfully if new transmission and distribution investments are mandated by the regulator or the legislature to accommodate remote resources such as wind or solar (e.g., Competitive Renewable Energy Zone transmission lines in ERCOT). These increases in fixed charges may or may not be offset by decreased generation costs.

Historically, reliability has been an important objective of all electricity systems. In some competitive regions, generators are compensated for the capacity they make available to the grid via long-term capacity markets in addition to energy they sell into the energy markets every hour. These capacity charges are also fixed in customer bills for extended periods of time. As such, changes in customer bills can arise from regulated infrastructure charges or capacity charges as well as market-based energy charges. In recent years, given that the low price of natural gas has kept wholesale electricity prices very low, increases in customer bills in competitive jurisdictions are most likely the result of investment in new T&D and/or generation infrastructure.

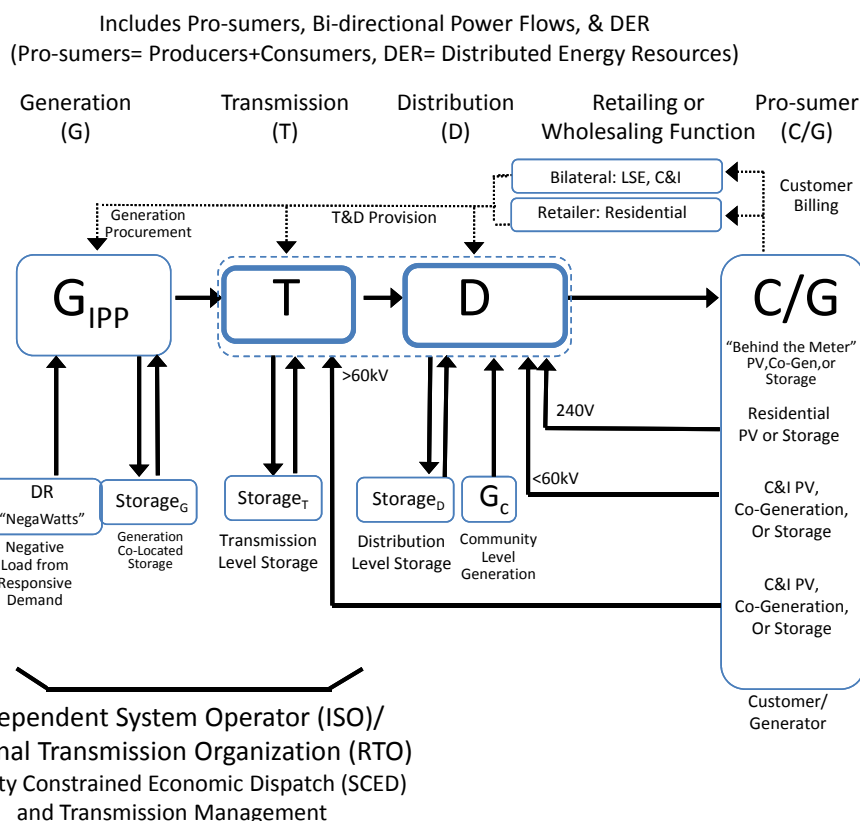
EVOLVING ELECTRIC GRID ORGANIZATIONAL STRUCTURES

Technological progress and cost reductions have introduced additional complexity and challenges to the previously described utility models of Figures

FIGURE 5:

Disruptive Technologies to the Existing Utility Model

21st Century Electricity Market Example



3 and 4. These changes are fostering even more complex business and regulatory models where customers can increasingly purchase electricity services from multiple vendors for multiple purposes (e.g., demand response (DR), distributed generation, energy storage) and in multiple ways (see Figure 5). Storage and generation systems can technically be located on multiple parts of the grid depending upon capabilities and needs.

Community level solar systems connected to the distribution system can reduce transmission loading and allow distribution companies or cooperatives to own small-scale generation for the first time or provide unique customer ownership opportunities for those who cannot install rooftop PV on their residences. Rooftop PV or cogeneration systems at homes and businesses can be a utility-owned distributed generation resource or customer-owned generation that reduces utility revenue. All of these configurations can provide an opportunity to improve (or complicate) the utility model, their finances, and in some cases the

technical operation of the grid. The emergence of distributed energy resources (DERs) either on the utility side of the meter, or behind the customer meter, may become a transformative force to the utility industry. While the discussions of such concepts as “transactive energy” and the models of distributed system platforms (DSP) or independent distribution system operators (DSOs) are beyond the scope of this paper, these concepts are part of ongoing restructuring efforts in a number of states. These efforts are attempts to accommodate new technology alternatives, associated business structures, market design, and the supporting regulatory structure to meet stakeholder objectives for their 21st century energy systems [14][15][16][17].

There will also likely be an increased demand for newer and more customer-centric regulatory frameworks that allow an increased number of technologies to be owned and operated by a larger number of players that serve more diverse customers. ■

5 | CONCLUSION

For a century, the scale economies associated with large centralized generation technologies encouraged vertical integration, drove down the cost of electricity, fostered universal access that improved citizens' quality of life, and provided for reliable electric service. The structure of the electricity industry started to evolve significantly starting in the 1970s. Higher fuel prices, environmental concerns, technological innovations and efforts to improve the economic efficiency of electricity service led to the rethinking of the traditional vertically-integrated, regional monopoly model. In the late 1970's and 1980's a series of government decisions deregulating wellhead natural gas prices and the pipeline industry made natural gas-fired electric power much less expensive. These efficient non-utility co-generation/CHP gas powered generators were some of the first disruptive technologies and firms that threatened the traditional vertically integrated utility model.

By the mid-1990s, policy makers began to restructure the electricity system, seeking to promote innovation and reduce electricity costs while incorporating policies that addressed environmental concerns. Federal

and state governments implemented environmental regulations, tax credits, and other programs that encouraged deployment of renewables such as wind and solar.

Continuing declines in the cost of wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, micro grids, and energy storage and demand response systems with progressively lower costs continue to provide opportunities to improve the traditional utility business model. These technology developments are strongly encouraging the industry to consider new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation, storage, or responsive demand capabilities that have the potential to significantly reduce utility revenues and profitability. With so many moving pieces, the policy and investment environment can be uncertain. The companion papers of the FCE- project and related research by team members offer more insights into the technologies, trends, or considerations that lead to disruptive changes and uncertainty. ■

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-109:
PacifiCorp 2025 Oregon RFP



825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

October 15, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UM 2383—PacifiCorp's Informational Filing

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its informational filing to provide notice that the 2025 Oregon Situs Request for Proposals (RFP) has been issued to market. PacifiCorp provides the following RFP, which has been informed by conversations with the Oregon Public Utility Commission Staff and the Independent Evaluator.

If you have any questions about this filing, please contact Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

A handwritten signature in dark ink, appearing to read "Robert Meredith", written over a horizontal line.

Robert Meredith
Director, Regulation

Enclosures



**2025 Oregon Situs
Request for Proposals
(2025 OR Situs RFP)**

**ISSUED: October 13, 2025
BIDS DUE: November 18, 2025**

**PacifiCorp
2025 OR Situs RFP
Resource & Commercial Strategy
2025ORSitusRFP@pacificorp.com**



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SECTION 1. OVERVIEW

A. PURPOSE AND SCOPE OF RFP

The PacifiCorp 2025 Integrated Resource Plan (IRP) established an action item to initiate a Request for Proposals (RFP) to procure resources for its Oregon customers that are aligned with the 2025 IRP preferred portfolio and that can achieve commercial operations by the end of December 2029.¹ The 2025 IRP calls for 1,570 megawatts of utility scale solar resources, 1,400 megawatts of utility-scale wind resources, and 320 megawatts of small-scale solar resources by the end of 2029. The 2025 IRP also calls for energy storage resources, including 509 megawatts of lithium-ion batteries with four-hour duration, and 272 megawatts of iron-air storage with 100-hour duration by the end of 2029. This RFP is seeking resources that are agnostic to both duration and technology type.

Consistent with these identified needs, the 2025 OR Situs RFP will accept and evaluate cost-competitive bids for resources with the following characteristics:

1. Minimum nameplate capacity of 1 megawatt;
2. Generates electricity from wind, photovoltaic (PV) solar, wave, geothermal, hydroelectric, biomass, or other sources of energy that support compliance with Oregon's House Bill 2021 emissions reduction requirements.
3. Storage resources (e.g., battery);²
4. Have a guaranteed commercial operation date (GCOD) on or before December 31, 2029;³
5. For Renewable Portfolio Standard (RPS)-eligible resources, the resources must be approved or certified by the Oregon Department of Energy as RPS-eligible generation resources (RPS Certification) within 90 days of commercial operation date (COD), and will maintain RPS Certification throughout the duration of any agreement with PacifiCorp;⁴
6. The bids submitted reflect firm pricing at the time of bid and pricing is held firm through June 22, 2026; and
7. The bids meet the minimum eligibility requirements of this RFP listed in Section 3.G Minimum Eligibility Requirements for Bidders, and otherwise complies with the requirements of this RFP.

¹ PacifiCorp 2025 Integrated Resource Plan, Chapter 1, Action Item 2b.

² For bids including storage, additional criteria are in Appendix C-2 Bid Summary and Pricing Input Sheet.

³ E.g., Section 11.1.2 in each of the two pro forma power purchase agreements. Commercial operation dates prior to December 31, 2029, must have a contract term that terminates no earlier than December 31, 2034.

⁴ OAR 860-091-0030(1) Projects used to comply with the standard in ORS 469A.210(2) must be an Oregon Renewable Portfolio Standard-approved generator.



Questions about minimum eligibility requirements or any other questions concerning the information presented in this RFP issuance may be submitted to PacifiCorp at: 2025ORSitusRFP@pacificorp.com for clarification.

This document outlines the 2025 OR Situs RFP process and requirements. **PACIFICORP IS NOT BOUND TO ACCEPT ANY BIDS AND MAY CANCEL OR SUSPEND THIS SOLICITATION AT ANY TIME AND AT ITS OWN DISCRETION.**

B. INTERCONNECTION REQUIREMENTS

Bidders submitting resources into the 2025 OR Situs RFP must demonstrate the ability of the bid resources to interconnect to a transmission or distribution system by providing one of the following: 1) a completed interconnection system impact study and/or facilities study, or, 2) for bids indicating interconnection service to PacifiCorp Transmission's system (on system bids), confirmation from PacifiCorp Transmission that bidder's proposed interconnection request has passed the screens as part of the Initial Review process or Supplemental Review process in the Fast Track Process for small generation interconnection service⁵, or 3) a signed interconnection agreement. An informational interconnection study is not sufficient interconnection documentation to be considered eligible for the 2025 OR Situs RFP.

For any bid that is proposing to interconnect to a third-party transmission system and secure transmission service to deliver the output of the resource to PacifiCorp at PACE or PACW, the bidder must provide 1) a completed system impact and/or facilities study by the third-party transmission provider, confirming ability to interconnect to the third party's transmission or distribution system, if such study or agreement is completed, and 2) satisfactory evidence⁶ that long-term, firm, point-to-point transmission rights or Bonneville Power Administration's conditional firm bridge transmission rights, are already secured in bidder or project owner's name or readily obtainable by bidder to deliver the full output of the resource to PacifiCorp on or before December 31, 2029.

⁵ "Fast Track Process", "screens", "Initial Review" and "Supplemental Review" are all described in PacifiCorp Transmission's Open Access Transmission Tariff (OATT).

⁶ Transmission service documentation demonstrating ability to deliver to PacifiCorp's system is two-fold: first, long-term, firm transmission service or Bonneville Power Administration's conditional firm bridge transmission service, is available from a third-party transmission provider and second, the bidder has made a request to the third-party transmission provider to acquire long-term firm point-to-point transmission service or Bonneville Power Administration's conditional firm bridge transmission service, to PacifiCorp's system. Documentation must include copies of direct, dated correspondence from transmission service provider to the bidder, showing evidence of a request for transmission service, and the transmission provider indicating to the bidder that long-term, firm, uninterruptible transmission service or Bonneville Power Administration's conditional firm bridge transmission service, will be available for the bidder to procure, for a specified OATT service, and an identified MW capacity, point of receipt, point of delivery, and term. Dated correspondence must be at least within six (6) months of bid submittal.



C. TRANSACTION TYPE

PacifiCorp is accepting qualified proposals for transactions using 1) existing resources from bidders who currently own or have legally binding rights to operate existing resources, and 2) new resources from bidders with development rights to construct new resources. PacifiCorp will accept bids in the 2025 OR Situs RFP from existing operating facilities subject to the following conditions:

1. Bidders cannot terminate an existing contract with PacifiCorp to bid into the 2025 OR Situs RFP; and
2. The existing contract must expire before the required on-line date as identified in a bidder's proposal, but no later than December 31, 2029; and
3. The submitted bid must meet all other requirements in the 2025 OR Situs RFP.

PacifiCorp will consider proposals with the following transaction structures:

1. **Power Purchase Agreement (PPA)** transaction for exclusive ownership by PacifiCorp of any and all energy, capacity, ancillary services (including reactive power) and environmental attributes associated with the generation (and storage if included in the bid). PacifiCorp will consider PPA terms between 5 and 20 years. PacifiCorp provides two forms of PPA: generation-only resources and generation resources collocated with a battery energy storage system (BESS) resource. With respect to collocated resources, the term length must be the same term for both the generation and the storage resource. PacifiCorp requires full dispatch control of the collocated or standalone battery (charge and discharge) as addressed in contractual terms in the applicable appendices to this RFP.
2. **Stand-alone Energy Storage Agreement (ESA)** transaction whereby PacifiCorp controls the output of a standalone storage resource (BESS, Pumped storage hydro (PSH) or other). PacifiCorp will consider energy storage agreement terms between 5 and 20 years.

In order to provide for a transparent and fair process, the RFP will be conducted under the oversight of an Independent Evaluator (IE) as further described in [Section 2.A Independent Evaluator](#). The IE will have been involved in the development of the RFP and will ensure the RFP process is conducted in a fair and reasonable manner. Potential bidders are invited and encouraged to contact the IE with questions or concerns. More information concerning the role of the IE is provided in **Appendix M – Role of the Independent Evaluator**.

D. OPERATING CAPABILITIES OF THE RESOURCE

All bids must have the ability to comply with technical and operating specifications for Automated Generation Control (AGC) for automated signal operation and Automatic Voltage Regulation functionality and be capable of following a four second signal. Bidders must review and understand the North America Electric Reliability Corporation (NERC)



guidelines regarding technical requirements.⁷ Additional information concerning AGC is in the pro forma PPA attached in **Appendix E-1 – PPA for Generation Only, Appendix E-2 – PPA for Generation with Storage, and Appendix E-3 for Energy Storage Agreement.**

SECTION 2. PROCEDURAL ITEMS

PacifiCorp will evaluate proposals based on the following:

1. Conformance with the RFP minimum eligibility requirements,
2. Final score and ranking for each conforming bid, per Section 6 Bid Evaluation and Selection.
3. Technical design, feasibility, and compliance with the documentation in **Appendix A – Technical Specifications and Required Submittals**,
4. Ability to provide acceptable credit security as determined per **Appendix D – Bidder’s Credit Information**, and
5. Acceptance of the standard form PPA and/or ESA contract provided in **Appendix E-1 - PPA for Generation Only, Appendix E-2 - PPA for Generation with Storage, or Appendix E-3 - ESA for Energy Storage.**

A. INDEPENDENT EVALUATOR

PacifiCorp is conducting the 2025 OR Situs RFP under the oversight of an IE. The IE will be retained by PacifiCorp on behalf of the Public Utility Commission of Oregon (Oregon Commission) as required by Oregon Administrative Rules § 860-89-200.¹ The IE will be involved in the RFP and provide oversight to ensure the RFP process is conducted in a fair and reasonable manner. Potential bidders are invited and encouraged to contact the IE with questions or concerns. More information concerning the role of the IE is provided in **Appendix M – Role of the Independent Evaluator.**

Contact information for the IE is as follows:

Independent Evaluators:
OREGON – PA Consulting Group, Inc.
2025AS_PAC_IE@paconsulting.com

B. STANDARDS OF CONDUCT; SEPARATION OF FUNCTIONS

Each bidder responding to this RFP must conduct its communications and activities in recognition of PacifiCorp’s obligation to comply with the Federal Energy Regulatory

⁷ Please refer to NERC, Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources, September 2019.



Commission (FERC)'s Standards of Conduct for Transmission Providers in **Appendix I – Standards of Conduct; Separation of Functions**, which require the functional separation of PacifiCorp's transmission and merchant functions. Interconnection with or transmission service on PacifiCorp's system is arranged through PacifiCorp's transmission function, and not PacifiCorp's merchant function, which administers this RFP. As part of a bid submittal, bidders will be requested to execute a customer consent form provided in **Appendix J – Seller Authorization to Release Generation Data to PacifiCorp** that enables PacifiCorp's merchant function to discuss the bidder's interconnection and/or transmission service application(s) with PacifiCorp's transmission function.

C. CONFIDENTIALITY

Bidders will be required to execute a confidentiality agreement in the form provided in **Appendix G-1 – Confidentiality Agreement**. As provided in the form of confidentiality agreement, PacifiCorp will endeavor to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order. It is the bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential and subject to the terms of the executed confidentiality agreement. Bidders may not mark an entire proposal as confidential, but bidders must mark specific information on individual pages to be confidential to receive confidential treatment for that information under the terms of the executed confidentiality agreement.

All information supplied to PacifiCorp or generated internally by PacifiCorp is and will remain the property of PacifiCorp. To the extent bidder receives information from PacifiCorp, bidder must maintain the confidentiality of such information and such information may not be provided to any third-party before, during or after this RFP process unless required by law or regulatory order.

D. PACIFICORP'S RESERVATION OF RIGHTS AND DISCLAIMERS

PacifiCorp reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend this RFP in whole or in part at any time. Without limiting the foregoing, PacifiCorp reserves the right to reject as non-responsive any or all bid proposals received for failure to meet any requirement of this RFP. PacifiCorp further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact PacifiCorp, and any evidence of collusive bidding or other anticompetitive behavior or conduct of bidders.

Bidders who submit bid proposals do so without recourse against PacifiCorp, its parent company, its affiliates and its subsidiaries, against any director, officer, employee, agent or representative of any of them, or against the Independent Evaluator, for any modification or withdrawal of this RFP, rejection of any bid proposal, or failure to enter into an agreement.



SECTION 3. GENERAL INFORMATION AND LOGISTICS

A. SCHEDULE

The proposed 2025 OR Situs RFP schedule is shown below and is subject to change.⁸

Event	Date
RFP issued to market and publicized	10/13/2025
Bidder workshop	10/21/2025
Last day for bidder questions to PacifiCorp and the IE	11/12/2025
Bid submissions due with pricing and issues list	11/18/2025
Staff/ IE proposals on model runs	12/2/2025
Staff hosted workshop on model runs	12/4/2025
Stakeholder comments on whether additional model runs are needed	12/18/2025
Staff/ IE final required model runs	1/6/2026
Bid evaluations, and IE review complete	4/1/2026
IE Report on final shortlist complete	4/14/2026
Commission acknowledgment	6/15/2026
Contracts finalized and executed ⁹	6/22/2026
Issuance of Second Phase of RFP	8/15/2026
Guaranteed commercial operation date (GCOD)	12/31/2029

The schedule above is subject to change. Actual dates may vary for reasons that include, but are not limited to, negotiation time, availability of key personnel, regulatory delays, due diligence, the evaluation or negotiation of any issues unique to any bid, bidder, or facility. PacifiCorp is not responsible for any costs or damages to bidders alleged to be attributable to changes in the RFP schedule stated above. PacifiCorp is not obligated to develop a shortlist of bidders, to make a final selection, or to initiate or complete negotiations on any transaction.

The schedule above also reflects the expectation from the Oregon Public Utilities Commission Order No. 25-343: “We expect PacifiCorp to engage with Staff and stakeholders on their analysis, including providing additional model runs in the list

⁸ Any schedule changes will be posted to PacifiCorp’s 2025 OR SITUS RFP website:

<https://www.pacifiCorp.com/suppliers/rfps/2025-oregon-situs-rfp.html>

⁹ This date is aspirational and contract execution may occur after this date.



development process, if necessary, and we reinforce the need for these analyses to support prudence review.”

Bidders must be available for calls and meetings with PacifiCorp regarding bid submittals and be responsive to bid deficiency questions within two (2) business days.

B. 2025 OR SITUS RFP BIDDER WORKSHOP

A bidder workshop will be scheduled and will cover the 2025 OR Situs RFP structure, deliverables, schedule, requirements, required forms and interconnection requirements. The bidder workshop will be scheduled as Microsoft Teams meetings for remote attendance. Additional details on the bidder workshop will be posted to the PacifiCorp website at <https://www.pacificorp.com/suppliers/rfps/2025-oregon-Situs-rfp.html>.

C. SUBMISSION OF QUESTIONS

Bidders may submit questions related to this solicitation by email, and PacifiCorp will respond in a timely fashion. While PacifiCorp will maintain the confidentiality of the party posing questions, all questions as well as PacifiCorp’s response to questions will be posted on the PacifiCorp website at <https://www.pacificorp.com/suppliers/rfps/2025-oregon-Situs-rfp.html>.

Bidders may submit questions to PacifiCorp and the IE by email at:

PacifiCorp: 2025ORSitusRFP@pacificorp.com and IE: 2025AS_PAC_IE@paconsulting.com

All questions submitted to PacifiCorp will be shared with the IE.

D. SUBMISSION OF BIDS

Each proposal submitted must include a cover letter signed by one or more representatives with the requisite corporate or other organizational authority to approve and submit the bidder’s proposal.¹⁰ Additionally, the cover letter must also include the following declaration, which may not be edited without the express approval of PacifiCorp:

“[Insert legal name of bidder] acknowledges receipt of PacifiCorp’s 2025 OR Situs Request for Proposal on or about [DATE]. The bidder makes the following representations to PacifiCorp:

1. All the statements and representations made in this proposal are true to the best of the bidder’s knowledge and belief.

¹⁰ If the proposal is bid under a partnership, the partnership must be fully established, including a legally binding agreement among the partners (not a letter of intent), before submission of a proposal under this RFP. Each partner must be bound to comply with the terms of this RFP and the proposal. The signature of each partner must be included on the cover letter, along with their contact information (i.e., company name, phone number, email address, etc.). The proposal must include evidence documenting the legal and binding partnership.



2. The bidder possesses ownership of, leasehold interest in, right to develop site, or valid title to property on which the resources included in this bid are located.
3. The bidder possesses or will obtain all required permits to site, construct and operate applicable facility(ies) under the bid.
4. The bidder agrees to comply with **Appendix S – Cyber Security Requirements**.
5. The bidder holds PacifiCorp harmless for all development activities related to the applicable facility(ies) under the bid.
6. With respect to any new facility(ies) sited and constructed in Oregon under the bid, the bidder understands the requirements in ORS 757.306¹¹ and will provide required attestations or Project Labor Agreements under ORS 469A.210 within 30 days of the date of construction begins.
7. The bidder agrees to report diversity representation by contractors.
8. With respect to any existing facility(ies) under the bid, the bidder has obtained RPS Certification. With respect to any new facility(ies) to be constructed under the bid, the bidder will apply for and obtain RPS Certification within 90 days of COD. In either case, the bidder agrees it will maintain the RPS Certification for the full term of the PPA.
9. Bid pricing takes into account the risk profile and other terms and conditions of the transaction documents in **Appendix E-1 PPA – for Generation Only, Appendix E-2 – PPA for Generation with Storage, or Appendix E-3 - ESA for Energy Storage**, as currently drafted without modification.
10. This proposal is a firm and binding proposal through June 22, 2026.

**PACIFICORP IS ACCEPTING ONLY ELECTRONIC COPIES OF A BID AND WILL NOT
ACCEPT HARD COPIES.**

For each individual bid, the bidder must submit one (1) electronic copy of the bid, sent to the RFP email address and IE email address specified below. The bid must include any required forms in PDF format and Microsoft Excel format, including all appendices and exhibit sheets. Hard copy submittals will not be accepted.

Each bid must be submitted as a separate document. For example, three separate bids must be sent in three separate emails.

¹¹ A person who constructs or repowers a large-scale project sited in Oregon will, at the time of contract finalization for development of the project or execution of a contract for delivery of energy from the project, provide a signed attestation or declaration stating to the best of their knowledge and belief, subject to penalty of perjury as described in ORS 162.065, that during all periods of construction all contractors and subcontractors working on the construction or repowering project will have done certain things related to apprenticeship programs, diversity hiring outreach, anti-employee harassment policies, and other required measures as required by ORS 757.306. ("Large-scale project" means a renewable energy generation, sequestration or storage facility with a capacity rating of 10 megawatts or greater.)



Submit bid(s) via email to:

PacifiCorp: 2025ORSitusRFP@pacificorp.com and IE: 2025AS_PAC_IE@paconsulting.com

Bidders must be aware of file size when delivering the electronic copy of their bids. PacifiCorp suggests limiting the size of each email with attached files to no more than 20 MB to ensure email delivery. Bidders may submit multiple emails for their bids and must label the emails accordingly (i.e. “1 of 3...,” “2 of 3...,” “3 of 3...”).

PacifiCorp will respond with email(s) confirming receipt.

Bids will be accepted until 5:00 p.m. Pacific Prevailing Time on November 18, 2025.

PacifiCorp will not accept any late proposals. Any bids received after dates and times stated above will be deleted.

All bid proposals will have a bid validity date through 5:00 p.m. Pacific Prevailing Time, June 22, 2026.

Each bid submission must include all the requirements listed in Section 4 RFP Content and Submittal Instructions of this RFP document.

E. BID SUBMISSION FEES

Fee	Amount	Activity	Refundable/Non-Refundable
Due by bid submission due date			
Bid Submission Initial Fee	\$10,000	This initial fee covers costs associated with minimum eligibility requirements screening, bid modeling, bid evaluation and bid scoring for each distinct RFP.	Non-refundable. Due at the bid submission due date.
Bid Fee - Independent Energy Performance Report Evaluation	\$10,000	A fee of \$10,000 will be used to cover the cost associated with a forecast generation evaluation conducted by an independent consultant hired by PacifiCorp.	Non-refundable. Due at the bid submission due date.



		**This fee is not required for a standalone battery bid and will be waived for bidders for whom this Independent Energy Performance Report Evaluation has already been obtained within the last two years for this same resource.	
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The Bid Fees will be used to cover the costs incurred by PacifiCorp in analyzing the proposals, including the costs of the IE and legal advisors.

Payment of Bid Submission Initial Fees.

Bid submission initial fees must be paid upon bid submission via wire transfer to PacifiCorp. Wire instructions provided upon request to parties who intend to submit bids. No cashier's checks will be accepted. As a bid requirement, when the bid is submitted, bidders must provide documentation of submitted bid submission initial fee and bid fee- independent energy performance report evaluation, such as a PDF receipt of the wire transfer or wire transfer confirmation number. The bid submission initial fee is non-refundable.

Bidders are responsible for all bid fees and all costs and expenses of any response to PacifiCorp in connection with its proposal for the 2025 OR Situs RFP. Such expenses may include but are not limited to 1) 2025 OR Situs RFP bid submission initial fees, 2) Bidder's fees paid for additional studies, 3) Bidder's cost of providing additional information, and bidder's own expenses in negotiating and reviewing any documentation. **PACIFICORP WILL HAVE NO LIABILITY OR OBLIGATION TO RETURN AMOUNTS PAID BY BIDDERS IN THE EVENT OF PACIFICORP'S REJECTION OF ANY PROPOSAL, REGARDLESS OF ANY RELIANCE BY BIDDERS ON ANY COMMUNICATION RECEIVED FROM PACIFICORP OR ANY OTHER REASON, UNDER ANY LEGAL THEORY OR PRINCIPLE OF EQUITY.**

F. BID NUMBERING AND FILE NAMING CONVENTION

Bid numbers will be self-assigned by bidders in accordance with the directives below. There is no limit to the number of bids that may be submitted, subject to having paid the applicable bid submission initial fee(s) and bid fee – independent energy performance report evaluation,) in accordance with Section 3.E Bid Submission Fees.



Different bids must be expressed as a whole number, beginning with the number 1. Each subsequent bid will have a separate sequential bid number (i.e., 2, 3, etc.). Each bid will have a corresponding bid number which must be used to identify a corresponding **Appendix C-2 – Bid Summary and Pricing Input Sheet**. For example, the first bid will be identified as “1” and subsequent bids will be identified as “2”.

File names must be kept short by using abbreviations wherever possible. All required documents must use the following naming convention:

[abbreviated bidder name]_[bid number]_[abbreviated_file_description]

G. MINIMUM ELIGIBILITY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of PacifiCorp, as determined in PacifiCorp’s sole discretion. If bids do not comply with these requirements, PacifiCorp has the option to deem the bid non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its bid include, but are not limited to:

1. Receipt of any bid after the bid submittal deadline.
2. Failure to submit the required bid submission initial fee and bid fee – independent energy performance report evaluation when due.
3. Failure to meet the requirements described in this RFP and provide all information requested in **Appendix C-2 – Bid Summary and Pricing Input Sheet** of this RFP.
4. For RPS-eligible resources, failure to receive RPS Certification within 90 days of COD and maintain RPS Certification throughout the duration of any agreement with PacifiCorp.
5. Bids for ineligible resources. Only bids for resources specified in Section 1.A Purpose and Scope of RFP will be accepted. All submissions must conform to the documentation in **Appendix A – Technical Specifications and Required Submittals**.
6. Failure to adequately demonstrate the viability of and a commitment to GCOD on or before December 31, 2029.
7. Failure to execute **Appendix G-1 – Confidentiality Agreement** and permit disclosure of information contained in the proposal to PacifiCorp’s agents, contractors, regulators, or non-bidding parties to regulatory proceedings consistent with terms of executed confidentiality agreement.
8. Any attempt to influence PacifiCorp in the evaluation of the proposals outside the solicitation process.
9. Failure to provide a firm proposal through the bid validity date outlined in Section 3.D Submission of Bids of this RFP.



10. Failure to disclose the commitment of any portion of the proposed resource to another entity.
11. Failure to disclose the real parties of interest in any submitted proposal.
12. Failure to clearly specify all pricing terms for each proposal.
13. For bids using on-system resources, failure to provide either 1) a completed system impact and/or facilities interconnection study, or 2) confirmation of having passed screens (see Section 1.B Interconnection Requirements), or 3) a signed generation interconnection agreement, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
14. Failure to offer the product delivered to a point of interconnection or point of delivery on PacifiCorp's transmission or distribution system.
15. For any bid that is proposing to interconnect to a third-party transmission system, failure to meet the requirements in Section 1.B Interconnection Requirements.
16. Failure to demonstrate and describe in sufficient detail the bidder's ability to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long-lead time equipment.
17. Failure to demonstrate that the bidder can meet the credit security requirements.
18. Failure to demonstrate that the bidder can meet the scheduled commercial operation date proposed.
19. Failure to submit information required by PacifiCorp to evaluate the proposal.
20. A determination by PacifiCorp that collusive bidding or any other anticompetitive behavior has occurred.
21. The bidder, or facility proposed in the bid is involved in bankruptcy proceedings.
22. Failure of the authorized officer of the bidder to sign the proposal cover letter as required in this document and without edits.
23. Any change in law or regulatory requirements that make the bidder's proposal non-conforming.
24. Failure to provide the resource performance estimate information as described in Section 5.B Facility Performance Estimate Information of the RFP.
25. Failure to provide a performance report and model output including hourly output values as identified in **Appendix C-3 – Energy Performance Report**.
26. Failure to provide **Appendix D – Bidder's Credit Information**.



27. Bid submission that includes a requirement that PacifiCorp provide credit assurances.
28. Failure to provide documentation of binding, exclusive site control for the applicable facility(ies).¹²
29. Bid submission with a facility(ies) description that is inconsistent with the facility(ies) description in existing interconnection study and/or executed generator interconnection agreement. In the event changes have been made to the proposed facility bid as compared to what is described in the current interconnection documentation, Bidder will need to provide documentation from interconnection provider that a material modification or interconnection restudy is not required that could materially impact the facility costs or estimated in-service date.
30. With respect to Oregon-sited resources, failure to agree to provide attestations or Project Labor Agreements as specified by ORS 469A.210 and in provisions in the pro forma contract agreements.
31. Failure to agree to track and report to PacifiCorp the bidder's use of diverse businesses.
32. Failure to comply with co-location/proximity requirements where the nameplate capacity rating of multiple resource bids, in the aggregate, exceeds the 80 megawatts threshold in OAR 860-089-0100(1)(c).
33. For bids representing generation co-located with storage, failure to: demonstrate the storage facility's ability to allow PacifiCorp to dispatch and charge the storage facility from the grid; and failure to provide adequate plans for (a) recycling all battery energy storage equipment, to the extent required to be in compliance with applicable laws and prudent practices, (b) fire protection with respect to the storage facility and (c) emergency response, in compliance with all applicable requirements of law and in accordance with prudent electrical practices.

SECTION 4. RFP CONTENT AND SUBMITTAL INSTRUCTIONS

A. ALL PROPOSALS

This section outlines the content and format requirements for all proposals. Bids that do not include the information requested as described in this section may, at the sole discretion of PacifiCorp, be deemed ineligible for further evaluation if the bidder does not provide information within two (2) business days of a request by PacifiCorp. PacifiCorp may deem information not relevant as determined by PacifiCorp in its sole discretion. All sections must be complete and in compliance with the RFP Section 3 General Information and Logistics for the bid to be accepted.

¹² Site control for the 2025 OR SITUS RFP requires a definitive, exclusive and binding lease or purchase agreement or option agreement.



B. GENERAL ORGANIZATION OF THE BID SUBMITTAL

Appendix B-2 – Bid Proposal Instructions and Required Information outlines the proposal instructions and requirements for submitting a bid. Each item listed in the appendix document is required unless it is specified as optional. Bids that are missing any of the required submittals identified in Appendix B-2 may be deemed ineligible for this RFP.

C. PPA AND ESA PROPOSALS

For new or existing generating and or storage facilities, PacifiCorp will consider transaction structures whereby the bidder develops the facility, assumes responsibility for construction and sells the power (and non-power attributes) and or storage services to PacifiCorp on a long-term basis, pursuant to the terms of a standard-form PPA or ESA, which will include certain performance guarantees. The bidder will be responsible for all aspects of the development and construction of the facility, including, but not limited to, permitting, engineering, procurement, construction, interconnection and long-term asset management and operational costs. Without limiting the foregoing, the bidder will be responsible for obtaining all permits, rights and resources required to construct and operate the generation facility consistent with the bidder's proposal.

Bidders must demonstrate the facility's interconnection studies and interconnection agreement are consistent with the proposed renewable resource equipment, capacity, configuration, and that the interconnection agreement scheduled commercial operation date is aligned with the bid's scheduled commercial operation date, and that no material modification¹³ or interconnection restudy will be required. PacifiCorp will consider bids where the interconnection study reflects a commercial operation date (COD) before the end of 2029, even if the COD proposed in the bid is not exactly aligned. In such cases, PacifiCorp will consult with PacifiCorp Transmission to determine whether the interconnection study adequately supports the interconnection needs of the proposed resource. However, to ensure compliance with House Bill 2021, both the COD reflected in the interconnection study and the COD proposed in the bid must fall before the end of 2029.

If a proposed resource intends to interconnect to a third-party transmission system, the bidder will be responsible under the PPA or ESA to arrange and maintain long-term firm point-to-point transmission service or Bonneville Power Administration's conditional firm bridge transmission service to deliver the full output of the PPA or ESA to a designated point of delivery on PacifiCorp's transmission or distribution system. Bidders must clearly articulate the point of delivery in their bid and include any and all third-party transmission service costs in their PPA or ESA price (see Section 3.G of Minimum Eligibility Requirements for Bidders).

The bidder's proposal must be priced to the standard-form pro forma documents supplied in **Appendix E-1 – PPA for Generation Only, Appendix E-2 – PPA for Generation with Storage, and Appendix E-3 – Energy Storage Agreement** as applicable. Note that the pro

¹³ As defined in PacifiCorp Transmission's Open Access Transmission Tariff (OATT).



forma agreements are tailored for new facilities and specific technologies; conforming changes may be required by PacifiCorp for existing facilities or other types of facilities.

Bidders are required to provide an issues list ("Issues List") and redlines to PacifiCorp and the IE by the date of bid submittal. In accordance with OAR 860-089-0250(3)(d), PacifiCorp will engage in contract negotiations that are mutually agreeable with bidders that make the final shortlist.

SECTION 5. RESOURCE INFORMATION

A. BID SUMMARY AND PRICING INPUTS

Bidders must review and follow the instructions in **Appendix B-2 Bid Proposal Instructions and Required Information**, **Appendix C-1 – Bid Summary and Pricing Input Sheet Instructions** and **Appendix C-2 – Bid Summary and Pricing Input Sheet**. Appendix C-2 is an Excel-based workbook that covers bid summary information, energy production profile, and pricing requirements.

B. RESOURCE PERFORMANCE ESTIMATE INFORMATION

Bidders are required to provide a facility performance estimate prepared by a third-party expert. PacifiCorp may accept an in-house energy performance report contingent upon PacifiCorp being able to replicate the results. The 8,760 hourly profile in **Appendix C-2 – Bid Summary and Pricing Input Sheet** is expected to be consistent with or supported by the bidder's provided facility performance estimate as part of Appendix C-3 referenced below.

Appendix C-3 – Energy Performance Report provides detailed directions for resource performance information by resource type.

C. DIRECT INTERCONNECTION TO PACIFICORP'S SYSTEM (ON SYSTEM BIDS)

All bidders are required to have met the interconnection requirements described in Section 1.B Interconnection Requirements. Any completed PacifiCorp Transmission interconnection study is to be included in **Appendix A-2 – Interconnection Studies and Agreements**. Off-system bidder requirements for interconnections are discussed in Section 5.D Transmission Service For Delivery to PacifiCorp's System (Off-System Bids) below. PacifiCorp will review the bidder's interconnection documentation to confirm it aligns with the bidder's submitted bid.

Bidders must document in their bid and otherwise provide all estimated interconnection costs identified in their interconnection studies and agreements, including direct assigned and network upgrade costs. Bid prices will include any estimated direct-assigned interconnection costs but will exclude the estimated network upgrades costs. Although the network upgrade costs are not to be included in the bid price, the network upgrade costs will be provided to PacifiCorp and included in the utility's valuation models.



D. TRANSMISSION SERVICE FOR DELIVERY TO PACIFICORP'S SYSTEM (OFF-SYSTEM BIDS)

Any off-system bid must, in addition to meeting the interconnection requirements described in Section 1.B Interconnection Requirements, meet all of the minimum eligibility requirement, including requirement #14 in Section 3.G Minimum Eligibility Requirements for Bidders. The off-system bid must reasonably demonstrate that the full proposed output of the resource, as identified in the bid, can be delivered by December 31, 2029.

Off-system bidders are responsible for any current or future third-party tariff requirements or tariff changes related to, but not limited to, any of the following: interconnection, variable energy resource, electric losses, reserves, transmission, integration, imbalance, scheduling, and ancillary service arrangements required to deliver to the bidder's selected point of delivery on PacifiCorp's transmission or distribution system. These costs will not be included in the evaluation of PPA proposals as they are assumed to be the responsibility of the bidder.

Off-system bidders must include in submitted bid prices all interconnection costs from the third-party interconnection provider, whether from a study or a signed interconnection agreement. Off-system bidders must also include in their bid price the estimated costs for all third-party transmission service.

In the event an off-system bid is awarded an agreement, such agreement will include appropriate provisions reflecting the bidder's obligation to timely arrange and maintain the necessary third-party, long-term firm, transmission service or Bonneville Power Administration's conditional firm bridge transmission service, facilitating delivery of the full output of the resource to the identified point of delivery, including associated events of default for failure to comply with such requirements.

E. PACIFICORP NETWORK TRANSMISSION SERVICE

PacifiCorp will request Designated Network Resource (DNR) service to serve PacifiCorp network load once a definitive agreement is fully executed.

F. TAX CREDITS AND/OR FACILITY INCENTIVES

Bidders bear all risks, financial and otherwise, associated with their or their facilities' eligibility to receive any state or federal energy tax credits, sales tax waivers or exemptions, payment in lieu of tax, or any other identified tax- or accounting-related, incentive, or benefit, including in the event of a change in tax law. The obligations of a bidder to perform under any executed agreement at the bid pricing resulting from this solicitation remain effective and binding regardless of whether a bidder or facility is eligible for or receives tax credits or other tax- or accounting-related incentives or benefits. Bidders must explain in their submitted **Appendix B-2 Bid Proposal Instructions and Required Information** whether a bid is dependent upon Production Tax Credits (PTC) or Investment Tax Credits (ITC).



G. ACCOUNTING

All proposals will be assessed for appropriate accounting and tax treatment. Bidders must supply all information reasonably required to make these assessments if a facility is selected to the final shortlist. According to Generally Accepted Accounting Principles, PacifiCorp will establish and maintain accounts for the revenue, expenses, assets, liabilities and owners' equity associated with all resource facilities acquired through this RFP and will ensure that all revenues and all expenses associated with the management and ownership of the resource(s) are properly recorded to these accounts. This will include expenses associated with work performed by PacifiCorp personnel. Additionally, PacifiCorp will account for the power costs associated with the resource(s) in a separate account(s).

SECTION 6. BID EVALUATION AND SELECTION

A. OVERVIEW OF THE EVALUATION PROCESS

PacifiCorp's bid evaluation and selection process is designed to identify the combination and amount of new resources that will maximize customer benefits through the selection of bids that will satisfy projected capacity and energy needs while maintaining reliability. The method for evaluating resources will be transparent, fair, and consistent with how market bids are evaluated with additional oversight by the IE.

The 2025 IRP selected individual resources and optimized a preferred portfolio from a list of generic "proxy" resources to reliably meet PacifiCorp's energy and capacity needs across its six-state service territory. The PLEXOS portfolio optimization model that PacifiCorp will use to evaluate the 2025 OR Situs RFP bids was also used to develop PacifiCorp's 2025 IRP. PacifiCorp uses PLEXOS to serve as a decision support tool that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost.

At a high level, the 2025 OR Situs RFP evaluation process involves, among other considerations:

1. Bid screening based on minimum eligibility requirements.
2. Identification of interconnection network upgrades.
3. Validation of bidder's generation profile.
4. Non-Price Scoring based on **Appendix P – Non-Price Scoring Questionnaire**.
5. Price Scoring:
 - a. Bid preparation for input into PLEXOS.
 - b. PLEXOS modeling, including bid selection, portfolio optimization, reliability testing, price-policy scenario analysis, stochastic risk analysis and price scoring.
6. Combination of price and non-price scoring and ranking of preferred resources:
 - a. Price Scoring - Weighted eighty (80) percent based on the net cost of the bid; i.e., highest benefit or lowest cost.



- b. Non-Price Scoring – Weighted twenty (20) percent

- 7. Final shortlist of proposals for pursuing contract negotiation.

Additional details regarding the 2025 OR Situs RFP evaluation process and cost-ranking methodology is provided below.

Methodology for scoring bids using Bonneville Power Administration's conditional firm bridge transmission service is provided in Appendix R – Bid Scoring Modeling.

B. BID ELIGIBILITY: MINIMUM ELIGIBILITY REQUIREMENTS

Upon receipt all bids will undergo screening to assess compliance with the minimum requirements and overall conformance with the RFP. After IE review and consultation, non-conforming bids will be notified and given five (5) business days to correct the deficiencies. Failure to do so may result in removal from further consideration.

C. EVALUATION OF BIDDER'S ENERGY PERFORMANCE REPORT

An independently prepared evaluation of bidder's energy performance report will be produced for each bid.

D. NON-PRICE SCORING

Eligible bids will be evaluated based on responses to the **Appendix P - Non-Price Scoring Questionnaire**.

PacifiCorp confirms that the non-price scoring is compliant with OAR 860-089-0400(2), non-price factors. Non-price scores primarily relate to resource characteristics identified in the Company's most recent acknowledged IRP Action Plan and reflect standard form contracts. Non-price score criteria that seek to identify minimum thresholds for a successful bid have been converted into minimum bidder requirements.

E. PRICE SCORING

- a. Bid Preparation into PLEXOS and Resource Shaping

All eligible bid resources will be prepared and uploaded into PLEXOS. PacifiCorp uses its proprietary Excel models to process bid costs for input to PLEXOS modeling with oversight by the IE.

Consistent with the treatment of capital revenue requirement in PacifiCorp's IRP modeling, PacifiCorp will convert any calculated revenue requirement associated with capital costs, as applicable (i.e., return on investment, return of investment, and taxes) to first-year-real-levelized costs. Consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling, all other bid costs will be summarized in nominal dollars and formatted for input into the bid evaluation models.



PacifiCorp's proprietary Excel model will calculate the delivered revenue requirement cost of each eligible bid, inclusive of any applicable carrying cost and net of tax credit benefits, all operations and maintenance expenses, property taxes, generation taxes, direct assigned interconnection costs and PacifiCorp Transmission estimated network upgrade costs, as applicable. In developing the delivered cost for each bid, PacifiCorp requires certain cost data as inputs to the bid preparation model.

Summary of Cost Components for a PPA

- i. PPA Price Schedule
- ii. Storage Costs (monthly capacity payment)
- iii. Network Upgrade Revenue Requirements

Any internal assumptions for key financial inputs (i.e., inflation, discount rates, marginal tax rates, asset lives, AFUDC rates, etc.) and PacifiCorp carrying costs (i.e., integration costs, owner's costs, etc.) will be applied consistently to all bids, as applicable, and reviewed by the IE prior to finalizing the bid preparation model for PLEXOS. Bids with different price structures and terms will be normalized prior to uploading into PLEXOS.

Upon bid submittal, PacifiCorp will engage a third-party to evaluate resource performance and degradation schedules. The third-party subject matter expert will provide data for input into the PLEXOS model, consistent with Oregon rule 860-089-0400 5(a).

b. PLEXOS Analysis: Bid Selection and Portfolio Optimization

The bid evaluation team will evaluate the bids using PLEXOS, the same production cost models used in the 2025 IRP. The PLEXOS production cost model will select the optimized portfolio of resources proposed as part of the 2025 OR Situs RFP.

PacifiCorp will summarize for the IE how the bid evaluation models function, and the IE will be provided with the inputs and outputs of PLEXOS model runs used during the evaluation process.

i. Bid Resource Portfolio Development

The PLEXOS model is used to develop an optimized portfolio of resources and candidates for the final shortlist. PacifiCorp uses PLEXOS to develop, test and evaluate the cost of multiple resource portfolios including sensitivities to understand the relative performance of portfolio and resource alternatives under certain conditions.

ii. Reliability Tests

PacifiCorp will perform a reliability assessment to ensure that the selected portfolio of resources can meet all hourly load and operating reserve requirements with sufficient margin ¹⁴ to account for other system uncertainties such as non-normal weather events. If incremental flexible resource capacity be required to maintain system reliability, the shortfall will be provided to the model to ensure it selects sufficient capacity to achieve the targeted reliability requirements.

iii. Price Policy Scenarios and Risk Analysis

PacifiCorp evaluates portfolios under a range of different environmental policy and market price scenarios (policy-price scenarios). ¹⁵ PLEXOS calculates the stochastic mean present value revenue requirement (PVR) and the risk-adjusted PVR for various policy-price scenarios to help identify whether top-performing portfolios exhibit especially poor performance under the range of scenarios. PacifiCorp summarizes and analyzes the portfolios to identify the specific bid resources that are most consistently selected among the policy-price scenarios.

In this way, PacifiCorp uses PLEXOS to optimize its selection of bid resources to identify the lowest cost, reliable portfolio under multiple scenarios for further consideration as part of the final shortlist process. PacifiCorp may select one or more 2025 OR Situs RFP resource portfolios for further scenario risk analysis.

PacifiCorp uses PLEXOS to test each portfolio and evaluate its ability to perform under dynamic weather and market conditions. PLEXOS measures the stochastic risk of each portfolio through its production cost estimates. By holding a resource portfolio fixed and using simulations of stochastic variables, including load, wholesale electricity and natural gas prices, hydro generation, wind generation, solar generation, and thermal unit outages, PLEXOS can measure the expected cost of each portfolio in an uncertain future.

iv. Price Scoring

PLEXOS will calculate the relative costs and benefits of each resource included in the model for evaluation. The operational characteristics of every bid will be included in the model so that PLEXOS will generate a value stream specific to each bid that will then be used to calculate a price score in accordance with **Appendix R - Bid Scoring and Modeling**.

¹⁴ Consistent with the reserve requirements in the 2025 IRP.

¹⁵ Policy-price scenarios will be conceptually consistent with those used in the 2025 IRP (i.e., alternative environmental policy assumptions among low, medium, and high price scenarios), but updated to reflect PacifiCorp's assessment of the most current information in consultation with the IE.



More information about bid modeling techniques and price scoring, including an example of how the bid scoring will work, may be found in **Appendix R – Bid Scoring and Modeling**.

E. FINAL SCORING AND RANKING TO RECOMMENDED FINAL SHORTLIST

Following the PLEXOS analysis to select resources and determine price scores for each of the bids, PacifiCorp will combine the price and non-price scores to generate a total final bid score and ranking for each bid. When calculating scores associated for any bids located in PacifiCorp's PACE balancing area, the capacity contribution for PacifiCorp's PACW balancing area will be reduced to zero, in consultation with the independent evaluator and OPUC Staff, and in accordance with the forthcoming capacity scoring proposal, once the capacity requirements have reached the transmission limit in the peak summer season. Furthermore, as part of the selection of a final shortlist, (a) PacifiCorp will evaluate House Bill 2021 compliance if implications arise from increases of unspecified market purchases that might occur when more PACE-sited resources produce generation that exceeds the available transmission from PACE to PACW, and (b) modeling will assess whether resource supply in or deliverable to PACW are sufficient in supporting PacifiCorp's balancing requirements as part of its California ISO Extended Day-Ahead Market (EDAM) participation.

If the ranked bids are inconsistent with the selected resources and preferred portfolio resulting from the PLEXOS performance optimization models, in coordination with the IE, PacifiCorp will investigate the discrepancy(ies) and may add or remove resources and run additional iterations of PLEXOS including, but not limited to, reliability tests and price-policy scenarios.

PacifiCorp will hold regular meetings with the IE both in the preparation process for preparing model inputs and analyses and after proposals are received during the evaluation and selection process. Before establishing a final shortlist, the IE will be provided with all bid preparation files and all of the PLEXOS outputs in order to evaluate the scoring and selection process. PacifiCorp may take into consideration, in consultation with the IE, other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.¹⁶

PacifiCorp will summarize and evaluate the results of its scenario risk analysis, considering PVRR results, to identify the specific least-cost, least-risk bids in combination with non-price scores. Based on these data and certain other factors as described above, and in consultation with the IE, PacifiCorp may establish a final shortlist.

After the final shortlist is established, PacifiCorp will engage with the selected bidders to initiate negotiation of their contract and prepare the contract for execution. Selection of a bid to the final shortlist does not constitute a winning bid. Only execution of a definitive

¹⁶ OAR 860-089-0400.



agreement between PacifiCorp and the bidder, on terms acceptable to PacifiCorp, in its sole and absolute discretion, will constitute a winning bid proposal.

Pursuant to Oregon Public Utility Commission order 25-343 in docket no. UM 2383, PacifiCorp acknowledges that capacity is to be scored system wide. A system wide scoring methodology is still being developed and will be supplemented after further coordination with Oregon Public Utility Staff and the Independent Evaluator.

In accordance with the Oregon Public Utility Commission's order no. 25-343 in docket No UM 2383, before the shortlist is finalized for PacifiCorp's Washington RFP, PacifiCorp will confer with the IE to determine and discuss any on-ramps to allow for Oregon to potentially participate in resources shortlisted for Washington that were also bid into the Oregon RFP.

SECTION 7. AWARDING OF CONTRACTS

A. INVITATION

This RFP presents only an opportunity for bidders to make proposals to PacifiCorp. No proposal is itself a binding contract except to the extent the parties execute a definitive agreement with complete documentation providing otherwise.

PacifiCorp may in its sole discretion do any one or more of the following:

1. Determine which proposals are eligible for consideration in response to this RFP.
2. Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each bidder.
3. Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
4. Negotiate with bidders to amend any proposal.
5. Select and enter into agreements with the bidders who, in PacifiCorp's sole judgment, submit proposals that best satisfy the interests of PacifiCorp and its customers. In exercising its sole judgment, PacifiCorp may consider factors other than price.
6. Waive any irregularity or informality on any proposal to the extent not prohibited by law.
7. Reject any or all proposals in whole or in part at any point in time, including proposals that are on the shortlist.
8. Vary any timetable.
9. Conduct any briefing session or further RFP process on any terms and conditions.
10. Withdraw any invitation to submit a response.



B. BASIS OF REJECTION

Proposals may be rejected for any reason including but not limited to not meeting the minimum eligibility requirements identified in Section 3.G Minimum Eligibility Requirements for Bidders of this RFP.

C. NON-RELIANCE LETTER

All parties will be required to sign **Appendix G-2 – Non-Reliance Letter** if they qualify for the final shortlist.

D. POST-BID NEGOTIATION

PacifiCorp will seek to enter into a final agreement with each bidder on the final shortlist. PacifiCorp will include in its final evaluation prior to contract execution any factor that may impact the total cost of a facility and associated risks, including but not limited to all the factors used in the final shortlist cost analysis plus consideration of the terms of the final agreement and accounting treatment and potential effects due to rating agency treatment, if applicable.

SECTION 8. SECOND PHASE OF RFP

In accordance with the Oregon Public Utility Commission's order 25-343 in docket no. UM 2383, PacifiCorp will issue to market a second phase of this RFP, anticipated in 2026, which would occur after the conclusion, and contracts are executed, for the first phase of this RFP. Order No. 25-343 provides clarification that "a second phase of the RFP [should be] timed to take advantage of additional clarity on the connection between Longhorn substation and PACW, or any other way PacifiCorp connects the Boardman to Hemingway transmission project to PACW."

A second phase will comply with order 25-343, by allowing on system bidders that obtain a completed Facilities Study or Generator Interconnection Agreement, and by allowing off system bidders that may be able to progress through the interconnection and transmission service request process with a third party utility. The intent of the second phase is to provide a known entry for potential bidders that are currently in an existing PacifiCorp Cluster Study, and projects that seek to interconnect and deliver over a third party utility, contingent on a transmission project or study that will allow delivery to PacifiCorp West, including the Boardman to Hemingway transmission project.

When PacifiCorp is prepared to issue a second phase of the RFP, PacifiCorp will provide notice via the PacifiCorp website and email notification list. To be added to the notification distribution list, email 2025ORSitusRFP@pacificorp.com. Furthermore, PacifiCorp will provide notice to the Oregon Public Utility Commission by making a filing in UM 2383 following the current request for proposals, or as soon as PacifiCorp is aware of opportunities for additional interconnection and transmission service. PacifiCorp's



understanding is that it would need to seek approval of the second phase of the RFP prior to market issuance, by the Oregon Public Utilities Commission, pursuant to per OAR Chapter 860-089.

PACIFICORP HAS NO OBLIGATION TO ENTER INTO ANY AGREEMENT WITH ANY BIDDER TO THIS RFP AND PACIFICORP MAY TERMINATE OR MODIFY THIS RFP AT ANY TIME WITHOUT LIABILITY OR OBLIGATION TO ANY BIDDER. IN ADDITION, THIS RFP DOES NOT IN ANY WAY PREVENT PACIFICORP FROM ENTERING INTO ANY AGREEMENT THAT PACIFICORP DEEMS PRUDENT, IN PACIFICORP'S SOLE DISCRETION, AT ANY TIME BEFORE, DURING, OR AFTER THIS RFP PROCESS IS COMPLETE. FINALLY, PACIFICORP RESERVES THE RIGHT TO NEGOTIATE ONLY WITH THOSE ENTITIES THAT PROPOSE TRANSACTIONS THAT PACIFICORP BELIEVES IN ITS SOLE DISCRETION HAVE A REASONABLE LIKELIHOOD OF BEING EXECUTED.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-110:
PacifiCorp 2024 URC RFP

2024 Utah Renewable Communities

Request for Proposals

“2024 URC RFP”

Program Renewable Resources

ISSUED: 5/22/2025

DUE DATE: 7/10/2025

2024 URC RFP Responses:

**Energy Strategies, LLC
111 East Broadway, Suite 1200
Salt Lake City, Utah 84111
www.URC2024RFP.com**

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Each of the Appendices referenced above are available at www.URC2024RFP.com. The 2024 URC RFP is utilizing Appendices from the PacifiCorp 2022 AS RFP to streamline the process for bidders that participated in the PacifiCorp 2022 AS RFP and to ensure that the Communities and PacifiCorp receive all of the information necessary for the Communities to evaluate and score the bids and for PacifiCorp to utilize in contracting.

However, the following appendices that were included in the PacifiCorp 2022 AS RFP are intentionally omitted from this solicitation:

- Appendix B-1 series: Notice of Intent to Bid, NOI Excel Spreadsheet, Bid Fee

- Calculator Worksheet
- Appendix E-2.2: Co-located Generating Resource with Energy Storage
- Appendix E-3: Tolling Agreement Documents
- Appendix H-3: PacifiCorp Transmission: Summary of OASIS queue positions
- Appendix L: Non-Price Scoring Matrix
- Appendix M: Role of Independent Evaluator
- Appendix N: PacifiCorp's Organization for RFP Process
- Appendix O: PacifiCorp's Company Alternative (Benchmark Resource)
- Appendix Q series: 2021 Demand Response, all DR appendices
- Appendix R series: Bid Scoring and Modeling, Bid Scoring Example
- Appendix H-1: PacifiCorp IRP Preferred Portfolio Transmission Upgrade Selections (update to reflect 2023 IRP Update)
- Appendix H-2: PacifiCorp IRP Preferred Portfolio Proxy Resource Selections (update to reflect 2023 IRP Update)

The following appendices that were included in the PacifiCorp 2022 AS RFP have been updated for use in this solicitation:

- Appendix A-1.4: BTA Solar Work Specifications (updates to preferred and prohibited vendors)
- Appendix A-1.6: BTA Battery Energy Storage System Technical Specification (updates to preferred and prohibited vendors)

Additionally, the following appendices that were included in the PacifiCorp 2022 AS RFP are included in the URC 2024 RFP but contain substantively different questions, information, conditions, or signatories:

- Appendix B-2: Bid Proposal Instructions and Required Information
- Appendix C-1: Bid Summary and Pricing Input Sheet Instructions (revised)
- Appendix C-2: Bid Summary and Pricing Input Sheet (additional tabs and questions)
- Appendix E-2.1: PPA Documents – Generating Resource Only (additional conditions)
- Appendix F-2: BTA Documents (additional conditions)
- Appendix G-1: Confidentiality Agreement
- Appendix G-2: Non-Reliance Letter
- Appendix S: Cyber Security Requirements

Finally, one additional appendix that was not included in the PacifiCorp 2022 AS RFP has been added for use in this solicitation:

- Appendix W: Payment Instructions

As noted herein, the Communities are solely responsible for the administration of the 2024 URC RFP. PacifiCorp dba Rocky Mountain Power (Company) is not administering the 2024 URC RFP and the use of the PacifiCorp 2022 AS RFP is a convenience to the Communities, to Company, and to the bidders and does not signify any greater involvement from PacifiCorp than is described herein.

SECTION 1. INTRODUCTION

This 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP), is administered by the Community Renewable Energy Agency (Agency)¹ on behalf of customers that participate in the Community Clean Energy Program (Program).² The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The resources must meet the criteria developed by the Agency in conjunction with Company and set forth in this RFP. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code §§ 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

Proposals must demonstrate to the Agency's satisfaction, and as determined in its sole discretion, that the proposed project(s) can successfully interconnect and achieve commercial operation within the timeframe listed in Section 2. The Agency is not bound to accept any bids and may cancel this solicitation at any time and at their own discretion.

Bids must be for new generation capacity not located behind any load served by a utility or net-metered, and each project must be individually metered and remotely monitored. The project bid may be for the partial output of new generation capacity so long as all other contracted output is for customers in Rocky Mountain Power's service territory. The minimum discrete project size is 2.0 MW AC and the maximum is 300.0 MW AC, and the Agency is seeking a project or projects to meet 600,000 MWhs of average annual forecasted demand for customers participating in the Program (Participating Customers) in the project(s)' first full calendar year of operation.

The Agency will accept proposals for generation from new wind, photovoltaic (PV) solar, geothermal, or hydroelectric resource projects capable of directly interconnecting with Company's network transmission system. These resources are required to self-provide ancillary services to the grid and may be subject to curtailment to ensure sufficient self-provided ancillary service. Other resource types may be considered as required by the Commission so long as they meet the other requirements of this solicitation.

Each bid **must** include the Base Bid as described below. It may optionally include up to two add-ons and two variants, also described below.

The required "Base Bid" shall include the fixed price (in dollars per Megawatt-hour or \$/MWh) at which the bidder proposes to sell all energy generated by the project to Company over a twenty-five (25) year term. This fixed price shall also include any and all environmental attributes associated with all energy generated, which will be transferred to and exclusively owned by the Agency on behalf of Participating Customers.³ The Base Bid may not combine generation resource types and is required of all bidders.

¹ The public-facing name of the Agency is the Utah Renewable Communities (URC).

² Additional information regarding the Agency, its formation and decision-making authority, is set forth in Section 3 below.

³ "Environmental Attributes" will be a defined term in the pro forma transaction documents for this RFP.

In addition to the Base Bid, the bidder may optionally include the following two add-ons:

1. A “Storage Add-On” option specifying the price to co-locate storage with the generating resource, priced in dollars per kilowatt-month for a twenty-five (25) year term. The Storage Add-On may or may not be evaluated by the Agency for scoring purposes but may feature in contract negotiations. Should the Agency select a bid with a Storage Add-On for contract negotiation, parties will discuss whether to address the storage component with a combined generation and storage agreement (using Appendix E-2.2 from PacifiCorp’s 2022 All-Source RFP as a starting point) or with a separate tolling agreement (using Appendix E-3 from PacifiCorp’s 2022 All-Source RFP as a starting point).
2. A “Post-PPA Sale Add-On” option priced in dollars whereby the bidder proposes to sell its project rights to Company at the conclusion of the twenty-five (25) year PPA term. The Post-PPA Sale Add-On will not be evaluated by the Agency for scoring purposes but may feature in contract negotiations.

In addition to the Base Bid, the bidder may optionally include the following two bid variants:

1. A “Twenty Year Bid Variant” PPA option specifying a fixed priced (in \$ per MWh) at which the bidder proposes to sell all energy generated by the project to Company over a twenty (20) year term that meets the other requirements of the Base Bid. The Twenty Year Bid Variant will not be evaluated by the Agency for scoring purposes but may feature in contract negotiations.
2. A “BTA Bid Variant” option priced in dollars whereby the bidder develops the generation project, assumes responsibility for construction and ultimately transfers the operating asset to Company prior to the Commercial Operation Date (COD), all pursuant to the terms of a build transfer agreement (BTA). Bidder is responsible for all development, design⁴, generation equipment supply, balance of plant (BOP) equipment, construction, commissioning, and performance testing. A bidder that elects to submit the optional BTA Bid Variant must submit a price for the generation resource and may also submit a price for the generation resource plus co-located storage. These BTA prices will not be evaluated by the Agency for scoring purposes but if a Base Bid selected for contract negotiation by the Agency also includes the optional BTA Bid Variant, then Company may elect to pursue the BTA Bid Variant.

The Agency reserves the right to reject non-compliant bids. Only the Base Bid will be evaluated for Phase 2 evaluation. The Agency may elect to select a Base Bid with optional Storage Add-On for Phase 3 evaluation. During the negotiation phase described in Section 7(D), below, the Agency reserves the right to use the bid pricing to propose an equivalent

⁴ The resource design must comply with Company’s pro forma technical specification as identified in RFP Appendices.

two-phase PPA price, with a higher fixed price in the first 1-5 years and a commensurately lower fixed price for the remaining years during contract negotiations.

Importantly, a PPA signed by Company to serve a Program under the Act may contain additional conditions precedent to become effective. If a bid's price exceeds its modeled financial benefit, resulting in a net-cost, then the Program will likely need to provide a reserve fund covering a substantial share of this net-cost before the PPA can become effective. For this reason, the Phase 3 price evaluation (described in Section 6) considers both the net-cost of energy (in dollars per Megawatt-hour) and the net-cost of contract (in dollars). Bidders should be advised that, while the net-cost of energy (in dollars per Megawatt-hour) for larger projects (closer to the upper end of the 300 MW cap) may be superior to smaller projects, the net-cost of contract (in dollars) for larger projects may be inferior to smaller projects because of the reserve fund requirement described above.

While not currently reflected in **Appendix E-2.1 Power Purchase Agreement**, the Agency and PacifiCorp are exploring other potential security mechanisms for the program that may impact Appendix E-2.1, including termination provisions, should the Agency and PacifiCorp come to an agreement on a working mechanism.

For bids selected by the Agency for contract negotiation, the Agency may specify a share of the project's generation that may be separately contracted by a large energy user within Company's service territory.

Company and Agency may request from bidder (1) financial statements and/or (2) documentation from an independent engineer that supports the economic useful life of the underlying asset. Please see Section 4.C for more information related to Variable Interest Entity (VIE) accounting and tax ownership.

Pursuant to the Act and associated Commission rules, Company is required to obtain Commission approval prior to entering into any PPA or BTA selected in connection with this RFP, and execution of any such BTA or PPA is contingent on Company receiving such approval.

The Agency is not required to utilize an independent evaluator (IE) in conducting the RFP.

SECTION 2. PROCEDURAL ITEMS

Bids will be evaluated based on the following:

- Cost to Participating Customers.
- Project location.
- Project size.
- Project readiness, including site control, development status (including status for all permits), developer's experience, and demonstration that the project's commercial operation date will be achieved between January 1, 2026 and December 31, 2029.
- Transmission access and interconnection status in conformance with the 2024 URC RFP requirements outlined in Section 5.B. Direct Interconnection.

- Bidder must include Base Bid PPA pricing as described above.
- Exceptions to the pro forma PPA and BTA terms as represented in **Appendix E-2 and Appendix F-2** respectively. Note that any bids that include exceptions that significantly alter the structure of the pro forma Build-Transfer Agreement as described in Section 4.B of this RFP may be rejected as non-compliant without regard to any other evaluation factors.
- Compliance with and verification of major equipment availability defined in **Appendix A – Technical Specification**, and as outlined in **Appendices A-1 through A-10** for each type of renewable technology.
- Ability to provide acceptable credit security for the bidder's proposed obligation and conformance to the pro forma agreements attached as **Appendices E-2 and F-2** to this RFP.

Each proposal will be prepared at the sole cost and expense of the bidder and with the express understanding that there will be no claims whatsoever for reimbursement from Company or the Agency. Neither the Agency nor Company is liable for any costs incurred by bidders in responding to this RFP, and bidder shall not be entitled to recover any damages arising out of or relating to the Agency's rejection of any proposal, or bidder's reliance upon any communication received from the Agency or from Company, for any reason. Bidder shall bear all costs, expenses, and bidder fees of any response to the Agency in connection with its proposal for the 2024 URC RFP, including providing additional information, the bidder fee, and bidder's own expenses in negotiating and reviewing any documentation. Bid fees are non-refundable in all circumstances, including in the event that no bids are selected or if the 2024 URC RFP is terminated. Additionally, winning bidder(s) may be required to provide a bidder success fee in the event bidder fees do not cover RFP administration and evaluation costs.

Appendix E-1 – PPA Instructions to bidder provides additional detail on preparation of bid document deliverables.

All proposals belong to the Agency and will not be returned. Confidentiality agreements and mutual nondisclosure agreements (NDAs) will be executed with Initial Short List projects as part of this RFP. The Agency will use reasonable efforts to protect information clearly and prominently marked as proprietary and confidential on the page it appears, but the Agency reserves the right to release such information to agents or contractors to help evaluate the proposal, as well as to Company, its regulators and non-bidding parties to regulatory proceedings subject to standard protective orders or confidentiality arrangements. The Agency shall not be liable for any damages resulting from any disclosure of such information, howsoever occurring.

Each bidder must submit a non-refundable bid fee as follows:

- for project bids of 10 MW or smaller: \$5,000
- for project bids larger than 10 MW: \$15,000

This bid fee will be required for each separate Base Bid. This bid fee will cover any associated optional add-ons (Storage Add-On, Post-PPA Sale Add-on) so long as the price for generation specified in the Base Bid remains constant. The bid fee will also cover any

associated optional Twenty-Year Bid Variant so long as the only difference from the Base Bid is the price for generation and the contract end date.

All optional bid add-ons and variants may not be evaluated by the Agency for scoring purposes. However, these optional elements may be evaluated by Agency or Company and may feature in contract negotiations.

Should a bid be selected for the Initial Short List for advancement to Phase 3 evaluation, PacifiCorp will require an additional \$12,500 bid analysis fee, payable to PacifiCorp. Any variant upon the original bid will be submitted as a new bid and subject to the full bid fee of \$12,500. The bid fee in support of Phase 3 is non-refundable should negotiations fail to produce an executed power purchase agreement. The bid fee may be partially refundable up to unused amounts of the bid fee total should a bidder successfully complete execution of a power purchase agreement.

SECTION 3. LOGISTICS

A. SCHEDULE (PROVISIONAL)

Milestone	Date
RFP Submitted to UT Public Service Commission for review	11/19/2024
RFP issued to market and Q&A period begins	5/22/2025
Q&A period ends	6/10/2025
RFP Bids Due	7/10/2025
Phase 1: Consultant Completes Bid Eligibility Screening and Begins Phase 2 Evaluation	7/25/2025
Phase 2: Agency Selects Initial Short List	8/18/2025
Phase 3: PacifiCorp Begins Modeling System Benefits	9/2/2025
Phase 3: PacifiCorp Delivers System Benefit Modeling Results to Agency	11/6/2025
Phase 3: System Benefit and Indicative Costs Discussions with Agency Begins	11/21/2025
Phase 3: System Benefit and Indicative Costs Discussions with Agency Ends	12/12/2025
Phase 3: Agency Completes Final Short List (FSL) Evaluation	12/16/2025
Execute Agreements	2/6/2026

The provisional schedule above is subject to change. Actual dates may vary from the provisional schedule for reasons that include, but are not limited to, negotiation time, availability of key personnel, due diligence, the evaluation or negotiation of any issues unique to any bid, bidder, or project, bidder's willingness to agree to forms of agreements desired by Company or the Agency, and actions required by any third parties. The Agency accepts no liability to the extent the actual schedule varies from the indicative schedule. The Agency is not obligated to develop a short list of bidders, to make a final selection, or to initiate or complete negotiations on any transaction.

Bidders should note the condensed schedule and be available for calls and meetings regarding bid submittals and be responsive to questions in a timely manner. The Agency will attempt to complete the bid review and screening as efficiently as possible but may require very short turnaround times on bid clarifications in order to meet the RFP milestones and schedule.

B. SUBMISSION OF QUESTIONS

Interested parties and bidders may submit questions related to this solicitation by the date indicated in Section 3.A., and the Agency will respond in a timely fashion. Pre-bid materials, bidder questions, and responses will be found at the following website: www.URC2024RFP.com.

C. AGENCY AUTHORITY AND RFP ROLES

The Agency was created pursuant to an interlocal cooperation agreement among the following communities, each of which passed a resolution stating a goal of achieving an amount equivalent to 100% of the annual electric energy supply for Participating Customers from renewable energy resources by 2030: Town of Alta, Town of Castle Valley, Coalville City, City of Cottonwood Heights, Emigration Canyon City, Francis City, Grand County, City of Holladay, City of Kearns, Midvale, Millcreek, City of Moab, Oakley City, Ogden City, Park City, Salt Lake City, Salt Lake County, Town of Springdale, and Summit County (Participating Communities). The Agency has authority to take action on behalf of all Participating Communities to implement the Act, including with regard to resource solicitation and resource acquisition in connection with the purposes of the Act. The Agency acts through the Community Renewable Energy Board (Board), made up of individual members of the Participating Communities and with voting and decision-making authority on behalf of the Agency.

This RFP has been developed by the Agency in conjunction with Company, as required by the Act. The Agency has engaged Energy Strategies (“Consultant”) to assist with bid collection, evaluation, and scoring.

Company has no role in administering the RFP or selecting winning project bids. Company is the contracting party to any BTA or PPA that may result from this RFP and, as such, retains certain rights and authority with respect to BTA and PPA structures, and the evaluation of exceptions to the pro forma BTA and PPAs set forth in the appendices hereto. Company will also conduct analysis of bid pricing to determine the net costs and estimate emissions reductions of projects bid into the RFP. If Company submits bids into the RFP, it will maintain separation between the personnel responsible for modeling all bids and those individuals responsible for bidding resources into the RFP.

D. SUBMISSION OF BIDS

Bidders must create a user account and upload electronic documents to the following website: www.URC2024RFP.com

Bidders will receive an automatically-generated receipt email.

Bids will be accepted until 5:00 p.m. Mountain Prevailing Time (MPT) on July 10, 2025 as evidenced by the electronic timestamp recorded by the website document repository.

The Agency will not accept any late proposals.

All bid proposals shall have a bid validity date through 5:00 pm MPT, April 30, 2026.

E. BID EVALUATION FEES

Each bidder must submit a non-refundable bid fee as follows:

- for project bids of 10 MW or smaller: \$5,000
- for project bids larger than 10 MW: \$15,000

This bid fee will be required for each separate Base Bid.

Should a bid be selected for the Initial Short List for advancement to Phase 3 evaluation, Company will require an additional \$12,500 analysis fee, payable to PacifiCorp. Any variations to the original bid will be submitted as a new bid and subject to the full \$12,500 bid fee. The bid fee in support of Phase 3 is non-refundable should negotiations fail to produce an executed power purchase agreement. The bid fee may be partially refundable up to unused amounts of the bid fee total should a bidder successfully complete execution of a power purchase agreement. In addition to the Base Bid, the bidder may optionally include a Storage Add-On, a Post-PPA Sale Add-On, a Twenty-Year Bid Variant, and/or a BTA Bid Variant as described in Section 1, but these options may not be evaluated by the Agency for scoring purposes. However, these optional elements may be evaluated by the Agency and/or Company and feature in contract negotiations.

Proposals must be submitted in the legal name of the respondent who would be bound by any agreement with Company.

Payment of Bid Fees for Phases 1 and 2. Non-refundable Bid Fees shall be paid to the Agency according to the instructions in Appendix W. Bidder shall provide documentation of submitted bid fees, such as a receipt or confirmation number when bid is submitted. The Agency will not refund any bid fees associated with any bid, regardless of the success or failure of that bid, or if the RFP is cancelled.

Payment of Bid Fees for Phase 3. The Bid Fees for Phase 3 shall be paid to PacifiCorp according to the instructions for Phase 3 in Appendix W.

F. MINIMUM ELIGIBILITY REQUIREMENTS FOR BIDDERS

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of the Agency as determined in its sole discretion. If proposals do not comply with these requirements, the Agency has the option

to deem the proposal non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its proposal include, but are not limited to:

1. Receipt of any proposal after the response deadline.
2. Failure to meet the requirements described in this RFP and provide all information requested in **Appendix C – Bid Summary and Pricing Input Sheet** of this RFP.
3. Failure to demonstrate a commercial operation date within the timeframe listed in Section 2.
4. Failure to permit disclosure of information contained in the proposal to the Agency's agents or contractors, to Company or regulators, or non-bidding parties to regulatory proceedings under appropriate confidentiality agreements.
5. Any attempt to influence the Agency, Company, or contractors in the evaluation of the proposals, outside the solicitation process.
6. Failure to provide a firm offer that includes a signed attestation from an officer of the bidder's company through the bid validity date outlined in Section 3.D. of this RFP.
7. Failure to disclose the real parties in interest in the submitted proposal.
8. Failure to clearly specify pricing for a 25-year term.
9. Failure to offer unit contingent (as generated) or system firm capacity and energy, directly interconnected with Company's network transmission system.
10. Failure to provide all estimated interconnection costs and transmission service costs, if applicable, in the bid proposal. Costs estimates shall be performed and provided by the project if a transmission provider study has not been completed or is not available at the time of submittal.
11. Proposal presents unacceptable level of development or technology risk including multiple resource types combined under a single bid.
12. Failure to materially comply with technical specification requirements in **Appendix A**.
13. Failure to submit development and construction milestone documentation that demonstrates a process to adequately acquire or purchase major equipment (i.e., wind turbine generators and related equipment, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries, etc.) and other critical long lead time equipment.
14. Failure to demonstrate, to the Agency's satisfaction, that it can meet the credit security requirements for the resource proposed.
15. Failure to submit information required by the Agency to evaluate the price and non-price factors described herein.
16. Failure to or inability to abide by the applicable safety standards.
17. Bidder submits an unacceptable contract structure, including but not limited to exceptions that significantly alter the structure of the pro forma PPA (**Appendix E-2**) as described in Section 4.B of this RFP.
18. Collusive bidding or any other anticompetitive behavior or conduct exists.
19. Bidder or proposed project being bid is involved in bankruptcy proceedings.
20. Failure of the bidder's authorized officer to sign the proposal.
21. Misrepresentation or failure to abide by Federal Trade Commission Green guidelines.
22. Any change in regulations or regulatory requirements that make the bidder's proposal non-conforming.

23. Any matter impairing the bidder, the specified resource or the generation of power or environmental attributes of the renewable resource.
24. Failure to provide a performance model output including hourly output values as identified in **Appendix A**.
25. Failure to provide **Exhibit D – Bidder’s Credit Information**, and **Appendix C – Form 1 – Pricing Input Sheet**.
26. Bidder’s failure to provide signed **Exhibit G-2 Non-reliance Letter**
27. Any matter impairing bidder, specified resources or the generation of power or non-power attributes therefrom.
28. Failure to provide documentation of site control for the project excluding right-of-way or easements for transmission, roads, or access to the site.
29. Bids containing energy generation types other than wind, PV solar, geothermal, and hydroelectric.
30. Failure of the project to directly interconnect with PacifiCorp’s transmission system
31. Failure to demonstrate that the project has a draft or executed generator interconnection agreement or interconnection study report (cluster study or facilities study) with PacifiCorp showing that the project can reach commercial operation by December 31, 2029.
32. Failure to submit a resume of similar generation projects developed by the bidder or bidder’s parent company that have reached commercial operation within the last five years with an explanation of any discrepancies between the original contractually agreed commercial online date (COD) and the achieved COD.
33. Failure to demonstrate that the bidder or bidder’s parent company has delivered within the last five years a project of the same generation type as the project bid
34. For wind projects, failure to submit one or more years of avian studies.
35. Failure to attain an Interconnection and Project Readiness Score of at least 70%.

If Agency rejects any bid on the grounds that it fails to meet the minimum eligibility requirements above, Agency will notify the bidder and identify the minimum eligibility requirement the bid failed to meet.

G. AGENCY AND COMPANY RESERVATION OF RIGHTS AND DISCLAIMERS

The Agency reserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids, and to terminate or suspend this RFP in whole or in part at any time. Without limiting the foregoing, the Agency reserves the right to reject as non-responsive any or all bid proposals received for failure to meet any requirement of this RFP outlined herein. The Agency further reserves the right without qualification and in its sole discretion to decline to enter into any agreement with any bidder for any reason, including, but not limited to, change in regulations or regulatory requirements that impact Company, and/or any collusive bidding or other anticompetitive behavior or conduct of bidders. Bid fees are non-refundable per Section 3, part E.

Bidders who submit bid proposals do so without recourse against the Agency or Company, its consultants, its individual members, or against any director, officer, employee, agent, the Participating Customers or representative of any of them, for any modification or withdrawal of this RFP, rejection of any bid proposal, failure to enter into an agreement, or for any other reason relating to or arising out of this RFP. Bidders will be required to

execute **Appendix G - Confidentiality Agreement** after the Initial Short List is identified and **Appendix G - Non-Reliance Letter**.

H. ACCOUNTING

All proposals will be assessed by Company for appropriate accounting and tax treatment. Bidders must supply all information Company reasonably requires in order to make these assessments if a project is selected to the Initial Short List. According to Generally Accepted Accounting Principles, Company will establish and maintain accounts for the revenue, expenses, assets, liabilities and owners' equity associated with any and all renewable resources acquired through this solicitation and will ensure that all revenues and all expenses associated with the management and ownership of the resource(s) are properly recorded to these accounts. This will include expenses associated with work performed by Company personnel. Additionally, Company will account for the power costs associated with the resource(s) in a separate account(s).

I. CONFIDENTIALITY

The Agency and its consultant(s) will attempt to maintain the confidentiality of all bids submitted, to the extent consistent with law or regulatory order, as long as such confidentiality does not adversely impact a regulatory proceeding. It is the bidder's responsibility to clearly indicate in its proposal what information it deems to be confidential. Bidders may not mark an entire proposal as confidential, but must mark specific information on individual pages to be confidential in order to receive confidential treatment for that information.

In an effort to maintain the confidentiality of project bid pricing, all bids will be submitted to Consultant via the RFP website for initial scoring and evaluation on behalf of the Agency. Underlying project bid data is not expected to be possessed by any member communities of the Agency. However, because the underlying bids may ultimately be deemed subject to Utah's Government Records Access Management Act (GRAMA), the Agency recommends that every project bid be submitted with a letter asserting a claim of business confidentiality pursuant to Utah Code Section 63G-2-305(2) and in accordance with Utah Code Section 63G-2-309. This letter must contain a description of all information in the bid that the bidder asserts is confidential and a concise statement of reasons supporting the bidder's claim of business confidentiality. The bidder expressly acknowledges that the Agency's consultant may retain information submitted by the bidder in connection with this RFP until June 30, 2026. To the extent bidder receives information from the Agency or its consultants, bidder shall maintain the confidentiality of such information and such information shall not be available to any entity before, during, or after this RFP process unless required by law or regulatory order.

Only those Agency agents or employees who are directly involved in the RFP process or with the need to know for business reasons will be afforded the opportunity to view submitted bids or bidder information.

Bidders should be aware that information supplied by bidders may be requested and supplied during regulatory proceedings, subject to appropriate confidentiality provisions applicable to that particular proceeding. This means that parties to regulatory proceedings

may request and view confidential information. If such a request occurs, the Agency will attempt to prevent such confidential bidder information from being supplied to intervening parties who are also bidders, or who may be providing services to a bidder, but the Agency cannot promise success in that endeavor and accordingly cannot be held liable for any information that it is ordered to be released or that is inadvertently released.

Calculations of net costs provided by Company to Agency are considered confidential by Company and results will not be shared with bidders.

SECTION 4. RFP CONTENT

A. ALL PROPOSALS

Bidders must create a user account and upload electronic documents to the following website: www.URC2024RFP.com

Bids must include all information as described in this solicitation narrative and further detailed in **Appendix B-2: Bid Proposal Instructions and Required Information**, which contains a list of appendices to be completed for the Base Bid, optional add-ons, and optional variants, and describes what information must be included in the written proposal.

B. POWER PURCHASE AGREEMENT

Bids must contain all of the information requested in **Appendix E-1 – PPA Instructions to Bidders**. For the required Base Bid, the term of the PPA shall be twenty-five (25) years with a fixed price in dollars per Megawatt-hour (\$ per MWh).

Appendix C – Bid Summary and Pricing Input Sheet shows the form of pricing information required for the Base Bid PPA structure as well as questions and forms related to the optional bid add-ons and variants. This is an Excel-based worksheet that covers bid summary information, electrical interconnection information, 8760 energy production profile, PV degradation information, and pricing for the PPA.

In the event Company is required to consolidate the entity under variable interest entity (VIE) accounting requirements, the entity will be required to provide the financial statement information to Company throughout the term of the agreement that is necessary to consolidate the entity.

The determination of consolidation under variable interest entity accounting requirements requires a comprehensive evaluation, including an assessment as to who has the ability to direct key economic decisions of the entity and who is required to absorb the gains and losses of the entity. The entity that meets these two requirements is generally considered the primary beneficiary and is required to consolidate the entity if it is considered a variable interest entity and if the contract is a variable interest. Typically, a fixed price per unit contract would indicate that Company does not have a variable interest and does not absorb the gains and losses of the entity. In this case, it is unlikely that the entity would be

consolidated. The Agency reserves the right to request additional information in order to complete its evaluation of tax ownership for VIE accounting requirements if necessary.

Please also refer to Section 5.F of this RFP.

For the purposes of evaluating tax ownership, bidders of longer-term contract offers must be prepared to submit, at Company's request, documentation from an independent engineer that supports the economic useful life of the underlying asset that will be used by the bidder.

The bidder's proposal must contain the information requested in **Appendix E-1 PPA Instructions to bidders**. The bidder must provide documentation and information, representations, and warranties sufficient to assure the Agency and Company that any proposed project will successfully complete construction and achieve full operation within the timeframe listed in Section 2, and that any new resource will be eligible to claim, as applicable, the full or partial federal PTC/ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service.

Bidders are required to include a redlined or marked up version of **Appendix E-2 Power Purchase Agreement** showing exceptions to the terms of the pro forma PPA document, unless they indicate that they will accept the PPA "as-is". Bidders objecting to terms should provide alternate language and context to the objections for the Agency and Company to evaluate the alternate language. Bidders should also submit comments to the pro forma agreement on issues that they have concerns with and identify alternatives to address the issues. Providing a redline is a requirement for eligibility; however substantive comments should also be provided to provide context to the redlined document.

BIDDERS SHOULD BE AWARE THAT, IF THEIR BID IS SELECTED, THE BIDDER WILL BE REQUIRED TO COMPLETE A QUALIFYING REPORTING ENTITY (QRE) SERVICES AGREEMENT AS PART OF THE PPA WHICH ESTABLISHES WREGIS REGISTRATION AND REPORTING OBLIGATIONS FOR PARTIES ONCE THE RESOURCE IS IN COMMERCIAL OPERATION.

C. BUILD TRANSFER AGREEMENT

Each bid may opt to include a BTA Bid Variant that includes a "Build-Transfer" transaction whereby the bidder develops the project, assumes full responsibility for construction and commissioning of the project, transfers title to the project, potentially in stages, to Company prior to mechanical completion and thereafter completes construction and commissioning of the project, all pursuant to the terms of the build transfer agreement ("BTA"). Bids including such BTA Bid Variant proposals shall provide the following information.

Appendix C – Bid Summary and Pricing Input Sheet shows the form of project information required for a "Build-Transfer" transaction. This is an Excel-based worksheet that covers bid summary information, electrical interconnection information, 8760 energy production profile, PV degradation information, and pricing and other cost assumption inputs for the BTA. The bidder's proposal must contain the information requested in **Appendix F-1 – BTA Instructions to Bidders**. The bidder must provide information, representations, and warranties sufficient to assure the Agency and Company that any

proposed project will successfully complete construction and achieve full commercial operation within the timeframe listed in Section 2. The bidder must also provide evidence that any new resource will be eligible to claim, as applicable, the full or partial federal PTC/ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service. Under the BTA, the bidder will assume full responsibility for the loss of any PTC/ITC, including due to failure to achieve full commercial operation within the timeframe listed in Section 2 or to satisfy applicable guidelines and rules of the Internal Revenue Service.

The BTA pro forma documents are attached as **Appendix F-2 – Build Transfer Agreement (BTA)**. Bidders should include a redlined or marked up version of **Appendix F-2 Build Transfer Agreement** showing exceptions to the terms of the pro forma BTA document. Bidders objecting to terms should provide alternate language and context to the objections for the Agency and Company to evaluate the alternate language. **Any exceptions that represent significant modifications to the pro forma BTA may result in rejection of the bid as non-compliant. The Agency will reject as non-compliant any bid which proposes to transfer to Company the stock or membership interest (as opposed to assets) of one or more companies which own the project.**

The BTA is structured such that Company makes progress payments on an agreed-upon schedule in exchange for the developer meeting certain milestones and deliverables. All bidders in this category must complete the information requested in **Appendix C – Bid Summary and Pricing Input Sheet** (BTA tabs). The Agency will only accept BTA proposals in which Company purchases the project prior to “mechanical completion” (as further specified in the BTA) and the bidder retains full responsibility to complete construction and commissioning of the project thereafter through commercial operation.

The bidder will be responsible for, in accordance with the requirements of this RFP, all aspects of the development and construction of the facility, including, but not limited to, site control, permitting, engineering, procurement, construction, interconnection and all related costs up to achieving commercial operation. Without limiting the foregoing, the bidder will be responsible for obtaining all necessary real property interests, permits, rights and resources required to construct and provide an operational generation resource consistent with the bidder’s proposal. BTA bids must identify and provide all taxes including but not limited to property, sales and use incurred during construction and are the responsibility of the developer.

Bidders will be responsible for submitting an operation and maintenance (O&M) service proposal as part of the overall BTA bid submittal consistent with **Appendix K (BTA) Operations and Maintenance Services**. **Any proposal that does not include an O&M proposal that provides pricing, scope and other key terms will be rejected as a nonconforming proposal.**

Bidders should note that any proposal submitted in this category that proposes new construction of a resource must comply with the applicable technical and construction specifications contained in **Appendix A – 2024 Utah Renewable Project Technical Specification** and must utilize the services of a single primary contractor.

To the extent the bidder uses a contractor or a separate legal entity other than the bidder itself, this entity must be experienced with the type of facility being proposed and meet credit criteria, all as deemed acceptable to the Agency and Company.

Bidders should indicate in their bid documents whether a purchase option for a BTA has already been negotiated or is in the process of being negotiated with Company.

SECTION 5. RESOURCE INFORMATION

A. BID SUMMARY INFORMATION

Bidders must supply bid summary and pricing information using the instructions in Appendix C-1 and filling out the spreadsheet in Appendix C-2.

B. DIRECT INTERCONNECTION WITH THE PACIFICORP TRANSMISSION SYSTEM

The Agency is seeking renewable resources capable of directly interconnecting with PacifiCorp's transmission system in its PACE balancing area.⁵ The Agency prefers bids that will not face significant transmission costs or constraints between: (1) the resource's point of interconnection or the resource's delivery point on PacifiCorp's transmission system; and (2) PacifiCorp network load. Bidders are thus required to provide as much granularity and documentation as possible regarding their proposed point of interconnection. Bidders should also indicate with their bids whether their project will include any jointly owned generation tie lines or other shared facilities arrangements.

As noted above, bidders should provide evidence that the proposed project has requested a direct interconnection with PacifiCorp's transmission system and has received, at a minimum, a cluster study report with PacifiCorp's transmission function supporting commercial operation no later than December 31, 2029.

All bid proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include a firm statement of the cost of interconnection (broken out between network upgrade costs and facility-specific or direct assigned interconnection costs), together with a diagram of the interconnection facilities. The interconnection costs included in the bids from all bidders will be considered by the bid evaluation team as firm costs and included in the bid evaluation. Interconnection costs should be clearly identified in the resource cost proposal and differentiate the portion of costs associated with network upgrades and that portion that are facility-specific.

Before any final transaction agreements with winning bidders are executed, the Agency will require an interconnection Facilities Study report to determine the final network upgrades and direct assigned cost for interconnection service. Bids will be evaluated based on the direct assigned interconnection costs submitted in the bids, which will be considered firm costs for the Initial Short List evaluation. Bids that are selected to the Initial Short

⁵ To further clarify, projects should interconnect directly to the PacifiCorp transmission system and be located in Idaho, Utah, or Wyoming.

List will be held to their pricing for the Final Short List evaluation. If selected to the Final Short List, bidder's agreement with Company, and any final transaction agreement, will include a condition precedent that states the Agency will compare the actual direct assigned and network upgrade costs associated with the interconnection from the most recent completed system impact/cluster study (SIS) or Facilities Study (FS) with the bidder's firm estimate provided in their best and final price. In the event the actual direct assigned SIS cost exceeds the bidder's interconnection cost in best and final pricing, bidder will be responsible for the cost above their best and final firm price. In the event the actual SIS direct assigned cost is less than the bidder's firm interconnection cost estimate, the Agency will require an adjustment of the final PPA price to reflect the reduction in interconnection costs. The Agency will examine critical study information such as: (1) whether the studies support a commercial operation date within the timeframe listed in Section 2; and (2) interconnection direct assigned and network upgrade costs.

All proposals will require firm transmission service on PacifiCorp's network transmission system and proposed resources must be able to be designated by PacifiCorp's Energy Supply Management (ESM) function as a Network Resource under the network service contract between PacifiCorp Transmission (www.oasis.pacifiCorp.com) and PacifiCorp ESM. The final transaction agreement includes a condition precedent that should designation as a Network Resource (DNR) require additional upgrades beyond those identified in the interconnection study, the bidder may be required to bear the additional cost.

C. FERC'S STANDARDS OF CONDUCT

Each bidder responding to this RFP must conduct its communications, implementation and operations in compliance with FERC's Standards of Conduct for Transmission Providers (see **Appendix I**), requiring the separation of transmission and merchant functions. Any interconnection or transmission service agreement is NOT a transmission service agreement with PacifiCorp's ESM merchant function; rather, it is with PacifiCorp's transmission function or other third-party transmission provider. As such, the bidder must follow the transmission provider's OASIS process. If requested, bidders shall execute a customer consent form (see Appendix J PacifiCorp Transmission Waiver) consistent with FERC requirements that enables PacifiCorp's ESM merchant function to discuss the bidder's interconnection and/or transmission service application(s) with the transmission interconnection or transmission service provider.

D. RESOURCE TYPES ELIGIBLE TO BID

The Agency is seeking new renewable energy resources capable of directly interconnecting to PacifiCorp's network transmission system between January 1, 2026 and December 31, 2029. The Agency is limiting the resource types to wind, PV solar, geothermal, and hydroelectric only and will not accept bids that combine these technologies with other technologies except for co-located storage resources. These resources must be capable of being interconnected with PacifiCorp's transmission system.

E. TAX CREDITS AND/OR PROJECT INCENTIVES

Bidders must bear all risks, financial and otherwise, associated with bidder's or the facility's eligibility to receive any state or federal energy tax credits, sales tax waivers or exemptions or any other identified tax credit or incentive, or qualify for accelerated depreciation for bidder's accounting, reporting or tax purposes, as applicable. The obligations of the bidder to perform under any executed agreement as a result of this solicitation shall be effective and binding regardless of whether the sale of or output from the bidder's facility under such agreement is eligible for, or receives investment tax credits, or other identified tax credits/incentives.

The Agency will require written documentation of the amount, timing and control of any and all available tax credits/incentives that the bidder's facility is eligible for, applied for, and/or received. Such documentation shall include but not be limited to ownership rights to the credit, grant or incentive, timing including expiration dates and milestones to achieve the credit, grant, or incentive.

F. ACCOUNTING AND TAX CONSIDERATIONS

All contracts proposed to be entered into as a result of this RFP will be assessed by Company for appropriate accounting and tax treatment. Bidders shall be required to supply Company with any and all information that Company reasonably requires in order to make preliminary assessments if the bid is selected to the Initial Short List. Specifically, given the term length of the PPA or BTA arrangement, accounting and tax rules may require either: (i) a contract be accounted for by Company as a finance lease or operating lease⁶ for book purposes pursuant to ASC 842, (ii) a contract be accounted for by Company as a capital lease for tax purposes⁷, or (iii) the seller or assets owned by the seller, as a result of an applicable contract, be consolidated as a VIE into Company's financial statements.⁸

G. COST ASSOCIATED WITH DIRECT OR INFERRED DEBT

The Agency will not take into account potential costs to Company associated with direct or inferred debt (described below) as part of its economic analysis in the short list evaluations. However, after completing the Final Short List and before the final resource selections are made, the Agency and Company may take direct or inferred debt into consideration. In so doing, Company may obtain a written advisory opinion from a rating agency to substantiate Company's analysis and final decision regarding direct or inferred debt.

Direct debt results when a contract is deemed to be a lease pursuant to ASC 842 and liability reflected on Company's balance sheet.

⁶ "Finance Lease" and "Operating Lease" - shall have the meaning as set forth in the Accounting Standards Codification (ASC) 842 as issued and amended from time to time by the Financial Accounting Standards Board.

⁷ See IRS Code Section 7701(e) describing the test for finance lease for tax purposes.

⁸ "Variable Interest Entity" or "VIE" - shall have the meaning as set forth in ASC 810 as issued and amended from time to time by the FASB.

Inferred debt results when credit rating agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing Company's credit standing.

SECTION 6. BID EVALUATION AND SELECTION

A. OVERVIEW OF THE EVALUATION PROCESS

The Agency's bid evaluation and selection process is designed to identify the combination and amount of new renewable projects bid into the 2024 URC RFP that will cost-effectively support URC member communities' goals to achieve net-100% renewable electricity on behalf of Participating Customers by 2030. The Agency will not make any of the evaluation models available to bidders.

The bid evaluation process will occur in three phases. In the first phase, the Agency will calculate an Interconnection and Project Readiness Score (IPRS) and reject non-conforming bids. Although not a scoring element, the IPRS will be used to reject project bids scoring less than 70% and to adjust non-price scoring elements in the third phase.

In the second phase, price (expressed in \$ per MWh) and non-price scoring elements will be evaluated to develop an Initial Short List of projects consisting of up to six bids across two categories: 1) wind and solar – W&S, and 2) geothermal and hydropower (G&H).

In the third phase, PacifiCorp will model two scoring inputs for each bid selected to the Initial Short List: a financial benefit (expressed in \$ per MWh) and avoided climate pollution through 2030 (expressed in metric tons of CO₂-equivalent). Any other factors not expressly included in the formal evaluation process but required by applicable law or Commission order, will be used by the Agency to establish the Final Short List.

Representatives from the Agency, its Consultant, or Company may contact bidders to confirm and clarify information presented in each proposal.

After the Final Short List is established, Company will initiate negotiations with projects from the Final Short List that are selected by the Agency by a vote of its Board. Selection of a bid to the Final Short List does not constitute a winning bid. Only execution of a definitive agreement between Company and the bidder, on terms acceptable to the Agency and Company, in their sole and absolute discretion, will constitute a winning bid proposal. Any definitive PPA or BTA will be in the form of the PPA or BTA contracts provided in **Appendices E-2** and **F-2**, respectively. If the bidder alters the PPA or BTA, or does not use it as the underlying agreement, bid evaluation and selection can be affected. The Agency welcomes bidders, at their own discretion, to provide written comments on the PPA or BTA provided in **Appendices E-2** and **F-2** as part of their bid. Neither the Agency nor Company has a legal obligation to enter into any agreement of any kind with any bidder.

B. PHASE 1 – INTERCONNECTION AND PROJECT READINESS

Project bids that have not already been rejected as non-conforming will be evaluated using an Interconnection and Project Readiness Score (IPRS). This evaluation consists of ten questions as follows:

Interconnection and Project Readiness Score Factors	Scoring Weight
1. Does project have site control necessary to support a generation facility? (Yes = 1, No = 0)	1
2. Does project have site control necessary to support a generation-intertie ("gen-tie") needed to interconnect the project on the transmission system? (Yes = 1, No = 0)	1
3. Does project have a signed generator interconnection agreement? (Yes = 1, No = 0)	1
4. Does this project have at least one of the following: (1) it has passed fast-tracked under section 50 of PacifiCorp's OATT, (2) it has been issued an executable interconnection agreement under PacifiCorp's OATT section 51.4.3, or (3) it has a facilities study, either final or draft? (Yes = 1, No = 0) <i>Please note: OATT references are to PacifiCorp's Open Access Transmission Tariff v.2.0.0 dated April 1, 2020</i>	1
5. Has this project been studied as a Network Resource Interconnection Service (NRIS) or does it pass as fast-tracked under section 50 of PacifiCorp's OATT? (Yes = 1, No = 0)	1
6. Wetlands are either not present or mitigation plans are in place. (True = 1, False = 0)	1
7. Endangered species are either not present on site or mitigation plans are in place (True = 1, False = 0)	1
8. Cultural resources are either not present or mitigation plans are in place (True = 1, False = 0)	1
9. Site is zoned for proposed use (True = 1, False = 0)	1
10. Permitting is complete (i.e., project is shovel-ready) (True = 1, False = 0)	1

The total points will be summed and divided by 10 total possible points to develop an IPRS expressed as a percentage. Project bids with an IPRS lower than 70% will be rejected and the IPRS will be carried forward into the second phase of project bid evaluation.

C. PHASE 2 – INITIAL SHORT LIST

1. Price Evaluation (up to 70 points)

The Agency is committed to procuring least cost/least risk renewable energy through this solicitation on behalf of the Participating Customers.⁹ In phase 2, the Agency will compare the all-in cost (expressed in \$ per MWh)—inclusive of network upgrade costs associated with interconnecting the resource—among all bids that have met the threshold requirements described in phase 1. The lowest cost bid will be awarded 70 points and all other bids will be awarded a pro-rated share of 70 points based on how much more expensive they are than the lowest cost bid. This price evaluation will consider the pricing

⁹ As noted above, the Agency is under no obligation to procure resources bid into this RFP.

of the base 25-year project term. Please see Section 6.C.3 for a discussion of how wind and solar (W&S) bids will be ranked in a different list from geothermal and hydropower (G&H) bids for the purpose of selecting up to six (6) bids for the Initial Short List.

Bids must include documentation that demonstrates that the project(s) qualify for and will receive the full or partial value of the federal PTC or ITC as interpreted by applicable guidelines and rules of the Internal Revenue Service at commercial operation. The bids will be ranked to determine an initial shortlist, after also taking into account the Non-Price Evaluation.

2. Non-Price Evaluation (Up To 13 points)

The non-price scoring factors will be evaluated as follows:

NON-PRICE FACTOR WEIGHTING

Non-Price Factors	Non-Price Scoring Weight
1. Is the project located in Utah? (Yes = 3, No = 0)	3
2. If your project is located in Utah, will at least 50% of construction labor hours be supplied by in-state labor at the bid price? (Yes = 1, No = 0)	1
3. Will your project meet prevailing wage requirements for construction labor at the bid price? (Yes = 1, No = 0)	1
4. Will at least 2% of construction labor hours be supplied by registered apprenticeship labor at the bid price? (Yes = 1, No = 0)	1
5. Is your project located in a (1) 2024 Coal Closure Energy Community * or (2) disadvantaged area** as indicated on Federal maps? (Yes = 2, No = 0)	2
6. Inclusive of construction activities, how much water will your project consume in gallons per MW-hr over its operational life? (None = 2, between 0 and 20 = 1, more than 20 = 0)	2
7. By what date can your project reach commercial operation and deliver energy to the PacifiCorp transmission system, as evidenced by the most recent cluster or facilities interconnection study report or generator interconnection agreement? (by Dec 2026 = 3, between Jan and Dec 2027 = 2, between Jan and Dec 2028 = 1, between Jan and Dec 2029 = 0)	3

***2024 Coal Closure Energy Communities are light- or dark-green shaded areas in the [United States Department of Energy Community Tax Credit Bonus Map](#)**

****Disadvantaged areas are green-shaded areas in the [archived EJScreen](#) tool. Please note: to turn on the Designated Disadvantaged Communities layer, click Places > Designated Disadvantaged Communities > EPA IRA Disadvantaged Communities and in the Map Contents box, ensure that EPA IRA Data 2.0 is checked.**

3. Initial Short List Selection

The Agency will use the combined price and non-price results for valid bids to rank them in two separate lists: one list of all wind and solar bids (W&S) and a second list of all geothermal and hydropower bids (G&H). So long as there are G&H bids that meet all

screening criteria and survive Phase 1 scoring, up to three (3) top scoring bids will be selected from the G&H category; then, three (3) or more top scoring bids will be selected from the W&S category to bring the total bids selected for the Initial Short List and advancing to Phase 3 to no more than six (6) bids. Should any project bids of 10 MW or smaller size advance to Phase 2, the Agency reserves the right to select up to one (1) such bid to the Initial Short List.

In making Initial Short List selections, the Agency will consider the anticipated impact on the program rate that will be paid by Participating Customers. The total contract cost, commercial online date, and need to establish a dedicated reserve fund are all factors that may influence the program rate.

The Agency anticipates that the Initial Short List will represent approximately 500 MW of aggregate capacity. However, the Agency may establish an Initial Short List containing less or more aggregate capacity depending upon the relative total bid score among the bids and the total capacity bid into each category.

Network customers of PacifiCorp transmission, including Company, can request non-binding studies to provide an estimate of potential, high-level costs related to adding a potential designated network resource at a particular location on the system. While intervening transmission service requests or other changes on the system could impact the accuracy of the non-binding study estimates, these nevertheless provide a reasonable tool to evaluate potential transmission service costs before a final agreement is reached with a bidder. Accordingly, for all bids included in the Initial Short List, the Agency also reserves the right to request an informal study from PacifiCorp transmission to identify potential network upgrade costs that might be necessary for the bidder's facility to be designated as a network resource on PacifiCorp's transmission system. The cost of this non-binding study is to be paid by the bidder.

D. PHASE 3 – FINAL SHORT LIST

1. Price Evaluation (up to 70 points)

To be evaluated for Phase 3, Company will require an additional \$12,500 bid analysis fee for each Base Bid, variant, and/or add-on selected by the Agency to the Initial Short List and a signed Appendix G-2: Non-Reliance Letter prior to calculating a financial benefit (expressed in \$ per MWh). For clarity, Phase 3 evaluation of a bidder's Base Bid and an optional Storage Add-On will be subject to a \$25,000 bid analysis fee. If a bidder does not (a) execute this agreement with Company and (b) deliver this payment to Company by August 22, 2025, the Agency may remove that bid from the Initial Short List and replace it with a different bid.

Company will assess Initial Short List bids for the appropriate accounting and tax treatment. PPA bids will be evaluated to determine: (i) whether a contract must be accounted for by Company as a finance lease or operating lease in accordance with ASC 842 for book purposes, (ii) whether a contract must be accounted for by Company as a capital lease for tax purposes, or (iii) whether the seller or assets owned by the seller, as a result of an applicable contract, shall be consolidated as a VIE into PacifiCorp's financial

statements. Potential accounting treatment impacts will be incorporated into the bid evaluation and selection process. Please also refer to Section 5.F of this RFP.

For project bids that involve generation types other than solar, wind, and hydro, or storage types other than batteries, the bidder may be required to cover the cost for Company to hire a third party to support calculation of the financial benefits.

Net-Cost of Energy (35 points)

For each Initial Short List bid, the net-cost of energy will be calculated as the difference between the PPA fixed price (expressed in \$ per MWh) and the financial benefit (expressed in \$ per MWh).

The Agency will compare the net-cost of energy (expressed in \$ per MWh) among all Initial Short List bids. The bid with the lowest net-cost of energy (which may be negative) will be awarded 35 points. For all other project bids, the net-cost of energy will be compared to the lowest net-cost of energy. For every \$1 per MWh of net-cost of energy that a project bid exceeds the lowest net-cost of energy bid, 2 points will be deducted from the 35 possible points. For example, if the lowest net-cost of energy bid is -\$5 per MWh and another project bid's net-cost of energy is \$0 per MWh, the first project bid would receive 35 points and the second project bid would receive $(35 - 10 =) 25$ points.

Net-Cost of Contract (35 points)

For each Initial Short List bid, the net-cost of contract will be calculated as the net present value of the net-cost of energy over the 25-year term of the PPA (expressed in \$).

The Agency will compare the net-cost of contract (expressed in \$) among all Initial Short List bids. The project bid with the lowest net-cost of contract (which may be negative) will be awarded 35 points while project bids with a net-cost of contract of \$45 million or more will be awarded 0 points. All other project bids will be awarded a prorated share of 35 points based on how much more expensive they are compared to the lowest net-cost of contract.

2. Non-Price Evaluation (up to 30 points)

Commercial Online Date Confidence Score (up to 4 points)

Consultant will review interconnection studies and related documentation for every Initial Short List bid and assign a Commercial Online Date Confidence Score as shown:

- No, the document review does not support the indicated online date: 0
- No, the document review suggests the indicated online date is unlikely: 1
- Maybe, the document review suggests the indicated online date is possible: 2
- Yes, the document review suggests the indicated online date is likely: 3
- Yes, the document review suggests the indicated online date is substantially supported: 4

Adjusted CO₂ Reduction Score (up to 13 points)

PacifiCorp will model projected carbon dioxide reductions for each Initial Short List bid from the indicated commercial online date through 2030 (expressed in metric tons of CO₂). These carbon dioxide reductions result from changes in how PacifiCorp's thermal power plants are dispatched in response to new sources of generation.

The modeled CO₂ reductions through 2030 will be adjusted by the Commercial Online Date Score converted to a percentage. For example, if an Initial Short List bid receives a Commercial Online Date Score of 2 out of 4 (50%), then the bid's modeled CO₂ reduction (in metric tons) will be adjusted to 50% of its original value.

The adjusted CO₂ reduction (in metric tons) will be compared among all Initial Short List bids. The bid with the largest adjusted CO₂ reduction through 2030 will receive 13 points and all other bids will be awarded a prorated share of 13 points based on how many fewer tons of adjusted carbon dioxide pollution they will reduce compared to the project bid with the largest reduction.

Non-Price Factors Previously Scored in Phase 2 (up to 13 points)

The non-price scoring factors from phase 2 will also be included in the non-price evaluation for phase 3.

3. Other Factors: Applicable Law and Statutory Requirements

The bid methodology has been designed to capture applicable law and statutory requirements. Before establishing a final shortlist, the Agency may take into consideration other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.

4. Final Short List Selection

The Agency will summarize and evaluate the results of its price and non-price scores among all surviving project bids. Based on these data and certain other factors as described above the Agency may establish a Final Short List. Once the Final Short List is established and bidders notified, the Agency may select by a vote of its Board one or more project bids for contract negotiation. Should any project bids of 10 MW or smaller advance to Phase 3, the Agency reserves the right to select up to one (1) such bid for contract negotiation.

In selecting one or more project bids from the Final Short List for contract negotiation, the Agency will consider the anticipated impact on the program rate that will be paid by Participating Customers. The net-cost of energy, net-cost of contract, total contract cost, commercial online date, and need to establish a dedicated reserve fund are all factors that may influence the program rate.

Company will not enter into any agreement without Agency approval.

5. BTA Bid Evaluation

If a Base Bid that contains a BTA Bid Variant is selected to the Final Short List and is approved by the Agency's Board for contract negotiation, Company may elect to pursue a BTA with the bidder when the project proceeds to the contract negotiation phase.

SECTION 7. INVITATION TO BID

A. INVITATION

This RFP contains only an invitation to make proposals to the Agency. No proposal is itself a binding contract unless the parties execute definitive and complete documentation providing otherwise.

The Agency may in its sole discretion do any one or more of the following:

1. Determine which proposals are eligible for consideration in response to this RFP.
2. Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each bidder.
3. Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
4. Negotiate with bidders to amend any proposal.
5. Require winning bidder(s) to provide an additional administrative fee.
6. Select and enter into agreements with the bidders who, in the Agency's sole judgment, are most responsive to the RFP and whose proposals best satisfy the interests of the Agency and the Participating Customers, and not necessarily on the basis of price alone or any other single factor.
7. Issue additional subsequent solicitations for proposals.
8. Waive any irregularity or informality on any proposal to the extent not prohibited by law.
9. Reject any or all proposals in whole or in part.
10. Vary any timetable.
11. Conduct any briefing session or further RFP process on any terms and conditions.
12. Withdraw any invitation to submit a response.

B. CONFIDENTIALITY AGREEMENT

In addition to the confidentiality provisions set forth herein, bidders should note that all parties will be required to sign **Appendix G-1 – Confidentiality Agreement** with the Agency upon bid submission, as well as a transmission voluntary consent notice to authorize the release of data to PacifiCorp's ESM Market Function from PacifiCorp Transmission.

C. NON-RELIANCE LETTER

All parties will be required to sign **Appendix G-2 - Non-Reliance Letter** if they qualify for the Initial Short List prior to the Company modeling the financial impact of the project bid.

D. POST-BID NEGOTIATION

Company will further negotiate both price and non-price factors during post-bid negotiations. The Agency will also include in its evaluation any factor that may impact the total cost of a resource, including but not limited to all of the factors used in the Final Short List cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable. Post-bid negotiation will be based on the Agency's cost assessment. The Agency will continually update its economic and risk evaluations until Company and the bidder execute a definitive agreement acceptable to Company. The Agency must approve any contract negotiated between Company and the bidder.

Neither the Agency nor Company shall have any obligation to enter into any agreement with any bidder to this RFP and the Agency may terminate or modify this RFP at any time without liability or obligation to any bidder. In addition, this RFP shall not be construed as preventing the Agency or Company from entering into any agreement that the Agency or Company deems prudent, in each of the Agency's and Company's independent sole discretion, at any time before, during, or after this RFP process is complete. Finally, the Agency reserves the right to negotiate only with those entities that propose transactions that the Agency believes in its sole discretion to have a reasonable likelihood of being executed.

E. SUBSEQUENT REGULATORY ACTION

Unless mutually agreed between the parties or unless required by actual (or proposed) law or regulatory order, at the time of contract execution, the Agency does not intend to include a contractual clause whereby the Agency is allowed to adjust contract prices in the event that an entity that has regulatory jurisdiction over Rocky Mountain Power does not fully recognize the contract prices. As of the issuance date for this solicitation, the Agency is unaware of any such actual law or regulatory order.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
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Association, Platte River Power)
Authority, Salt River Project,)
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Motion to Intervene and Request for Rehearing and Stay of
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Exhibit 2-111:
Western Energy Imbalance Market Webpage

WESTERN ENERGY MARKETS



The ISO's Western Energy Imbalance Market enhances grid reliability while meeting the needs of an evolving industry through collaborative efforts across the West

Western Energy Imbalance Market (WEIM)

The ISO's Western Energy Imbalance Market is a real-time energy market, the first of its kind in the western United States.

The WEIM's advanced market system automatically finds low-cost energy to serve real-time consumer demand across the west. Since its launch in 2014, the WEIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the WEIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

Participants

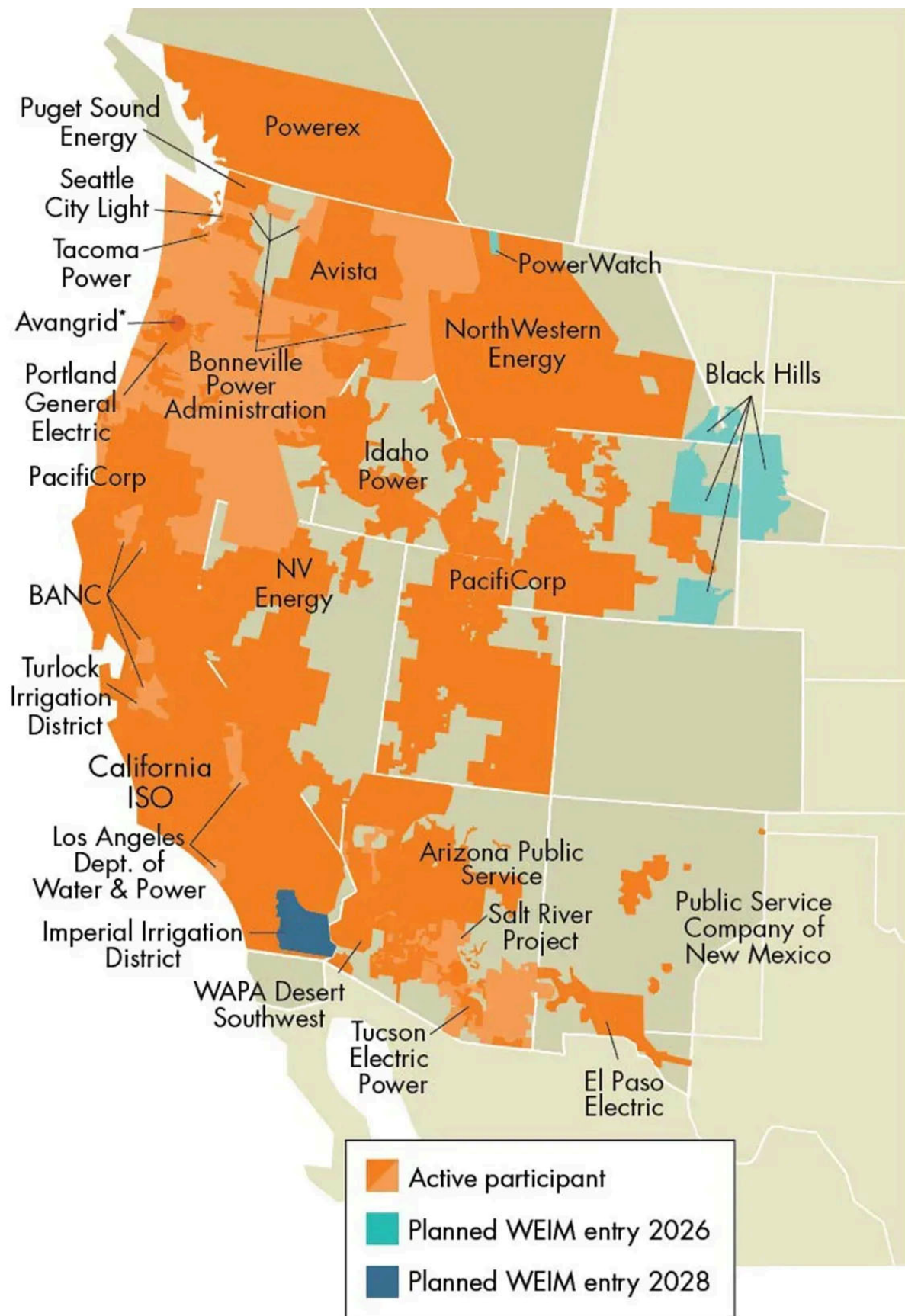
- [Imperial Irrigation District](#) – *planned entry 2028*
- [Black Hills](#) – *planned entry 2026*
- [PowerWatch \(formerly BHE Montana\)](#) – *planned entry 2026*
- [Avangrid](#) – entered 2023
- [El Paso Electric](#) – entered 2023
- [WAPA Desert Southwest Region](#) – entered 2023

Back to top

- [Bonneville Power Administration](#) – entered 2022
- [Tucson Electric Power](#) – entered 2022
- [Avista](#) – entered 2022
- [Tacoma Power](#) – entered 2022
- [NorthWestern Energy](#) – entered 2021
- [Los Angeles Department of Water & Power](#) – entered 2021
- [Public Service Company of New Mexico](#) – entered 2021
- [Turlock Irrigation District](#) – entered 2021
- [Salt River Project](#) – entered 2020
- [Seattle City Light](#) – entered 2020
- [Balancing Authority of Northern California](#) – entered 2019
- [Idaho Power Company](#) – entered 2018
- [Powerex](#) – entered 2018
- [Portland General Electric](#) – entered 2017
- [Puget Sound](#) – entered 2016
- [Arizona Public Service](#) – entered 2016
- [NV Energy](#) – entered 2015
- [PacifiCorp](#) – entered 2014
- [California ISO](#) – entered 2014

[View implementation documents for participants](#)

Participant map



**Avangrid office; generation only BAA with distribution across multiple states. Map boundaries are approximate and for illustrative purposes only. Copyright © 2025 California ISO*

[Download map](#)

See the [latest quarterly benefits report](#).

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Exhibit 2-112:
WEIS — Southwest Power Pool



WESTERN ENERGY IMBALANCE SERVICE MARKET

Quick Links

- [SPP WEIS Marketplace Protocols](#)

News Release Quick Links

- [May 12, 2021, release announcing Colorado Springs Utilities joining SPP's western market](#)
- [Dec. 23, 2020, release announcing FERC's approval of the WEIS tariff](#)
- [Nov. 12, 2020, release announcing SPP and stakeholders will consider RTO expansion to the west; study anticipates \\$49M in annual savings for current and new members](#)
- [Feb. 21, 2020, release announcing WEIS tariff filing](#)
- [Dec. 12, 2019, release announcing new participants of the WEIS](#)
- [Sept. 9, 2019, release announcing the first agreements with participants of the WEIS](#)
- [June 17, 2019, release announcing WEIS proposal and design](#)

SPP invites utilities to help build an electricity market to serve the west

SPP's Western Energy Imbalance Service market (WEIS) will balance generation and load regionally and in real time for participants in the Western Interconnection.

SPP began administering WEIS on a contract basis February 2021. Utilities do not have to be a member of the SPP regional transmission organization (RTO) to participate. The market will centrally dispatch energy from participating resources throughout the region every five minutes, enhancing both the reliability and affordability of electricity delivery from utilities to their customers.

The following are participants of the WEIS Market:

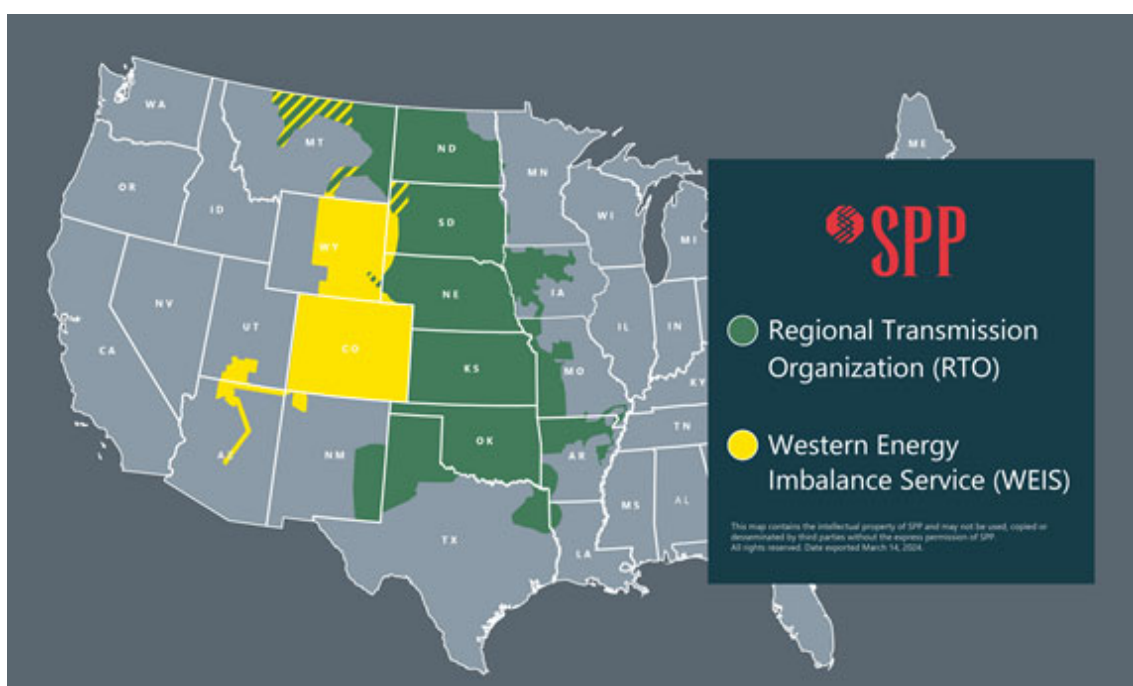
- Basin Electric Power Cooperative
- Black Hills Energy (effective April 2023)
- City of Farmington NM Electric Utility
- Colorado Springs Utilities (effective August 2022)
- Deseret Power Electric Cooperative
- Guzman Energy
- Municipal Energy Agency of Nebraska
- Platte River Power Authority (effective April 2023)
- Tri-State Generation and Transmission Association
- United Power, Inc.
- Western Area Power Administration
 - Upper Great Plains West
 - Rocky Mountain Region
 - Colorado River Storage Projects
- Xcel Energy (effective April 2023)

SPP's previous energy imbalance market went live in 2007 and provided participants with \$103 million in benefits in its first year of operation.

As the market's administrator, SPP maintains reliability of the region's transmission system and meets demand with the most cost-effective generation available, reducing wholesale electricity costs for participants. Like SPP's previous markets, the WEIS provides price transparency of wholesale energy, allows parties to trade bilaterally and hedges against costly transmission congestion.

In designing the WEIS, SPP leveraged existing constructs in the west and its experience successfully building and operating its own energy imbalance market from 2007-2014, after which the RTO introduced day-ahead unit commitment and other services in the transition to its current Integrated Marketplace.

An overview of the WEIS' proposed scope and design is available in the Related Documents menu to the right.



Governance and Stakeholder Involvement

For more than 75 years, SPP has distinguished itself as a stakeholder-driven organization that achieves its business objectives through consensus-building. While SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market, an open, transparent, and inclusive stakeholder process is a hallmark of our culture and business model. This same approach has been brought to the governance of the WEIS market to provide ample opportunities for stakeholder engagement and to ensure the market remains effective, efficient and competitive.

Stakeholders can stay informed of, and participate in, WEIS Market development through the Western Markets Working Group.

SPP's **Western Markets Working Group (WMWG)** is the forum for customers of SPP's western energy imbalance service market to engage in matters of WEIS Market related governance and strategy and with other stakeholders.

Its meetings serve as an open forum for entities looking to learn about SPP or to have a say in the development of the WEIS market in the west.

Attendees may [register on SPP.org for WMWG meetings](#), which may be attended in-person or by phone. Those interested in learning more about SPP's provision of energy imbalance service in the west are encouraged to register and attend or to contact SPP's customer relations department.

To stay updated on the WEIS Market, subscribe to the [SPP WMWG Exploder](#). If you do not have an account, you may [create one](#) using the Create Account button at the top right of the page.

The [Change User Forum](#) (CUF) engages market participants and monitors market and SPP readiness for the western energy imbalance service market. The CUF makes project management and process improvement recommendations to SPP staff and/or the [Western Markets Executive Committee](#).

Want to learn more?

If you are interested in learning more about SPP's Western Energy Imbalance Service (WEIS) market, training is available. SPP provides several online self-study courses about key features of the WEIS market and participant responsibilities. If you work for an organization that is an active WEIS participant, you already have access. Register or log into the [SPP Learning Center](#). And if you need assistance logging in or are not currently a member of SPP's WEIS market, contact [SPP's Stakeholder Training Group](#).

WESTERN SERVICES

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[Western Events](#)

[Markets+](#)

[RTO Expansion](#)

[Western Resource Adequacy Program](#)

[Western RC Services](#)

[Western Interconnection Unscheduled Flow Mitigation Plan \(WIUFMP\)](#)

[WEIS](#)

- [WEIS Revision Requests](#)
-

RELATED DOCUMENTS

[Western Energy Imbalance Service Market \(WEIS\) Proposal](#)

[WMEC Charter](#)

[WEIS Implementation Milestones](#)

[WEIS Implementation Program Overview](#)

[2023 WEIS Course Catalog](#)

RELATED DOCUMENT GROUPS

 [Western Energy Imbalance Service Market \(WEIS\)](#)

Western Stakeholder Groups

Meeting materials, member info, and more.

Western Energy Service Documents

Filings, governing documents, and other resources.

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Exhibit 2-113:
Craig Station, AMD data 2020 through 2025

State	Facility Name	Facility ID	Unit ID	Associated Year	Operating	Sum of the	Gross Load	Steam Load	SO2 Mass	SO2 Rate (lb)	CO2 Mass	CO2 Rate (lb)	NOx Mass	NOx Rate (lb)	Heat Input	Primary Fuel	Secondary Unit Type	SO2 Control	NOx Control	PM Control	Hg Control	Program Code
CO	Craig	6021	C1	2020	8511	8490.94	2517304		560.023	0.0431	2726442	0.105	3097.992	0.2329	25995872	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C1	2021	8123	8119.01	2563445		573.766	0.0439	2751844	0.105	3095.465	0.2316	26238031	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C1	2022	8413	8393.53	2797335		742.279	0.0518	2917219	0.1049	3492.321	0.2465	27814864	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C1	2023	8083	8072.47	2015029		526.926	0.0474	2210610	0.105	2518.031	0.2337	21077513	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C1	2024	8541	8536.69	1824100		335.429	0.0325	2058659	0.105	2211.571	0.2218	19628748	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C1	2025	8097	8082.35	1724209		368.808	0.0376	1971712	0.105	2085.183	0.2159	18799715	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C2	2020	7993	7961.83	2300379		517.033	0.0404	2562694	0.105	763.524	0.0618	24434513	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C2	2021	8635	8628.91	2822038		476.124	0.0301	3177713	0.105	1014.748	0.0667	30298549	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C2	2022	8427	8420.82	2629692		645.904	0.0451	2948921	0.105	987.563	0.0698	28117158	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C2	2023	5582	5573.88	1245370		282.48	0.0381	1457229	0.105	401.375	0.0562	13894277	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C2	2024	8405	8400.47	1801957		302.703	0.0271	2209975	0.105	625.283	0.0587	21071487	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C2	2025	8480	8477.53	1873143		351.27	0.0307	2288772	0.105	648.473	0.0591	21822755	Coal	Pipeline N: Dry bottom Wet Limes' Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C3	2020	7811	7789.23	2821877		1644.329	0.1077	3145100	0.105	3152.793	0.2047	29987627	Coal	Pipeline N: Dry bottom Dry Lime F: Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C3	2021	7426	7415.67	2579840		1307.602	0.1058	2635046	0.1049	2731.044	0.2108	25124446	Coal	Pipeline N: Dry bottom Dry Lime F: Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C3	2022	7708	7697.91	2783361		1714.714	0.1259	2837603	0.105	2973.326	0.2122	27055733	Coal	Pipeline N: Dry bottom Dry Lime F: Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C3	2023	7624	7611.42	1981366		1195.702	0.117	2135790	0.105	2131.88	0.2023	20364134	Coal	Pipeline N: Dry bottom Dry Lime F: Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C3	2024	6146	6137.68	1441766		666.086	0.0852	1610839	0.105	1495.032	0.1898	15358887	Coal	Pipeline N: Dry bottom Dry Lime F: Low NOx B Baghouse					ARP, MATS
CO	Craig	6021	C3	2025	3586	3574.77	653641.1		303.611	0.0823	764357.6	0.105	709.173	0.1884	7287928	Coal	Pipeline N: Dry bottom Dry Lime F: Low NOx B Baghouse					ARP, MATS

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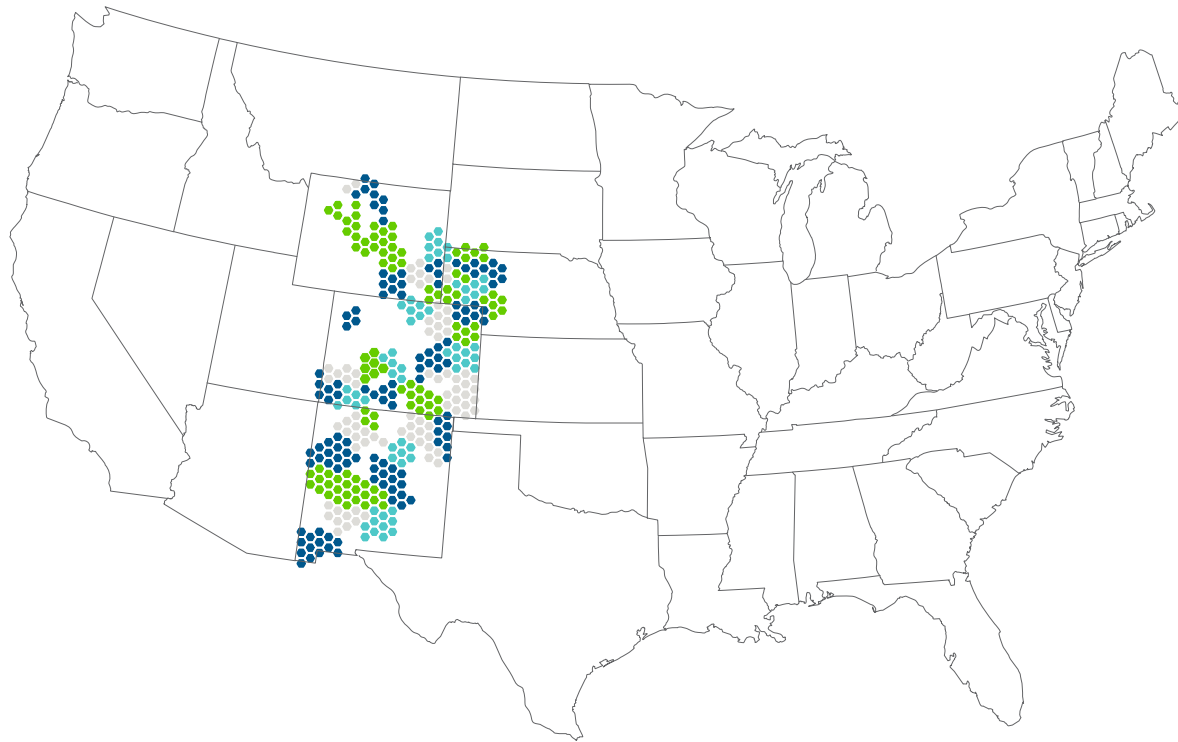
Exhibit 2-114:
Tri-State Members

[MENU](#)

What it means to be a member

Tri-State is more than just an energy provider—we're a community of member-owned utilities and businesses working together across Colorado, Nebraska, New Mexico, and Wyoming. As a cooperative, our strength comes from our members, and our board of directors reflects that diversity. These board members aren't just representatives—they're ranchers, farmers, and local business owners who live and work in the same communities served by our utilities. Their firsthand experience and deep local ties help guide the decisions that shape Tri-State's future, ensuring we stay true to our mission and values.

With our members, we supply power and services that support the rural communities they serve. That is the cooperative difference—we answer to our neighbors, not shareholders.



Member List </member-list>

70+

Tri-State was founded in 1952, which means we've been supplying electricity to the rural West for over 70 years.

1M

Together with our members, we serve nearly one million people and businesses across nearly 200,000 square miles.

5.32

We average 5.32 consumers per mile, vs. the national average of 32.4. We serve electricity to some of the most rural parts of the U.S.

Meet the board chairman at the end of the line

The son of a World War II veteran and life-long New Mexico rancher, Tri-State Board Chairman Tim Rabon has seen the powerful effect of people coming together and discusses how that is the foundation of the co-op model.



Listen to the podcast

</podcast-western-watts-cooperative-roots-tim-rabon-tri-state>



Power in numbers

Our association was formed to bring electricity to our members in the rural West when other power providers would not. Together we can capture economies of scale while sharing the costs and risks of supplying power to areas with few consumers, difficult terrain and a lot of ground to cover. Even today, some of our members serve as few as one connection per mile of distribution line.

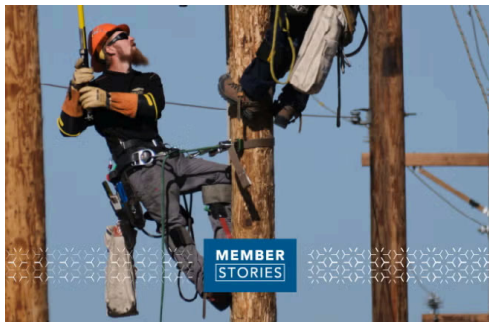
But whether they're in the desert, mountains, rural towns or plains—all our members still need reliable, affordable, responsible power. By pooling resources, collectively buying and selling power and managing the backbone of infrastructure that transports that power, we can negotiate better prices and build more efficient facilities than individual distribution cooperatives could on their own. This results in lower cost, more reliable electricity for our members.



Bridging communities through member programs

We want to help members make electrification and efficiency upgrades accessible for all so we use rebate, education and financing programs. These options and incentives benefit our members and their communities and consumers. Together, we can Electrify and Save®.

Our programs </programs>



Empowering Cooperatives: Inside Mesa Hotline School's Dedication to Excellence



</empowering-cooperatives-inside-mesa-hotline-schools-dedication-excellence>

Every May, over 500 line workers, teachers and volunteers gather in Grand Junction, Colorado at the Mesa Hotline School for the two-week annual learning event. The school attracts participants from across the United States, emphasizing safety and reliability in electrical transmission and distribution. It's an energetic and transformative learning experience with the aim of equipping people with the knowledge and skills needed to keep the lights on for the communities they serve.

[Read more > </empowering-cooperatives-inside-mesa-hotline-schools-dedication-excellence>](#)

The Power of Collaboration - Electric Engines for a Cleaner Future

</power-collaboration-electric-engines-cleaner-future>

As a cooperative, we know that when people come together, we can achieve greater results than any one of us could have done alone. Such was the case in the electrification of the Dahlia Station, a key depot along the Amarillo-to-Albuquerque pipeline managed by NuStar Energy – one of the nation's largest independent liquids terminal and pipeline operators.

[Read more > </power-collaboration-electric-engines-cleaner-future>](#)

Communities Win with Rebates: Two Business Owners Make Rebates Work for Them

</communitieswin>

Cooperatives like Big Horn are always looking for ways to better serve their member-owners. One way of doing that is by offering rebates for energy-efficient home and business upgrades.

[Read more > </communitieswin>](#)

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English 

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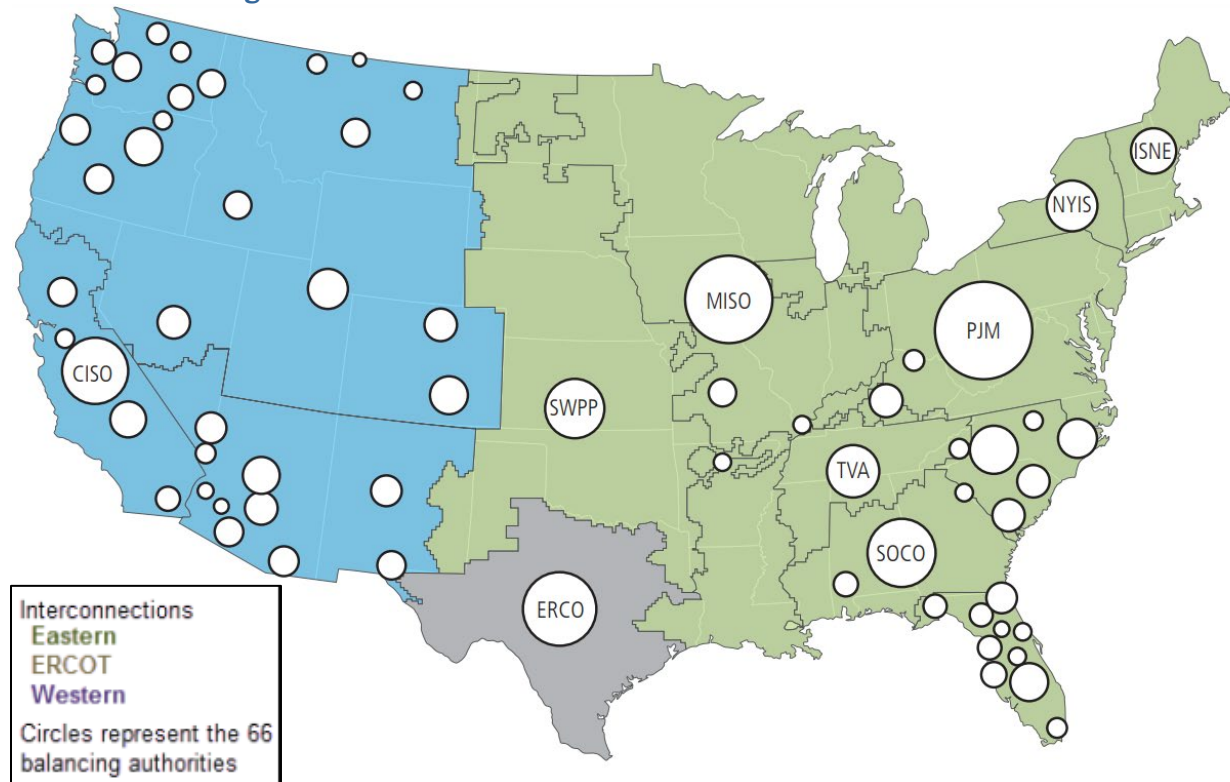
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Exhibit 2-115:
Department Explainer on Balancing Authorities

How it Works: The Role of a Balancing Authority

There are many key players in the electricity supply chain that work together to reliably supply power to electric customers. One key player is the balancing authority, which manages the operation of the electric system within a specific geographic area. There are more than 60 balancing authorities in the U.S., and they are typically either utilities, Power Marketing Administrations (PMAs), or a group of utilities that have formed regional entities called regional transmission organizations (RTOs) and independent system operators (ISOs).¹

Exhibit 1. Balancing Authorities Across the U.S.



Source: Quadrennial Energy Review: Transforming the Nation's Electricity System: The Second Installment of the QER (January 2017)

See EIA [Hourly Electric Grid Monitor](#) for interactive map.

A balancing authority ensures that power system demand and supply are always balanced, which maintains safe and reliable operation of the power system. If supply falls below demand, it can cause a drop in frequency below the stable system frequency, risking significant permanent physical damage to electrical equipment and prolonged grid-wide blackouts. During such situations, balancing authorities may direct utilities to “shed load” (i.e., implement rolling blackouts) to bring supply and demand into balance.

¹ U.S. Energy Information Administration Form 930

Balancing authorities also manage transfers of electricity (interchanges) with other balancing authorities and use economic dispatch to optimize the use of various generating units to minimize real-time costs. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC) and approved by the U.S. Federal Energy Regulatory Commission (FERC).

ISOs/RTOs

The formation of ISOs and RTOs came at the encouragement of FERC (click to read on [FERC orders](#) and [RTOs/ISOs](#)) to operate the transmission system independently of—and foster competition for electricity generation among—wholesale market participants. ISOs/RTOs do not own transmission or generation assets, nor do they directly serve or establish pricing for retail electric customers. They are not a part of any government, so they also do not have any enforcement authority over any electric generation facilities, electric transmission or distribution lines, or substations.²

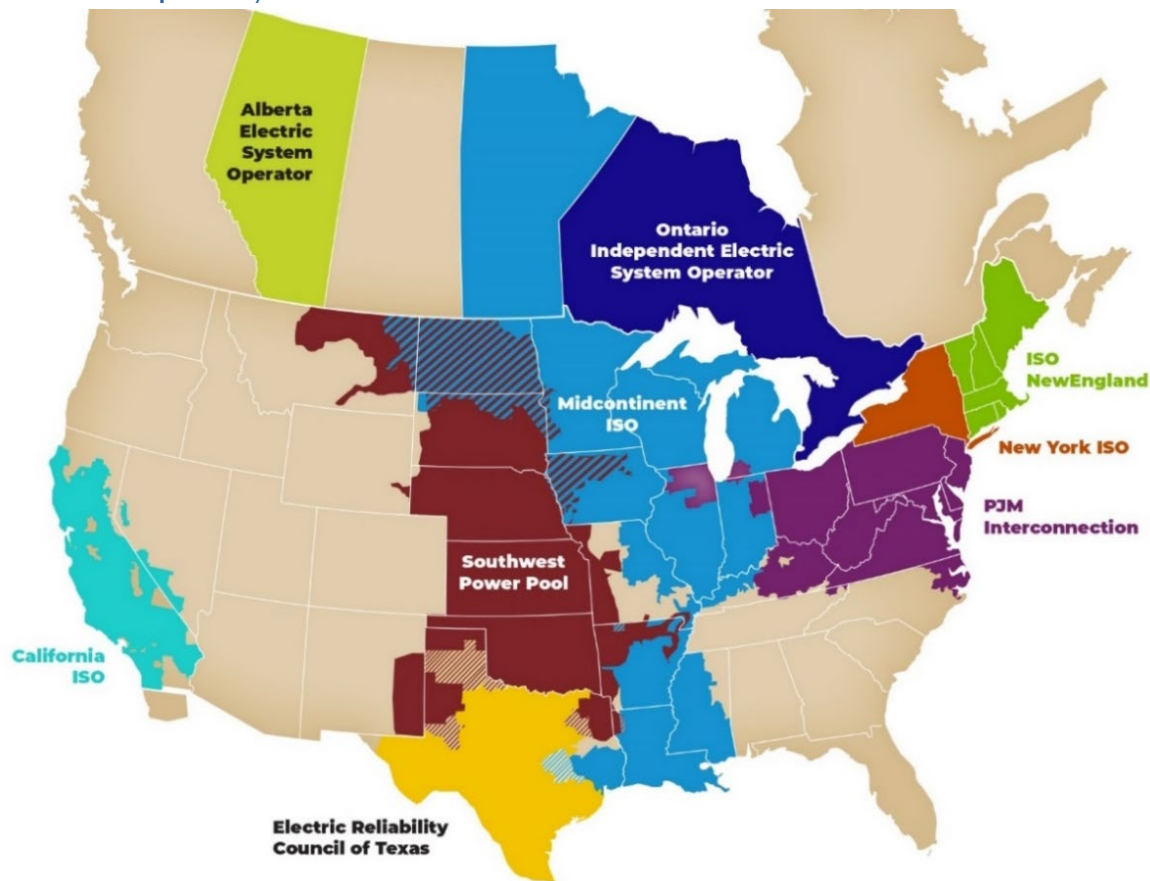
The role of ISOs and RTOs are similar, but ISOs do not meet the minimum requirements specified by FERC to hold the designation of RTO or have not applied for the status. An ISO operates the region's electricity grid, oversees the region's wholesale electricity markets, and provides reliability planning for the region's bulk electricity system. RTOs perform the same functions as the ISOs but have greater responsibility for planning near- and long-term transmission maintenance, upgrades, and expansion projects in collaboration with the actual transmission system owners. Utilities in areas where there is no RTO or ISO serve all these functions for their own territories. There are currently three ISOs and four RTOs that operate within the U.S.:

Independent System Operators (ISO)	California ISO	CAISO
	New York ISO	NYISO
	Electric Reliability Council of Texas ³	ERCOT
Regional Transmission Operator (RTO)	PJM Interconnection	PJM
	Midcontinent Independent System Operator	MISO
	Southwest Power Pool	SPP
	ISO New England	ISO-NE

Although two-thirds of the nation's electricity load is served in RTO/ISO regions (as can be seen from the map in Exhibit 2), there are large sections of the United States—particularly in the Southeast and the West—where there is no ISO or RTO. Electric utilities in these areas are still subject to the same reliability regulations under NERC/FERC.

² The North American Electric Reliability Corporation (NERC) issues and enforces reliability standards for balancing authorities, which are approved by the U.S. FERC and, in Canada, by Canadian regulators. NERC relies on [Regional Entities](#) to enforce reliability standards with bulk power system owners.

³ ERCOT does not fall under FERC authorities over interstate transmission and wholesale markets since it is entirely within the state of Texas and is not interconnected with the rest of the region. ERCOT is still subject to NERC oversight and FERC regulation for reliability.

Exhibit 2. Map of ISO/RTO Territories

Source: [ISO/RTO Council](#)

Grid Operation

Balancing authorities function as grid operators that dispatch electric generators to provide reliable power at the lowest cost. Because each generator has differing variable costs, generation is dispatched using the least costly generator first, in a way that is consistent with the relevant constraints of the transmission system and reliability requirements. Traditional utilities that are balancing authorities manage economic dispatch within their service areas, while ISOs and RTOs determine economic dispatch using bid-based markets where buyers and sellers bid for or offer generation. The dispatch process occurs in two phases: day-ahead unit commitment for the next day's dispatch, and real-time system dispatch.

- **Day-Ahead Commitment:** Balancing authorities decide which generating units should be committed to be online for each hour of the next 24-hour period. In selecting the most economic generators to commit, operators consider forecasted load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and the minimum time a generator must run once it is started. Load forecasting uses mathematical models to predict demand across the balancing authority's footprint, incorporating weather/climate, past energy consumption data, typical behavioral patterns, and economic activity.
- **Real-Time System Dispatch:** Balancing authorities must decide the appropriate level at which each available resource from the day-ahead commitment should be operated, given the real-

time load and other grid conditions, so that overall production costs are minimized. Actual demand will vary from the forecasted load and the balancing authorities must adjust the actual dispatch to match. As part of real-time operations, demand, generation, and interchange (imports and exports) must be continually kept in balance to maintain the stable system frequency. This is typically done by automatic generation control to change the generation dispatch as needed.

Contingency Resources and Capacity Markets

Grid operators maintain excess contingency resources in the form of power generation capacity, inertia⁴ capacity, and electricity storage to ensure that electricity supply is always available to meet anticipated peak demand. This “reserve margin” is required to meet Federal and State reliability requirements and can be used to provide a cushion or buffer during unexpected demand spikes, or potential loss of supply or transmission resources. If reserve margins fall below specified levels, grid operators may initiate emergency procedures to use additional resources—such as ancillary services and load management measures—that are only available during scarcity conditions.

RTO/ISOs typically use capacity markets to ensure that there are sufficient resources available to serve anticipated load and meet reserve margin requirements. Capacity markets may use auctions to lock in prices for electric capacity from generation resources in advance of the need. Capacity markets can also be marketplaces for [demand response](#), in which customers reduce demand when called upon in exchange for capacity payments similar to what generators receive. Capacity prices vary by location and timing of capacity commitments, and typically not by size or fuel type. ISO-NE, PJM, MISO, and NYISO operate capacity markets, while other ISOs currently do not.

Ancillary Services

Ancillary services are intended to maintain electric reliability and support electricity transmission. They mainly include services related to frequency stability like operating reserves; services related to voltage stability like reactive power support and voltage control, and other services like black start generation. Ancillary services are becoming more important for variable energy resources—such as wind and solar power—due to their production variability and forecast uncertainty. Within ISOs/RTOs, ancillary services are typically procured through bid-based auction markets, tariff fixed or formula-based rates, or competitive solicitations.

Operating reserves are needed to quickly restore load and generation balance when a supply resource trips offline. Operating reserves are provided by dispatchable generating units increasing output or demand-side resources reducing demand to restore balance. There are three types:

1. **Spinning reserves** are provided by generators that are online (synchronized to the system frequency) with some spare capacity and capable of increasing its electricity output within a short time period (within 10 minutes).
2. **Non-spinning reserves** are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a short time period (within 10 minutes). Non-spinning reserves can also be provided by demand-side resources.
3. **Supplemental reserves** are provided by generating units that can be made available within a longer time period (between 10 to 30 minutes).

⁴ An inertia is an interconnection permitting passage of current between two or more electric utility systems

Black start generating units—primarily hydroelectric facilities and diesel generators—can transition from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. These are the first facilities to start up in the event of a system failure or blackout to restore the rest of the grid.

Emergency Measures

Balancing electricity supply and demand to preserve grid stability is a critical function of balancing authorities. If supply falls below demand, it causes a frequency drop on the electrical grid below the stable system frequency, which can cause vibrations resulting in significant permanent physical damage to electrical equipment. As the frequency drops below safe operating levels, many generators will automatically disconnect from the grid for self-protection. As generators and other electrical equipment shut down, this further reduces electricity supply, causing the system frequency to drop even further.

If no interventions are taken to stabilize the grid, this cascading effect can lead to collapse of the electricity grid and prolonged grid-wide blackout. During the [February 2021 Extreme Cold & Winter Weather Incident](#), significant electricity generation assets went offline in the ERCOT region, causing a frequency drop that triggered additional generation loss. To rebalance supply and demand to stabilize the grid, ERCOT had to quickly shed substantial load, calling on its member utilities to proactively cut off electricity to their customers on a rotating basis over a period of three days. Although grid conditions in neighboring balancing areas were not as severe as in ERCOT, both MISO and SPP implemented brief periods of load shedding during the event.

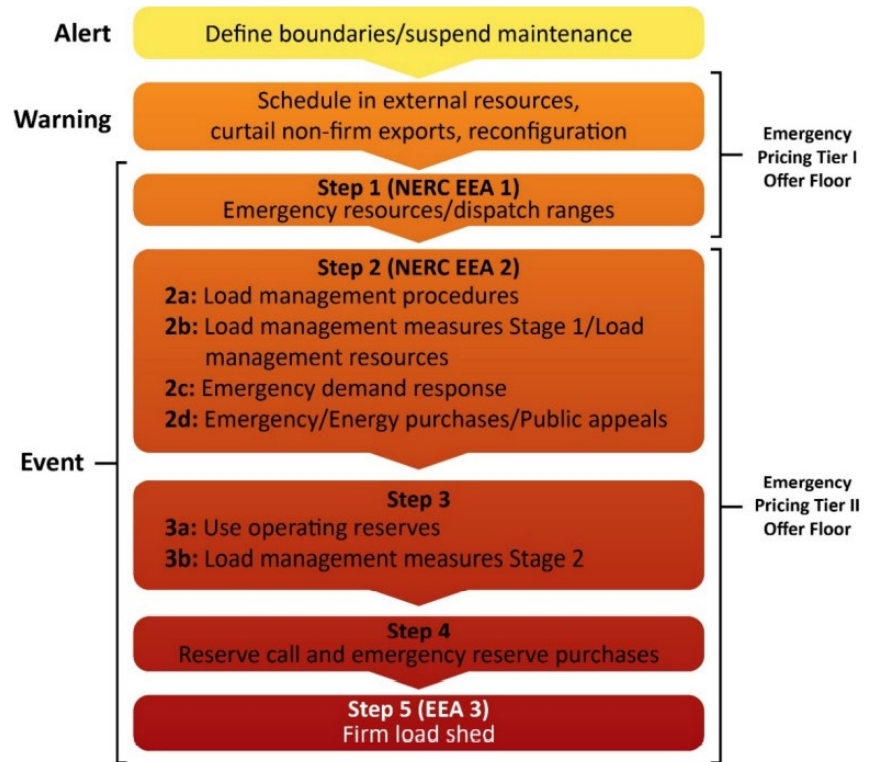
When a balancing authority predicts there will be a shortage of electricity, there are response measures they can take to rebalance supply and demand. Each balancing authority has its own response protocol with response measures increasing as the anticipated shortage becomes more severe. The first step is typically to issue an alert to market participants describing the situation and suspending non-essential work (such as regular maintenance) to maximize the availability of generation and transmission resources. Balancing authorities may also issue Conservation Alerts, in which they ask consumers to voluntarily reduce their energy usage to reduce demand, especially during peak demand hours. Examples of consumers reducing energy usage include adjusting their thermostats, avoiding using large electric appliances, turning off non-essential lights, etc.

If initial response measures are insufficient to rebalance supply and demand, then a balancing authority will begin declaring energy emergency alerts (EEAs). EEAs have different levels depending on the event.

- At EEA Level 1, a balancing authority will typically call on all available power supplies (regardless of economics), including power from other grids if available, and enable certain demand-side resource deployments.
- At EEA Level 2, a balancing authority will typically initiate demand response programs that shed load from large industrial customers that have contractually agreed. They will also typically make a public appeal for all customers to cut back on electricity consumption.
- At EEA Level 3,

balancing authorities will typically order utilities to shed load and inform them how much load they individually need to shed, and each utility then sheds the load by disconnecting circuits around customers with firm contracts. These outages are often “rotated” through the utility’s service territory with customers losing power for several hours at a time, although sometimes customers are without power for the entire event. During load sheds, utilities typically will not disconnect circuits serving critical customers (hospitals, water treatment plants, etc.).

Exhibit 3. Emergency Alert Levels



Source: [NERC](#)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

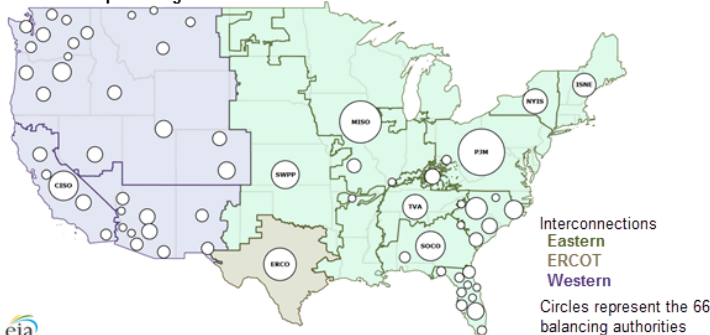
Exhibit 2-116:
EIA Explainer on Balancing Authorities

Today in Energy

July 20, 2016

U.S. electric system is made up of interconnections and balancing authorities

U.S. electric power regions



Source: U.S. Energy Information Administration

Note: The locations of the electric systems are illustrative and are not geographically accurate. The sizes of the circles are roughly indicative of electric system size.

Electricity generated at power plants moves through a complex network of electricity substations, power lines, and distribution transformers before it reaches customers. In the United States, the power system consists of more than 7,300 power plants, nearly 160,000 miles of high-voltage power lines, and millions of low-voltage power lines and distribution transformers, which connect 145 million customers.

Local electricity grids are interconnected to form larger networks for reliability and commercial purposes. At the highest level, the United States power system in the Lower 48 states is made up of three main interconnections, which operate largely independently from each other with limited transfers of power between them.

- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

The network structure of the interconnections helps maintain the reliability of the power system by providing multiple routes for power to flow and by allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service.

These interconnections describe the physical system of the grid. The actual operation of the electric system is managed by entities called balancing authorities. Most, but not all, balancing authorities are electric utilities that have taken on the balancing responsibilities for a specific portion of the power system. All of the [regional transmission organizations](#) in the United States also function as balancing authorities. ERCOT is unique in that the balancing authority, interconnection, and the regional transmission organization are all the same entity and physical system.

A balancing authority ensures, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result.

Balancing authorities maintain appropriate operating conditions for the electric system by ensuring that a sufficient supply of electricity is available to serve expected demand, which includes managing transfers of electricity with other balancing authorities. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the [North American Electric Reliability Corporation](#) and approved by the U.S. [Federal Energy Regulatory Commission](#) and, in Canada, by Canadian regulators. These operators monitor the grid to identify potential problems before a situation becomes critical.

Principal contributor: Sara Hoff

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-117:
NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Balancing Authority
 - 4.1.2 Reliability Coordinator
 - 4.1.3 Transmission Operator
 - 4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
 - 4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
 - 4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

- R1.** Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
- 1.1.** Roles and responsibilities for activating the Operating Plan(s);
 - 1.2.** Processes to prepare for and mitigate Emergencies including:
 - 1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
 - 1.2.2.** Cancellation or recall of Transmission and generation outages;
 - 1.2.3.** Transmission system reconfiguration;
 - 1.2.4.** Redispatch of generation request;
 - 1.2.5.** Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:
 - 1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
 - 1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;
 - 1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
 - 1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;
 - 1.2.5.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and
 - 1.2.6.** Provisions to determine reliability impacts of:
 - 1.2.6.1.** Cold weather conditions; and
 - 1.2.6.2.** Extreme weather conditions.
- M1.** Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

- R2.** Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

- M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

- evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.
- R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:
- 3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;
 - 3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and
 - 3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.
- M3.** The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.
- R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*
- M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.
- R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

- communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.
- R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.
- R7.** Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*
- M7.** Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.
- R8.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
- 8.1.** Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:
- 8.1.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
 - 8.1.2.** Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;
 - 8.1.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
 - 8.1.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

- 1.1. Compliance Enforcement Authority:** “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.
- 1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
 - The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
 - The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
 - The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
 - The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.
- 1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11, 2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24, 2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. <i>N. Am. Elec. Reliability Corp.</i> , 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

- 1. Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
- 2. Notification.** A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

- 1. EEA 1 — All available generation resources in use. Circumstances:**
 - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
 - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- 2. EEA 2 — Load management procedures in effect. Circumstances:**
 - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
 - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

- 2.1 Notifying other Balancing Authorities and market participants.** The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.
 - 2.2 Declaration period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
 - 2.3 Sharing information on resource availability.** Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.
 - 2.4 Evaluating and mitigating Transmission limitations.** The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
 - 2.5 Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:
 - 2.5.1 All available generation units are on line.** All generation capable of being on line in the time frame of the Emergency is on line.
 - 2.5.2 Demand-Side Management.** Activate Demand-Side Management within provisions of any applicable agreements.
- 3. EEA 3 — Firm Load interruption is imminent or in progress. Circumstances:**
- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

- 3.1 Continue actions from EEA 2.** The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

- 3.2 Declaration Period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.
- 3.3 Reevaluating and revising SOLs and IROLs.** The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:
- 3.3.1 Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.
- 3.4 Returning to pre-Emergency conditions.** Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.
- 3.4.1 Notification of other parties.** Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.
- Alert 0 - Termination.** When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.
- 3.4.2 Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-118:
Department Press Release on Centralia Order

[Home](#) [Topics](#) [Strengthen Grid Reliability and Security](#) [Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, ...](#)

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

[Energy.gov](#)

December 17, 2025

 2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today [issued](#) an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

“The last administration’s energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won’t let that happen,” said **Energy Secretary Wright**. “The Trump administration will continue taking action to keep America’s coal plants running so we can stop the price spikes and ensure we don’t lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining.”

According to DOE’s [Resource Adequacy Report](#), blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability

Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The [NERC Winter Reliability Assessment](#) warns that “extreme winter conditions extending over a wide area could result in electricity supply shortfalls.” With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

###

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Energy Department Grants Woodside Louisiana
LNG Project Additional Time to Commence
Exports

December 16, 2025

Just Launched: A Critical Materials Career Map

December 17, 2025

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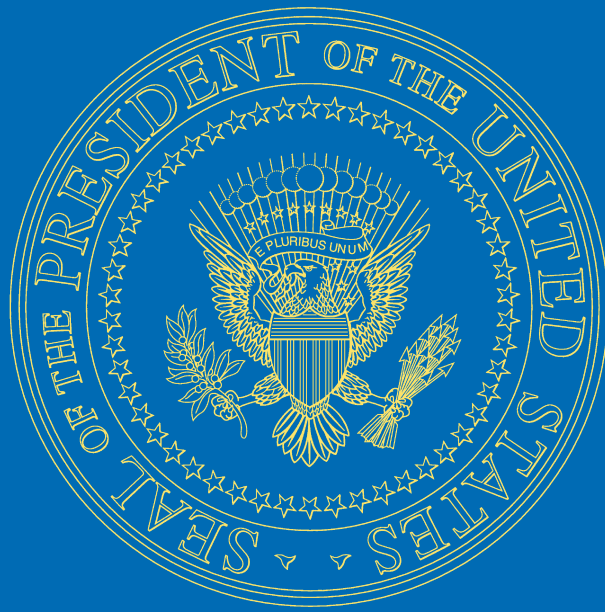
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-119:
2001 National Energy Policy

National Energy Policy



Report of the
National Energy Policy Development Group

May 2001

Reliable, Affordable, and Environmentally Sound Energy for America's Future

**Report of the
National Energy Policy Development Group**

*“America must have an energy policy that plans
for the future, but meets the needs of today.
I believe we can develop our natural resources
and protect our environment.”*

— President George W. Bush



THE VICE PRESIDENT
WASHINGTON

May 16, 2001

The Honorable George W. Bush
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

On behalf of the National Energy Policy Development Group, I submit for your consideration our National Energy Policy report. As you directed us at the outset of your Administration, we have developed a national energy policy designed to help bring together business, government, local communities and citizens to promote dependable, affordable and environmentally sound energy for the future.

The report reflects the requirements and philosophy you set out for our work. It envisions a comprehensive long-term strategy that uses leading edge technology to produce an integrated energy, environmental and economic policy. To achieve a 21st century quality of life -- enhanced by reliable energy and a clean environment -- we must modernize conservation, modernize our infrastructure, increase our energy supplies, including renewables, accelerate the protection and improvement of our environment, and increase our energy security.

We submit these recommendations with optimism. The tasks ahead are great but achievable. To meet our energy challenge, we must put to good use the resources around us and the talents within us. It summons the best of America and offers a healthier environment, a stronger economy and a brighter future for the American people.

Sincerely,

A handwritten signature in blue ink that reads "Dick Cheney". The signature is fluid and cursive, with the first name "Dick" and the last name "Cheney" clearly legible.

Enclosure

Members of the National Energy Policy Development Group

DICK CHENEY

The Vice President

COLIN L. POWELL

The Secretary of State

PAUL O'NEILL

The Secretary of the Treasury

GALE NORTON

The Secretary of the Interior

ANN M. VENEMAN

The Secretary of Agriculture

DONALD L. EVANS

The Secretary of Commerce

NORMAN Y. MINETA

The Secretary of Transportation

SPENCER ABRAHAM

The Secretary of Energy

JOE M. ALLBAUGH

The Director of the Federal Emergency Management Agency

CHRISTINE TODD WHITMAN

The Administrator of the Environmental Protection Agency

JOSHUA B. BOLTEN

The Assistant to the President and Deputy Chief of Staff for Policy

MITCHELL E. DANIELS

The Director of the Office of Management and Budget

LAWRENCE B. LINDSEY

The Assistant to the President for Economic Policy

RUBEN BARRALES

Deputy Assistant to the President and Director of Intergovernmental Affairs

Executive Director: Andrew D. Lundquist

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Overview

Reliable, Affordable, and Environmentally Sound Energy for America's Future

In his second week in office, President George W. Bush established the National Energy Policy Development Group, directing it to “develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future.” This Overview sets forth the National Energy Policy Development (NEPD) Group’s findings and key recommendations for a National Energy Policy.

America in the year 2001 faces the most serious energy shortage since the oil embargoes of the 1970s. The effects are already being felt nationwide. Many families face energy bills two to three times higher than they were a year ago. Millions of Americans find themselves dealing with rolling blackouts or brownouts; some employers must lay off workers or curtail production to absorb the rising cost of energy. Drivers across America are paying higher and higher gasoline prices.

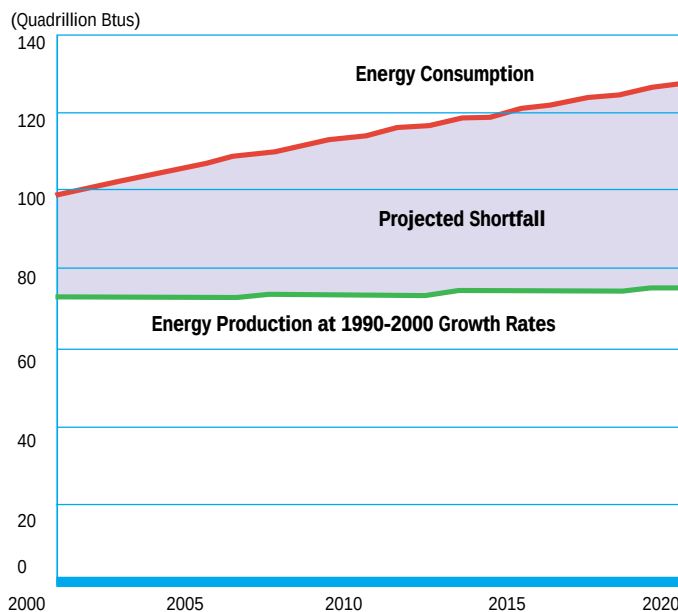
Californians have felt these problems most acutely. California actually began the 1990s with a surplus of electricity generating capacity. Yet despite an economic boom, a rapidly growing population, and a corresponding increase in energy needs, California did not add a single new major electric power plant during the 1990s. The result is a demand for electricity that greatly exceeds the amount available.

A fundamental imbalance between supply and demand defines our nation’s energy crisis. As the chart illustrates, if energy production increases at the same rate as during the last decade our projected energy needs will far outstrip expected levels of production.

This imbalance, if allowed to continue, will inevitably undermine our economy, our standard of living, and our national security. But it is not beyond our power to correct. America leads the world in scientific achievement, technical skill, and entrepreneurial drive. Within our country are abundant natural resources, unrivaled technology, and unlimited human creativity. With forward-looking leadership and sensible policies, we can meet our fu-

Figure 1

Growth in U.S. Energy Consumption Is Outpacing Production



Over the next 20 years, growth in U.S. energy consumption will increasingly outpace U.S. energy production, if production only grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.



America's expanding economy, growing population, and rising standard of living will be sustained by our unmatched technological know-how.

ture energy demands and promote energy conservation, and do so in environmentally responsible ways that set a standard for the world.

The Challenge

America's energy challenge begins with our expanding economy, growing population, and rising standard of living. Our prosperity and way of life are sustained by energy use. America has the technological know-how and environmentally sound 21st century technologies needed to meet the principal energy challenges we face: promoting energy conservation, repairing and modernizing our energy infrastructure, and increasing our energy supplies in ways that protect and improve the environment. Meeting each of these challenges is critical to expanding our economy, meeting the needs of a growing population, and raising the American standard of living.

We are already working to meet the first challenge: using energy more wisely. Dramatic technological advances in energy efficiency have enabled us to make great strides in conservation, from the operation of farms and factories to the construction of

buildings and automobiles. New technology allows us to go about our lives and work with less cost, less effort, and less burden on the natural environment. While such advances cannot alone solve America's energy problems, they can and will continue to play an important role in our energy future.

The second challenge is to repair and expand our energy infrastructure. Our current, outdated network of electric generators, transmission lines, pipelines, and refineries that convert raw materials into usable fuel has been allowed to deteriorate. Oil pipelines and refining capacity are in need of repair and expansion. Not a single major oil refinery has been built in the United States in nearly a generation, causing the kind of bottlenecks that lead to sudden spikes in the price of gasoline. Natural gas distribution, likewise, is hindered by an aging and inadequate network of pipelines. To match supply and demand will require some 38,000 miles of new gas pipelines, along with 255,000 miles of distribution lines. Similarly, an antiquated and inadequate transmission grid prevents us from routing electricity over long distances and thereby avoiding regional blackouts, such as California's.

“America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment.”

— President
George W. Bush

Increasing energy supplies while protecting the environment is the third challenge. Even with successful conservation efforts, America will need more energy.

Renewable and alternative fuels offer hope for America's energy future. But they supply only a small fraction of present energy needs. The day they fulfill the bulk of our needs is still years away. Until that day comes, we must continue meeting the nation's energy requirements by the means available to us.

Estimates indicate that over the next 20 years, U.S. oil consumption will increase by 33 percent, natural gas consumption by well over 50 percent, and demand for electricity will rise by 45 percent. If America's energy production grows at the same rate as it did in the 1990s we will face an ever-increasing gap.

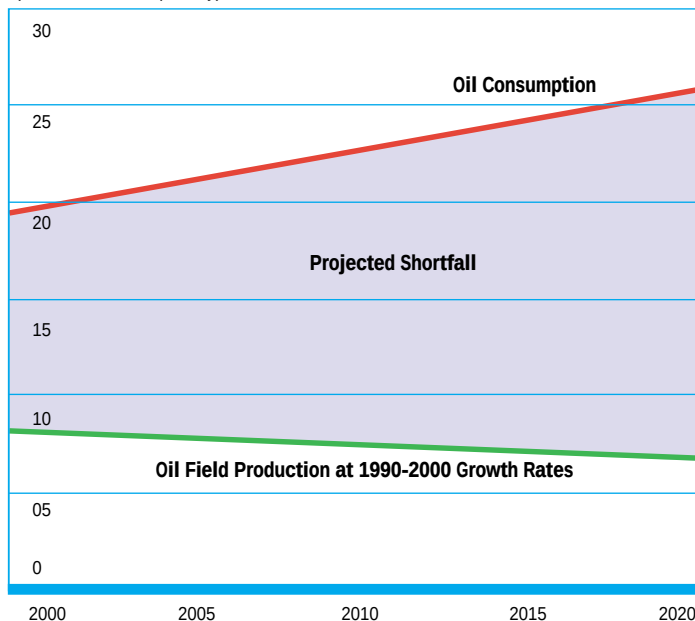
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

Extraordinary advances in technology have transformed energy exploration and production. Yet we produce 39 percent less oil today than we did in 1970, leaving us ever more reliant on foreign suppliers. On our present course, America 20 years from now will import nearly two of every three barrels of oil – a condition of increased dependency on foreign powers that do not always have America's interests at heart. Our increasing demand for natural gas – one of the cleanest forms of energy – far exceeds the current rate of production. We should reconsider any regulatory restrictions that do not take technological advances into account.

Figure 2

U.S. Oil Consumption Will Continue to Exceed Production

(Millions of Barrels per Day)



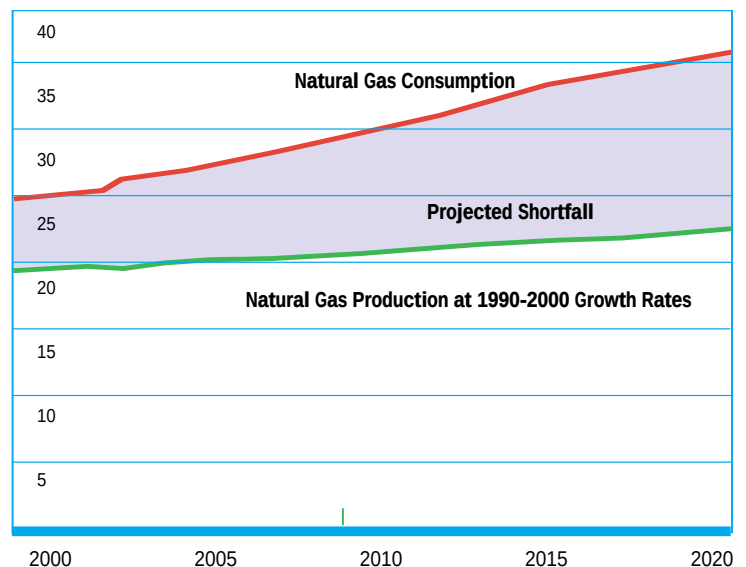
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 7.5 million barrels per day. In 2020, U.S. oil production would supply less than 30 percent of U.S. oil needs.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

Figure 3

U.S. Natural Gas Consumption Is Outpacing Production

(Trillion Cubic Feet)



Over the next 20 years, U.S. natural gas consumption will grow by over 50 percent. At the same time, U.S. natural gas production will grow by only 14 percent, if it grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

erview chart

We have a similar opportunity to increase our supplies of electricity. To meet projected demand over the next two decades, America must have in place between 1,300 and 1,900 new electric plants. Much of this new generation will be fueled by natural gas. However, existing and new technologies offer us the opportunity to expand nuclear generation as well. Nuclear power today accounts for 20 percent of our country's electricity. This power source, which causes no greenhouse gas emissions, can play an expanding part in our energy future.

The recommendations of this report address the energy challenges facing America. Taken together, they offer the thorough and responsible energy plan our nation has long needed.

Components of the National Energy Policy

The National Energy Policy we propose follows three basic principles:

- The Policy is a long-term, comprehensive strategy. Our energy crisis has been years in the making, and will take years to put fully behind us.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, we urge action to meet five specific national goals. America must modernize conservation, modernize our energy infrastructure, increase energy supplies, accelerate the protection and improvement of the environment, and increase our nation's energy security.

Modernize Conservation

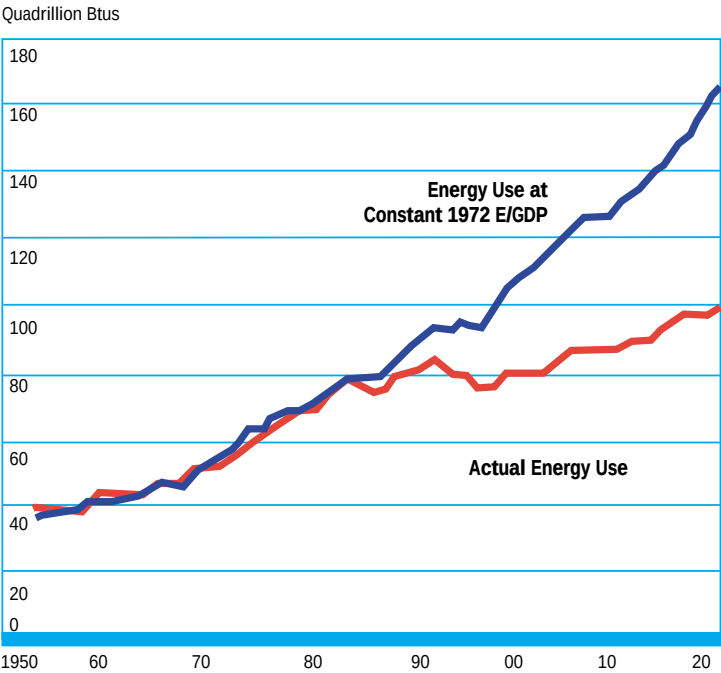
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, communities, and businesses all depend upon reliable and affordable energy services for their well being and safety. From transportation to communication, from air conditioning to lighting, energy is critical to nearly everything we do in life and work. Public policy can and should encourage energy conservation.

Over the past three decades, America has made impressive gains in energy efficiency. Today's automobiles, for example, use about 60 percent of the gasoline they

“Here we aim to continue a path of uninterrupted progress in many fields... New technologies are proving that we can save energy without sacrificing our standard of living. And we’re going to encourage it in every way possible.”

— Vice President
Richard B. Cheney

Figure 4
U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

“For the electricity we need, we must be ambitious. Transmission grids stand in need of repair, upgrading, and expansion. . . . If we put these connections in place, we’ll go a long way toward avoiding future blackouts.”

— Vice President
Richard B. Cheney

did in 1972, while new refrigerators require just one-third the electricity they did 30 years ago. As a result, since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent. In the 1990s alone, manufacturing output expanded by 41 percent, while industrial electricity consumption grew by only 11 percent. We must build on this progress and strengthen America’s commitment to energy efficiency and conservation.

The National Energy Policy builds on our nation’s successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken.
- Increase funding for renewable energy and energy efficiency research and development programs that are performance-based and cost-shared.
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles.
- Extend the Department of Energy’s “Energy Star” efficiency program to include schools, retail buildings, health care facilities, and homes and extend the “Energy Star” labeling program to additional products and appliances.
- Fund the federal government’s Intelligent Transportation Systems program, the fuel cell powered transit bus program, and the Clean Buses program.
- Provide a tax incentive and streamline permitting to accelerate the development of clean Combined Heat and Power technology.
- Direct the Secretary of Transportation to review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards

with due consideration to the National Academy of Sciences study of CAFE standards to be released in July, 2001.

Modernize Our Energy Infrastructure

The energy we use passes through a vast nationwide network of generating facilities, transmission lines, pipelines, and refineries that converts raw resources into usable fuel and power. That system is deteriorating, and is now strained to capacity.

One reason for this is government regulation, often excessive and redundant. Regulation is needed in such a complex field, but it has become overly burdensome. Regulatory hurdles, delays in issuing permits, and economic uncertainty are limiting investment in new facilities, making our energy markets more vulnerable to transmission bottlenecks, price spikes and supply disruptions. America needs more environmentally-sound energy projects to connect supply sources to growing markets and to deliver energy to homes and business.

To reduce the incidence of electricity blackouts, we must greatly enhance our ability to transmit electric power between geographic regions, that is, sending power to where it is needed from where it is produced. Most of America’s transmission lines, substations, and transformers were built when utilities were tightly regulated and provided service only within their assigned regions. The system is simply unequipped for large-scale swapping of power in the highly competitive market of the 21st century.

The National Energy Policy will modernize and expand our energy infrastructure in order to ensure that energy supplies can be safely, reliably, and affordably transported to homes and businesses. This report includes recommendations to:

- Direct agencies to improve pipeline safety and expedite pipeline permitting.
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis

in an environmentally sound manner, and establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected.

- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines and highways.
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability, and promotes renewable energy.
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards.
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

Increase Energy Supplies

A primary goal of the National Energy Policy is to add supply from diverse sources. This means domestic oil, gas, and coal. It also means hydropower and nuclear power. And it means making greater use of non-hydro renewable sources now available.

One aspect of the present crisis is an increased dependence, not only on foreign oil, but on a narrow range of energy options. For example, about 90 percent of all new electricity plants currently under construction will be fueled by natural gas. While natural gas has many advantages, an over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions. There are several other fuel sources available that can help meet our needs.

Currently, the U.S. has enough coal to last for another 250 years. Yet very few

coal-powered electric plants are now under construction. Research into clean coal technologies may increase the attractiveness of coal as a source for new generation plants.

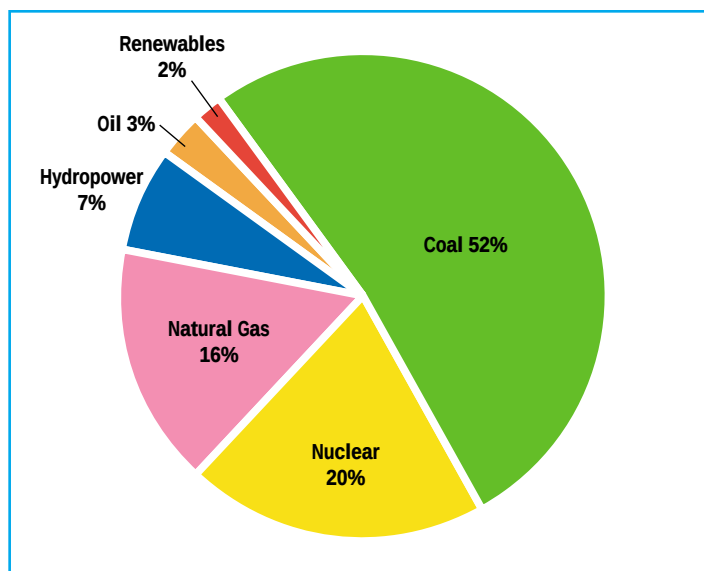
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of electricity generated in 10 states in the Northeast, South, and Midwest. Other nations, such as Japan and France, generate a much higher percentage of their electricity from nuclear power. Yet the number of nuclear plants in America is actually projected to decline in coming years, as old plants close and none are built to replace them.

Enormous advances in technology have made oil and natural gas exploration and production both more efficient and more environmentally sound. Better technology means fewer rigs, more accurate drilling, greater resource recovery and envi-

“As a country, we have demanded more and more energy. But we have not brought on line the supplies needed to meet that demand.... We can explore for energy, we can produce energy and use it, and we can do so with a decent regard for the natural environment.”

—Vice President
Richard B. Cheney

Figure 5
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for nearly 75 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration

“We will insist on protecting and enhancing the environment, showing consideration for the air and natural lands and watersheds of our country.”

— Vice President
Richard B. Cheney

ronmentally friendly exploration. Drilling pads are 80 percent smaller than a generation ago. High-tech drilling allows us to access supplies five to six miles away from a single compact drilling site, leaving sensitive wetlands and wildlife habitats undisturbed. Yet the current regulatory structure fails to take sufficient account of these extraordinary advances, excessively restricting the environmentally safe production of energy from many known sources.

Our policy will increase and diversify our nation’s sources of traditional and alternative fuels in order to furnish families and businesses with reliable and affordable energy, to enhance national security, and to improve the environment. This report includes recommendations to:

- Issue an Executive Order directing all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies a detailed statement on the energy impact of the proposed action.
- Open a small fraction of the Arctic National Wildlife Refuge to environmentally regulated exploration and production using leading-edge technology. Examine the potential for the regulated increase in oil and natural gas development on other federal lands.
- Earmark \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR to fund research into alternative and renewable energy resources – including wind, solar, biomass, and geothermal.
- Enact legislation to expand existing alternative fuels tax incentives to include landfills that capture methane gas emissions for electricity generation and to electricity produced from wind and biomass. Extend the number of eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources.
- Provide \$2 billion over 10 years to fund clean coal technology research and a new credit for electricity produced from biomass co-fired with coal.
- Direct federal agencies to streamline the

hydropower relicensing process with proper regard given to environmental factors.

- Provide for the safe expansion of nuclear energy by establishing a national repository for nuclear waste, and by streamlining the licensing of nuclear power plants.

Accelerate Protection and Improvement of the Environment

America’s commitment to environmental protection runs deep. We are all aware of past excesses in our use of the natural world and its resources. No one wishes to see them repeated. In the 21st century, the ethic of good stewardship is well established in American life and law.

We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future. The primary reason for that has been steady advances in the technology of locating, producing, and using energy. Since 1970, emissions of key air emissions are down 31 percent. Cars today emit 85 percent less carbon monoxide than 30 years ago. Lead emissions are down 90 percent. Lead levels in ambient air today are 98 percent lower than they were in 1970. America is using more, and polluting less.

One of the factors harming the environment today is the very lack of a comprehensive, long-term national energy policy. States confronting blackouts must take desperate measures, often at the expense of environmental standards, requesting waivers of environmental rules, and delaying the implementation of anti-pollution efforts. Shortfalls in electricity generating capacity and short-sighted policies have blocked construction of new, cleaner plants, leaving no choice but to rely on older, inefficient plants to meet demand. The increased use of emergency power sources, such as diesel generators, results in greater air pollution.

New anti-pollution technologies hold great promise for the environment. The same can be said of 21st century power generators that must soon replace older models; signifi-

cant new resources for land conservation efforts; and continued research into renewable energy sources. All have a place in the National Energy Policy.

The National Energy Policy will build upon our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Enact “multi-pollutant” legislation to establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators.
- Increase exports of environmentally friendly, market-ready U.S. technologies that generate a clean environment and increase energy efficiency.
- Establish a new “Royalties Conservation Fund” and earmark royalties from new, clean oil and gas exploration in ANWR to fund land conservation efforts.
- Implement new guidelines to reduce truck idling emissions at truck stops.

Increase Energy Security.

The National Energy Policy seeks to lessen the impact on Americans of energy price volatility and supply uncertainty. Such uncertainty increases as we reduce America's dependence on foreign sources of energy. At the same time, however, we recognize that a significant percentage of our resources will come from overseas. Energy security must be a priority of U.S. trade and foreign policy.

We must look beyond our borders and restore America's credibility with overseas suppliers. In addition, we must build strong relationships with energy-producing nations in our own hemisphere, improving the outlook for trade, investment, and reliable supplies.

Energy security also requires preparing our nation for supply emergencies, and assisting low-income Americans who are most vulnerable in times of supply disruption, price spikes, and extreme weather.

To ensure energy security for our nation and its families, our report includes these recommendations:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalty payments to LIHEAP when oil and natural gas prices exceed a certain amount.
- Double funding for the Department of Energy's Weatherization Assistance Program, increasing funding by \$1.4 billion over 10 years.
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies.
- Support a North American Energy Framework to expand and accelerate cross-border energy investment, oil and gas pipelines, and electricity grid connections by streamlining and expediting permitting procedures with Mexico and Canada. Direct federal agencies to expedite necessary permits for a gas pipeline route from Alaska to the lower 48 states.

Looking Toward the Future

The President's goal of reliable, affordable, and environmentally sound energy supplies will not be reached overnight. It will call forth innovations in science, research, and engineering. It will require time and the best efforts of leaders in both political parties. It will require also that we deal with the facts as they are, meeting serious problems in a serious way. The complacency of the past decade must now give way to swift but well-considered action.

Present trends are not encouraging, but they are not immutable. They are among today's most urgent challenges, and well within our power to overcome. Our country has met many great tests. Some have imposed extreme hardship and sacrifice. Others have demanded only resolve, ingenuity, and clarity of purpose. Such is the case with energy today.

We submit these recommendations with optimism. We believe that the tasks ahead, while great, are achievable. The energy crisis is a call to put to good use the resources around us, and the talents within us. It summons the best of America, and offers the best of rewards – in new jobs, a healthier environment, a stronger economy, and a brighter future for our people.

“The goals of this strategy are clear: to ensure a steady supply of affordable energy for America's homes and businesses and industries.”

— President
George W. Bush

Taking Stock

Energy Challenges Facing the United States

America's current energy challenges can be met with rapidly improving technology, dedicated leadership, and a comprehensive approach to our energy needs.

Our challenge is clear—we must use technology to reduce demand for energy, repair and maintain our energy infrastructure, and increase energy supply. Today, the United States remains the world's undisputed technological leader; but recent events have demonstrated that we have yet to integrate 21st-century technology into an energy plan that is focused on wise energy use, production, efficiency, and conservation.

Prices today for gasoline, heating oil, and natural gas are dramatically higher than they were only a year ago. In California, homeowners, farmers, and businesses face soaring electricity prices, rolling blackouts, increasing financial turmoil, and an uncertain energy future. Our nation's dependence on foreign sources of oil is at an all-time high and is expected to grow. Current high energy prices and supply shortages are hurting U.S. consumers and businesses, as well as their prospects for continued economic growth.

Our national energy policy must be comprehensive in scope. It must protect our environment. It must also increase our supply of domestic oil, natural gas, coal, nuclear, and renewable energy sources. Our failure over the past several years to modernize our energy infrastructure—the network of transmission lines, gas pipelines, and oil refineries that transports our energy to consumers and converts raw materials into usable fuels—is a result of the

lack of careful planning and lack of a comprehensive national energy plan. The United States faces serious energy challenges: electricity shortages and disruptions in California and elsewhere in the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers. These challenges have developed from years of neglect and can only be addressed with the implementation of sound policy. There are no easy, short-term solutions.

Our increased dependence on foreign oil profoundly illustrates our nation's failure to establish an effective energy policy. Between 1991 and 2000, Americans used 17 percent more energy than in the previous decade, while during that same period, domestic energy production rose by only 2.3 percent. While U.S. production of coal, natural gas, nuclear energy, and renewable energy has increased somewhat in recent years, these increases have been largely offset by declines in domestic oil production. As a result, America has met almost all of its increased energy demand over the past ten years with increased imports.

U.S. energy consumption is projected to increase by about 32 percent by 2020. Unless a comprehensive national energy policy is adopted, Americans will continue to feel the effects of an inadequate electrical transmission grid, a pipeline system stretched to capacity, insufficient domestic energy supply, and a regional imbalance in supply sources. It is important that we meet these challenges with a comprehensive energy plan that takes a long-term approach to meeting our energy needs.



The U.S. economy depends on reliable and affordable energy. In the coming months, we face several serious long-term energy challenges: electricity shortages and disruptions in California and the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers.



California's Energy Challenge

Recent and looming electricity blackouts in California demonstrate the problem of neglecting energy supply. They also foretell the consequences of failing to implement a long-term energy plan for our nation as a whole. Though weather conditions and design flaws in California's electricity restructuring plan contributed, the California electricity crisis is at heart a supply crisis.

Since 1995, California's peak summer demand for electricity has risen by at least 5,500 megawatts (MW), while in-state generation has failed to keep pace. California's generation shortfall did not stem from a lack of interest in building capacity. Since 1997, power producers filed applications to build an additional 14,000 MW of new capacity in California.

In addition to a lack of new generation, a crucial transmission bottleneck in the middle of the state—called Path 15—prevents power in the south from being shipped to the north during emergencies.

This year, reduced hydropower availability due to low rainfall, higher than expected unplanned plant outages, and the financial problems of California's utilities exacerbated this growing supply-demand imbalance. As a result, California's supply problem turned into a crisis, resulting in soaring electricity bills for homes and businesses and rolling blackouts.

In part due to the interconnected nature of the western electricity grid, California's critical electricity shortages have helped to drive up electricity costs in the West.

Unfortunately, there are no short-term solutions to long-term neglect. It can take new power plants and transmission facilities years to site, permit, and construct. Despite expedited federal permitting, California's emergency efforts to increase new generation by 5,000 MW by July appear to be falling short. Less than 2,000 MW of new generation is expected to be in place by summer. Even with aggressive conservation measures, peak demand this summer is projected to outstrip supply by several thousand megawatts. The California grid

operator expects more than 30 days of blackouts.

California officials have warned that the crisis may last several years. Though California's efforts to increase generation may not suffice to prevent blackouts this summer, if continued and strengthened, they promise to limit the duration of the crisis.

Recommendations:

★ The National Energy Policy Development (NEPD) Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

Conservation and Energy Efficiency

Conservation and energy efficiency are crucial components of a national energy plan. Energy efficiency is the ability to use less energy to produce the same amount of useful work or services. Conservation is closely related and is simply using less energy. Improved energy efficiency and conservation reduces energy consumption and energy costs, while maintaining equivalent service in our homes, offices, factories, and automobiles. Greater energy

efficiency helps the United States reduce energy imports, the likelihood of energy shortages, emissions, and the volatility of energy prices.

Over the last three decades, the United States has significantly improved its energy efficiency by developing and expanding the use of energy efficient technologies. Although our economy has grown by 126 percent since 1973, our energy use has increased by only 30 percent. Had energy use kept pace with economic growth, the nation would have consumed 171 quadrillion British thermal units (Btus) last year instead of 99 quadrillion Btus.

About a third to a half of these savings resulted from shifts in the economy, such as the growth of the service sector. The other half to two-thirds resulted from greater energy efficiency. Technological improvements in energy efficiency allow consumers to enjoy more energy services without commensurate increases in energy demand. The rate at which these efficiency improvements are made varies over time, depending on the extent to which factors—such as energy policies, research and development, prices, and market regulations—encourage the development of new, efficient products and consumer investment in these products. An increased rate of improvement in energy efficiency can have a large impact on energy supply and infrastructure needs, reducing the need for new power plants and other energy resources, along with reduced stress on the energy supply infrastructure.

Load management is the ability to adjust energy loads to reflect immediate supply conditions. In the very short term, direct appeals for conservation can ease strained energy supply markets for a time. Over the longer run, the ability to adjust demand on an as-needed basis can be an important source of energy reserves, resulting in lower energy bills for participating customers.

The impact that improvements in energy efficiency can have on energy supply markets grows over time. Electricity demand is projected to rise by 1.8 percent a year over the next 20 years, requiring the addition of some 393,000 MW of generation capacity. At the same time,

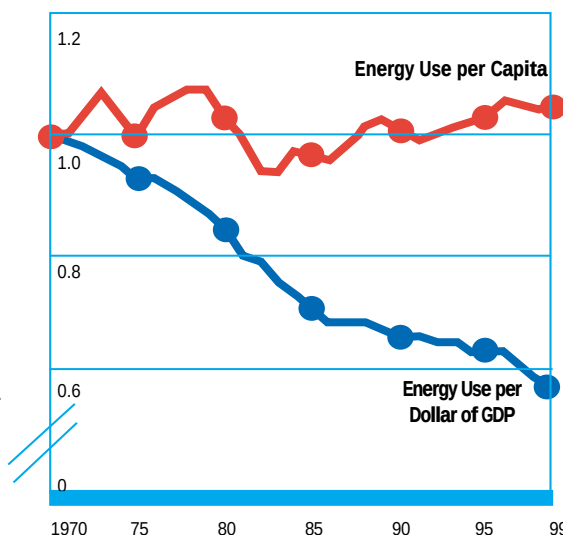
energy efficiency is projected to continue to improve between 2000 and 2020. A decrease in demand from 1.8 percent to 1.5 percent would reduce the need for new generating capacity next year by about 2,000 MW. Extending that reduction over the next 20 years would reduce the need for new generation by 60,000 to 66,000 MW.

While this projection shows that conservation can help ensure the United States has adequate energy supplies for the future, it also shows that conservation alone is not the answer. Even with more conservation, the U.S. will need more energy supplies. Today, new technologies offer new opportunities to enhance our energy efficiency. As these technologies gain market acceptance, they will help ensure a reliable and affordable energy and electric power supply for the nation.

Energy Intensity

The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). It now takes only about 56 percent of the energy required in 1970 to produce a

Figure 1-1
U.S. Energy Use per Capita and per Dollar of GDP: 1970–1999
(Index: 1970 = 1)



The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). By that yardstick, U.S. energy intensity declined significantly between 1970 and 1985, and has continued to decline, albeit at a slower rate.

Source: U.S. Department of Energy, Energy Information Administration.

Measures of Electrical Power

A watt is a measure of the amount of energy that can be produced during a specific period of time.

- 1 kilowatt (KW)= 1,000 watts
- 1 megawatt (MW)=1million watts
- 1 gigawatt (GW)=1 billion watts
- 1 terawatt (TW)=1 trillion watts

U.S. Energy Efficiency Is Improving

- New home refrigerators now use about one-third less energy than they did in 1972.
- New commercial fluorescent lighting systems use less than half the energy they did during the 1980s.
- Federal buildings now use about 20 percent less energy per square foot since 1985.
- Industrial energy use per unit of output declined by 25 percent from 1980 to 1999.
- The chemical industry's energy use per unit of output has declined by roughly 40 percent in the past 25 years.
- The U.S. government has reduced its energy use in buildings by over 20 percent since 1985.
- The amount of energy required to generate 1 kilowatt-hour of electricity has declined by 10 percent since 1980.

What Causes Transmission Constraints?

When additional electricity flow from one area exceeds a circuit's capacity to carry that flow to another area, the overloaded circuit becomes congested and blocks a steady flow of power. To prevent transmission bottlenecks, system operators curtail transactions between areas or increase generation on the side of the constraint where the electricity is flowing and reduce generation on the opposite side. Transmission constraints result in price differences between regions that exceed differences due to line losses, because electricity can no longer flow freely to the affected area.

A pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand.

dollar of GDP today (Figure 1-1). This reduction is attributable to improved energy efficiency, as well as to structural changes in the economy, particularly the relative decline of energy-intensive industries.

The decline in the nation's energy intensity accelerated between 1999 and 2000, a period when nonenergy-intensive industries experienced rapid growth. Energy intensity is projected to continue to decline through 2020 at an average rate of 1.6 percent a year. This is a slower rate of decline than experienced in the 1970s and early 1980s, which was characterized by high energy prices and a shift to less energy-intensive industries, but is a more rapid rate of decline than experienced on average during the latter part of the 1980s and the 1990s.

Challenges Confronting Electricity Supply

Our nation's electricity supply has failed to keep pace with growing demand. This imbalance is projected to persist into the future. The adverse consequences have manifested themselves most severely in the West, where supply shortages have led to high prices and even blackouts. In other regions, inadequate supply threatens the reliability and affordability of electric power.

Large amounts of new generating capacity are slated for installation around the country from 2001 to 2004. However, there is a geographic mismatch between where we will generate energy and where it is needed. For example, little capacity is being added where it is most needed, such as in California and eastern New York.



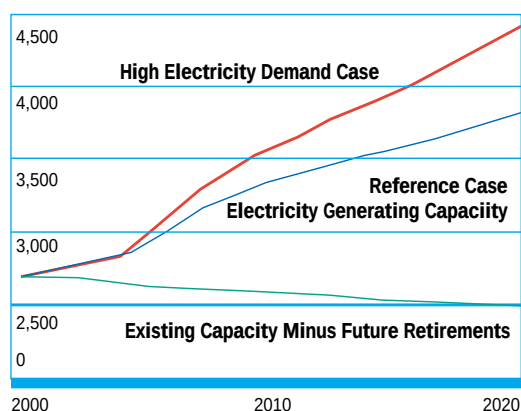
Electricity supply conditions in the Southeast are expected to be tight in the summer of 2001, much as they have been the previous two years. The Northeast may also face supply shortages. If the temperatures of the summer of 2000 had been normal rather than unseasonably cool, New York and New England would most likely have experienced electricity supply shortfalls and price spikes. Critical supply problems could arise if the weather in the summer of 2001 is unusually warm or if plant outages rise above average levels.

Our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand. Across the country, we are seeing the same signs that California faced in the mid-1990s: significant economic regulatory uncertainty, which can result in inadequate supply. This level of uncertainty can vary across the country, depending on state and local regulations. Of the approximately 43,000 MW of new generating capacity that power companies planned in 1994 for construction from 1995 to 1999, only about 18,000 MW were actually built. Although plans have been announced to build more capacity than the country will need over the next five to seven years, this new construction assumes market and regulatory conditions that are not yet assured. Over the next twenty years, the United States will need 1,300 to 1,900 new power plants, which is the equivalent of 60 to 90 new power plants a year (Figure 1-2).

But even with adequate generating capacity, we do not have the infrastructure to ensure reliable supply of electricity. Investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. Since 1989, electricity sales to consumers have increased by 2.1 percent annually, yet transmission capacity has increased by only 0.8 percent annually. As electricity markets become more regional, transmission constraints are impeding the movement of electricity both within and between regions.

The price spikes in the Midwest in the summer of 1998 were in part caused by trans-

Figure 1-2
The U.S. Needs More Power Plants



The nation is going to require significant new generation capacity in the next two decades. Depending on demand, the United States will need to build between 1,300 and 1,900 new power plants—or about one new power plant a week.

Source: U.S. Department of Energy, Energy Information Administration.

mission constraints, which limited the region's ability to import electricity from other regions at a time of high demand. Transmission bottlenecks contributed to the blackouts in California over the past year, and have been a persistent cause of price spikes in New York City during peak demand. Constraints on New England's ability to import low-cost power from Canada could raise electricity prices during periods of high demand.

Electricity is a secondary source of energy, generated through the consumption of primary sources (Figure 1-3). The largest source of U.S. electricity generation is coal, followed by nuclear energy, natural gas, hydropower, oil, and non-hydropower renewable energy.

Coal

Coal is America's most abundant fuel source. The United States has a 250-year supply of coal. Over 1 billion tons of coal were produced in 25 states in 2000. About 99.7 percent of U.S. coal production is consumed domestically, with electricity generation accounting for about 90 percent of coal consumption.

After peaking in 1982, coal prices have generally declined. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to

remain the dominant fuel in meeting increasing U.S. electricity demand through 2020, energy policy goals must be carefully integrated with environmental policy goals. The Clean Air Act Amendments of 1990 and related state regulations require electricity generators to reduce emissions of sulfur dioxide and nitrogen oxide.

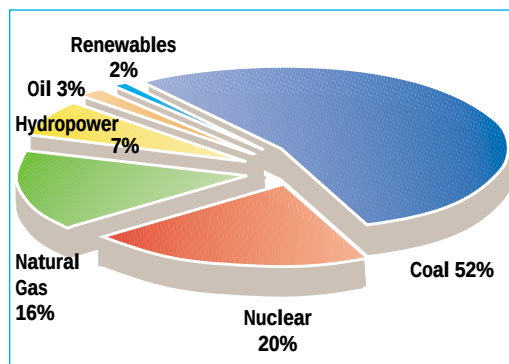
Nuclear Energy

Nuclear energy is the second-largest source (20 percent) of U.S. electricity generation. Nuclear power is used exclusively to generate electricity. Nuclear power has none of the emissions associated with coal and gas power plants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Costs of electricity generation by nuclear plants compare favorably with the costs of generation by other sources.

While the number of nuclear plants has declined due to retirements, nuclear electricity generation has steadily increased in recent years. Several factors have created a more favorable environment for nuclear energy: safe, standardized plant designs; an improved licensing process; effective safety oversight by the Nuclear Regulatory Commission (NRC); the advent of new technologies; and uncertain, volatile natural gas prices. This more favorable environment has resulted in increased re-licensing of nuclear plants and the consolidation of several plants in the hands of fewer, more experienced operators.

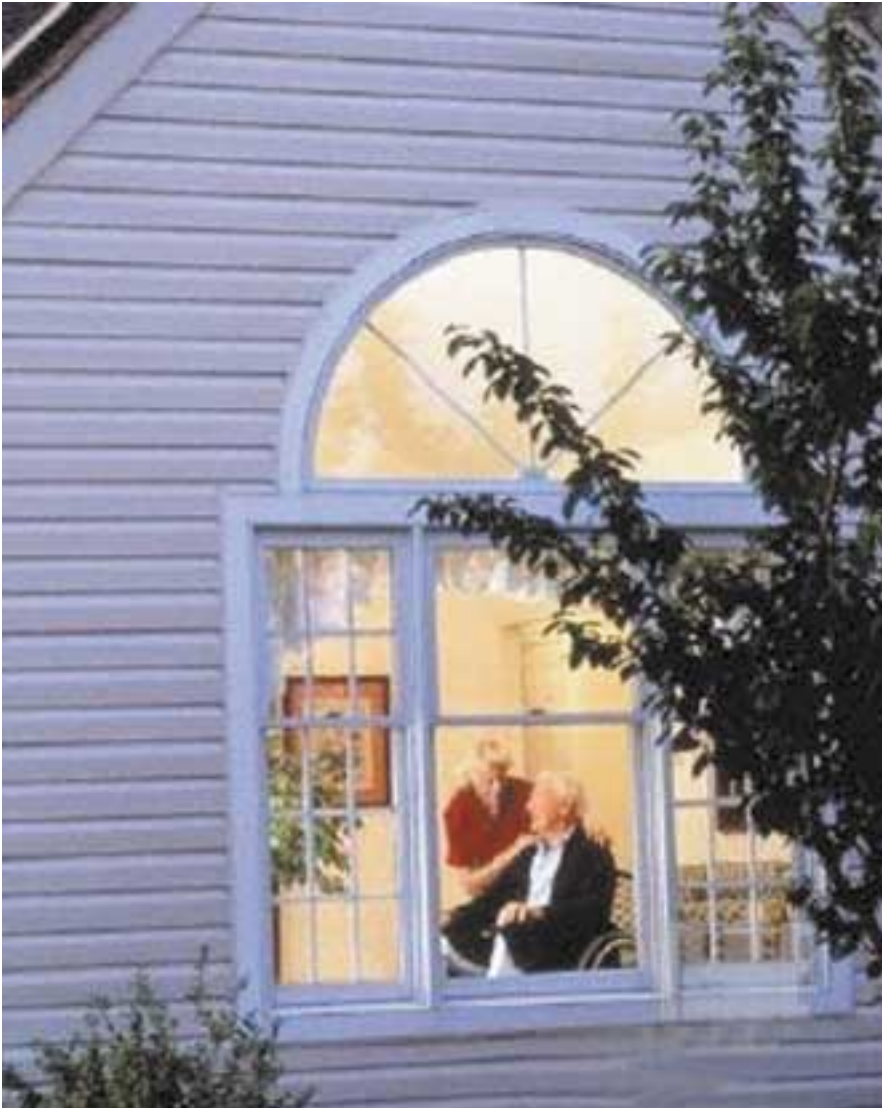
Figure 1-3

Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for over 70 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration.



Many Americans received high heating bills this winter as a result of sharp increases in natural gas prices.

The nuclear industry is closely regulated by the NRC, which provides oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations, and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. In addition to rigorous inspection criteria, the installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the nuclear industry's strong safety record.

An important challenge to the use of nuclear energy is the issue of safe and

timely long-term storage of spent nuclear fuel and high- and low-level radioactive waste. Currently, no plans exist to construct any new nuclear plants. However, due to more favorable conditions, the decline in nuclear energy generation has not been as rapid as was predicted only a few years ago, as evidenced by increased re-licensing.

Natural Gas

Natural gas is the third-largest source of U.S. electricity generation, accounting for 16 percent of generation in 2000. Under existing policy, natural gas generating capacity is expected to constitute about 90 percent of the projected increase in electricity generation between 1999 and 2020. Electricity generated by natural gas is expected to grow to 33 percent in 2020—a growth driven by electricity restructuring and the economics of natural gas power plants. Lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions give gas an advantage over coal and other fuels for new generation in most regions of the country.

However, natural gas is not just an electricity source. It is used in many different ways, including as vehicle fuel, as industrial fuel, and in our homes. In addition, natural gas is used as a feedstock during the manufacturing process of such products as chemicals, rubber, apparel, furniture, paper, clay, glass, and other petroleum and coal products. Overall, natural gas accounts for 24 percent of total U.S. energy consumed and for all purposes 27 percent of domestic energy produced.

Eighty-five percent of total U.S. natural gas consumption is produced domestically. The import share of consumption rose from 5 percent in 1987 to 15 percent in 2000, and net imports have comprised more than 50 percent of the growth in gas demand since 1990. Canada, with very large gas supplies and easy pipeline access to the lower 48 states, accounts for nearly all U.S. natural gas imports. Unlike oil, almost all natural gas is produced and sold within the same region. Therefore, prices are determined by regional, rather than global, markets.

In 2000, natural gas prices moved

sharply higher after fifteen years of generally flat prices. Futures prices surged by 320 percent in 2000 to an all-time high of \$9.98 per million Btus in late December 2000—nearly five times higher than the \$2.05 per million Btu average from 1991 to 1999. While prices have declined since the beginning of 2001, they remain much higher than recent levels.

Between 2000 and 2020, U.S. natural gas demand is projected by the Energy Information Administration to increase by more than 50 percent, from 22.8 to 34.7 trillion cubic feet. Others, such as Cambridge Energy Research Associates, expect gas consumption to increase by about 37 percent over that period. Growth is projected in all sectors—industrial, commercial, residential, transportation, and electric generation. More than half of the increase in overall gas consumption will result from rising demand for electricity generation.

Although high natural gas prices have negative effects on consumers, businesses, industries, and the economy as a whole, they also promote more rapid development and adoption of new energy efficient technologies, investment in distribution systems, and greater investment in exploration and development. Although these market responses do not occur rapidly enough to prevent near-term price spikes, over time, they help to hold down prices.

As a result of the sharp increase in natural gas prices, many consumers received historically high utility bills this winter. The price spike has had a particularly severe impact on low-income consumers who use natural gas for heating. In recent months, 5 million consumers have applied for federal and state assistance to pay their heating bills—an increase of 1 million consumers over last year.

The projected rise in domestic natural gas production—from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020—may not be high enough to meet projected demand. In the near term, incremental production of natural gas is expected to come primarily from unconventional sources in the Rocky Mountain, Gulf Coast, and mid-continent regions; the North Slope of Alaska; and the offshore Gulf of Mexico. Onshore federal lands currently contribute

about 10 percent of U.S. production, and federal offshore production contributes about 26 percent.

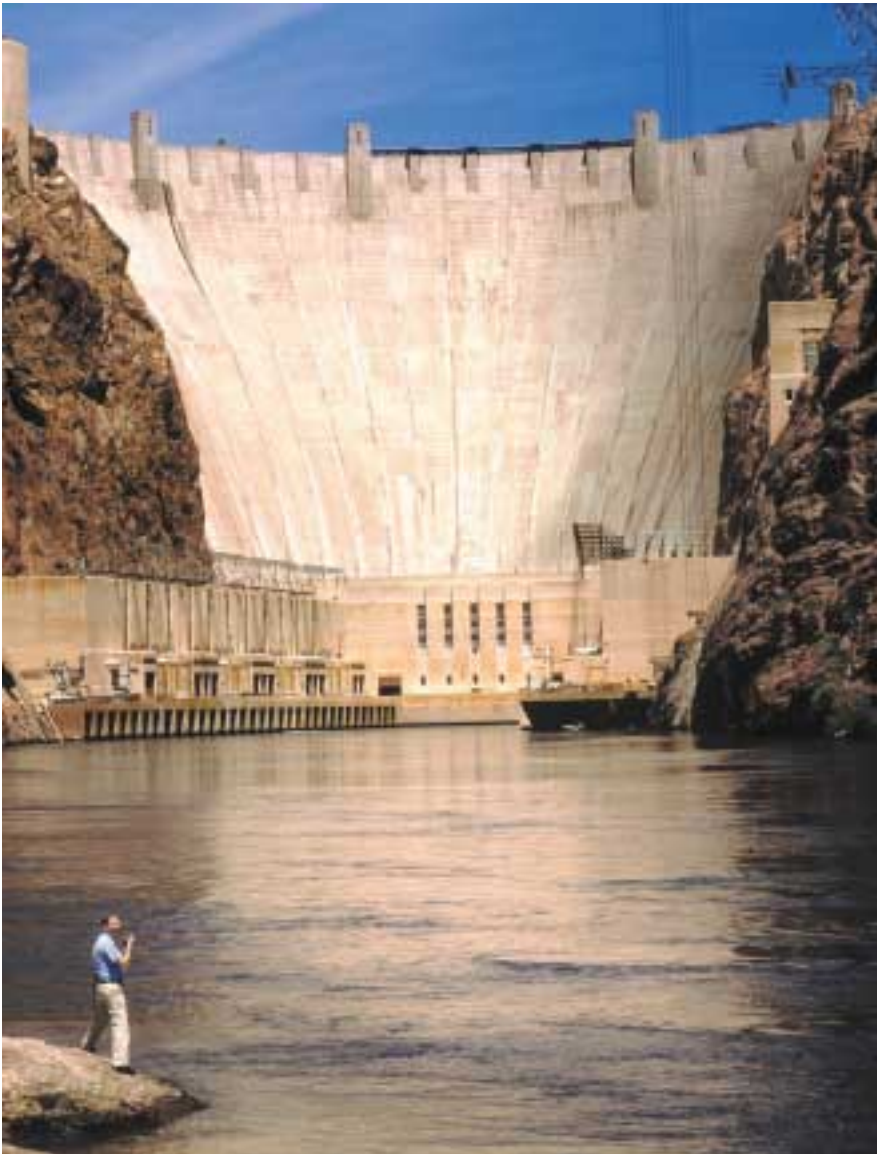
The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with consequent impacts on electricity prices, home heating bills, and the cost of industrial production. These concerns will redouble if policy decisions sharply reduce electricity generation by any other source, since it is doubtful that natural gas electricity generation could expand to the extent necessary to compensate for that loss of generation.

To meet this long-term challenge, the United States not only needs to boost production, but also must ensure that the natural gas pipeline network is expanded to the extent necessary. For example, although natural gas electricity generation in New England is projected to increase by 16,000 MW through 2000, bottlenecks may block the transmission of necessary supplies. Unless pipeline constraints are eliminated, they will contribute to supply shortages and high prices, and will impede growth in electricity generation.

Hydropower

Hydropower is the fourth-largest source of U.S. electricity generation, accounting for about 7 percent of total generation in 2000. In some regions of the country, such as the Northwest and New York, hydropower makes a much bigger contribution to electricity generation. Although the United States is second only to Canada in hydropower generation, hydropower generation has remained relatively flat in the United States for years.

Hydropower has significant environmental benefits. It is a form of low-cost electricity generation that produces no emissions, and it will continue to be an important source of U.S. energy for the future. Given the potential impacts on fish and wildlife, however, it is important to ef-



Hydropower is the fourth-largest source of U.S. electricity generation. The most significant challenge confronting this source of energy is regulatory uncertainty regarding the federal licensing process.

ficiently and effectively integrate national interests in both natural resource preservation and environmental protection with energy needs.

There are two categories of hydropower projects in the United States: (1) those operated by federal electric utilities, such as the federal power marketing administrations (Bonneville, Western, Southwestern, and Southeastern); and (2) the approximately 2,600 non-federal hydropower dams licensed or exempted by the Federal Energy Regulatory Commission (FERC). The federal utilities have large hydropower systems operated by the Bureau of Reclamation and Army Corps of Engineers, and play an important role meeting electricity

demand, especially in the Northwest and the West. Hydropower projects operate with multiple purposes, such as electricity generation, flood control, navigation, and irrigation.

Although most potential for hydropower has already been developed, there is some undeveloped hydropower capacity in the United States. Much of this capacity could be expanded without constructing a new dam.

The most significant challenge confronting hydropower is regulatory uncertainty regarding the federal licensing process. The process is long and burdensome, and decision-making authority is spread across a range of federal and state agencies charged with promoting different public policy goals. Reforms can improve the hydropower licensing process, ensuring better public participation, ensuring that effective fish and wildlife conditions are adopted, and providing interagency resolution before conflicting mandatory license conditions are presented. The licensing process needs both administrative and legislative reforms. In addition, FERC should be encouraged to adopt appropriate deadlines for its own actions during the process.

Oil

Oil accounts for approximately 3 percent of electricity generation. Oil is used as a primary source to fire electricity generation plants in some regions. Specifically, oil is an important source of electricity in Hawaii, Florida, and some northeastern states. Oil can also be used as an additional source of fuel for electricity generation in plants that can use either natural gas or oil. However, electricity generation from oil is projected to decline to about one-half of one percent of total electricity generation by 2020.

Renewable Energy: A Growing Resource

Renewable energy technologies tap natural flows of energy—such as water, wind, solar, geological, and biomass sources—to produce electricity, fuels, and heat. Non-hydropower renewable electricity generation is projected to grow at a faster rate

than all other generation sources, except natural gas. These sources of energy are continuously renewable, can be very clean, are domestically produced, and can generate income for farmers, landowners, and others. Although its production costs generally remain higher than other sources, renewable energy has not experienced the price volatility of other energy resources.

Non-hydropower renewable energy sources currently account for only about 4 percent of total energy consumption and 2 percent of total electricity generation. The sources of non-hydropower renewable electricity generation are biomass (the direct combustion of plant matter and organic residues, such as municipal solid waste use); geothermal (use of naturally occurring steam and hot water); wind; and solar. Biomass and geothermal account for most renewable electricity generation.

The most important long-term challenge facing renewable energy remains economic. Renewable energy costs are often greater than those of other energy sources. However, these costs have declined sharply in recent years, due to improved technology. If this trend continues, renewable energy growth will accelerate. By 2020, non-hydropower renewable energy is expected to account for 2.8 percent of total electricity generation.

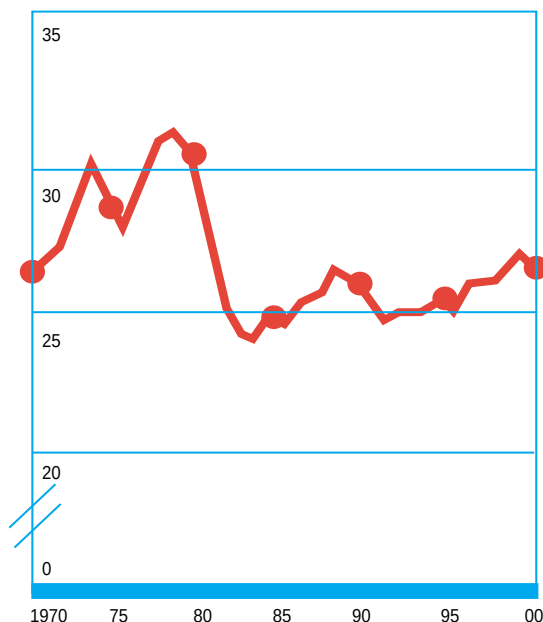
Transportation Energy Needs

Oil is the nation's largest source of primary energy, serving almost 40 percent of U.S. energy needs. In 2000, the United States consumed an average of 19.5 million barrels of oil every day. Transportation fuels account for about two-thirds of our oil consumption, and the industrial sector for 25 percent. Residential and commercial uses, such as heating oil and propane—important fuels in the Northeast and Midwest—account for most of the rest.

The share of oil in U.S. energy supply has declined since the early 1970s, the result of growth in other fuels, particularly coal and nuclear. Per capita oil consumption, which reached a peak in 1978, has fallen by 20 percent from that level (Figure 1-4).

Figure 1-4
U.S. Per Capita Oil Consumption: 1970–2000

(Barrels per Year)



Per capita oil consumption reached a peak in 1978 of 31 barrels. It has fallen by 20 percent since then to 26 barrels per capita.

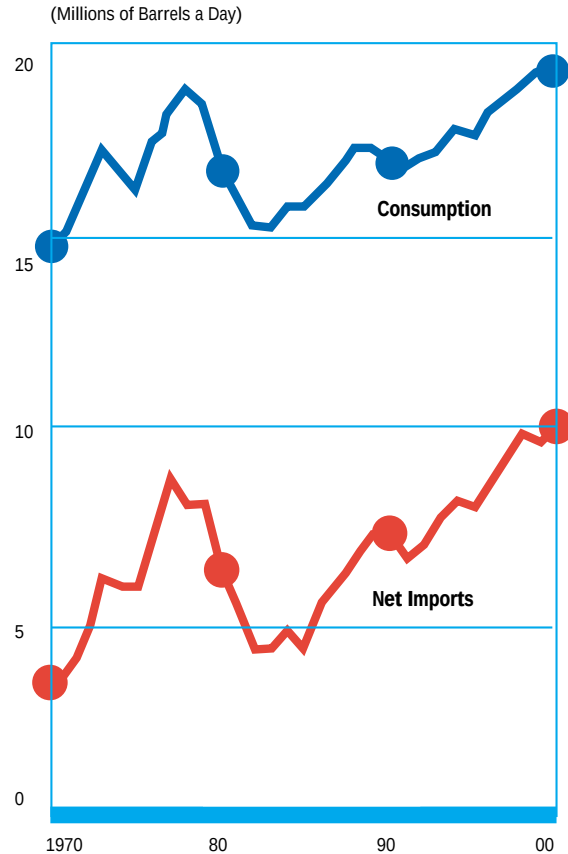
Source: U.S. Department of Energy, Energy Information Administration

Renewable energy technologies tap natural flows of energy to produce electricity, fuels, and heat.

U.S. DEPARTMENT OF ENERGY, NATIONAL
RENEWABLE ENERGY LABORATORY



Figure 1-5
Dependence on Foreign Sources of Oil



U.S. dependence on oil imports is a serious long-term challenge. The economic security of our nation and our trading partners will remain closely tied to global oil market developments.

Source: U.S. Department of Energy, Energy Information Administration.

In 2020, oil is projected to account for roughly the same share of U.S. energy consumption as it does today.

The United States has been a net importer of energy since the 1950s, and U.S. dependence on imports has grown sharply since 1985 (Figure 1-5). Today, oil accounts for 89 percent of net U.S. energy imports. Net oil imports account for most of the rise in energy imports since the mid-1980s, and have grown from about 4.3 million barrels per day (bpd) in 1985 to 10 million bpd in 2000.

World oil prices have been marked by notable price volatility over the past several years. For example, the average initial purchase price of crude oil rose from \$8.03 a barrel in December 1998 to \$30.30 a barrel in November 2000. Spot prices rose even higher. This dramatic price swing was the product of several events. A series of production cuts by the Organization of Petroleum Exporting Countries (OPEC) in 1998 and 1999 sharply curtailed global oil supplies. At the same time, rebounding demand for oil in Asia following roughly two years of economic weakness, and rapid economic growth in the United States boosted oil consumption and squeezed supplies even further. By September 2000, oil prices peaked as markets faced limited supply of crude and petroleum products



Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. For example, U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products.

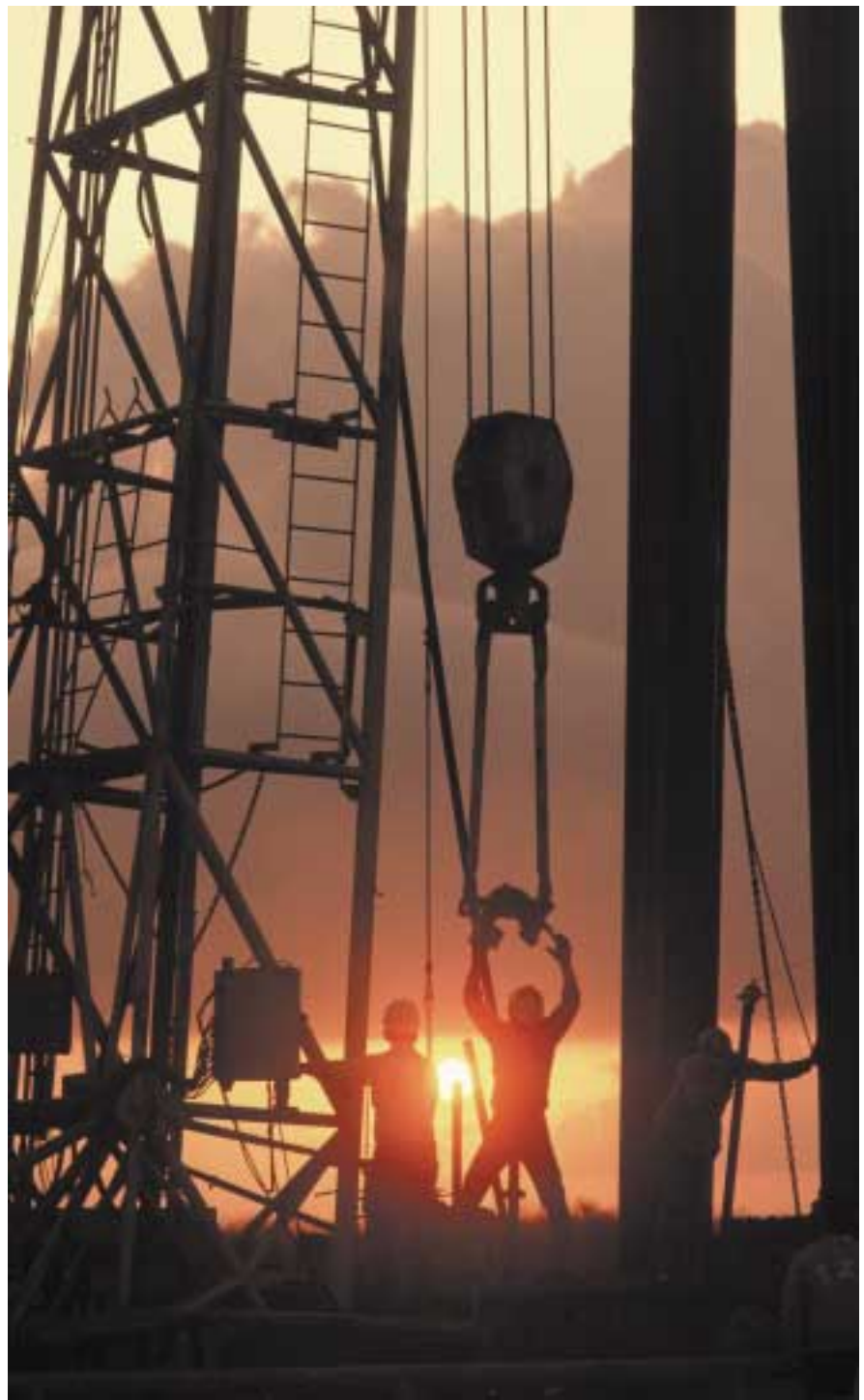
ahead of the winter season, when demand is typically higher. In December 2000, oil prices fell after the market absorbed the impact of a series of OPEC production increases.

This recent price volatility illustrates the effect of intermittent market power exerted by cartel behavior in a global petroleum market. Moreover, prices are set in a market where supply is geographically concentrated. Almost two-thirds of world proven reserves are in the Middle East. Elsewhere, Central and South America account for 9 percent; Africa, 7 percent; North America, 5 percent; Eastern Europe and the former Soviet Union, 5 percent; the rest of Asia, 4 percent; and Western Europe, 2 percent. OPEC's huge oil reserves and production capacity and its periodic efforts to influence prices add to volatility in the market.

Oil prices are expected to remain high through 2002, affecting the cost of transportation, heating, electricity generation, and industrial production. High oil prices mean high prices for petroleum products, such as gasoline, diesel fuel, heating oil, propane, and jet fuel. The summer 2001 base case average gasoline price from the Department of Energy *Short-Term Energy Outlook* is \$1.49 per gallon. However, prices have risen more rapidly than anticipated since the report's release, and a much higher summer average in the range of \$1.50 to \$1.65 per gallon is likely. Some areas have already experienced gasoline prices above \$2.00 per gallon. Gasoline inventories going into the driving season are projected to be lower than last year, which could set the stage for regional supply problems that once again create significant price volatility in gasoline markets.

Price Volatility in Gasoline Markets

During the early summer of 2000, low inventories set the stage for a gasoline price run-up in the Midwest. Several pipeline and refinery problems sent marketers scrambling for limited supplies of both reformulated gasoline (RFG) and conventional gasoline, driving prices up rapidly. In Chicago, the spot price for blend stock for RFG, ex-



cluding ethanol, doubled in about six weeks, from 83 cents per gallon on April 25 to \$1.65 on June 7. Spot prices then fell back over the next five weeks to 84 cents on July 12 as extra supply began arriving. Retail regular-grade RFG prices in the Midwest rose from \$1.47 on April 24 to just over \$2.00 per gallon on June 19, before falling back to \$1.43 by July 24, showing the typical tendency of

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries.

retail prices to lag spot price changes.

Refiners face additional challenges as a result of various state and local clean fuel requirements for distinct gasoline blends (“boutique fuels”). These different requirements sometimes make it difficult, if not impossible, to draw on gasoline supplies from nearby areas or states to meet local needs when the normal supply is disrupted.

In 2000, very low inventories of gasoline and other refined products on the U.S. East and Gulf coasts increased the market’s susceptibility to external shocks, such as operating problems in refineries or pipelines, or short-term surges in demand. Last winter, heating oil prices were at near-record levels. During 2000, the federal government reduced the vulnerability of the Northeast to heating oil shortages, such as those experienced in January 2000, by creating a 2-million-barrel heating oil reserve in New Jersey and Connecticut.

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries, particularly OPEC countries. In addition, access to promising domestic oil reserves is limited. U.S. oil production in the lower 48 states reached its peak in 1970 at 9.4 million bpd. A surge in Alaskan North Slope oil production beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska’s production peaked in 1988 at 2 million bpd, and fell to 1 million bpd by 2000. By then, U.S. total oil output had fallen to 5.8 million bpd, 39 percent below its peak.

By 2020, U.S. oil production is projected to decline from 5.8 to 5.1 million bpd under current policy. However, oil consumption is expected to rise to 25.8 million bpd by 2020, primarily due to growth in consumption of transportation fuels. Given existing law, production from offshore sources, particularly the Gulf of Mexico, is predicted to play an increasingly important role in the future, accounting for a projected high of 40 percent of domestic oil production by 2010, up from 27 percent today. Technological advances can mitigate the decline in U.S. oil production by enhancing recovery from domestic oil reserves and

lowering production costs.

Our projected growing dependence on oil imports is a serious long-term challenge. U.S. economic security and that of our trading partners will remain closely tied to global oil market developments. Without a change in current policy, the share of U.S. oil demand met by net imports is projected to increase from 52 percent in 2000 to 64 percent in 2020. By 2020, the oil for nearly two of every three gallons of our gasoline and heating oil could come from foreign countries. The sources of this imported oil have changed considerably over the last thirty years, with more of our imports coming from the Western Hemisphere. Despite progress in diversifying our oil suppliers over the past two decades, the U.S. and global economies remain vulnerable to a major disruption of oil supplies.

The Strategic Petroleum Reserve (SPR), the federal government’s major tool for responding to oil supply disruptions, has not kept pace with the growth in imports. The number of days of net oil import protection provided by the Reserve declined from 83 days of imports in 1992 to 54 days of imports today. Net domestic oil imports have increased significantly since 1992, while the SPR’s oil inventory actually decreased.

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products. Unless changes take place, the net effect will likely be increased imports, regionally tight markets, and circumstances in which prices for gasoline, heating oil, and other products rise independently of oil prices.

Greater price volatility for gasoline, diesel fuel, heating oil, propane, and jet fuel is likely to become a larger problem over time, unless additional refining capacity and expanded distribution infrastructure can be developed at the same time cleaner products are required. Increasing domestic oil production and reducing demand, particularly for transportation fuels, will re-

quire adoption of a comprehensive national energy policy.

Alternative Transportation Fuels

Development of alternative fuels such as ethanol and other biofuels (liquid fuels derived from organic matter, such as crops), natural gas, and electricity, can help diversify the transportation sector that is so reliant on oil.

Ethanol, a biofuel based on starch crops such as corn, is already making a significant contribution to U.S. energy security, displacing more oil than any other alternative fuel. Other biofuels, such as biodiesel, which can be made from soybean, canola oils, animal fats, and vegetable oils, are making an increasingly important con-

tribution

The success of the federal alternative fuels program has been limited, however. The program focuses on mandating that certain fleet operators purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. Reforms to the federal alternative fuels program could promote alternative fuels use, such as expanding the development of an alternative fuels infrastructure.

Summary of Recommendations

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy, and to explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

Regional U.S. Energy Challenges

MIDWEST

Energy consumption in the Midwest is dominated by the industrial sector, the sector with the fastest-growing consumption rate through 2020. The transportation sector has the second-fastest consumption growth rate through 2020. States are affected by higher prices for natural gas, propane, and gasoline, and they expect gasoline price spikes this summer. Electricity supplies in some parts of the region may be tight during peak summer demand. High energy prices will drive up farm operating costs, particularly for fertilizer, irrigation, grain drying, and fuel for tractors.

Illinois consumers are reeling from high heating and cooling costs. Landlords are forced to pass on these costs in the form of higher rents. Farmers face low commodity prices, high fuel costs, and dramatically higher fertilizer costs. A key refinery is closing in part because of the cost of meeting cleaner-burning gasoline requirements.

Minnesota's residential electricity use has increased due to population growth and a healthy economy.

Iowa imports over 90 percent of its energy. Farmers are paying twice the 1999 price of fertilizer because of higher prices for natural gas, which is a major component in the fertilizer production.

WEST

Energy consumption in the West is dominated by the transportation sector, which is followed closely by the industrial sector. The region's drought emergency is exacerbating an already challenging energy picture. California is likely to experience more severe electricity blackouts this summer. The Pacific Northwest faces a major shortage of hydropower generation due to low water levels. Electricity prices will remain high in the West until more supply is added. Gasoline could be in short supply this summer in California and other states.

California's energy consumption has grown by about 7 percent a year, while production has remained flat. The point has been reached where demand is occasionally exceeding supply, which has caused rolling blackouts. The situation is likely to worsen this summer when demand will peak.

Oregon's lowest snow pack in history will result in the most severe short-term electricity problem in decades. The state will face high spot market prices and reports the highest gasoline prices in the country.

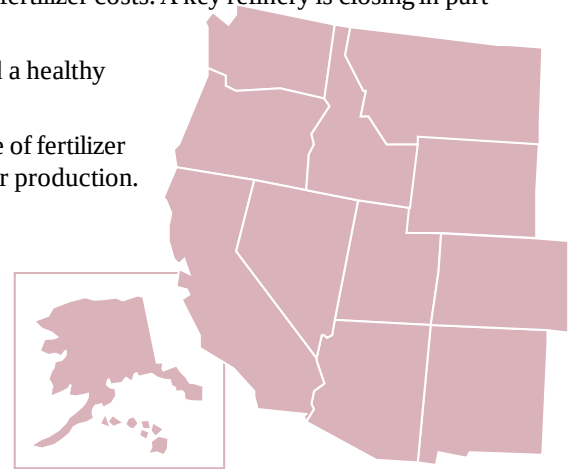
Washington businesses are closing down or cutting back on production. Electricity costs of \$400 per unit compared to \$35 a year ago contributed to the closure of a major paper plant employing 800 employees.

Colorado small business are suffering as well. A 169 percent jump in natural gas prices in one year may force small businesses to close.

Idaho utilities are offering to pay their irrigation customers to not farm portions of their fields to reduce electricity demand and make that saved power available for other local customers. The low snow pack has reduced water in river systems needed for hydropower generation.

Hawaii's geographic isolation contributes to its many energy issues, such as importing 100 percent of its energy, its disproportionately high consumption of jet fuel and heavy reliance on tourism, and its dependence on imported oil for over 90 percent of its primary energy, the majority from sources in the Asia-Pacific region. Electricity is produced mainly from oil, including residuals and distillates from refineries and coal. Because the Islands' electric grids are not interconnected, electric utilities must operate with high reserve margins.

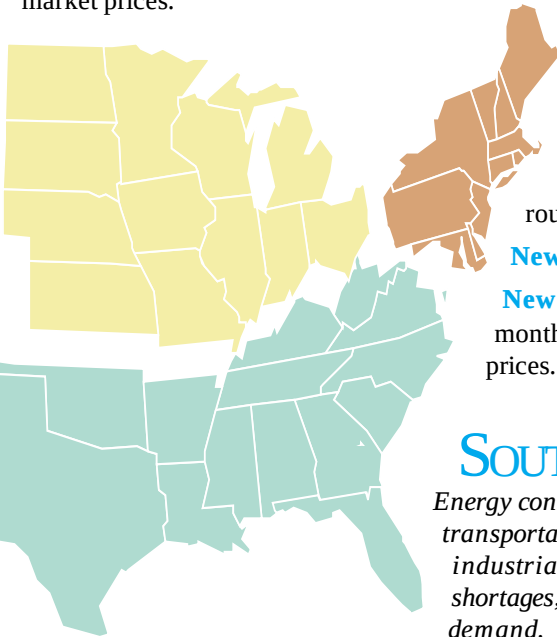
Nevada is covered in large part by federal lands that require federal approval for permitting new transmission and generation facilities. The permitting process can be protracted and cumbersome, despite efforts by federal agencies to streamline and coordinate. The desert climate requires both heating and cooling, the cost of which can be burdensome. While the desert climate is also conducive to geothermal, wind, and solar technologies, additional work is needed to make these technologies economically competitive.



NORTHEAST

Energy consumption in the Northeast is dominated by the transportation sector. Forecasts developed by the Energy Information Administration indicate that the transportation sector will also remain the dominant sector with the fastest-growing consumption rate through 2020. Northeast states' energy challenges include reducing vehicle pollution and interstate transport of power plant emissions. Heavy dependence on heating oil results in disproportionate impacts during cycles of high prices. Energy supplies in the region are limited by electric transmission and gas pipeline bottlenecks.

New York is rushing to complete 11 small natural gas turbines to avoid blackouts in New York City this summer, where customers pay market prices.



Delaware needs upgraded transmission lines to handle increasing loads.

Traditional distributed generation using diesel generators may address these shortfalls, but could raise environmental problems.

Connecticut expects no power shortages this summer, but brownouts are possible if there is a prolonged spike in energy use while power plants are shut down for routine maintenance.

New Hampshire must conserve power on hot days to avoid summer blackouts.

New Jersey regulators have had to allow utilities to raise natural gas rates by 2 percent a month through July 2001 to make up for money lost during the winter due to high fuel prices.

SOUTH

Energy consumption in the South is dominated by the industrial sector, followed by the transportation sector. The transportation sector, however, is expected to grow faster than the industrial sector through 2020. While no state in the region anticipates summer power shortages, electricity supplies in parts of the region may be tight during peak summer demand.

Arkansas' costs of natural gas and propane have doubled and then tripled, contributing to employee layoffs.

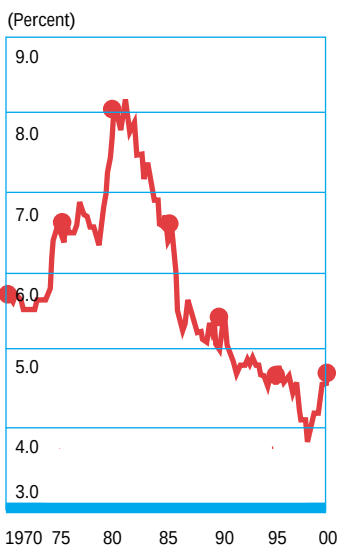
Oklahoma's second-largest industry is the oil and gas industry. The volatility of oil and gas markets can severely affect Oklahomans and the state's economy.

Striking Home

The Impacts of High Energy Prices on Families, Communities, and Businesses

American families, communities, and businesses all depend on reliable and affordable energy for their health, safety, and livelihood. Energy is a critical component of nearly everything that affects our daily lives, from transportation to communication, from food production to medical services, and from air conditioning to heating. Americans expect these services to enhance our lives, and are keenly aware that each additional, unanticipated energy expense is a decrease in funds available for other needs.

Figure 2-1
Income Spent on Energy



Until recently, the share of disposable household income spent on energy steadily declined, falling to a low of 3.8 percent at the end of 1998. Higher prices for oil and other energy products and record cold temperatures in late 2000 bumped this share up to 4.8 percent in the fourth quarter.

Note: Plotted quarterly through the fourth quarter of 2000.

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

Impacts of High Energy Prices on the Daily Lives of Americans

Many American families and businesses have already felt the strain of rising prices and unreliable energy supplies. Every time energy prices rise, American families have fewer dollars available to meet their needs. Low-income households, energy-intensive industries, and

farmers generally find it difficult to make rapid adjustments to energy price increases.

Rising oil prices act like a tax by foreign oil exporters on Americans. Changing energy prices impose economic costs, such as forcing plants to change schedules, replace machinery, or even shut down. These costs can eventually impact economic growth. So far, increased capital investment by domestic energy producers has offset only a small part of the dampening effects of higher energy costs on consumer spending.

Families

Energy bills for the 74 million middle-class American households consist primarily of home and transportation related expenses. Heating and cooling expenses represent about 40 percent of household energy costs. Other energy expenses include costs for lighting, hot water, appliances, and transportation.

For almost twenty years, the share of household income that Americans spent on their energy needs steadily declined. However, between 1998 and the end of last year, family spending on energy rose by more than 26 percent, from 3.8 to 4.8 percent of after-tax income (Figure 2-1).

Last winter, heating bills for many families tripled. Roughly 50 percent of American families heat their homes with natural gas. Because the last two months of 2000 were particularly cold in some parts of the country, heating bills increased significantly relative to the previous winter. Last winter, average natural gas heating costs in the Midwest increased by 73 percent, from \$540 to \$933. New Englanders' heating bills rose by 27 percent, from \$760 to \$967.





Higher energy prices have forced some energy-intensive manufacturing industries to halt or scale back production and lay off workers.

Many working households can usually accommodate such increases in energy by cutting back on other needs. However, low-income households often have more difficult choices to make. Energy costs for an average low-income household could total 14 percent of family income during the winter of 2000–01, up from about 11 percent for the previous winter. In contrast, energy costs typically represent only about 4 percent of a middle-class family's household budget.

The Low Income Home Energy Assistance Program (LIHEAP) is a federal block grant program that helps low-income consumers pay their energy bills. Last winter, 1.2 million more American families applied for LIHEAP assistance to pay their heating bills, bringing the total close to 5 million American families—up by 26 percent over last year's 3.9 million applicants. As many as 3.6 million families in eighteen states and the District of Columbia risk being unable to pay their bills and having their energy cut off because of the effects of rapidly increasing energy costs.

Recommendations:

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

The low-income elderly are particularly vulnerable to disruptions in energy supply. If they keep their homes at a reasonable temperature, the high cost of electricity may make it difficult for them to pay their higher electricity bills. This could further result in an elimination of service. Another summer of very hot weather and high energy bills could cause serious health problems for some Americans, particularly those sensitive to high temperatures.

The Department of Energy's Weatherization Assistance Program has reduced the heating and cooling costs of low-income households by weatherizing more than 5 million homes since its inception in 1976. The President has requested \$1.2 billion in additional funding for this program over ten years, roughly double the current level of spending. Consistent with that commitment, the 2002 budget will include a \$120 million increase over 2001.

The Department of Energy's Weatherization Assistance Program

The energy burden on low-income households, as a proportion of income, is four times greater than for other American households. The Weatherization Program provides grant funding for a network of all states and some 970 local weatherization agencies to provide insulation, duct system improvements, furnace upgrades, and other cost-effective, energy-saving improvements based on the energy needs of each home weatherized. Currently, each dollar spent on home weatherization generates \$2.10 worth of energy savings over the life of the home; with additional economic, environmental, health, and safety benefits associated with the installations and resulting home improvements. Typical savings in heating bills, for a natural gas heated home, grew from about 18 percent in 1989 to 33 percent today.

Businesses

For businesses, higher energy prices and disruptions in energy supply may increase inflation and reduce profits, production, investment, and employment. The im-

pact of higher energy prices takes two forms: the higher costs of paying for the energy to run the business, and the higher costs when raw fuel sources are used in manufacturing.

In some energy-intensive industries, rising energy prices have had a significant effect on product prices and operations. For instance, while nonenergy producer prices at the intermediate stage of processing have risen by only 3.6 percent since December 1998, prices of industrial materials and plastic resins, which use petroleum inputs, are up 14 and 23 percent, respectively. DuPont, the leading U.S. producer of plastics, chemicals, and fibers derived from oil and natural gas, faced an increase of \$1.3 billion in raw material costs last year, the largest increase in the industry in a decade. The company expects further disruptions this year due to high energy costs.

The Federal Reserve has reported that businesses have experienced higher energy costs for a number of months, but have been unable to pass these increases on to customers due to intense foreign and domestic competition and slowing demand. On March 7, 2001, the Federal Reserve reported that businesses across the country experienced higher fuel and other energy costs in February 2001, but most businesses were unwilling or unable to pass these costs on to consumers.

This absorption of much of the higher costs of energy has deteriorated the profit

margins of many businesses. About one-quarter of the increase in total unit costs of nonfinancial, nonenergy corporations in the final quarter of last year reflected a rise in energy costs. A more moderate pace of consumer spending, due in part to higher energy prices (natural gas in particular) also contributed to the margin squeeze. The reduction in businesses' purchasing power has also constrained outlays for plants and equipment and most likely intensified the slowdown in business investment that occurred in the last half of 2000.

Energy-intensive manufacturing industries are very sensitive to changes in energy prices, and adjust their production accordingly. Some companies have been forced to halt or scale back production and lay off workers. Others have deemed it more profitable to sell their energy than to produce their products. In the Pacific Northwest, Georgia-Pacific's paper mill closed down and laid off 800 workers until diesel generators could be installed. In recent months, the company's average power costs soared from \$1.2 million to \$10 million.

For other industries, such as computer-driven service industries, energy is not an important component of the total cost. However, many such businesses require a high-quality, reliable source of power. Even a brief loss of power can impose significant costs on high-technology firms.

Energy supply disruptions also impose costs on firms when products or prod-



Disruptions in the supply of energy impose hardships on businesses when products or product inputs are damaged or destroyed, or when production runs are interrupted.



Many companies have been unable to pass higher energy costs on to their customers, which has sharply reduced their profit margins.



Farmers have been hit especially hard by higher fuel and oil prices, which accounted for over a third of the rise in the cost of running their farms.

uct inputs are damaged or destroyed, or when production runs are interrupted. For example, a survey of small businesses conducted by the National Federation of Independent Business in February, 2001, found that more than half of the firms surveyed that had experienced blackouts this year in California were forced to reduce or shut down business operations altogether during the blackouts. About one-third lost sales, almost 21 percent said materials were damaged or destroyed, and nearly 40 percent had to absorb wage costs for work that was not completed.

For businesses that seek to mitigate energy price volatility, an important factor is access to derivatives markets. Both exchange-traded futures and over-the-counter derivative contracts allow firms to substantially reduce their exposure to changes in energy prices. A wide variety of highly liquid futures contracts on energy products such as oil, natural gas, and electricity allow energy users and market participants to reduce or add financial exposure to energy prices. More so-

phisticated and customizable products are available in the over-the-counter derivative markets. As these markets become increasingly liquid and efficient, more firms will take advantage of these products, reducing the economy's sensitivity to shifts in energy prices. However, most small businesses currently lack the resources or sophistication to take advantage of these products, and will therefore remain vulnerable to rising energy costs. The U.S. government should continue to support the development of efficient derivatives markets.

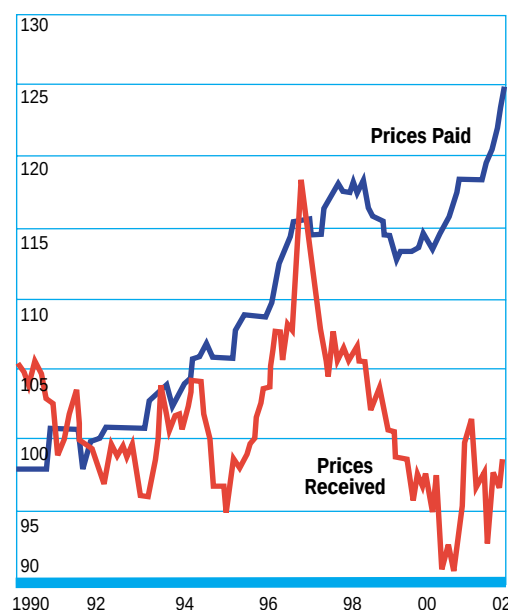
Agriculture

Farmers need ample, affordable energy to run their machinery and equipment. Today, farm production costs are rising sharply, while farm income remains low. Increasing oil prices and interest rates, along with higher prices for other production inputs (including hired labor), boosted farmers' production expenses by 4 percent, or \$7.6 billion, in 2000. The rise in farm production expenses has occurred at a time of continued weakness in the prices farmers receive for their products (Figure 2-2).

Higher fuel and oil prices accounted for over one-third of the increase in farm

Figure 2-2
Farmers Are Being Squeezed by Energy Prices

(Index: 1990–92 = 100)



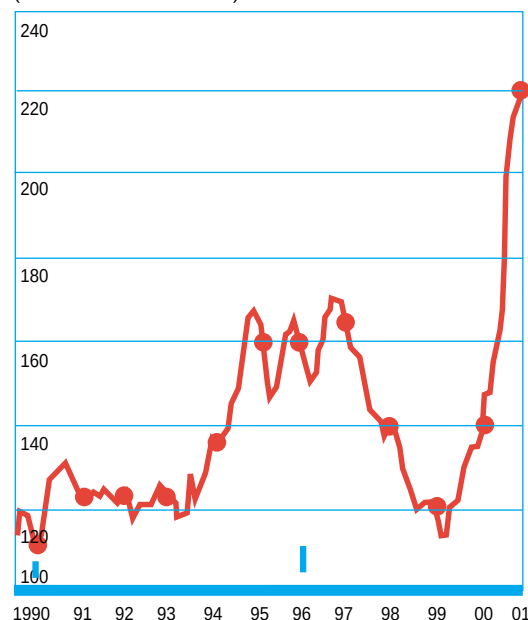
Costs for fuel, fertilizer, and electricity have boosted total prices paid by farmers, while prices farmers receive for their products have remained weak.

Note: Prices paid are for goods, services, interest, taxes, and wages; prices received are for all farm products.

Source: U.S. Department of Agriculture.

Figure 2-3
Farm Costs Are Increasing

(Index: December 1979 = 100)



Rising energy prices had a significant effect on product prices in some industries that are heavily dependent on energy inputs. The most dramatic example is the 90 percent increase in the price of nitrogenous fertilizer since December 1998.

Source: U.S. Department of Labor.

production costs. Retail diesel prices this past winter were \$1.60 a gallon, compared to about \$1.40 a year ago and only \$1.00 two years ago. Propane prices were over \$1.60 a gallon this winter, compared to \$1.10 a year ago. And, natural gas prices hit \$10.00 per million Btus in January, after averaging about \$2.50 for most of 1998–99. Although natural gas prices have declined, they remain much higher than earlier levels.

Natural gas is an important component of farm production costs. For example, it is used to dry grain, heat farm buildings, and run food-processing equipment. Heating costs for poultry producers soared last winter, sharply reducing earnings.

Natural gas also is a major component in the production of fertilizers, pesticides, and other farm chemicals. It accounts for 70 to 90 percent of the cost of producing anhydrous ammonia, a key source of nitrogen fertilizer. Surging natural gas prices have boosted the price of nitrogenous fertilizer by 90 percent since 1998 (Figure 2-3). During last December and January, several nitrogen production plants shut down, and capacity utilization fell to 50 percent. Anhydrous ammonia recently sold for \$330 a ton in the Midwest, compared to \$210 a ton for

all of 2000 and \$160 to \$170 a ton at the start of 2000.

Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops. Farm operating costs are highest where fertilizer use is heaviest and natural gas is used for irrigation pumps, such as wheat, cotton, and corn farms in the West and southwestern plains states. Costs are high for greenhouse and nursery crops that use natural gas for heating. Perishable crops also face problems, as energy costs in processing are markedly higher.

Most of California's 9.5 million irrigated acres use electricity to pump water. In addition to higher bills, California farmers will likely face rolling blackouts this summer, which may disrupt farming and processing operations. Low stream flows in the West this year may lead to more pumping of ground water, which will add to irrigation costs in the West. As a result, the costs of California's agricultural products may rise significantly.

In 2001, farmers' total cash production expenses are forecast to increase by an additional \$1.5 billion to a record \$179.5 billion.

Farm production costs are rising sharply, while farmers' incomes remain low. Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops



Even though total planted acreage is expected to fall this year, higher natural gas prices will raise expenses for nitrogen fertilizer. At the same time, net cash farm income is projected to decline from \$56.4 billion in 2000 to under \$51 billion in 2001, as production expenses continue to rise.

Taken together, fertilizer, fuel, and electricity costs for farmers are forecast to reach \$24 billion for 2001, up by about 28 percent from \$18.7 billion in 1999. This increase is about 9 percent of U.S. net cash farm income, and that share could be much higher for many individual commodities.

Transportation

The transportation sector accounts for nearly 30 percent of total U.S. energy consumption. The major transportation fuel sources are petroleum-based gasoline and diesel, jet, and marine-mode bunker fuels. Natural gas pipelines are used for product distribution, and electricity is the primary source of power for rail transit and liquid pipeline transmission and distribution.

During 2000, oil prices surged to a nine-year high, and gasoline prices skyrocketed. On average, fuel prices rose by 30 to 40 cents a gallon from 1999 prices, resulting in sharp increases for most modes of trans-



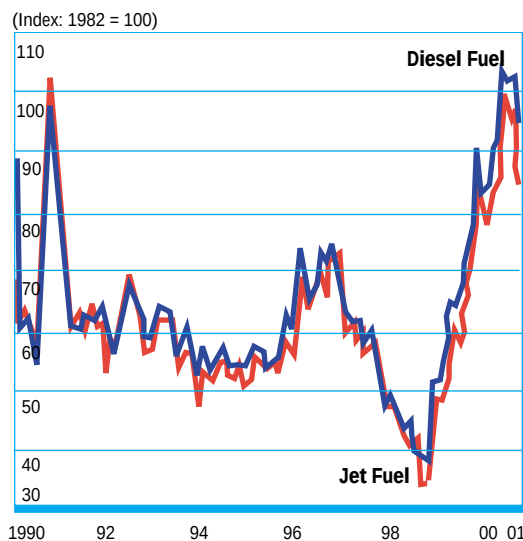
A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as \$16 billion annually, and \$5 billion in the Bay area alone.

portation, with nearly a 60 percent increase in railroad diesel fuel prices.

Price spikes have hit the travel and trucking industries particularly hard and have led to the closure of some operations. Trucking bankruptcies are currently at an all-time high. Over 3,500 motor carrier operations failed in 2000, a dramatic increase over the previous record high of 2,700 motor carrier failures in 1997. Producer prices for intermediate diesel fuel and aviation fuel each rose by about 140 percent from a low in December 1998, affecting passenger and freight transport in the highway, airline, rail, and other transportation sectors (Figure 2-4).

For most transport operations, energy-related expenses were 7 to 14 percent of total operating costs in 1998–99. This share was expected to jump to 10 to 25 percent in 2000. Excluding private auto travel, U.S. passenger and freight operations in 1999 generated about \$600 billion in annual revenue and paid approximately \$60 billion for fuel and power. If the volume stayed the same in 2000, the various increases in fuel costs for each mode of transportation would yield a fuel bill of

Figure 2-4
Transportation Costs Are on the Rise



The recent 140 percent rise in producer prices for intermediate diesel and airline fuels has affected the price of passenger and freight transport.

Note: Plotted through February 2001.
Source: U.S. Department of Labor.

about \$80 billion—an increase of one-third over the prior year's bill.

Economic Impacts of California's Energy Crunch

In California, 43 percent of small businesses surveyed in February, 2001, said the power problem had dimmed their views about California as an attractive place for doing business. When asked whether they agreed with the statement, "The electricity problem has forced me to take concrete steps exploring the possibility of moving my business out of California," 18.3 percent of small business respondents said they either agreed or strongly agreed with the statement. More than 31 percent said they will probably or definitely cut back on planned business investment, and almost 20 percent are exploring a move to another state. Half of these small businesses concluded that blackouts would reduce their earnings.

The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over \$100 million dollars because of one day of rolling blackouts in June 2000. Countless more millions of dollars have been lost by interruptible commercial power users. Fontana-based California Steel Industries estimates it lost \$2.4 million in a single day after its interruptible power was cut off twice for a total of about 12 hours. A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as \$16 billion annually, and \$5 billion in the Bay area alone.

The example of California's utilities illustrates the potentially severe negative effects on companies whose business is highly sensitive to energy prices. In this instance, rising energy costs coupled with an inability to pass those costs along to customers has created a sharp increase in short-term liabilities. Pacific Gas & Electric has been forced to file for bankruptcy as a result, and Southern California Edison, while avoiding bankruptcy for the time being, has seen its access to credit markets disappear and the value of its financial assets plummet. Resulting concerns about solvency have led to a withdrawal of bank-

lending facilities and supplier credit.

The situation in California is of particular concern because of the major role the state plays in the regional and national economies. California's economy is equivalent to about 13 percent of U.S. gross domestic product (GDP), and it has accounted for an even larger share of U.S. GDP growth in recent years. Some businesses and consumers have been affected by production losses, lost wages, and higher energy bills resulting from rolling blackouts and higher natural gas prices.

The power supply crunch in California and the West could affect the region's economy, as energy supply uncertainty could reduce investment in the region. California's troubles could also spill over to the national economy:

- California accounted for 11 percent of U.S. manufacturing output in 1998. Sectors in other regions that rely on those products, or that supply inputs to California manufacturers, may share any pain caused by the energy squeeze.

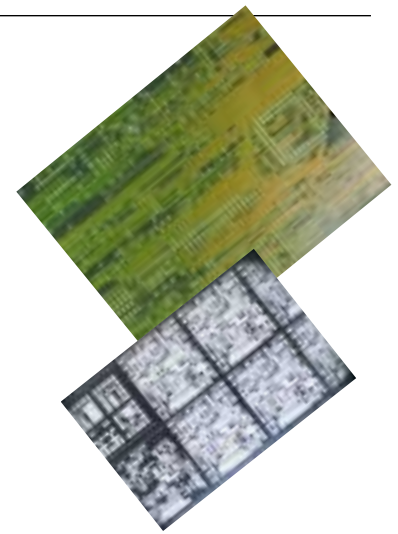
- Disruptions to California's economy could have negative impacts on our international trade. California accounts for over 16 percent of total U.S. commodity exports; nearly 25 percent of industrial equipment and computers, electronics, and instruments exports; and over 15 percent of farm commodity and food product exports.

- The credit problems of the California utilities have boosted commercial paper rates for all lower-rated borrowers, and liquidity in the commercial paper market has fallen. This will push some firms to seek other sources of financing, which can be more costly than commercial paper.

American consumers and businesses are best served when markets function freely. Free markets allow prices to reflect changes in demand and supply, and avoid subsidies, price caps, and other constraints.

Improvements in Energy Efficiency Can Help

Improved energy efficiency strengthens energy security. The 42 percent decline in the intensity of U.S. energy use since the energy crisis in 1973 reflects a combination of technological advances, conservation ef-

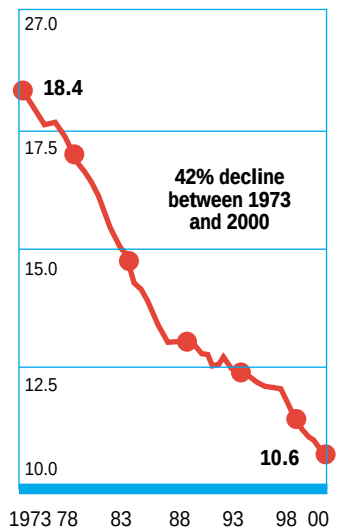


The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over \$100 million dollars because of only one day of rolling blackouts in California.

Figure 2-5

Conservation Through Higher Efficiency Energy Consumption per Dollar of Real GDP

(Thousands of Btus)



Energy intensity is the amount of energy used to produce a dollar's worth of gross domestic product (GDP). As a result of the 42 percent decline in energy intensity since the first energy crisis in 1973, the U.S. economy is far better prepared to day than it was in the 1970s to adjust to energy price or supply shocks.

*Note: Real GDP in 1996 chained dollars.
Source: U.S. Department of Energy,
Energy Information Administration.*

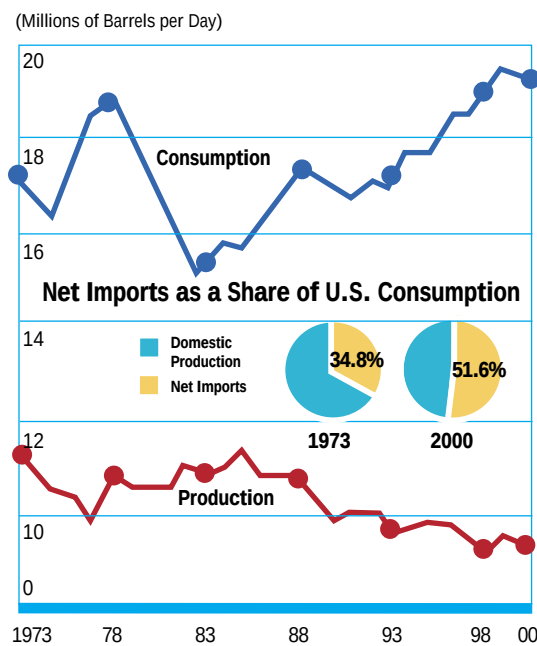
forts, regulatory action, market response, and a shift toward a service economy (Figure 2-5). Our improvements in energy efficiency have prevented our current energy problems from becoming worse.

The macroeconomic effects of a substantial rise in energy prices take two forms. First, to the extent that energy resources are imported, more U.S. dollars must be sent abroad to finance energy consumption, thus reducing funds available for investing in our own country. Second, higher prices cause dislocations among certain sectors of the economy, which could ultimately feed through to lower GDP growth and higher inflation.

Reliance on Foreign Energy

Between 1973 and 2000, U.S. dependence on foreign oil rose from about 35 percent to more than 52 percent of U.S. consumption (Figure 2-6). During the same period, the import share of natural gas consumption climbed from less than 5 percent to more than 15 percent and continues to rise.

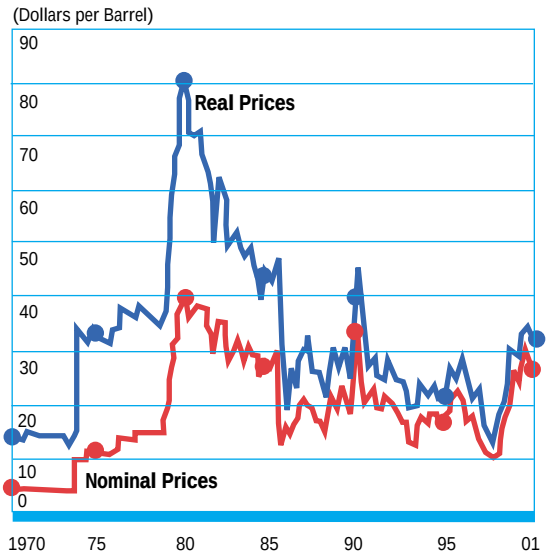
Figure 2-6
Dependence on Oil Imports Is Rising



Over the past few decades, U.S. consumption of oil and petroleum products has increasingly outpaced domestic production. Today the United States imports over half of the oil it consumes—up from about 35 percent in the early 1970s.

*Note: Petroleum includes both crude oil and petroleum products.
Source: U.S. Department of Energy, Energy Information Administration.*

Figure 2-7
Oil Prices Have Risen Sharply
Monthly Spot Price of West Texas Intermediate Crude Oil



Despite the sharp rise in crude oil prices since late 1998, real prices still remain lower than at any time from 1974 to 1985.

Note: Real prices in 2000 dollars. Prices deflated using the Consumer-Price Index—Urban (CPI-U) Research Series for all items linked to CPI-U-X1 prior to December 1977.

Sources: Wall Street Journal; U.S. Department of Labor, Bureau of Labor Statistics.

Imports of energy products make up nearly 11 percent of all U.S. imports. By contrast, U.S. energy exports are relatively small. The energy trade deficit relative to our GDP represents the share of U.S. income that must be exported to purchase foreign fuel to meet domestic energy needs. The U.S. energy trade deficit in 2000 was about \$120 billion, most of which was spent on oil imports.

As a share of GDP, the energy trade deficit had fallen to as low as 0.4 percent at the beginning of 1999, when prices for imported crude oil were less than \$10 a barrel. However, by the end of 2000, these prices had tripled to more than \$30 a barrel (Figure 2-7). As a result of both the oil price spike and growing U.S. demand, the energy deficit deteriorated significantly to 1.3 percent of GDP by the fourth quarter of last year—the largest deficit relative to GDP since the mid-1980s (Figure 2-8). The rise in oil prices alone has added about 0.7 percent of GDP to the U.S. trade deficit, compared to 0.9 percent in the euro currency area, and 0.8 percent in Japan.



Figure 2-8
The U.S. Energy Trade Deficit Has Worsened



The energy trade deficit relative to GDP represents the share of domestic income that must be exported to support domestic energy needs. For the past several years, the United States has been a net importer of energy products. As a consequence, our energy trade balance has been in deficit. By the fourth quarter of 2000, the energy deficit had deteriorated significantly to 1.3 percent of GDP—the largest since the mid-1980s.

Note: Plotted quarterly through the fourth quarter of 2000.
 Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Net U.S. oil imports are 4 billion barrels a year, which means that each \$1 increase in the price of imported crude oil boosts U.S. expenditures by about \$4 billion. Given these guidelines, the \$20 per barrel increase from early 1999 to late 2000 translates into an export of roughly \$80 billion a year (0.9 percent of GDP) when measured from the low price prevailing at the end of 1998.

Impacts of Energy Prices on Financial Markets

An analysis of the financial impacts of higher energy prices can be divided into two parts: the effects on individual firms whose securities comprise the financial markets, and the macroeconomic impact on inflation and interest rates. Rising energy costs and greater volatility in energy prices can have a negative effect on both individual firms and the broader financial environment, generally producing lower asset prices and higher interest rates. The financial market impact to date of rising energy prices has been limited to firms with high sensitivity to energy costs and to those with significant exposure to the California crisis. The second broad effect of rising energy costs is an increase both in measured inflation

Financial markets react to energy costs and the effect those energy costs have on both individual firms and sectors of the market.

and in expectations for future inflation. Both factors have considerable impact on interest rates and, therefore, on the borrowing costs for businesses and consumers throughout the economy.

Inflation Expectations and Interest Rates

Measurable inflation, for both producers and consumers, is a primary concern of the Federal Reserve in conducting monetary policy. Energy costs represent roughly 16 percent of the producer price index for finished goods and 8 percent of the consumer price index. This means that sharply rising energy costs can have a substantial impact on the Federal Reserve's decision-making process. Additional impacts will come from the market's anticipating Federal Reserve actions and pushing short-term interest rates higher than they otherwise would have been. Higher short-term interest rates raise the nominal cost of borrowing for firms and individuals and can slow economic growth.

Rising energy prices can also raise the inflation expectations of lenders, which can result in higher interest rates for borrowing at longer maturities. Rising long-term interest rates can reduce long-term investment, limiting future economic growth and productivity gains. Such an outcome would carry negative consequences for growth-sensitive financial sectors, such as equity and high-yield debt markets.

More broadly, declining credit fundamentals for certain business sectors could raise borrowing costs for firms not directly affected by higher energy prices. For example, commercial paper rates for all lower-rated borrowers have been affected by the credit problems of the California utilities, and liquidity in the market has fallen. As a result, firms may need to seek other sources of financing, such as bank loans (if obtainable) or asset-backed loans, that can be more costly than traditional commercial paper issuance.

Global Financial Markets

The upward pressure on interest rates that may result from higher U.S. energy costs also affects markets beyond our borders. U.S. monetary policy and related movements in short-term interest rates can have a significant impact on other countries. While the effect varies from region to region, many emerging mar-

ket economies, particularly in Latin America, are vulnerable to upward moves in U.S. interest rates.

Higher nominal interest rates in the developed countries tend to reduce the amount of capital flowing to emerging markets. To the extent that this reduces investment, economic activity may be further reduced. In addition, borrowing in dollars is a significant source of funding for sovereign and private-sector entities worldwide, particularly in the emerging markets. Rising U.S. interest rates will increase the interest expenses for these borrowers, diverting funds from more productive uses and reducing overall credit quality.

The global market for energy is highly fragmented and region-specific, with the exception of oil. Nevertheless, certain nations and regions are net importers of energy and are highly sensitive to changing prices. Japan, a major importer of oil and natural gas, is particularly vulnerable. Europe is a net importer of energy, with certain exceptions, while emerging market nations vary widely in their dependence on foreign energy sources.

At the macroeconomic level, rising energy prices will increase the current account deficit of energy-importing nations. Since current account deficits must be financed, these nations will most likely need to pay higher interest rates to attract the necessary capital. As noted, this will tend to reduce domestic investment and lower long-term growth. In some countries, such as the United States or Japan, changes in interest rates and growth expectations can have substantial global impact.

Central banks and monetary authorities vary in the degree to which they focus on inflation in setting monetary policy, making some countries more or less likely than others to raise interest rates in an environment of rising energy prices.

Although Japan maintains a current account surplus due to manufacturing exports, its role as an international creditor could diminish. This may have additional impacts on the global financial markets, since Japanese financial institutions are generally suppliers of global credit.

The impact of rising energy costs on the dollar is likely to be mixed. While slower U.S. growth generally reduces demand for dollars, rising oil prices are likely to increase demand, since oil contracts are usually denominated in dollars.

Summary of Recommendations

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- -FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

Protecting America's Environment

Sustaining the Nation's Health and Environment

Over the last three decades, American ingenuity has led to a reduction in adverse environmental and public health impacts from energy development and use. Americans demand a reliable energy supply and a clean environment, and we can achieve both. Spurred by strong environmental concerns, competitive forces, and environmental regulations, businesses have developed innovative technologies and pollution-prevention techniques to protect the environment. However, more can be done.

As our energy needs continue to grow and our production and distribution system is strained to capacity, it is clear that the lack of a comprehensive energy policy has environmental costs. For example, to prevent blackouts, California officials must tolerate a large short-term increase in smog-forming nitrogen oxides emissions. In Los Angeles, older, dirtier power plants have had to run longer than expected. California is also rushing to use mid-sized “peaker power plants” and diesel-fired emergency backup generators to keep the lights on.

The short-term cost in increased pollutant emissions of these emergency measures has been stark. Preliminary figures from California's South Coast Air Quality Management District indicate emissions have doubled in the first three months of the year compared with last year. In addition to nitrogen oxides emissions, diesel-fired backup generators also emit toxic soot. But with many days of blackouts predicted in California this summer, these generators will most likely run for much longer than expected, and could greatly increase emissions.

In the longer term, penalties and technological improvements should offset the impact of these increased emissions. However, California's experience demonstrates the environmental costs of not building an adequate supply of clean energy.

Government's Role

The federal government has a unique role in facilitating energy development while simultaneously protecting the environment and conserving our country's natural resource legacy. Energy development initiatives will be successful only if they adequately address their impacts on natural resource values.

Federal, state, tribal, and local governments have the responsibility of protecting unique natural resources and environmental values. In fact, some environmental protections we enjoy today are often taken for granted. For example, lead levels in ambient air today are 98 percent lower than they were in 1970, largely because government regulations required that lead be removed from gasoline. The reduced number of children with IQs below 70 is attributed to reducing lead in our environment.

As U.S. energy needs grow, additional innovations will be necessary to continue improving environmental conditions and to meet new environmental challenges. As we improve the energy production and distribution system, all levels of government must ensure that regulatory systems protecting public health and the environment are rigorous and efficient, and encourage innovation and improvement.



Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Air Quality Regulatory Programs

Advances in technology and environmental regulations have decreased aggregate emissions of key air pollutants over the last three decades, despite a marked increase in energy consumption (Figure 3-1). Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Nonetheless, fossil fuel-fired power plants, other industrial sources, and vehicles remain significant sources of air pollution (Figure 3-2). These emissions can be associated with significant health problems, including respiratory and cardiopulmonary disease, cancer, and birth defects. In addition, they can be harmful to forests, water bodies, and fish, and can decrease visibility in scenic areas.

Environmental Protection Agency's (EPA) Acid Rain Program, enacted as part of the 1990 Clean Air Act Amendments, is the only program directed primarily at reducing air emissions from electric utilities.

Using flexible market-based incentives instead of technology-forcing standards, the program has reduced sulfur dioxide (SO₂) emissions from utilities faster than required by law for a fraction of the initial cost estimates. By 2010, EPA expects the program will reduce annual SO₂ emissions by 10 million tons from 1980 levels, thus avoiding significant health problems and the costs associated with those levels.

Federal and state regulatory programs also limit air pollution directly by restricting emissions from cars and trucks, and indirectly by setting criteria for the fuel for these vehicles. An individual car meeting 2004 federal requirements will emit 95 percent less carbon monoxide (CO), 94 percent fewer nitrogen oxides (NO_x), and 98 percent fewer hydrocarbons than an average car did before laws limiting such vehicle pollution. Although individual cars and trucks are far cleaner today than they were in 1970, total emissions from the fleet of highway vehicles have remained relatively constant, because Americans drive twice as many miles today (2.5 trillion miles a year) as they did in 1970

(1.1 trillion miles a year).

Despite these and other achievements, further air quality improvements can be sought, as well as ways to address new problems identified by recent scientific findings. EPA has recently adopted new, more stringent standards to further reduce ozone and particulate matter. To meet public health and environmental challenges, power plants, industrial sources, and vehicles will need to produce fewer potentially harmful emissions.

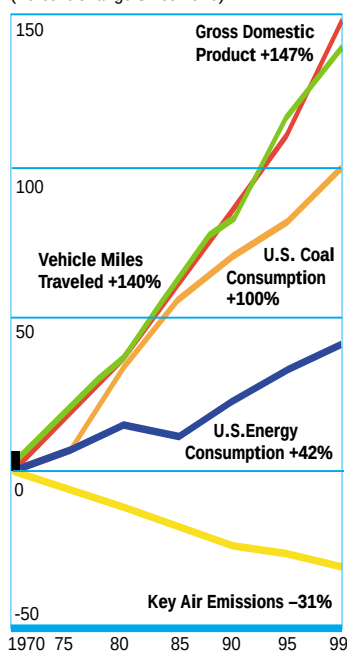
Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions-trading credits to help achieve the required reductions.

Figure 3-1
Cleaner Air: Energy Consumption Has Risen While Emissions Have Declined

(Percent Change Since 1970)



Despite a marked increase in U.S. energy consumption, a combination of environmental regulations and technologies has decreased aggregate emissions of key air emissions: SO₂, NO_x, mercury, CO, and volatile organic compounds.

Sources: U.S. Department of Energy, Energy Information Administration, and U.S. Environmental Protection Agency.

Cleaner, More Efficient Technologies

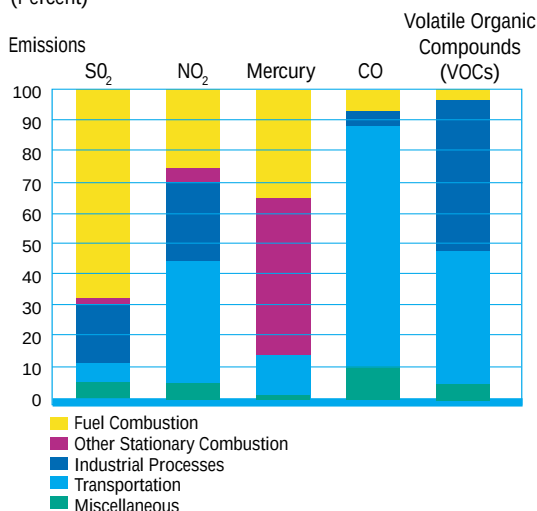
Emission control technologies and emission prevention not only decrease pollution but can also contribute to economic prosperity. Innovative emission control and prevention technology and increasingly efficient energy systems have developed at a brisk pace, increasing our ability to provide cleaner, cheaper energy. Besides reducing pollution, environmental technologies account for about \$21.3 billion in U.S. exports, and support approximately 136,000 U.S. jobs.

The need to reduce emissions from cars and trucks has contributed to technological innovations that have transformed the domestic and global automotive industries. U.S. vehicle emission standards were the primary driving force for the original development of innovative technologies, many of which have become standard design features of today's high-tech vehicles: sophisticated three-way catalysts, on-board computers, oxygen sensors, and fuel-injection systems for cars and advanced fuel systems for trucks. Technologies such as these have allowed today's vehicles to be much cleaner, more efficient, higher performing, more reliable, and more durable than their counterparts of the 1960s and 1970s. Manufacturers are now working on developing state-of-the-art pollution control technology to further reduce emissions from motor vehicles. For optimal performance, this technology requires low-sulfur fuel that, consistent with applicable law, will be required in 2004 for gasoline and 2006 for diesel fuel. Some vehicles use alternative fuels (*e.g.*, natural gas, propane, ethanol, and electricity); others operate with a hybrid gasoline and electrical motor; and others are using fuel cells.

Cleaner Electricity

The source of energy used for power generation significantly affects the amount of air emissions. Clean energy can be generated from nuclear plants, hydropower facilities, wind farms, and solar energy systems with negligible (if any) air emissions. These sources today make up about 30 percent of our electricity supply. Solar and

Figure 3-2
Sources of Pollutants from Energy Generation and Use
(Percent)



wind energy systems will continue to improve with advances in short-term weather and climate forecasting. Improved forecasting can also maximize hydropower efficiency.

Technology significantly reduces pollution from coal-fired power plants, which generate more electricity in the United States than any other source. For example, scrubbers can remove 95 percent of the SO₂ emissions from a coal-fired power plant. With the innovative, market-based SO₂ reduction requirements of the Clean Air Act Amendments of 1990, the estimated cost of using a scrubber on a coal-fired power plant to remove one ton of SO₂ has dropped approximately 40 percent in four years, from \$474/ton in a 1993 estimate to \$282/ton in a 1997 estimate, and continues to decline. Other existing control technologies for coal-fired plants can reduce NO_x emissions by more than 90 percent.

A recently permitted state-of-the-art coal-fired unit, for example, at a Kansas City Power & Light facility, has 88 percent lower NO_x, 99 percent lower particulate matter, and 92 percent lower SO₂ emissions than would an uncontrolled facility.

Recent research by the Department of Energy (DOE), EPA, and private companies suggests that existing technologies can also significantly reduce mercury emissions.

Technologies for Reducing SO₂ Emissions

Many power plants use flue-gas desulfurization, or scrubbers, to reduce SO₂ emissions from burning coal. The most common wet scrubber, the limestone forced-oxidation (LSFO) process, removes SO₂ from the flue gas by sorption and through chemical reactions with the limestone. LSFO technologies can remove up to 98 percent of SO₂ and significant amounts of mercury. The most common dry scrubber, the lime spray-drying process, is used for plants that burn lower-sulfur coals. A lime slurry mixes with the hot flue gas in a spray dryer and reacts with SO₂. By recapturing sorbent at the bottom of the spray dryer removed in a particulate control device, dry scrubbers can remove up to 96 percent of SO₂.

Clean Coal Technologies

New clean coal technologies are showing that air pollution can be reduced, and energy efficiency increased, by using America's abundant supply of coal.

Most conventional air emission control technologies installed on coal-fired electric-generating boilers have been designed to remove a specific pollutant from the stack flue gas. Because these technologies may not be the most cost effective means of reducing multiple pollutants, several companies are developing a single-control technology to reduce multiple air pollutants to levels equivalent to those achieved by conventional controls.

For example, a First Energy plant in New Hampshire recently pilot-tested state-of-the-art technology that has cut NO_x emissions by 76 percent, SO₂ by 44 percent, total particulate matter by 99.94 percent, and mercury by 81 percent. The process uses electrically charged particles instead of catalysts to oxidize the air pollutants into products that are easily removed and can be converted to gypsum, fertilizer, and concentrated acids. American Electric Power is installing a wet scrubber system that it expects will remove up to 75 percent NO_x and

90 percent mercury. It injects a phosphorus mixture into the hot flue gas, causing the release of ozone. The ozone then oxidizes the mercury into ionic mercury and the NO_x into N₂, both of which are water-soluble and easily removed.

Technologies for Improved Efficiencies

Two-thirds of the energy used in a conventional coal-fired power plant is wasted in the production of electricity. These losses can be minimized through a number of innovations, including installing high efficiency steam turbines, reducing steam leaks, and using software to optimize combustion efficiency. New coal-burning power plants can achieve efficiencies of over 40 percent using existing technology, and companies are developing even more efficient technologies. Wasted energy can also be recycled for use in industrial processes or for heating buildings.

A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building-scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emission reductions of 614,000 tons of NO_x emissions and 44 million metric tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.

The U.S. Department of Energy, through its Clean Coal Technology Program, is working with utilities and scientists to develop even cleaner, more efficient electricity-generating systems using coal. One of the most promising new approaches to using coal for clean production of electricity is integrated gasification combined-cycle (IGCC) technology. IGCC power plants convert coal to a gaseous fuel, from which most

Using flexible market-based incentives, EPA's Acid Rain Program has reduced sulfur dioxide (SO₂) emissions from utilities faster than required by law for a fraction of the initial cost estimates.



Clean Coal Technologies Up Close

The Wabash River Coal Gasification Project in Terre Haute, Indiana, is one of the cleanest, most efficient coal-burning facilities in the country. Partly funded by the Department of Energy (DOE) as part of its Clean Coal Technology Program, the 262-MW coal gasification facility is owned and operated by PSI Energy and Global Energy, Inc. Instead of being directly burned, the coal is gasified and then combusted in a combined-cycle gas turbine. This allows the coal to burn more efficiently—which means it gets more energy than a traditional plant out of the same amount of coal. The Wabash River Facility is over 20 percent more efficient than a typical coal-fired power plant.

The gasification process also allows many of the impurities in the coal to be removed before it is combusted to generate electricity. At the Wabash River project, over 99 percent of the sulfur is removed from the coal and marketed to industrial users of sulfur. Slag is also removed and is marketed to the construction industry. The plant's design allows it to burn other fuels, such as petroleum coke.

DOE is currently working with Global Energy and other industry partners to see if the plant could also be used to co-produce chemical feedstocks and transportation fuels. Additionally, DOE and its partners are studying lessons learned from the project to design a less expensive, more efficient coal gasification facility that would be ready for commercial deployment by 2005.

of the impurities are removed prior to combustion, and then use the gaseous fuel in a combustion turbine to produce electricity. Waste heat from the turbine is used to generate steam and drive a steam turbine, to produce more electricity.

Coal gasification plants offer the flexibility to burn other fuels, such as petroleum coke, and to make other products in addition to electricity, such as chemical feedstocks and transportation fuels. Hydrogen, which is produced directly in the coal gasifier, can be used in fuel cell-equipped vehicles. Methane, hydrogen, and other gasified coal products can be recombined into more traditional fuels, such as methanol, gasoline, or diesel fuel. Because these fuels would contain essentially no sulfur, they would easily meet EPA's sulfur standards for transportation fuels, and they would be usable in fuel cell-equipped vehicles designed for these fuels.

Two plants demonstrating coal gasification technology have already been built in the United States and have achieved over 98 percent SO₂ reduction, 90 percent NO_x reduction, particulate emissions below detectable levels, and approximately 38 percent efficiency. EPA believes that lessons

learned will enable the next plant of this design to achieve 42 percent efficiency, and the research goal is to achieve 60 percent efficiency for plants introduced after 2015.

A modern gas-fired power plant has virtually no SO₂ or mercury emissions and emits 97 percent less NO_x and 50 percent less carbon dioxide (CO₂) than a traditional coal-fired plant. Natural gas as a source of electricity generation is on the rise, in part because it can help generators meet increasingly stringent clean air requirements.

Conservation and Environmental Protection

Conserving energy minimizes adverse environmental effects. Government partnerships with businesses and consumers are improving the energy efficiency of homes, office buildings, transportation sources, and industrial sites throughout the country. EPA's voluntary conservation and energy efficiency programs include Energy Star products labeling; Energy Star Residential programs for both new homes and home improvement; Energy Star Buildings, principally for commercial buildings; and new Energy Star for Industry, which focuses on manufacturers. In 2000, business participation in EPA's voluntary energy efficiency

programs reduced NOx emissions by more than 160,000 tons.

Through EPA's and the Department of Transportation's Commuter Choice Leadership Initiative, private-public employers are offering employees a variety of commuting options, which encourage commuting patterns that save fuel and energy while reducing emissions. For example, a 10 percent reduction in the rate of growth in vehicle miles traveled can result in annual savings of 38 million barrels of gasoline (82 million barrels of oil) by 2005, and can remove 45,000 metric tons of NOx, 37,000 metric tons of hydrocarbons, and 4.8 million metric tons of carbon-equivalent emissions.

Energy efficiency and conservation in the home are also important factors. Examples include EPA's home improvement program, which involves efficient appliances, duct work to prevent air conditioners from leaking, efficient windows, programmable thermostats, and efficient residential lighting.

Federal and state regulators are working with businesses and communities to mitigate adverse environmental impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and still meet energy production goals; and requiring reclamation and mitigation of any environmental damage.

Water Quality

Oil, gas, and coal extraction processes can degrade water quality through their discharges. Energy generation and use can also degrade water quality by directly discharging pollutants into water bodies; changing the temperature, timing, and flow characteristics of water bodies; and emitting pollutants into the air that are ultimately deposited in water. Leaking storage tanks and pipelines release petroleum and fuel additives that can contaminate surface water and ground water, including drinking-water supplies.

Federal and state regulators are working with businesses and communities to mitigate these adverse impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and meet energy production goals; and requiring reclamation and mitigation of any environmental damage. For example, as a result of an analysis under the National Environmental Policy Act of the impacts of a new power plant in California, the company building the plant agreed to change the design to use a dry cooling method. This change reduced ground-water consumption by 95 percent and eliminated both cooling tower "blowdown" water and particulate emissions, while still achieving the desired energy production. Adverse impacts to aquatic life from cooling-water intakes, thermal discharges, and hydropower intakes can be minimized with proper design and environmental controls. A cooperative government, industry, and community-based approach during project siting and design will help ensure full consideration of the effects upon fish and aquatic resources.

Programs to reduce air pollution also help clean up water bodies. For example, reducing electric utilities' air emissions of NOx and SO₂ and vehicles' NOx emissions reduces eutrophication and acid deposition in estuaries, both of which can harm fish populations and threaten commercial and recreational yields. For example, roughly 25 percent of nitrogen (which contributes to



eutrophication) entering Chesapeake Bay is from air emissions. And by significantly reducing SO₂ air emissions, the Acid Rain Program has helped reduce the acidification of water bodies.

Airborne mercury emitted by coal-fired power plants has been deposited into thousands of water bodies, and humans can be exposed to toxic methyl mercury when they eat fish from these waters. The Bush Administration will propose legislation adding mercury to the list of pollutant emissions from power plants that will be subject to mandatory limits.

Fish, Wildlife, and Their Habitat

Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, and other activities that contribute billions of dollars to the U.S. economy every year. Oil and gas exploration and production, hydropower dams, power plants, pipelines, and other energy-related projects can potentially affect fish, wildlife, and habitat. However, technological advances, a strong commitment to environmental protection, and the use of appropriate regulatory tools can enable proper energy development to go forward in an environmentally sensitive manner. It is important to recognize and to continue the progress in this area.

When energy development is proposed, the federal government has the dual

Recommendation: A

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.



responsibilities of facilitating such energy development and conserving our natural resource legacy.

Special efforts are often necessary to ensure that proposed energy projects do not diminish the vitality of these unique resources. Working together, the public, businesses, and federal, state, tribal, and local governments can ensure that environmental impacts are carefully evaluated when considering energy exploration and production activities. For example, such precautions have been important for the exploration and production that is already allowed today in 42 National Wildlife Refuges.

Hydropower Generation

Hydropower, although a clean energy source, does present environmental challenges. Unless properly designed and operated, hydropower dams can injure or kill fish, such as salmon, by blocking their passage to upstream spawning pools. Innovations in fish ladders, screens, and hatcheries are helping to mitigate these adverse impacts. Ongoing dam relicensing efforts are resulting in community involvement and the industry's application of the latest technologies to ensure the maintenance of downstream flows and the upstream passage of fish. These efforts also have been successful in identifying and removing older, nonfunctioning dams and other impediments to fish movements.

Technological advances and a strong commitment to environmental protection are enabling the healthy coexistence of our nation's diverse ecosystems with the development of energy resources.



Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, enhance our quality of life, and other activities that contribute billions of dollars to the U.S. economy every year.



Some natural resource areas are to be protected from any exploration. In other areas, energy development can proceed using the most advanced designs and technologies to ensure that proposed energy projects do not diminish the vitality and diversity of these unique resources.

An example of such successful collaboration involves the Wanapum Dam on the Columbia River. In coordination with the National Marine Fisheries Service, the Grant County Public Utility District No. 2 installed spillway deflectors that effectively reduced concentrations of total dissolved gas that can harm fish and other aquatic life. Furthermore, through the unique collaboration on this project, the cost for the spillway deflectors was a fraction of that for deflectors installed at other hydropower projects.

Coal, Oil, and Gas Exploration and Production

Certain exploration and production activities can pose environmental impacts to wildlife habitat, unless conducted in a way that protects the environment. In sensitive areas, these effects can often be avoided or minimized by timing exploration and operation activities in light of migration, nesting, and other critical time periods for wildlife. In addition, new technologies designed to lessen these and other impacts can be used, such as double-walled pipes to reduce the risk of oil spills.

Surface impacts from coal mining and oil exploration can temporarily damage habitats during the operation phases until reclamation is complete. To mitigate impacts during mining, for example, storm-water runoff and discharge into undisturbed environments are controlled. After mining is complete, reclamation efforts required by the Surface Mining Control and Reclamation Act restore viable habitats through careful reconstruction of physical and botanical resources. For instance, in the Powder River Basin, as part of reclamation, coal companies strategically place large boulders and other rock material to create wildlife cover and denning habitat. Restoration of wildlife habitat on these reclaimed areas has been quite successful.

In Alaska's Arctic—home to such animals as polar bears, musk oxen, caribou, wolves, and arctic fox—the bitterly cold winters have proven to be beneficial for environmentally responsible energy development. For example, when the North Slope is

frozen and snow-covered, seismic trains can travel across it to gather geophysical information. Furthermore, companies have adopted innovative techniques to reduce the possible impacts of exploration and development. In Alaska's National Petroleum Reserve, the "footprint" from most exploratory wells on federal lands is short-lived and has minimal impact due to the use of ice roads and ice pads that melt with the spring thaw. Advances in extended-reach drilling technologies have also served to minimize environmental effects during energy production activities.

A lengthy 1999 Department of Energy study examined the environmental benefits of new exploration and production technologies and concluded that "improvements over the past 40 years have dramatically reduced industry's footprint on the fragile tundra, have minimized waste produced, and have protected the land for resident and migrating wildlife." The same study concluded that "it is important to tell this remarkable story of environmental progress in E&P [exploration and production] technology. Greater awareness of the industry's achievements in environmental protection will provide the context for effective policy, and for informed decision-making by both the private and public sectors."

Waste Management

Vigilant management and careful disposal of waste from energy extraction and production can prevent the contamination of our air, land, and water. Federal and state authorities are working to ensure that energy projects maintain sound programs to safely handle wastes from mining, drilling, generation and transmission.

Nuclear power plants present waste management challenges unique among energy-generating technologies. They generate spent fuel, as well as other radioactive waste, which must be isolated from ecosystems and human contact for long periods of time. Currently, spent fuel is stored at reactor sites in a number of states, although capacity is limited. Newer technologies have been developed to reduce the volume and

increase the manageability of spent fuel, but such spent fuel will still require safe handling and long-term isolation.

While the federal government has the responsibility to address such high-level wastes, states have the responsibility to address low-level wastes from nuclear plants, such as clothing and equipment. Disposal options for this type of radioactive waste are limited, because siting these facilities has been controversial. In fact, there are only three disposal facilities active in the United States.

Accidental Releases

Since the passage of the Oil Pollution Act in 1990, which, among other things, required double-hulled vessels and improved industry readiness, oil spilled in coastal zone waters has decreased from almost 8 million gallons in 1990 to just over 1 million gallons in 1999. Most energy production facilities implement comprehensive risk-management plans, which reduce the potential for accidents and help local officials prepare for accidents that may arise.

In contrast, inland oil spills do not appear to be decreasing at the same rate as coastal spills. The federal government receives many more inland oil spill notifications (9,000 notifications a year in the early 1990s versus 10,000 to 12,000 a year in the late 1990s), and many very large inland oil spills occur each year (over 100,000 gallons). The continued problem with inland oil spills may be due to aging pipelines, storage tanks, and other infrastructure components.

Since the advent of commercial nuclear power generation, there have been no radiation-related injuries or deaths associated with the operation of a commercial nuclear power plant in the United States. The most significant incident from a nuclear plant in the United States, at Three Mile Island in 1979, prompted improved safety regulation of nuclear plants. New nuclear reactor designs promise even higher safety levels than the reactors currently operating in this country.

Radiation exposure from nuclear facilities is extremely rare. In fact, roughly 82 percent of human exposure to radiation comes from natural sources: radon gas; the human body, which contains radioactive elements; outer space; and rocks and soil. Radon accounts for about 55 percent of our exposure to natural sources of radiation; radioactive elements in our own bodies account for 11 percent; rocks and soil account for 11 percent; and outer space, including the sun, accounts for 8 percent. The remaining 18 percent of average human radiation exposure comes from man-made sources, primarily medical and dental X-rays and consumer products.

The safety of U.S. nuclear energy plants has improved sharply in recent years. A safe nuclear energy plant is one that runs well, experiences few unplanned outages, and has a well-disciplined work force that follows procedures and avoids accidents. The safety of a U.S. nuclear energy plant is typically gauged by monitoring indicators of its performance in these areas: unplanned automatic reactor shutdowns, the annual percentage of possible power generated, and the industrial safety accident rate for plant workers.

In 2000, for the fourth year in a row, the number of unscheduled reactor shutdowns was zero. The industry generated 91.1 percent of its potential maximum output, breaking its 1999 record of 88.7 percent, far better than the typical 80 percent number of ten years ago.

Today, U.S. nuclear plants are more efficient and safer than ever. In the increasingly deregulated marketplace, competition has forced improvements in plant operations that have benefited safety performance as much as economic performance.

Climate Change

Energy-related activities are the primary sources of U.S. man-made greenhouse gas emissions, representing about 85 percent of the U.S. man-made total carbon-equivalent emissions in 1998.

Forests can absorb carbon dioxide, which accounts for the largest share of greenhouse gas emissions. Working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley.

Scientists continue to learn more about global climate change, its causes, potential impacts, and possible solutions.

The United States recognizes the seriousness of this global issue as scientists attempt to learn more about climate change. The United States is making progress in reducing emissions of greenhouse gases. Recent data show that the rate of growth in U.S. greenhouse gas emissions has begun to decline, even as the U.S. economy has been growing at an unprecedented rate. For example, historically U.S. CO₂ emissions have grown at roughly half the rate of GDP. In recent years, however, very robust growth in the nation's GDP has been accompanied by a slowdown in the growth of greenhouse gas emissions. In both 1998 and 1999, U.S.

GDP grew by more than 4 percent a year, while CO₂ emissions grew by less than 1.5 percent a year. In addition, the carbon intensity of the U.S. economy—the amount of CO₂ emitted per unit of GDP—declined by 15 percent during the 1990s.

The United States has reduced greenhouse gas emissions by promoting energy efficiency and the broader use of renewable energy through a wide range of public-private partnership programs. These programs save energy, cut energy bills, enhance economic growth, and reduce emissions of conventional air pollutants as well as greenhouse gases.

The U.S. government, businesses, and nongovernmental organizations are sequestering carbon, at home and abroad. For example, working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley. It is projected that this project will sequester approximately 13.5 million tons of carbon, improve fish and wildlife populations by restoring the natural forest wetland habitats, and enhance the Gulf of Mexico's near-shore aquatic environment by restoring natural forested wetland filters to the Mississippi River floodplain.

Industry and the federal government are researching various new technologies that will reduce greenhouse gas emissions or sequester those emissions, in geologic formations, oceans, and elsewhere.



Regulatory Structure

The United States has adopted many regulatory protections to limit the environmental damage and public health consequences of the exploration, extraction, production, and use of energy. Most environmental controls are implemented through state or federal permitting or review systems, which often require time for agency review and public participation. Facilities may need several different permits or reviews from different agencies, and they may also need to meet local licensing or zoning laws. Businesses have an interest in moving expeditiously to respond to consumers' needs. The public also has an interest in participating in the system to ensure that appropriate health and environmental precautions will be taken.

Regulatory requirements are not static. New scientific information and new control technologies result in new regulations and modifications to existing regulations over time. However, some level of certainty in the regulatory environment is important for all parties. Businesses can plan more effectively in such an environment, and regulators can focus on ensuring that the desired outcomes are in fact achieved consistently. For example, studies have shown that if electricity generators knew today what their emission requirements for several emissions would be for a defined time period, they would most likely control emissions more cost effectively and sooner than if their emission requirements were decided upon one gas at a time.

Traditional permit and regulatory programs may not always be the most effective and efficient way to protect the environment. Increasingly, regulatory programs are considering approaches that include market-based incentives. These types of incentives offer advantages over traditional forms of regulation because they set high performance standards and then allow market forces to determine the most effective way to meet them. While not appropriate for every situation, market-based incentives can control pollution at a lower cost to society than traditional regulation, stimulate

technological improvements, and be structured to achieve larger reductions in pollution than would result from traditional regulations.

A good example of a U.S. market-based program is the Acid Rain Program, which has reduced SO₂ air emissions from utilities at a fraction of the initial cost estimates. Other emerging market-based environmental protection mechanisms include effluent trading, wetland mitigation banks, tradable development rights, easement purchases, off-site mitigation, and leasing or purchasing of water rights. These programs can reduce mitigation or pollution control costs, increase business flexibility, and provide transparency and environmental protection for the public.



The environmental review process can also be made more open, understandable, predictable, and coordinated among federal agencies and with state and local agencies. It can be improved by providing greater information to clarify expectations for energy developers, facilitating concurrent reviews by federal agencies by standardizing certain information needs, sharing information received by project applicants, and seeking opportunities to integrate required environmental processes and reviews.

Recommendation:

★ The NEPD Group recommends that the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Summary of Recommendations

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Using Energy Wisely

Increasing Energy Conservation and Efficiency

The Department of Energy has installed two low-sulfur light bulbs as a test at its Forrestal Building headquarters in Washington, D.C. The two golf ball-sized bulbs, like those on the opposite page, are at each end of a 240-foot, 10-inch-wide reflective plastic “light pipe.”

U.S. DEPARTMENT OF ENERGY

Energy efficiency is the ability to use less energy to produce the same amount of lighting, heating, transportation, and other energy services. For a family or business, conserving energy means lower energy bills. For the country as a whole, greater energy efficiency helps us make the most of U.S. energy resources, reduces energy shortages, lowers our reliance on energy imports, mitigates the impact of high energy prices, and reduces pollution. Improvements in efficiency can be particularly effective in reducing energy demand when energy is most expensive.

Conservation and energy efficiency are important elements of a sound energy

policy. Improved energy efficiency is the result of many decisions, including those of individual consumers; manufacturers of cars and appliances; home builders; and state, federal, and local government officials. The federal government can promote energy efficiency and conservation by including the dissemination of timely and accurate information regarding the energy use of consumers' purchases, setting standards for more energy efficient products, and encouraging industry to develop more efficient products. The federal government can also promote energy efficiency and conservation through programs like the Energy Star program, and search for more innovative technologies that improve efficiency and conservation through research and development.

Since 1973, the U.S. economy has grown nearly five times faster than energy use (126 percent versus 26 percent). Had Americans continued to use energy as intensively as in 1970, the U.S. would have consumed about 177 quadrillion Btus of energy last year, compared to about 99 quadrillion Btus actually consumed.

British Thermal Unit (Btu)

A British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sea level. Put another way, it is approximately the same amount of energy contained in a wooden match head.

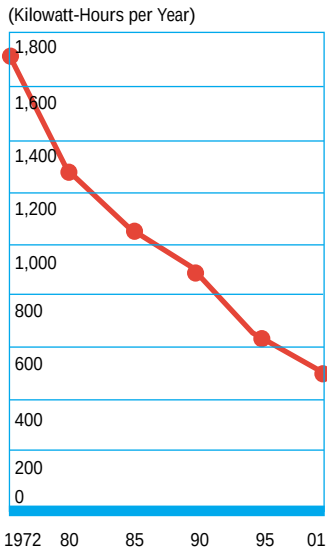


U.S. DEPARTMENT OF ENERGY



Figure 4-1

New Refrigerator-Freezers are Using Less Energy Consumption per Unit for New Shipments



Over the last thirty years, the energy efficiency of refrigerator-freezer appliances has increased by approximately 70 percent.

Sources: AHAM 2000 Major Home Industry Fact Book and BTS appliance standard.

Improving Efficiency through Innovative Technologies

One measure of energy efficiency is energy intensity—the amount of energy it takes to produce a dollar of gross domestic product (GDP). While about half of the long-term decline in energy intensity can be attributed to changes in the economy, especially the shift from manufacturing to services, the other half reflects improved energy efficiency. Gains in energy efficiency over the last three decades were built on a combination of technological improvements, better management practices, and learning to put these technologies and practices to their best use in automobiles, homes, offices, factories, and farms. In many areas the results have been quite impressive. New home refrigerators use about one-third of the electricity they used in 1972 (Figure 4-1). Compact fluorescent lights use about 25 percent of the electricity of the incandescent bulbs they replace. Automobiles use roughly 60 percent of the gasoline they did in 1972 per mile driven. These individual technological improvements have resulted in significant reductions in energy use (Figure 4-2).

Several new and innovative technolo-

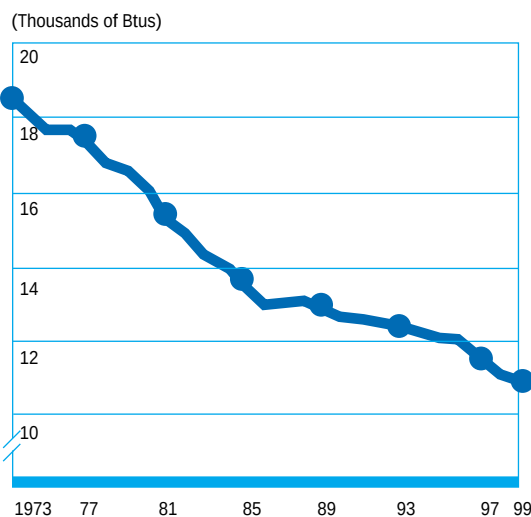
gies offer expanded opportunities to improve our energy efficiency. For example, advanced sensors and controls enable more efficient operation of buildings and factories, and allow equipment and lights to be turned off or dimmed when not in use. Hybrid vehicles use power electronics and battery storage to get more out of every gallon of gasoline consumed, and provide the ability to double vehicle mileage. Cogeneration of electricity and heat and combined heat and power allow for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to produce electricity.

District Energy St. Paul— A Combined Heat and Power Plant

District Energy St. Paul, Inc., is a combined heat and power plant that can operate on natural gas, oil, or clean-burning coal that is mixed with wood chips. These wood wastes come from downed trees, trimmings, and branches. District Energy has been able to keep its rates stable because it is able to rely on a diverse fuel supply. District Energy serves about 75 percent of all building space in the city. Nearly 150 large buildings and 3,200 residential units use the system. It is the largest system of its kind in the nation.

Figure 4-2

The U.S. Economy Has Become More Energy Efficient



The amount of energy used by the United States in relation to its economic output has steadily declined since the early 1970s.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Consumer Choices

The two most important factors in consumers' decisions about purchasing an energy efficient product are price and the life of the product. When energy prices are high, consumers tend to weigh energy efficiency more heavily. Unless consumers are informed about the price of energy, they may not have the incentive to select the most energy efficient product.

Consumers do not receive timely signals about rising electricity costs in order to make adjustments to their energy use and efficiency. When consumers' peak costs are averaged with off-peak costs, the higher cost of peak electricity supplies is masked. As a result, consumers may not recognize the benefits of investing in technologies that best target peak consumption.

Some energy efficiency improvements are easiest and most cost effective to undertake when first building new factories, cars, equipment, appliances, and buildings. Some energy-using equipment, like computers, are used for only a few years before being replaced. Other equipment is used from five to twenty years, such as home appliances, home electronics, and lighting systems. Some capital stock, such as buildings and boilers, can last a half a century or more.

The average car now lasts fourteen years, and newer cars have even more longevity. Vehicle efficiency improvements require significant technological changes. Development of new-car production models requires at least three to four years, which limits the rate at which new technologies can enter the market. Making fundamental changes, such as switching to the use of a fuel cell, would take even longer. Once those new vehicles are in the showroom, it then takes several more years before they constitute any sizable percentage of total vehicles.

In a typical U.S. home, appliances are responsible for about 20 percent of the energy bills. Refrigerators, freezers, clothes washers, dryers, dishwashers, and ranges and ovens are the primary energy-using appliances in most households. Taking steps to save energy while using these appliances, and replacing old inefficient appli-



ances with modern ones can save money.

The federal government established a mandatory program in the 1970s requiring that certain types of new appliances bear a label to help consumers compare the energy efficiency of various products. Under this program, all refrigerators, freezers, clothes washers, and dishwashers are sold with yellow Energy Guide labels to indicate their energy efficiency. These labels provide an estimated annual operating cost of the appliance, and also indicate the cost of operating the models with the highest annual operating cost and the lowest annual operating cost. By comparing a model's annual operating cost with the operating cost of the most efficient model, you can compare their efficiencies. This labeling program ensures that consumers have the information they need to make the right decisions when they purchase major home appliances. However, Energy Guide labels are not currently required for some products, such as kitchen ranges, microwave ovens, clothes dryers, on-demand water heaters, portable space heaters, and lights.

The federal government not only ensures consumers have information on the energy efficiency of major home appliances. It also promotes the most energy efficient products through the Energy Star program, a joint program run by the Department of Energy and the Environmental Protection

Some efficiency improvements are easiest and most cost-effective to undertake when first building new factories, cars, equipment, appliances and buildings.



In April 2001, the Sustainable Buildings Industry Council showcased a net-zero-energy home featuring passive solar design strategies, an integrated photovoltaic system, domestic solar hot water, high-efficiency lights and appliances, and a host of sustainable, market-ready components and systems.

SUSTAINABLE BUILDINGS INDUSTRY COUNCIL



A 48-story skyscraper at the corner of Broadway and 42nd Street in New York City has a photovoltaic skin that uses thin-film PV panels to replace traditional glass cladding material. The PV curtain wall extends from the 35th to the 48th floors on the south and east walls of the tower, making it a highly visible part of the New York City skyline.

U.S. DEPARTMENT OF ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY

Agency. Energy Star is only awarded to appliances that significantly exceed minimum energy efficiency standards. The Energy Star program does not extend to all products. Energy efficiency would be further promoted if the Energy Star program were expanded to a broader range of products.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, ap-

pliances, and services.

- Strengthen Department of Energy public education programs relating to energy efficiency.

Energy efficiency can also be improved by the establishment of minimum energy efficiency standards. Congress enacted legislation in 1987 and 1988 to establish minimum energy efficiency standards for many major appliances. These standards apply to manufacturers, not consumers. Appliance manufacturers must produce products that meet the minimum level of energy efficiency. These rules do not affect the marketing of products manufactured before the standards went into effect, and any products made beforehand can be sold. The new standards will stimulate energy savings that benefit the consumer, and reduce fossil fuel consumption, thus reducing air emissions.

These laws established minimum energy efficiency standards for many appliances, including refrigerators, refrigerator-freezers, freezers, room air conditioners, fluorescent lamp ballasts, and incandescent reflector lamps, clothes dryers, clothes washers, dishwashers, kitchen ranges, and ovens, pool heaters, and water heaters. The Energy Policy Act of 1992 added standards for fluorescent and incandescent reflector lamps, plumbing products, electric motors, and commercial water heaters, and heating, ventilation, and air conditioning systems. Under current law, the Department of Energy can raise the minimum energy efficiency standards for these appliances if certain criteria are met, such as cost, technological feasibility, and the impact on competition among appliance manufacturers. In addition, the Department can set energy efficiency standards for appliances not covered by these laws.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to take steps to improve the energy efficiency of appliances.

- Support appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standard program, setting standards for additional appliances where technologically feasible and economically justified.

Energy Efficiency

Government Agencies

As the largest energy consumer in the nation, the U.S. government's cost- and energy-saving opportunity is enormous. In 1999, the government consumed nearly 1.1 percent of all U.S. energy and spent nearly \$8 billion for its vehicles, operations, and its nearly 500,000 buildings.

The federal government has reduced its energy use in buildings by about 30 percent from 1990 levels, largely by installing energy efficient technologies (Figure 4-3). It has reduced its energy use for vehicles and equipment by 35 percent. Some of these improvements are attributable to the Department of Energy, whose Federal Energy Management Program helps government agencies reduce their energy and water use, manage their utility costs, and promote renewable energy.

Recommendations:

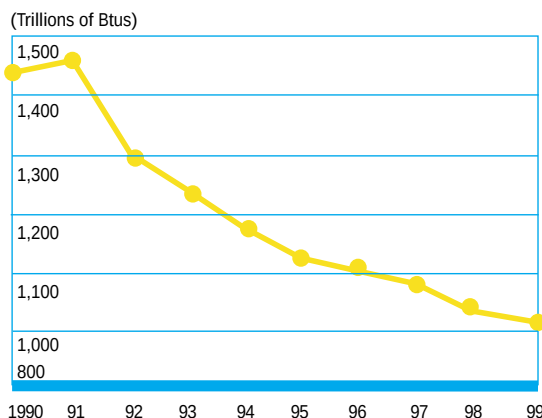
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand.
- Agencies should report to the President, through the Secretary of Energy, within 30 days of the conservation actions taken.

State and local governments have unique opportunities for energy savings in schools, transportation, state buildings, and building codes. For example, the Texas School Energy Management Program could save school districts as much as \$100 million in energy costs every year by helping school districts evaluate their energy needs and resources. Similarly, Wisconsin's Energy Initiative is working with utilities to make basic changes to public buildings. By installing new lighting fixtures and taking other steps, Wisconsin estimates that it will save \$60 million in state spending on energy over ten years.

Residential and Commercial Buildings

There are significant opportunities to improve the energy efficiency of buildings and homes through technologies and better practices. For existing homes, immediate options for improving efficiency include reducing air infiltration with caulking and weather stripping, installing modern thermostats, sealing ductwork, and adding insulation. These steps can reduce the 40 percent share of residential energy bills that

Figure 4-3
The U.S. Government is Reducing Its Energy Consumption



During the 1990s, energy use in federal buildings decreased by about 30 percent.

Source: U.S. Department of Energy, Energy Information Administration.



PULTE HOMES

Building America—Pulte Homes

Pulte Homes Southwest Division has used technical assistance from the Department of Energy's Building America program to create what one residential expert calls "the best production house in the world," which won the 2001 National Association of Home Builders' Energy Value Award. In Tucson, Phoenix, and Las Vegas, Pulte Homes has worked with the Department of Energy to redesign the energy features of its basic models.

Using advanced insulation techniques, highly efficient equipment and windows, and right-sized heating and cooling systems, the homes look the same, but perform so well they use half the energy for heating and cooling at virtually no increase in construction costs.

The whole building/systems engineering approach used in the Building America program allows builders to add more insulation and more efficient windows while reducing the size of the heating and cooling equipment. The trade-off means no added cost to the builder, better value for the buyer, reduced electric load for the utility, and improved affordability.

go toward heating and cooling. Additional savings are possible when efficient appliances are purchased or major home renovations are undertaken. Installing a new, more efficient gas furnace can save up to 20 percent annually on natural gas. New buildings offer the greatest energy efficiency opportunities and can be designed to be both more comfortable and more efficient, cutting heating and cooling costs by close to 50 percent.

In commercial buildings, typically the quickest, most cost effective way to increase energy efficiency is to replace the lighting systems. Sensors help to avoid 24-hour operation of lights and equipment that are only used for a portion of the day. As with homes, advances in windows, heating and air conditioning systems, overall building designs, and equipment and appliances present significant energy saving opportunities.

Many families and businesses can face obstacles to realizing energy cost reductions.

Insufficient Information

Monthly energy bills generally report only total electricity or natural gas used, leaving families and businesses unsure about which energy services are most responsible for their energy use, and which investments could best help them reduce their costs. In addition, consumers may be unsure about the credibility of the energy-saving claims of individual manufacturers, salesmen, and designers. This incomplete information causes imperfections in the marketplace that hinder purchases of efficient technologies that would actually save families and businesses money.

Lack of Availability

Frequently, the most energy efficient products cost more and are not widely available, especially in smaller communities. Builders who would like to construct more efficient homes and businesses face the same problem at the wholesale level. For example, to keep costs down, builders are less likely to install top-of-the-line,

highly efficient products. The less expensive and generally less efficient products are heavily stocked and deeply discounted due to volume ordering. The decisions made about the energy efficiency of buildings and homes are not usually made by the consumer who will ultimately pay the energy bills. The incentive is for the builders to choose the material that poses the least cost to the builder, which is not necessarily the most energy efficient choice.

Lack of Automation

People often walk out of their offices and homes with the lights on and the air conditioner running. Turning off unused appliances, electronics, and lights is not always easy. Lack of automation (e.g., daylight sensors) means that conservation mostly depends on people turning off switches. Some appliances and electronics, such as stereos, video tape players, and televisions, continue to use electricity even after they are turned off.

Higher Initial Costs

Efficient products often cost more than less efficient versions, especially when they are first introduced to the market. Unless consumers can verify the resulting savings, they may be reluctant to pay the additional costs. Businesses that adopt labeling programs that spell out energy savings may be more successful in selling a more efficient, yet initially more expensive product. Higher initial costs can be particularly difficult for the purchaser or builder of a new home or office building.

Industry and Agriculture

Six industries consume three-quarters of all industrial energy: lumber and paper; chemicals; petroleum refining; primary metals; food processing; and stone, clay, and glass. Improved energy efficiency in these energy-intensive industries yields even larger improvements in overall productivity, product quality, safety, and pollution prevention. Manufacturing companies generally obtain their largest savings from



improved efficiency of motors (motors account for 54 percent of electricity use in manufacturing) and from improved steam and hot-water systems. Many companies can reduce energy needs further by cogenerating their electricity and heat for steam.

Energy use for U.S. agriculture grew during the 1960s and 1970s, peaking in 1978. High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel-efficient diesel-powered engines, adopting conservation tillage practices, shifting to larger multiprocessor machines, and using energy saving methods for drying and irrigating crops. These measures helped farmers reduce their energy use by 41 percent from 1978 to 1998, while agricultural output grew by about 40 percent over the same period.

Farmers can reap additional energy savings as they replace old machinery with more energy efficient equipment. Furthermore, farmers can adopt more advanced practices, such as precision farming, that optimize the use of machines, chemicals, and fertilizers to achieve energy savings. New seed varieties can also reduce energy-intensive chemical requirements.

Despite the opportunity for increased energy efficiency, the industrial and agricultural sectors face several obstacles. Because many manufacturing and farming operations are highly specialized, they need specific information on energy-saving opportunities to effectively respond to energy price signals and supply problems.

High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel efficient diesel-powered engines and by adopting conservation tillage practices.

Cogeneration

In 1998, Malden Mills Industries, a textile manufacturer employing 2,300 workers in Lawrence, Massachusetts, installed a state-of-the-art combined heat and power (CHP) facility. The system uses two 4.3 MW industrial gas turbines, retrofitted with ceramic combustion liners, that were developed as part of the Department of Energy's Advanced Turbine Systems program, and that enable higher operating temperatures and lower emissions. The CHP system saves Malden Mills more than \$1 million annually. The liners have accumulated more than 9,500 hours of successful operation and have cut emissions of nitrogen oxides and carbon monoxide to less than 15 parts per million.



In order for manufacturing or agriculture to switch to more efficient energy products and practices, significant costs are incurred due to production delays, waste and spoilage, and labor costs. As a result, manufacturers and farmers tend to use readily available and reliable equipment when upgrading, instead of untested, newer products and approaches.

Because of their large needs for both heat and electricity, businesses find combined heat and power (CHP) systems particularly attractive. However, replacing old, inefficient boilers with highly efficient CHP systems may add a number of new regulatory requirements (such as air permits), but does not offer the same tax depreciation incentives the tax code grants to power plants.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with the Congress on legislation to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfield sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

Conservation can be improved by car pooling, telecommuting, increasing public transit choices, and pricing highway use during periods of peak demand.

Transportation

Transportation plays a key role in a growing U.S. economy, comprising 16 percent of GDP in 1998, 10.5 percent of total employment, and 27 percent of total U.S. energy consumption. Trucks and automobiles account for over three-fourths of the sector's petroleum use, with the remainder attributable to rail, ship, air, and pipeline systems. Mass transit ridership has increased by 21 percent since 1996. Automobiles today use roughly 60 percent of the gasoline they did in 1972 per mile driven, due in part to new technology, such as better engine and design controls, improved transmission, weight reduction, and improved aerodynamics. Despite the adoption of more efficient transportation technologies, average fuel economy for passenger vehicles has remained relatively flat for ten years and is, in fact, at a twenty-year low, in large part due to the growth and popularity of low-fuel-economy pickup trucks, vans, and sport utility vehicles (Figure 4-4).

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

Opportunities for reducing oil demand in the transportation sector include increasing conservation, vehicle efficiency, and alternative fuels. Conservation can be improved by car pooling, telecommuting, and increasing transit choices. For example, an increase in the average fuel economy of the on-road vehicle fleet by three miles per gallon would save one million barrels of oil a day, or about half of the global shortfall between supply and demand that triggered the oil price increases since 1998. In addition, fuel conservation can be further improved by technologies to reduce congestion.

A recent analysis indicates that the fuel economy of a typical automobile could be enhanced by 60 percent by increasing engine and transmission efficiency and reducing vehicle mass by about 15 percent. Several promising efficiency technologies are being presented to the U.S. market. For example, some automobile manufacturers have already introduced hybrid vehicles, and others have announced that they will introduce hybrid vehicles within the next several years. Advanced lightweight materials offer up to 6 percent improvement in mileage for each 10 percent reduction in body weight. Although promising, it may be many years before hybrids become a substantial part of the automotive fleet.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and to work with the Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid or fuel cell vehicles between 2002 and 2007.

Higher Initial Production Costs

Because of the large economies of scale in automobile manufacturing, new technologies with limited early production runs often enter the market at higher initial costs. In this highly competitive international market, higher initial production costs can be a significant impediment to the introduction of new technologies. Unless U.S. automakers can remain competitive with their overseas counterparts, it is unlikely they will invest in new, more efficient technologies. Vehicle efficiency technologies, such as advanced engines, fuel cells, and cutting-edge electronic drive-train technologies, will become widely available only when component costs are reduced or demand is increased.

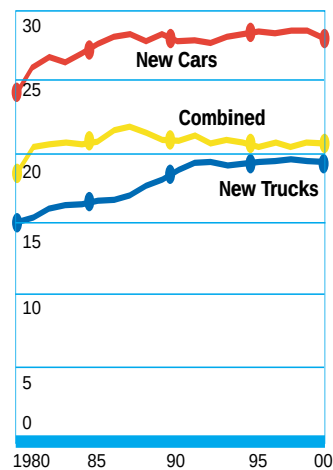
Hybrid Vehicles

The engine of a conventional gasoline vehicle is typically sized for the small amount of time the driver spends accelerating to enter the freeway, to pass another car, or to climb a hill. Most of the time it operates at less than 20 percent efficiency. An attractive alternative is to use a hybrid system that allows the engine to operate at peak efficiency, and get a boost from a battery when entering the freeway or climbing a hill. Not only does this system allow improved performance from a smaller engine, but the energy usually lost in stopping the car can be recovered and stored in the battery.

What does this mean to the average American? Significantly improved fuel economy and reduced emissions.

Figure 4-4
Fuel Efficiency of Light Vehicles Has Remained Flat

(Miles per Gallon)



Despite the adoption of more efficient transportation technologies, U.S. average fuel economy has been flat for 10 years. In large part, this is due to the growth of low-fuel-economy pickup trucks, vans, and sport utility vehicles.

Source: U.S. Department of Energy, Energy Information Administration.

Summary of Recommendations

Using Energy Wisely: Increasing Energy Conservation and Efficiency

- ★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.
 - Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
 - Extend the Energy Star labeling program to additional products, appliances, and services.
 - Strengthen Department of Energy public education programs relating to energy efficiency.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.
 - Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
 - Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.
- ★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.
- ★ The NEPD Group recommends that the President direct the Secretary of Transportation to:
 - Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly

crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.

- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.

- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low-emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about \$400) a year on their home energy bill by using Energy Star-labeled products.

Energy for a New Century

Increasing Domestic Energy Supplies

America's energy strength lies in the abundance and diversity of its energy resources, and in its technological leadership in developing and efficiently using these resources. Our nation has rich deposits of coal, oil, and natural gas. The United

States is the third-largest oil-producing nation in the world, despite a thirty-year decline in domestic production. While our economy runs primarily on fossil fuels, we also have long experience with hydropower and nuclear energy. We are pursuing the ability to further capture the energy of sunlight, the heat of the earth, and the power of wind.

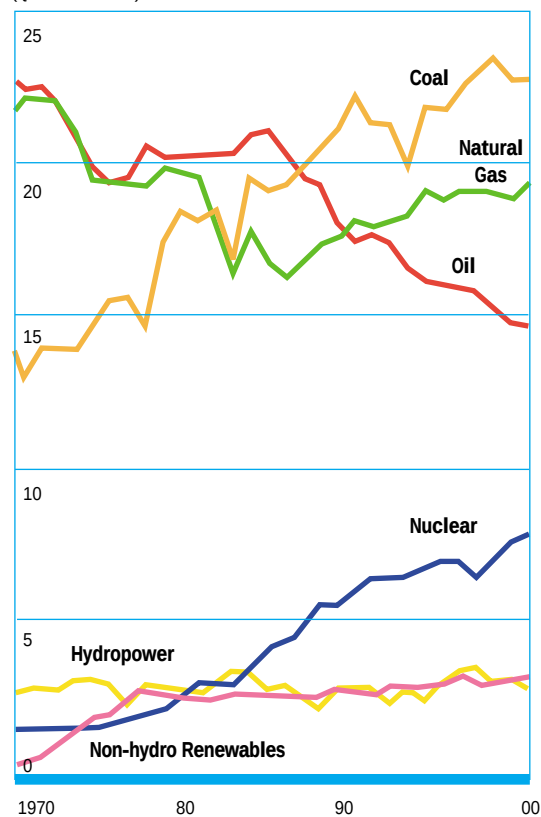
Economic factors will help determine the future development of our nation's energy sources. These factors will be shaped not only by conservation, energy demand, and the cost of energy development, but also by the regulations that federal, state, and local governments put in place to balance energy needs with legitimate competing aims, including the protection of the environment. A number of factors will make it difficult to increase domestic energy production in response to the growing demand for energy: economic and technological factors associated with depletion of the fossil fuel resource base in the U.S.; regulatory uncertainty; limitations on access to federal lands with high potential for new discoveries; infrastructure constraints, such as electricity transmission and gas pipeline bottlenecks; and conflicts with legitimate land use, environmental, and other public policy goals.

The United States has significant domestic energy resources, and remains a major energy producer. Between 1986 and 2000, production of coal, natural gas, nuclear energy, and renewable energy increased. However, these increases have been largely offset by declines in oil production (Figure 5-1).

Figure 5-1

U.S. Energy Production: 1970–2000

(Quadrillion Btus)



Production of coal, the nation's most abundant fuel source, exceeded 1 billion tons in 2000. Electricity generation accounted for about 90 percent of U.S. coal consumption last year.

Source: U.S. Department of Energy, Energy Information Administration.



Even with improved energy efficiency, the United States will need more energy supply. U.S. energy demand is projected to rise to 127 quadrillion Btus by 2020, even with significantly improved energy efficiency. However, domestic production is expected to rise to only 86 quadrillion Btus by 2020. The shortfall between projected energy supply and demand in 2020 is nearly 50 percent. That shortfall can be made up in only three ways: import more energy; improve energy efficiency even more than expected; and increase domestic energy supply.

The challenge for our nation is to use technology to maintain and enhance the diversity of our supplies, thus providing a reliable and affordable source of energy for Americans. These goals can and must be accomplished while maintaining our commitment to environmental protection.

Oil and Natural Gas

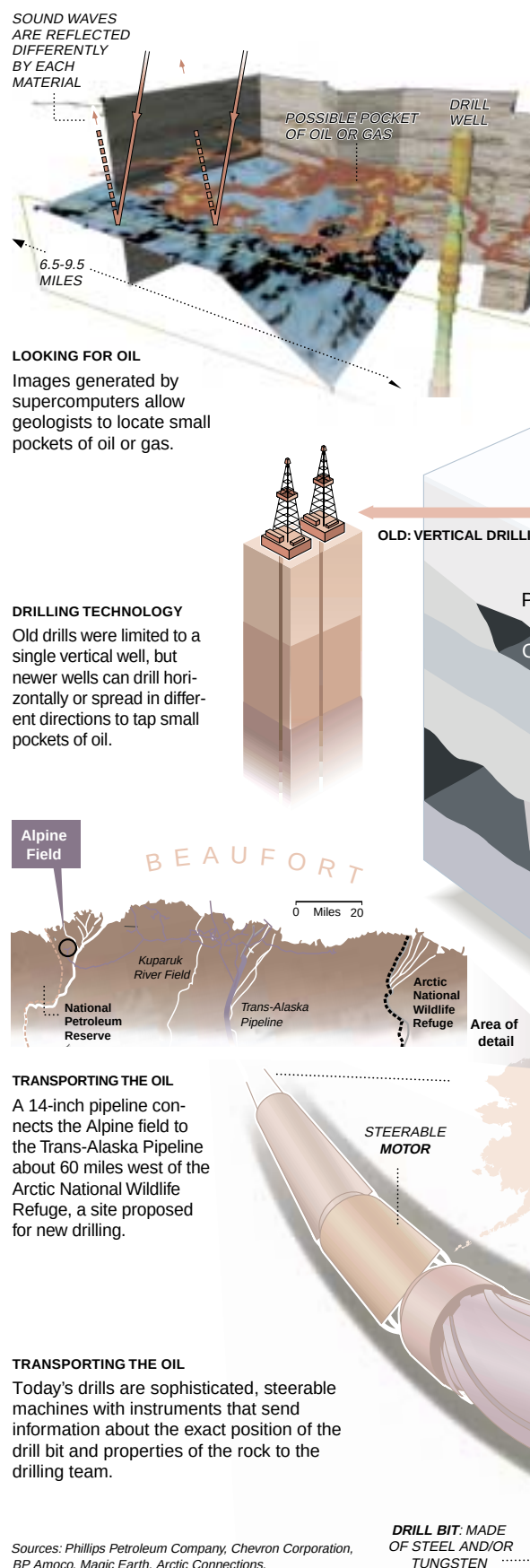
Oil and natural gas are the dominant fuels in the U.S. economy, providing 62 percent of the nation's energy and almost 100 percent of its transportation fuels. By 2020, the Energy Information Administration expects the United States will need about 50 percent more natural gas and one-third more oil to meet demand.

U.S. oil production is expected to decline over the next two decades. Over the same period, demand for natural gas will most likely continue to outpace domestic production. As a result, the United States will rely increasingly on imports of both natural gas and oil from Canada, and imports of oil and liquefied natural gas from producers across the globe.

21st Century Technology

Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs, (e.g., deep water

Figure 5-2



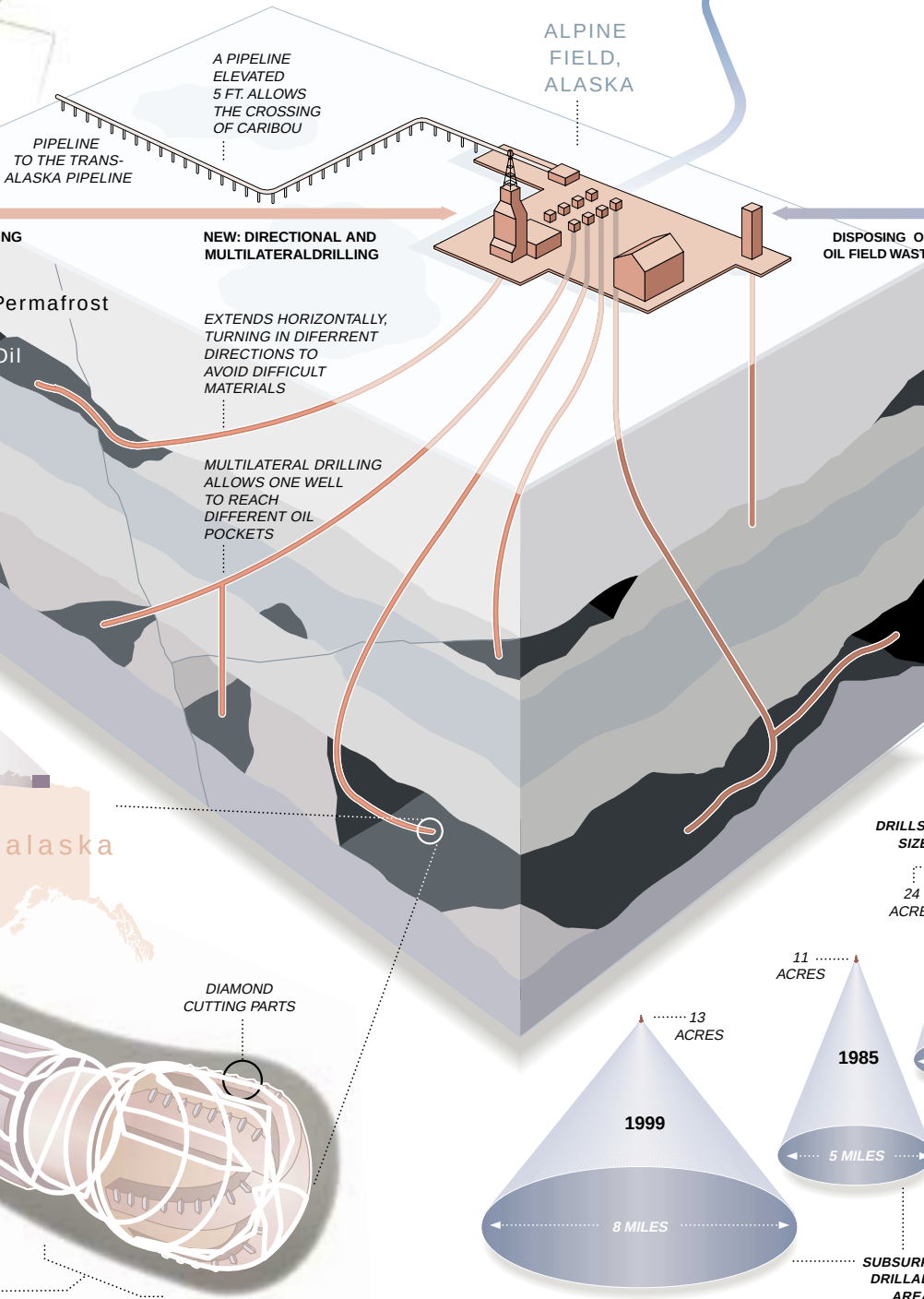
Using the Latest Drilling Technology to Reduce Environmental Damage

Oil drilling sites like those in the Alpine field on Alaska's North Slope are using cutting-edge technology in hopes of reducing environmental damage.

Recent advances are lessening the industry's impact on the fragile Arctic ecosystem.



BP Amoco



GETTING THERE

To minimize the project's impact on the environment, temporary ice roads are used in the winter, leaving few traces after they thaw.

DISPOSING OF WASTES

Mud and debris from drilling used to be placed in big reserve pits. Today, rock cuttings are crushed, mixed with the mud, and sent deep into the earth where they originated. This minimizes the size of well pads.

CROSSING A RIVER

Although traditional pipelines are built above ground, the pipeline to the Trans-Alaska Pipeline plunges beneath the Colville River, preserving the surface and the river bed environment.

OCCUPYING LESS OF THE TUNDRA

The new drilling technology allows for smaller surface production pads and larger areas explored in the earth.

Source: New York Times News Service

21st Century Technology: The Key to Environmental Protection and New Energy Production

Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques allow for sophisticated energy production as well as enhanced environmental protection. A technology evolution has occurred in the way oil and natural gas are found. The computer, three dimensional seismic technology, and other technologies have transformed the process from one based on "feel," to one highly dependent on the most advanced and sophisticated technology available. These technologies reduce cost and protect the environment.

Today's oil and gas exploration technology, for example, is boosting the success rate of pinpointing new resources. The results: fewer dry holes, reduced waste volumes, and a cleaner environment. Smaller, lighter drilling rigs coupled with advances in directional and extended-reach drilling significantly increase protection of the environment.

- Advanced, more energy efficient drilling and production methods:
 - reduce emissions;
 - practically eliminate spills from offshore platforms; and
 - enhance worker safety, lower risk of blowouts, and provide better protection of groundwater resources.
- With each improvement in operational performance and efficiency, more oil and gas resources can be recovered with fewer wells drilled, resulting in smaller volumes of:
 - cuttings;
 - drilling muds and fluids; and
 - produced waters.
- Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable:
 - production of oil and gas with increased protection to wetlands and other sensitive environments;
 - reduced greenhouse gas emissions;
 - and worker safety through the use of innovative best management practices.

Other examples of advanced technology include:

- 3-D seismic technology that enables geologists to use computers to determine the location of oil and gas before drilling begins, dramatically improving the exploration success rate;
- deep-water drilling technology that enables exploration and production of oil and gas at depths over two miles beneath the ocean's surface;
- high-powered lasers that may one day be used for drilling for oil and gas; and
- highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site.

:

and harsh environments).

While the resource base that supplies today's natural gas is vast, U.S. conventional production is projected to peak as early as 2015. Increasingly, the nation will have to rely on natural gas from unconventional resources, such as tight sands, deep formations, deep water, and gas hydrates. Also, many resources are in environmentally sensitive areas that require use of less intrusive technologies.

New technologies are being developed to reduce both the environmental effects and the economic costs of exploration for oil and gas. These exciting new technologies, like horizontal drilling and three-dimensional seismic technology allow for much greater precision and significantly less impact on the environment (Figure 5-2).

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states. However, even when new technology is available, independent producers can lack the investment capital needed to apply the technology and be unable to cope with the increased economic and technical risks associated with harder-to-recover resources.

For example, most new gas wells drilled in the United States will require hydraulic fracturing. This is a common procedure used by producers to complete gas wells by stimulating the well's ability to flow increased volumes of gas from the reservoir rock into the wellbore. During a fracture procedure, fluid and a propping agent (usually sand) are pumped into the reservoir rock, widening natural fractures to provide paths for the gas to migrate to the wellbore. In certain formations, it has been demonstrated that the gas flow rate may be increased as much as twenty-fold by hydraulic fracturing. Each year nearly 25,000 oil and gas wells are hydraulically fractured.

The use of hydraulic fracturing in natural gas production from coal seams is one of the fastest-growing sources of gas production. This source will most likely face added controls, and costs to ensure that disposal (by re-injection or discharge) of production waters is done in an environmentally sensitive manner.

For each of these issues, opportunities exist to better coordinate, improve performance, and meet America's energy, public health, safety and environmental goals.

Recommendation:

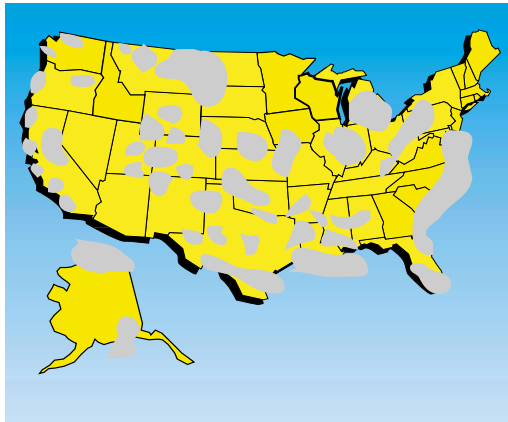
★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states.

Anywhere from 30 to 70 percent of oil, and 10 to 20 percent of natural gas, is not recovered in field development. It is estimated that enhanced oil recovery projects, including development of new recovery techniques, could add about 60 billion barrels of oil nationwide through increased use of existing fields (Figure 5-3).

Figure 5-3

Major U.S. Oil and Gas Fields



The United States is the most mature oil-producing region in the world, and much of our easy-to-find resource base has been depleted. Advanced exploration and production technologies of the past two decades have played a key role in recovering additional oil and natural gas from existing fields.

Source: U.S. Department of Energy, Energy Information Administration.

Public Lands Leasing

The federal government owns about 31 percent of the nation's land, so it can have a major role in increasing energy production in appropriate places. A large portion of U.S. energy resources are contained in these federal lands and offshore areas. Public lands provide nearly 30 percent of

annual national energy production, and are estimated to contain a substantial majority of the nation's undiscovered domestic energy resources.

Portions of federal onshore and offshore lands are off-limits to oil and gas exploration and development. Access is restricted for a variety of reasons, including administrative land withdrawals for competing land uses, such as national defense or water projects; and stipulations affecting surface occupancy, use, and timing for environmental compatibility.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

Offshore

Congress has designated about 610 million acres off limits to leasing on the Outer Continental Shelf (OCS), which contains large amounts of recoverable oil and gas resources. These Congressional moratoria have been expanded by Presidential action through 2012, effectively confining the federal OCS leasing program to the central and western Gulf of Mexico, a small portion of the eastern Gulf, existing leases off California's shore, and areas off of Alaska.

Concerns over the potential impacts of oil spills have been a major factor behind imposition of the OCS moratoria. For areas that are available for possible development, it is projected that with advanced technology, we could recover 59 billion barrels of oil and 300 trillion cubic feet of natural gas. This type of exploration and production from the OCS has an impressive environmental record. For example, since 1985, OCS operators have produced over 6.3 billion barrels of oil, and have spilled only 0.001 percent of production. Naturally occurring oil seeps add about 150 times as much oil to the oceans. Additionally, about 62 percent of OCS energy production is natural gas, which poses little risk of pollution.

For those areas that are available for potential coastal zone and OCS exploration and production activity, businesses must comply with a variety of federal and state statutes, regulations, and executive orders. Aspects of these, under the Coastal Zone Management Act and the Outer Continental Shelf Lands Act and their regulations, attempt to provide for responsible development while considering important environmental resources. However, effectiveness is sometimes lost through a lack of clearly defined requirements and information needs from federal and state entities, as well as uncertain deadlines during the process. These delays and uncertainties can hinder proper energy exploration and production projects.

The Deep Water Royalty Relief Act of 1995, granting variable royalty reductions for new leases in deep water, contributed to a significant increase in deep-water leasing in the central and western Gulf over the last five years. The opportunities created in deep water help spur the development of new

technologies and infrastructure for this frontier area. However, substantial economic risks remain to investment in deep water and continued incentives could help draw investment in other countries. Similar incentives could spur development in other technological frontiers, such as deep gas, or make possible continued production from both offshore and onshore fields near the end of their economic life.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

Arctic Outer Continental Shelf

It is estimated there are significant undiscovered resources in the two planning areas of the Arctic OCS. Geologists estimate that there are approximately 22.5 billion barrels of oil and 92 trillion cubic feet of natural gas in the Arctic OCS. The Beaufort Sea Planning Area encompasses approximately 65 million acres. Active leases within the Beaufort Sea Planning Area represent only 0.4 percent of the total acreage, and only 5 percent of the leased acreage is being actively pursued for development and production. The Chukchi Sea Planning Area encompasses approximately 63.7 million acres, none of which is currently leased.

Lease offerings totaling 58 million acres over the past twenty years have resulted in 34 exploratory wells. Two oil discoveries are now moving toward production, but economic factors have delayed several others. These discoveries have estimated recoverable reserves of more than 260 million barrels of oil. This is another area where periodic, well-scheduled lease sales can help contribute to national energy production.



The high-technology oil industry requires an educated, technologically sophisticated work force. Many workers left the industry in the mid-1980s because of job insecurity caused by price volatility. The lack of an experienced work force today may limit the amount and increase the cost of future exploration and production activity.

U.S. DEPARTMENT OF ENERGY

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

Onshore

North Slope Oil and Gas

The Alaska North Slope is a promising area for discovery of additional reserves to increase our domestic production of oil and natural gas. Currently, state lands on Alaska's North Slope provide about 17 percent of U.S. oil production. Oil and gas development in the Arctic, however, needs to be done in an environmentally responsible manner, using new technology and relying upon the best available scientific information. Such technology is making it possible to explore and develop oil and gas with significantly less impact on the environment. Areas with potential for oil and gas development are the National Petroleum Reserve-Alaska (NPR-A), the Arctic Outer Continental Shelf, and the Arctic National Wildlife Refuge (ANWR).

National Petroleum Reserve–Alaska

The National Petroleum Reserve–Alaska lies between the Brooks Range and the Arctic Ocean. The U.S. Geological Survey (USGS) estimates a high potential for oil and gas resources in the NPR–A, with a mean estimate of 2.1 billion barrels of oil and 8.5 trillion cubic feet of gas. A leasing program was designed and initiated in 1999 for the northeast sector of NPR–A, resulting in the award of 133 leases covering 900,000 acres. Eight exploratory wells have been completed in the past two years, and additional exploratory wells are expected this coming winter.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve–Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

Arctic National Wildlife Refuge

The Alaska National Interest Lands Conservation Act expanded ANWR from 9 million acres to 19 million acres, and designated 8 million acres as wilderness. Congress specifically left open the question of management of a 1.5-million-acre Arctic Coastal Plain area of ANWR because of the likelihood that it contains significant oil and gas resources. Section 1002 of the Act directed the Department of the Interior to conduct geological and biological studies of the Arctic Coastal Plain, “the 1002 Area,” and to provide to Congress the results of those studies with recommendations on future management of the area. Section 1003 of the Act prohibits leasing of the 1002 Area until authorized by an act of Congress.

In 1987, after more than five years of biological baseline studies, surface geological studies, and two seasons of seismic ex-

ploration surveys, the Department of the Interior recommended to Congress that the 1002 Area be leased for oil and gas exploration and production in an environmentally sensitive manner. In 1995, both the Senate and the House passed legislation containing a provision to authorize leasing in the 1002 Area, but the legislation was vetoed.

In May 1998, the USGS issued revised estimates of oil and gas resources in the 1002 Area. The 1998 USGS assessment shows an overall increase in estimated oil resources when compared to all previous government estimates. The estimate reaffirms the 1002 Area’s potential as the single most promising prospect in the United States. The total quantity of recoverable oil within the entire assessment area is estimated to be between 5.7 and 16 billion barrels (95 percent and 5 percent probability range) with a mean value of 10.4 billion barrels. The mean estimate of 10.4 billion barrels is just below the amount produced to date from North America’s largest field, Prudhoe Bay, since production began 23 years ago. Peak production from ANWR could to be between 1 and 1.3 million barrels a day and account for more than 20 percent of all U.S. oil production. ANWR production could equal 46 years of current oil imports from Iraq.

Technological improvements over the past 40 years have dramatically reduced industry’s footprint on the tundra, minimized waste produced, and protected the land for resident and migratory wildlife. These advances include the use of ice roads and drilling pads, low-impact exploration approaches such as winter-only exploration activities, and extended reach and through-tubing rotary drilling. These technologies have significantly reduced the size of production-related facilities on the North Slope. Estimates indicate that no more than 2,000 acres will be disturbed if the 1002 Area of ANWR is developed. For purposes of comparison, ANWR is about the size of the state of South Carolina, whereas the developed area is estimated to be less than one-fifth the size of Washington D.C.’s Dulles International Airport.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

Other Onshore Restrictions

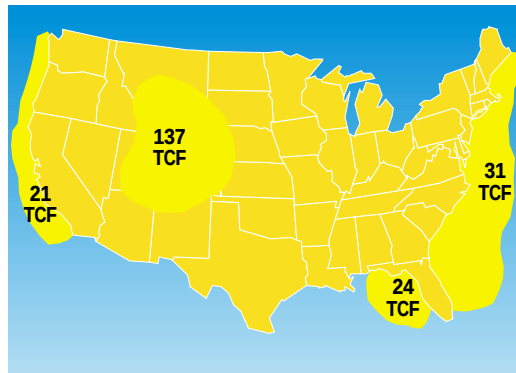
There is a significant potential for oil and gas resources on federal land in the lower 48 states as well. According to the most recent estimates from the USGS and the Minerals Management Service, oil resources underlying federal lands in the lower 48 states are estimated to be 4.1 billion barrels, and natural gas reserves are estimated to be 167 trillion cubic feet (Figure 5-4). Much of these potential resources have been placed off-limits or are subject to significant restrictions. For example, about 40 percent of the natural gas resources on federal land in the Rocky Mountain region have been placed off-limits.

The Department of the Interior initiated a study to examine the energy potential and restrictions on development on federal lands in the lower 48 states. In many cases, limits on oil and gas development are appropriate. However, improved technology has helped to reduce the impact of oil and gas development on the environment.

Exploration and Production

To meet increased natural gas demand in the coming decades, total wells drilled annually will need to double the 1999 level by 2020. Very few new onshore rigs have been built since the mid-1980s, because the oil field supply and service sectors have been hit especially hard by price volatility. Major additions to the offshore rig fleet will also be needed just to develop existing leases. The lack of an experienced work force may limit the speed and increase the cost of exploration and production activity.

Figure 5-4
**Restricted Natural Gas Resource Areas
in the U.S. Lower 48**



Much of the nation's oil and gas resource base resides on federal lands or in federal waters. A large portion of this is not open to exploration and development. For example, an estimated 40 percent or 137 trillion cubic feet of potential natural gas resource in the Rockies is either closed to exploration (29 tcf) or is open to development under restrictive provisions (108 tcf).

Source: U.S. Department of Energy, Energy Information Administration.

Electricity

Electricity is an essential part of modern life. When supply fails to keep pace with demand, costs to consumers and businesses rise and reliability falls. The California experience demonstrates the crippling effect that electricity shortages and blackouts can have on a state or region. This summer, the possibility exists for more intense electricity shortfalls in the West, with additional problems possible in New York City and on Long Island.

Electricity demand is projected to grow sharply over the next twenty years. Based on current estimates, the United States will need about 393,000 MW of new generating capacity by 2020 to meet the growing demand. If the U.S. electricity demand continues to grow at the high rate it has recently, we will need even more generating capacity. To meet that future demand, the United States will have to build between 1,300 to 1,900 new power plants; that averages out to be more than 60 to 90 plants a year, or more than one a week.

Over the next few years, if the demand for electricity continues to grow as predicted, and if we fail to implement a

comprehensive energy plan that recognizes the need to increase capacity, we can expect our electricity shortage problems to grow. The result will be higher costs and lower reliability.

Electricity Restructuring

One of the most important energy issues facing the Administration and Congress is electricity restructuring. The electricity industry is going through a period of dramatic change. To provide ample electricity supplies at reasonable prices, states are opening their retail markets to competition. This is the most recent step in a long transition from reliance on regulation to reliance on competitive forces.

Changes in Wholesale Electricity Market

This transition from regulation to competition began in 1978 with enactment of the Public Utility Regulatory Policies Act, which promoted independent electricity generation. Open-access transmission policies adopted by the Federal Energy Regulatory Commission (FERC) in the late 1980s further promoted competition in wholesale power markets. Congress largely ratified these policies with enactment of

the Energy Policy Act of 1992, which further promoted non-utility generation. FERC took another large step to promote competition with its open-access rule in 1996, which provided greater access to the transmission grid, the highway for interstate commerce in electricity.

Changes in the Retail Electricity Market

Increased competition in wholesale power markets encourages states to open retail electricity markets. Under current law, FERC has jurisdiction over the wholesale power market, while states have jurisdiction over retail markets. Beginning in 1996, states began opening their retail markets to competition in order to lower electricity prices. Twenty-five states have opted to open their retail electricity markets to competition.

Most new electricity generation is being built not by regulated utilities, but by independent power producers. These companies assume the financial risk of investment in new generation, and their success rides on their ability to generate electricity at a low cost.

These dramatic changes affecting the industry led to important structural changes. Independent power producers, which were once infant industries, now dwarf many utilities. Utility mergers, which were once rare, are now commonplace. U.S. utilities have been purchased by foreign companies, and U.S. utilities have in turn purchased utilities abroad. While utilities had service areas that were limited to a single state or region, independent power producers are international companies that can build power plants across the globe. Many utilities that were once vertically integrated divested themselves of generation, either voluntarily or because of state law.

Pending Congressional Action

Since 1995, Congress has been grappling with electricity competition legislation. Initial efforts sought to require states to open their retail markets by a date certain. Subsequent efforts focused on promoting competition in electricity markets and complementing state retail competition plans. Under this

Electricity demand is projected to rise sharply over the next twenty years. If we fail to build the 1,300–1,900 new power plants needed to increase generation and transmission capacity, current electricity shortages will become more frequent and more widespread.

U.S. DEPARTMENT OF ENERGY



approach, federal legislation focused on core federal issues, including:

- regulation of interstate commerce;
- assuring open access to the interstate and international transmission system;
- enhancing reliability of the grid;
- lowering barriers to entry;
- reforming outdated federal electricity laws, such as the Public Utility Holding Company Act and Public Utility Regulatory Policies Act of 1978;
- reforming the role of federal electric utilities in competitive markets;
- protecting consumers; and
- clarifying federal and state regulatory jurisdictions.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

California Electricity Crisis

The California electricity crisis is not a test of the merits of competition in electricity markets. Instead, it demonstrates that a poorly designed state retail competition plan can have disastrous results if electricity supply does not keep pace with increased demand. At heart, the California electricity crisis is a supply crisis. California allowed demand to outstrip supply, and did little to lower barriers to entry through reform of an inflexible siting process. The risk that the California experience will repeat itself is low, since other states have not modeled their retail competition plans on California's plan.

The California crisis also shows that state electricity markets do not stay neatly confined within legal and jurisdictional bounds. Due to regional interconnection, disastrous mistakes made by the State of California have dire effects on the entire West. California's failure to reform flawed regulatory rules affecting the market drove up wholesale prices. Actions such as forcing utilities to purchase all their power through volatile spot markets, imposing a single-price auction system, and barring bilateral contracts all contributed to the problems that California now faces.

Lessons Learned from Successful Deregulation

As stated previously, 25 states have decided to open their retail electricity markets. A comparison of the different approaches taken by California and other states demonstrates that competition will benefit consumers if implemented effectively. A better gauge of the potential for retail competition to lower prices can be found in Pennsylvania, where electricity prices have fallen significantly as a result of competition. There is also reason to believe that the plan in Texas will have similar success.

A major difference between the California experience and the approaches taken by Pennsylvania and Texas is that the latter states ensured they had adequate electricity supplies. Pennsylvania and Texas took steps to ensure that procedures for adding new power plants were efficient. Unlike California, which imports 25 percent of its electricity, Pennsylvania is a net exporter of power, and Texas imports almost no power from other states. For these reasons, Pennsylvania and Texas have ample electricity supply to meet demand, while California is confronting a serious supply shortage.

In addition, California required its utilities to divest themselves of much of their generation, unlike Pennsylvania and Texas. This action forced California utilities to rely much more heavily on buying power, at ever-increasing prices, instead of generating power themselves.

Another major difference is that Pennsylvania and Texas did not require their utilities to purchase electricity through volatile spot markets. This requirement, combined with frozen retail rates imposed by the State, forced California utilities to purchase power at much higher costs than could be passed along to the consumer. As a result, the California regulatory plan resulted in unreliable service, destroyed the financial health of the State's utilities, and drove one utility into bankruptcy.

The federal government does not site power plants; that is a responsibility of the states. For that reason, delays relating to the construction of new power plants are usually the result of state action. A number of federal agencies, such as the Environmental Protection Agency, the Department of Commerce, and the Department of the Interior, do issue air and other permits for generation facilities. Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. These agencies, pursuant to President Bush's Executive Order, have expedited permit-processing applications for energy production in California.

Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. For example, in 1999–2000, the time for issuing air permits (including the time for public participation) for turbines was reduced to three to four months (compared to the twelve months allowed by the regulations) for the majority of permit applications.

Fuels for Electricity Generation

Electricity is not a primary source of energy. It is generated by the use of primary energy sources (Figure 5-5). Coal, nuclear energy, natural gas and hydropower account for about 95 percent of total electricity generation, with oil and renewable energy contributing the remainder. Despite this healthy diversity of energy sources, each type of electricity resource is faced with constraints to maintaining or expanding its contribution to electricity production.

Coal

Coal is used almost exclusively to generate electricity. Coal power plants account for over 50 percent of all U.S. electricity generation, and over 80 percent of generation in twelve states in the Midwest, Southeast, and West. Coal electricity generation costs are low, and coal prices have proved remarkably stable. In 1999, the United States produced 1.1 billion tons of coal. Production of coal from federal and tribal lands, which has increased substantially in the past decade, accounted for 38 percent of this total.

Although coal is the nation's most abundant fossil energy source, production and market issues can affect the adequacy of supply. Production issues include the protection of public health, safety, property, and the environment, and the effectiveness of federal and state agencies implementing various laws governing coal mining. These issues have resulted in some coal resources becoming uneconomical to produce. Statutory, regulatory, and administrative difficulties also may limit or prevent the production of some coal resources. However, technological advances in cleaner coal technology have allowed for significant progress toward reducing these barriers. There are also opportunities to protect the environment while lowering costs through further improvements in technology.

Over the past decade, greater efficiencies, lower capital costs, fewer emissions and quicker start-up times have made power plants fueled by natural gas a more attractive choice for new coal generation. Recently, however, rising natural gas prices have renewed interest in building coal power plants.

Uncertainty about future environmental controls is of particular concern for companies that operate existing coal power plants. Regulations under development include a variety of measures requiring reductions in emissions of nitrogen oxide, sulfur dioxide, and mercury. In addition, rules related to discharges to streams and cooling-water intake structures, possible regulation of large-volume wastes as hazardous wastes,

uncertainty over rules requiring air permits for certain modifications to power plants, and uncertainty over global and domestic efforts to reduce carbon dioxide emissions also play a role. This regulatory uncertainty discourages power producers from building coal power plants and is one reason the United States is relying so heavily on natural gas power generation to meet growing electricity demand.

Much of the current uncertainty has resulted because regulators do not weigh the cumulative impacts of their proposals. Compliance decisions by businesses concerning each new regulation must often be made without the benefit of clear information regarding additional requirements that may be imposed. More effective and economical compliance strategies are possible if companies know the full range of requirements with which they must comply.

If rising U.S. electricity demand is to be met, then coal must play a significant role. Under current policies, in the next two decades, nuclear electricity generation and hydropower are projected to decline. Natural gas electricity generation is projected to increase from about 16 to 36 percent of total generation, which would require the tripling of natural gas used for electricity generation. Significantly, this projected increase in natural gas genera-

tion assumes that coal electricity generation will continue to account for about 50 percent of U.S. electricity generation. If policies are adopted that sharply lower coal electricity generation, then the likely result is an even greater dependence on natural gas generation. This creates concern about the adequacy of natural gas supplies and policies.

Clean Coal Technology

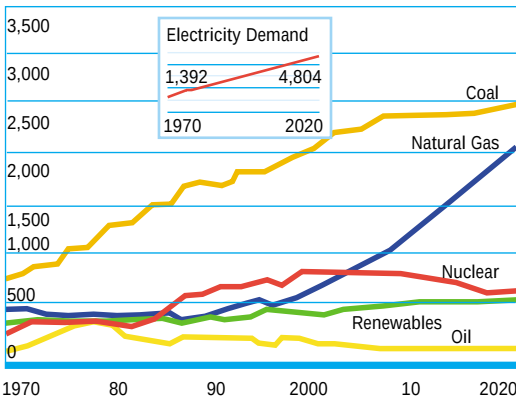
Technology has been and will continue to be a key to achieving our energy, economic, and environmental goals. In recent years, technological advancements through efforts of both the public and private sectors have led to substantial reductions in the cost of controlling sulfur dioxide and nitrogen oxide emissions, while the effectiveness of control systems increased significantly. The Department of Energy, through its Clean Coal Technology Program, has worked to provide effective control technologies. These nitrogen oxide and sulfur dioxide control technologies have moved into the utility marketplace and now provide a means to achieve cost effective regulatory compliance.

For example, most power plants that can use low nitrogen oxide burners have now installed them, and about 25 percent of all coal power plants have either ordered or installed selective catalytic reduction technology, which reduces nitrogen oxide emissions.

Technologies like fluidized-bed combustion and integrated gasification combined cycle have been developed that further reduce emissions. Fluidized-bed combustion is a low-emitting nitrogen oxide combustion technology that allows the use of fuels, such as coal pile washer waste, that were not formerly usable. Integrated gasification combined cycle is a relatively new technology that uses refinery waste as fuel.

Future coal electricity generation will need to meet new challenges to reduce emissions even further, especially mercury emissions. The Department of Energy is supporting efforts to develop more cost effective control technology. Indeed, the goal

Figure 5-5
Electricity Generation by Fuel: Current Trends
(Billions of Kilowatt-Hours)



Source: U.S. Department of Energy, Energy Information Administration

Clean Coal Technology

Clean Coal Technology describes a category of technologies that allow for the use of coal to generate electricity while meeting environmental regulations at low cost.

- In the short term, the goal of the program is to meet existing and emerging environmental regulations, which will dramatically reduce compliance costs for controlled mercury, NO_x, SO₂, and fine particulate at new and existing coal power plants.

- In the mid-term, the goal of the program is to develop low-cost, super-clean coal power plants, with efficiencies 50 percent higher than today's average. The higher efficiencies will reduce emissions at minimal costs.

- In the long term, the goal of the program is to develop low-cost, zero-emission power plants with efficiencies close to double that of today's fleet.

of these research, development, and demonstration programs is to develop and demonstrate coal power systems with near zero environmental emissions, while maintaining low production costs.

Recommendations:

- ★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing R&D tax credit.
- Directing agencies to explore regulatory approaches that will encourage advancements in environmental technology.

- ★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

Nuclear Energy

Nuclear energy accounts for 20 percent of all U.S. electricity generation, and more than 40 percent of the electricity generation in ten states in the Northeast, the South, and the Midwest. Despite the closure of several less efficient plants during the 1990s, the 103 U.S. nuclear energy plants currently operating produce more electricity today than at any time in history.

There are a number of reasons why nuclear energy expansion halted in the 1980s. Regulatory changes implemented after the Three Mile Island incident in 1979 lengthened the licensing period to an average of fourteen years, resulting in large cost overruns. Increased public concern

about the safety of nuclear energy after the accident often resulted in active opposition to proposed plants. As a result, the last completed nuclear energy plant in the United States was ordered in 1973.

Since the 1980s, the performance of nuclear energy plant operations has substantially improved. While U.S. nuclear energy plants once generated electricity only around 70 percent of the time, the average plant today is generating electricity close to 90 percent. This improved performance has lowered the cost of nuclear generation, which is now competitive with other sources of electricity (Figure 5-6).

There is potential for even greater generation from existing nuclear energy plants. Experts estimate that 2,000 MW could be added from existing nuclear power plants by increasing operating performance to 92 percent. In addition, about 12,000 MW of additional nuclear electricity generation could be derived from uprating U.S. nuclear power plants, a process that uses new technologies and methods to increase rated power levels without decreasing safety. However, modifications to uprate plants can be expensive and require extensive licensing review and approval by the Nuclear Regulatory Commission (NRC). Another way to increase nuclear generation from existing plants is through license renewal. Many nuclear utilities are planning to extend the operating license of existing nuclear plants by twenty years, and the licenses of as many as 90 percent of the currently operating nuclear plants may be renewed.

The nuclear energy industry is closely regulated by the NRC, which provides rigorous oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. The NRC has made great strides to provide greater regulatory certainty while maintaining high safety standards.

The installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the strong safety record of the nuclear energy industry. Since the Three Mile Island incident in 1979, the nuclear industry's safety record has significantly improved. This safety record has been achieved through a defense-in-depth philosophy accomplished by way of engineering design, quality construction, safe operation, and emergency planning. This philosophy provides for diverse and redundant systems to prevent accidents from occurring, as well as multiple safety barriers to mitigate the effects of accidents in the highly unlikely event they do occur.

Over the last several years, utilities have begun purchasing nuclear plants from other operators as the industry undergoes consolidation. Several nuclear utilities have merged, creating management teams with extensive expertise in running and maintaining nuclear plants. These mergers are impeded by tax rules relating to the transfer of decommissioning funds.

Utilities are also considering nuclear energy as an option for new generation. The NRC

has certified three standardized nuclear power plant designs, and Congress enacted legislation in 1992 to reform the nuclear licensing process. Under this process, a utility can apply for a combined construction and operating license for one of these standardized designs in a streamlined process. This reformed licensing process provides for site permits—a way to resolve siting issues early in the process. Building new generators on existing sites avoids many complex issues associated with building plants on new sites. Many U.S. nuclear plant sites were designed to host four to six reactors, and most operate only two or three; many sites across the country could host additional plants.

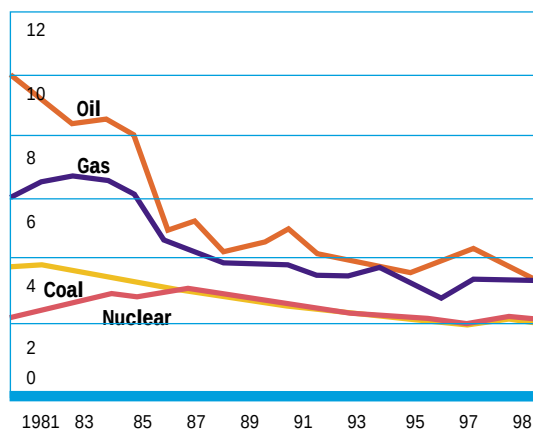
Advanced reactor technology promises to improve nuclear safety. One example of an advanced reactor design is the gas-cooled, pebble-bed reactor, which has inherent safety features. The industry has an interest in this and other advanced reactor designs.

The federal government must also provide for the safe disposal of nuclear waste. At present, nuclear waste continues to be stored at local plant sites. The Department of Energy is over a decade behind schedule for accepting nuclear waste from utilities, but has made progress toward characterization of the Yucca Mountain, Nevada site. Construction of an exploratory studies facility has been completed, a viability assessment was published, and recently scientists placed their extensive research about Yucca Mountain on the record for public scrutiny. However, key regulatory standards to protect public health and the environment at the repository have not been issued.

The Administration will continue to study the science to determine whether to proceed with the consideration of this site as the location for the repository. If the Administration decides to proceed, the Department of Energy must file a license application with the NRC. No waste will be sent to any location until the NRC determines it to be safe.

Other countries have developed different approaches for nuclear waste disposal. For example, the French, British and Japanese rely on reprocessing, an in-

Figure 5-6
Nuclear Generation is Competitively Priced
(1998 Cents per Kilowatt-Hour)



Note: Fuel costs are included.⁶

Source: Utility Data Institute via the Nuclear Energy Institute.⁶



Calvert Cliffs is the first U.S. nuclear plant to receive a renewed license from the Nuclear Regulatory Commission. The renewal will allow the plant to continue producing environmentally sound electricity for an additional twenty years.

CONSTELLATION ENERGY GROUP

dustrial approach that separates nuclear waste into usable fuel and highly concentrated waste. While this approach does not obviate the need for geologic disposal of nuclear waste, it could significantly optimize the use of a geologic repository. There is growing interest in new technology known as accelerator transmutation, which could be used in combination with reprocessing to reduce the quantity and toxicity of nuclear waste.

Recommendations:

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.

- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies, in collaboration with international partners with highly developed fuel cycles and a record of close cooperation, to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

Hydropower

Although hydropower generation accounts for only about 7 percent of overall U.S. electricity generation, the following states depend heavily on this source of energy: Idaho, Washington, Oregon, Maine, South Dakota, California, Montana, and New York.

Hydropower generation has remained relatively flat for years. The most significant constraint on expansion of U.S. hydropower generation is physical; most of the best locations for hydropower generation have already been developed. Potential does remain for some increases in hydropower generation, and capacity can be optimized by adding additional turbines and increasing efficiency at existing facilities.

Also, the amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages. The amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages.

The Federal Energy Regulatory Commission is required to incorporate mandatory conditions proposed by different state and federal resource agencies into hydropower licenses. Decision-making authority in the licensing process is diffused among a host of federal and state agencies, all of which are pursuing different statutory missions. The hydropower licensing process is prolonged, costly, and poses regulatory uncertainty. The challenge is to efficiently and effectively balance national interests in natural resource and environmental preservation with energy needs.

Recommendation:

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities, and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Natural Gas

Currently, natural gas provides about 16 percent of U.S. electricity generation. Seven states obtain over one-third of their generation from natural gas (Rhode Island, New York, Delaware, Louisiana, Texas, California, and Alaska). Perhaps more importantly, natural gas-fired electricity is projected to constitute about 90 percent of capacity additions between 1999 and 2020. The amount of natural gas used in electricity generation is projected to triple by 2020.

Ensuring the long-term availability of adequate, reasonably priced natural gas supplies is a challenge. Low gas prices in 1998 and 1999 caused the industry to scale back gas exploration and production activity. Since 2000, the North American natural gas market has remained tight due to strong demand and diminished supplies. Last year, natural gas prices quadrupled, which resulted in substantially higher prices for electricity generated with natural gas.

While the largest barriers to expanded natural gas electricity generation relate to production and pipeline constraints, there are several other barriers. Environmental regulations affect the use of gas for electricity generation. Although natural gas electric plants produce fewer emissions than coal-fired power plants, they still emit nitrogen oxides, carbon dioxide and small amounts of toxic air emissions.'

Oil

While oil fuels only about 3 percent of total U.S. electricity generation, it is the dominant source of electricity generation in Hawaii, and provides over 20 percent of the generation in Massachusetts, Connecticut, Delaware, Maine, and Florida. Over the next twenty years, market conditions are expected to reduce today's level of oil electricity generation by about 80 percent.

Renewable Energy

Hydropower is, to date, the most successful form of renewable energy. However, some forms of renewable energy generation—wind, geothermal, and biomass—have the potential to make more significant contributions in coming years, and the cost of most forms of renewable energy has declined sharply in recent years. The most important barrier to increased renewable energy production remains economic; nonhydropower renewable energy generation costs are greater than other traditional energy sources. The following chapter discusses renewable and alternative energy in greater detail.

High-tech power plants, like this combined cycle plant, are signaling a new age in electric power generation. The capability to co-produce electricity and a slate of fuels and chemicals makes the technology economically attractive to a broad range of industrial applications.

TAMPA ELECTRIC COMPANY



Summary of Recommendations

Energy for a New Century: Increasing Domestic Energy Supplies

- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).
 - Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
 - Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Nature's Power

Increasing America's Use of Renewable and Alternative Energy

A sound national energy policy should encourage a clean and diverse portfolio of domestic energy supplies. Such diversity helps to ensure that future generations of Americans will have access to the energy they need.

Renewable energy can help provide for our future needs by harnessing abundant, naturally occurring sources of energy, such as the sun, the wind, geothermal heat, and biomass. Effectively harnessing these renewable resources requires careful planning and advanced technology. Through improved technology, we can ensure that America will lead the world in the development of clean, natural, renewable and alternative energy supplies.

Renewable and alternative energy supplies not only help diversify our energy portfolio; they do so with few adverse envi-

ronmental impacts. While the current contribution of renewable and alternative energy resources to America's total electricity supply is relatively small—only 9 percent—the renewable and alternative energy sectors are among the fastest growing in the United States. Non-hydropower only account for 2 percent of our electricity needs. However, electricity generation from non-hydropower renewable energy grew by nearly 30 percent in the 1990s. Continued growth of renewable energy will continue to be important in delivering larger supplies of clean, domestic power for America's growing economy.

Renewable energy resources tap naturally occurring flows of energy to produce electricity, fuel, heat, or a combination of these energy types. One type of renewable energy, hydropower, has long provided a significant contribution to the U.S. energy supply and today is competitive with other forms of conventional electricity. However, there is limited growth potential for hydropower. Non-hydropower renewable energy is generated from four sources: biomass, geothermal, wind, and solar (Figure 6-1). The United States has significant potential for renewable resource development. These nondepletable sources of energy are domestically abundant and often have less impact on the environment than conventional sources. They can provide a reliable source of energy at a stable price, and they can also generate income for farmers, landowners, and others who harness them.

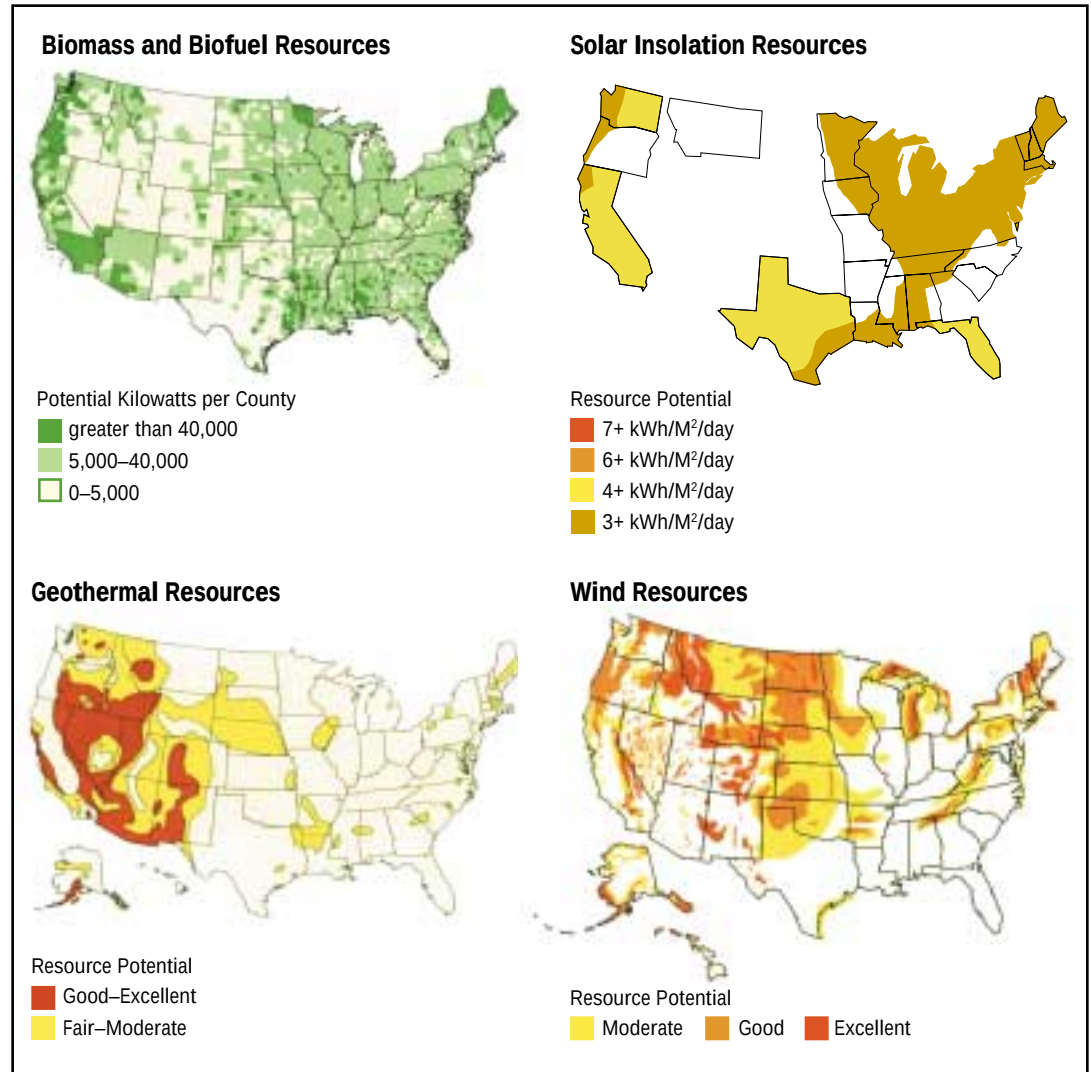
Renewable hydropower has long provided a significant contribution to the U.S. energy supply. Today, hydropower is competitive with other forms of conventionally generated electricity.





Figure 6-1

U.S. Resource Potential for Renewable Energy



Almost every state has the potential for wind energy and for biomass and biofuel production. The Southwest has the greatest potential for solar energy, and geothermal energy resources are most abundant in the West.

Source: U.S. Department of Energy, National Renewable Energy Laboratory.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable-energy production, such as biomass, wind, geothermal, and solar.

Alternative energy includes: alternative fuels that are transportation fuels other than gasoline and diesel, even when the

type of energy, such as natural gas, is traditional; the use of traditional energy sources, such as natural gas, in untraditional ways, such as for distributed energy at the point of use through microturbines or fuel cells; and future energy sources, such as hydrogen and fusion.

Both renewable and alternative energy resources can be produced centrally or on a distributed basis near their point of use. Providing electricity, light, heat, or mechanical energy at the point of use diminishes the

need for some transmission lines and pipe lines, reducing associated energy delivery losses and increasing energy efficiency. Distributed energy resources may be renewable resources, such as biomass cogeneration in the lumber and paper industry or rooftop solar photovoltaic systems on homes, or they may be alternative uses of traditional energy, such as natural gas microturbines.

Recommendations:

★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Renewable Energy Technologies

Biomass

Biomass is organic matter that can be used to provide heat, make fuel, and generate electricity. Wood, the largest source of biomass, has been used to provide heat for thousands of years. Many other types of biomass are also used as an energy source, such as plants, residue from agriculture or forestry, and the organic component of municipal and industrial wastes. Landfill gas is also considered a biomass source. Biomass resources can be replenished through culti-

Microturbines

Microturbines are small combustion turbines approximately the size of a refrigerator with outputs of 25 to 500 kilowatts. Microturbines can be used to power a home or small business. This technology has evolved largely from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines.

Compared to other technologies for small-scale power generation, microturbines offer a number of significant advantages, including a small number of moving parts; compact size; lightweight, optimal efficiency; lower emissions and electricity costs; and opportunities to use waste fuels. For these reasons, microturbines could easily capture a significant share of the distributed generation market.

vation of what are known as energy crops, such as fast-growing trees and grasses.

Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called biofuels, to meet our transportation needs. The two most common biofuels are ethanol and biodiesel.

Ethanol is made by fermenting any biomass that is rich in carbohydrates, such as corn. It is mostly used as a fuel additive to reduce a vehicle's emissions. Biodiesel is made using vegetable oils, animal fats, algae, or even recycled cooking greases. It can be used as a diesel additive to reduce emissions or in its pure form to fuel a vehicle. Beyond energy benefits, development of biomass benefits rural economies that produce crops used for biomass, particularly ethanol and biomass electricity generation.

Biomass, like corn, that is rich in carbohydrates can be converted directly into biofuels to meet our transportation needs. The biofuel ethanol is mostly used as a fuel additive to reduce vehicles' smog-causing emissions. In June 1992, the Greater Peoria Mass Transit District began operating fourteen ethanol-powered buses along regular city routes.

U.S. DEPARTMENT OF ENERGY



Biomass is also used to generate electricity. This is accomplished through the direct combustion of wood, municipal solid waste, and other organic materials; co-firing with coal in high efficiency boilers; or combustion of biomass that has been chemically converted into fuel oil. In the lumber and paper industries, wood scraps are sometimes directly fed into boilers to produce steam for their manufacturing processes or to heat their buildings. For that reason, renewable energy offers a particular advantage to the lumber and paper industry, and many analysts project the industry may soon become a net seller of electricity. Co-firing coal power plants with biomass has environmental benefits, since co-firing can significantly reduce emissions. Biomass accounts for 76 percent of renewable electricity generation and 1.6 percent of total U.S. electricity supply.

Even gas for generating electricity can be produced from biomass. Gasification systems use high temperatures to convert biomass into a gas that is used to fuel a turbine. The decay of biomass in landfills also produces methane, a gas that can be captured and burned in a boiler to produce steam for electricity generation or for industrial processes. Using methane emissions increases electricity supplies, reduces pollution from landfills and reduces greenhouse gas emissions. The technologies to collect and use landfill methane to generate electricity are already in the market. How-

ever, they have not been successfully integrated at present due to the perceived higher risk of new technologies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury, to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

Geothermal

Geothermal energy is the use of steam and hot water generated by heat from the Earth to perform work. Some geothermal power plants use steam or hot water from a natural underground reservoir to power a generator. Others use hot water to provide direct heat for residential and other buildings, and for other applications.

The most readily accessible resources for geothermal power generation in the United States are located in the West, Alaska, and Hawaii. A wide array of high technology geological, geochemical, and geophysical techniques are used to locate geothermal resources. In large measure, the technology for developing these resources has been adapted from the oil industry. Improvements in drill bits, drilling techniques, advanced instruments, and other technological advances have made energy production from geothermal resources increasingly efficient.

Geothermal accounts for 17 percent of renewable electricity generation and 0.3 percent of total U.S. electricity supply. However, the net installed capacity of U.S. geothermal power plants has increased significantly, from 500 MW in 1973 to 2,800 MW today.

Hot water near the surface of the Earth can also be used directly for heat. These direct-use applications include heat

The Geysers in northern California is the world's largest producer of renewable geothermal power. The dry-steam field has successfully produced power since the early 1960s, when Pacific Gas & Electric installed the first 11-megawatt plant. Today, nearly 2,000 megawatts are on line – enough energy to supply the electricity needs of San Francisco and Oakland.

PACIFIC GAS & ELECTRIC



ing buildings, growing plants in green houses, drying crops, heating water at fish farms, and several industrial processes, such as pasteurizing milk.

In addition, individual homeowners, farmers, and businesses can tap into geothermal energy through geothermal heat pumps to heat and cool buildings. A geothermal heat pump system consists of a heat pump, an air delivery system, a heat exchanger, and a system of pipes buried in the shallow ground near the building. In the winter, a heat pump removes heat from the heat exchanger and pumps that heat into the indoor air delivery system. In the summer, the process is reversed, and the heat pump moves heat from the indoor air into the heat exchanger. The heat removed from the indoor air during the summer can also be used to provide a free source of hot water. Geothermal heat pumps can be used almost anywhere in the United States, and can significantly increase system efficiencies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

Wind Energy

Wind energy has been used since at least 200 B.C. for grinding grain and pumping water. By 1900, windmills were used on farms and ranches in the United States to pump water and, eventually, to produce electricity. Windmills developed into modern-day wind turbines.

Wind turbines are used for several applications. Wind power uses the naturally occurring energy of the wind for practical purposes like generating electricity, charging batteries, or pumping water. Large, modern wind turbines operate together in wind farms to produce electricity for utilities. Small turbines are used by homeowners, farmers, and remote villages to help meet localized energy needs.

Wind turbines capture energy by using propeller-like blades that are mounted on a



rotor. These blades are placed on top of high towers, in order to take advantage of the stronger winds at 100 feet or more above the ground. The wind causes the propellers to turn, which then turn the attached shaft to generate electricity. Wind can be used as a stand-alone source of energy or in conjunction with other renewable energy systems. Wind and natural gas hybrid systems are a promising approach that offers clean power to consumers.

Wind energy accounts for 6 percent of renewable electricity generation and 0.1 percent of total electricity supply. However, advances by research labs, universities, utilities, and wind energy developers have helped cut wind energy's costs by more than 80 percent during the last twenty years. The industry is poised for growth. In some parts of the country, electricity from wind power can be produced at prices that are comparable to other conventional energy technologies. The United States has many areas with abundant wind energy potential, namely in the West, the Great Plains and New England.

Solar

Sunlight, or solar energy, can be used to generate electricity; heat water; and heat, cool, and light buildings. Photovoltaic (solar cell) systems use semiconductor materials similar to those used in computer chips to capture the energy in sunlight and to convert it directly into electricity. Photovoltaic cells have been used in everything from

In 1996, the National Association of Home Builders constructed advanced townhouses featuring standing-seam roofs and other energy efficient materials and systems. The townhouse on the right differs from the others in that it has an integrated photovoltaic standing-seam roof that also produces electricity.

TIM ELLISON, ENERGY CONVERSION DEVICES

the solar cells in calculators to the space station Freedom.

Another technology for harnessing the sun's energy is a concentrating solar power system, which uses the sun's heat to generate electricity. The sunlight is collected and focused with mirrors to create a high intensity heat source that in turn can be used to generate electricity through a steam turbine or a heat engine.

Solar hot water systems use the sun to heat water for domestic or industrial use. Many large commercial buildings also use solar collectors for heat. A solar ventilation system can be used in cold climates to pre heat air as it enters a building. The heat from a solar collector can even be used to provide energy for cooling a building.

Some architects are using careful design and new optical materials to use sunlight to reduce the need for traditional lighting and to cut down on heating and cooling costs. For example, materials that absorb and store the sun's heat can be built into the sunlit floors and walls. The floors and walls

will store heat during the day and slowly release heat at night.

While solar energy technologies have undergone technological and cost improvements and are well established in high value markets like remote power, satellites, communications, and navigational aids, continued research is needed to reduce costs and improve performance. Solar energy accounts for 1 percent of renewable electricity generation and 0.02 percent of total U.S. electricity supply.

Alternative Energy

Alternative Transportation Fuels

Alternative fuels are any transportation fuels made from a nontraditional source, including ethanol, biodiesel, and other biofuels. These can be made from biomass resources, including liquid fuels (e.g., ethanol, methanol, biodiesel) and gaseous fuels (e.g., hydrogen and methane). Biofuels are primarily used to fuel vehicles, but can also fuel engines or fuel cells for electricity generation. Alternative fuels also

Recommendations:

- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using renewable technology, such as wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

Alternative Fuel Vehicles

Alternative fuel vehicles (AFVs) can run on methanol, ethanol, compressed natural gas, liquefied natural gas, propane, hydrogen, electricity, biodiesel, and natural gas. Today, more than 450,000 alternative vehicles are operating in the United States. Some of the barriers to using AFVs include:

Cost—For example, a Ford Crown Victoria that runs on compressed natural gas costs about \$4,000 more than its gasoline counterpart.

Refueling Infrastructure—Refueling infrastructure is limited, which can make refueling inconvenient and travel options difficult.

Travel Distance—Ability to travel a long distance on a single volume of fuel. Alternative fuels have an energy content lower than that of gasoline, which means that AFVs cannot travel as far as traditional vehicles on a single tank of fuel.

In the short term, natural gas and propane offer the greatest potential for market growth, especially in niche markets where lower fuel costs make them attractive, such as transit buses, school buses, shuttles, and other heavy-duty vehicles. Ethanol vehicles offer tremendous potential if ethanol production can be expanded. Electric vehicles could reach large numbers in the future if technology breakthroughs help bring costs down and increase driving distance. Fuel cell vehicles operating on compressed hydrogen offer long-term potential. Compressed natural gas offers a distribution stepping-stone to a hydrogen-refueling infrastructure.

include traditional energy sources, such as natural gas and liquid propane that are traditionally not used as a transportation fuel.

Currently, there are approximately 450,000 alternative fuel vehicles in the United States, and more than 1.5 million flexible-fuel vehicles that can use gasoline or a mixture of ethanol and gasoline. Ethanol is made by converting the carbohydrate portion of biomass into sugar, which is then converted into ethanol through a fermentation process. Ethanol is the most widely used biofuel, and its production has increased sharply since 1980, rising from 200 million gallons a year to 1.9 billion gallons. Today, many states are considering phasing out the use of MTBE (methyl tertiary butyl ether), an oxygenate additive for gasoline. If they do so, that will likely spur greater reliance on ethanol.

Each year, approximately 65 percent of the oil consumed in the United States is used for transportation. As a result, vehicle emissions have become the leading source of U.S. air pollution. However, recent advances in fuels and vehicle design are helping increase fuel efficiency and reduce toxic substances discharged into the air.

Changes in the composition of trans

portation fuels, such as gasoline and diesel fuels, are one way to improve vehicle performance while reducing emissions and lowering oil consumption. Reformulated gasoline contains fuel additives such as ethanol to increase oxygen content, which reduces harmful emissions such as carbon monoxide. Low-sulfur gasoline reduces sulfur oxide emissions. New diesel fuels, some of which have lower sulfur contents or are produced from clean-burning natural gas, can help vehicles with diesel engines achieve lower emissions.

In addition to advanced transportation fuels, alternative fuels are being developed, such as biodiesel, electricity, ethanol, hydrogen, methanol, natural gas, and propane. These alternative fuels not only reduce dependence on petroleum transportation fuels. They reduce or entirely eliminate harmful emissions as well. With the exception of natural gas and propane, these fuels also have the potential of being generated from renewable resources, such as ethanol from corn. The federal government has promoted development of alternative fuels for many years and this program has helped to reduce U.S. reliance on oil-based fuels.

The evolution toward more efficient,

environmentally friendly transportation fuels has been mirrored by improvements in vehicle design, components, and materials. Alternative fuel vehicles, which can either switch between two fuels or run on a mixture of two fuels such as gasoline and ethanol, are now available. Recent developments in both alternative fuel vehicles and petroleum-based vehicles, such as advances in engines, drive trains, and emission-control technologies, may double or triple the efficiency of current vehicles. Some of these new technologies include hybrid electric vehicles, which combine an engine with an electric motor, and fuel cells, which produce electricity by converting a fuel, generally hydrogen and oxygen, into water.

A number of issues drive the research and marketability of advanced alternative fuel vehicles and petroleum-based vehicles in the United States. The goal of reducing U.S. dependence on imported oil, combined with the link between vehicle emissions and air pollution, have prompted the development of emissions and fuel economy standards for car manufacturers. In addition, federal, state, and local governments have enacted regulations, laws, and incentives designed to reduce the number of vehicle miles traveled and to encourage businesses and individuals to purchase alternative fuel vehicles.

The success of the federal alternative fuels program has been limited, however. The current program focuses on mandating certain fleet operators to purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. The Clean Air Act required the use of oxygenates, such as MTBE (methyl tertiary butyl ether) and ethanol in fuel. These oxygenates account for 92 percent of alternative fuel use. Reforms to the federal alternative fuels program could promote alternative fuels use instead of mandating purchase of vehicles that ultimately run on petroleum fuels.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Treasury to work with Congress to continue the ethanol excise tax-exemption.-

Distributed Energy

Untapped opportunities for reducing energy demand loads could be realized by better integrating electricity supply systems and customers. Improved integration can produce a variety of benefits for tight energy markets, including reducing peak demand loads, bypassing congested areas of transmission by placing new generating capacity closer to the consumer, and thus achieving greater overall system efficiencies.

Current electricity load management efforts are typically limited to cutting off interruptible or nonfirm customers, appeals to the public to conserve, and brownouts. Some utilities are incorporating current generation metering, sensor, and control technologies to take the next step: selective reduction of individual energy-using appliances. In some areas, residents can reduce their monthly bills by allowing the utility to electronically turn off selected appliances, such as water heaters, on a rotating basis. If this option is well managed, consumers are unaware of the temporary loss service, and critical systems continue to run unimpeded. Advanced integrated supply-and-demand load management controls also allow for widespread “demand auctions,” in which consumers can decide which energy services to forego on which days.

Distributed energy resources describe a variety of smaller electricity-generating options well suited for placement in homes, offices, and factories, or near these facilities. Distributed energy systems have the distinct advantage of being brought on line faster than new central power plants. While natural gas microturbines and solar roof panels are the most familiar types of distributed energy, other distributed energy resources include: combined heat and power, stationary fuel cells, generation of

bioenergy from landfill methane recovery, and small wind systems. Photovoltaic solar distributed energy is a particularly valuable energy generation source during times of peak use of power.

Efficiency gains from distributed energy come from three sources. First, transmission and distribution line losses (about 5 percent) are reduced because the energy is generally used near the source. Second, the co-location with consumption makes it more feasible to use waste heat, displacing otherwise needed natural gas or electricity for heating purposes. And, third, the co-location with consumption allows for the integration of on-site energy efficiency and generating capabilities. For example, in the residential market, distributed energy applications can make possible the concept of the “net zero energy home,” in which the overall level of energy produced at the home equals or exceeds the amount of energy used in the home.

Despite these advantages, a number of impediments and competing policy objectives discourage the wider application of integrated electricity supply and demand solutions, many of which reflect the relative newness and lack of familiarity with these technologies.

For example, the lack of standards governing interconnection of distributed energy to the grid impedes development. The lack of standards prevents a uniformly effective means of getting excess distributed energy to the grid.

In addition, current air quality regulations do not take into account the additional energy savings from many distributed energy technologies. Likewise, distributed energy systems purchased by consumers may receive different tax rates than those purchased by traditional electricity producers.

Although distributed energy can alleviate distribution constraints, these systems often cannot be sited and permitted in a timely manner. For instance, land-use zoning codes may not allow generating equipment in association with residential or commercial land uses, and building code officials may not know enough about solar roof systems to provide timely building permits.

As with energy efficiency equipment, load management integrating systems, both controls and distributed energy, have higher first costs associated with lower future energy bills.

Another barrier to development of distributed energy is the need for net metering, which enables consumers to install a small electricity project at their homes and sell the excess to the local utility, offsetting their purchases from the utility at other times. Net metering can lower the cost to consumers of distributed energy projects. Some consumers are reluctant to install distributed renewable energy resources because many regions do not have the regulatory framework under which consumers can sell energy back to the grid under a net metering system.

Future Energy Sources

As we look to the long-term future of alternative energy technologies, there is significant promise in these technologies to meet an ever-growing portion of our nation’s energy needs.

Hydrogen

In the long run, alternative energy technologies such as hydrogen show great promise. Hydrogen is the most common element in the universe and can be made from water. Converting hydrogen into energy is compatible with existing energy technologies, such as fuel cells, engines, and combustion turbines. The energy for extracting hydrogen could come from existing, traditional fuels, or it could be derived from renewable energy sources, such as solar, nuclear, and fossil, to achieve the cleanest possible energy cycle. Hydrogen can be converted into useful energy forms efficiently and without detrimental environmental effects. Unlike other energy sources, its production by-product is water.

In the future, hydrogen may be able to be used in furnaces and as a transportation fuel for automobiles, buses, trains, ships and airplanes. Hydrogen could also be converted directly into electricity by fuel cells. Combustion of hydrogen with oxygen results in pure steam, which has many appli-



There is a significant promise in renewable technologies to meet an ever-growing portion of our nation's energy needs. Wind power has significant growth potential. The principal challenges to achieving this level of renewable energy generation are cost and market acceptance of renewable power technologies.

U.S. DEPARTMENT OF ENERGY, NATIONAL
RENEWABLE ENERGY LABORATORY

cations in industrial processes and space heating. Moreover, hydrogen is an important industrial gas and raw material in numerous industries, such as computer, metallurgical, chemical, pharmaceutical, fertilizer and food industries.

An energy infrastructure that relies on hydrogen could enable much greater use of distributed energy systems. These systems are small, modular electricity generators that can be placed right where they are needed for heating, cooling, and powering offices, factories, and residences. Hydrogen fuel cells are a promising type of distributed energy system that can provide the exacting reliability needed for the high-tech industry.

Fuel cells can produce electricity and heat from hydrogen, natural gas, and petroleum fuels, and fuel gases derived from coal and biomass. What makes fuel cells unique is that they can use fuels without combustion, simply by chemical reactions, making them extremely clean and efficient.

Fuel cells were developed by the National Aeronautics and Space Administration to generate electricity, heat, and water in space vehicles. The first-generation fuel cells for stationary power applications entered the commercial market in 1995. This type of fuel cell is used to generate very high-quality electricity and heat with negligible emissions in commercial and industrial settings. It is most likely to be used in cases where users are willing to pay a premium for cleaner, more reliable power than is available from the commercial grid.

The second generation of stationary fuel cells is currently in the demonstration phase, including a combined fuel cell–turbine hybrid. These fuel cells are expected to be more efficient and cost less when used in similar distributed energy systems. Smaller fuel cells for residential units are also being developed, and some are in the demonstration phase.

Despite technical progress, high costs remain the main deterrent to widespread fuel cell use. Significant cost reductions must be achieved before fuel cells will be competitive with internal combustion engines, and the size and weight of fuel cell systems must be reduced even more to ac-

commodate vehicle packaging requirements.

The primary challenge to using more hydrogen in our energy systems is the cost of producing, storing, and transporting it. A serious challenge confronting a move toward distributed energy is the transition away from centralized energy systems of supply and production. These challenges are not expected to be resolved overnight, but progress made in the last few years has already far surpassed the expectations of just a decade ago.

A significant amount of promising research and development has already been completed. The automobile industry is aggressively exploring the fuel cell as the future of the industry. Moreover, a new first generation class of distributed energy technologies are already hitting the market.

Fusion

Fusion—the energy source of the sun—has the long-range potential to serve as an abundant and clean source of energy. The basic fuels, deuterium (a heavy form of hydrogen) and lithium, are abundantly available to all nations for thousands of years. There are no emissions from fusion, and the radioactive wastes from fusion are short lived, only requiring burial and oversight for about 100 years. In addition, there is no risk of a melt-down accident because only a small amount of fuel is present in the system at any time. Finally, there is little risk of nuclear proliferation because special nuclear materials, such as uranium and plutonium, are not required for fusion energy. Fusion systems could power an energy supply chain based on hydrogen and fuel cells, as well as provide electricity directly.

Although still in its early stages of development, fusion research has made some advances. In the early 1970s, fusion research achieved the milestone of producing 1/10 of one watt of fusion power, for 1/100 of a second. Today the energy produced from fusion is 10 billion times greater, and has been demonstrated in the laboratory at powers over 10 million watts in the range of a second.

Internationally, an effort is underway in Europe, Japan, and Russia to develop plans for constructing a large-scale fusion science and engineering test facility. This test facility may someday be capable of steady operation with fusion power in the range of hundreds of megawatts.

Both hydrogen and fusion must make significant progress before they can be come viable sources of energy. However, the technological advances experienced over the last decade and the advances yet to come will hopefully transform the energy sources of the distant future.

Recommendation:

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation-technology—including hydrogen and fusion.-
- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.

Current Markets for Renewable and Alternative Energy Advances in Technology

Non-hydropower renewable energy accounts for about 4 percent of current U.S. energy production, divided evenly between electricity generation and transportation fuels such as ethanol. Between 1990 and 1999, renewable energy generation grew by 29 percent, and renewable energy is projected to continue to grow (Figure 6-1). Renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 1.1 percent a year through 2020. In 2020, 55 percent of renewables are projected to be used for electricity generation and the rest for dispersed heating, industrial uses, and fuel blending.

The success of renewables is, in part,

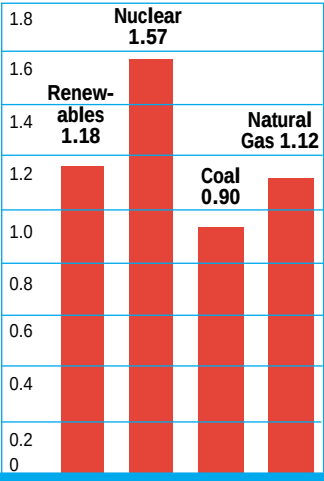
the result of over twenty years of research, development, and demonstration conducted by the public and private sectors. This work has dramatically improved these technologies and has reduced their costs by as much as 90 percent. For example:

- The Department of Energy (DOE), the National Renewable Energy Laboratory (NREL), and Alstom Energy Systems jointly created Advanced Direct-Contact Condensers, which improve the efficiency and generating capacity of electric power plants by providing the best surface area for condensing spent steam. This technological advance, tested in geothermal applications in California, can improve the efficiency of electricity production by 5 percent and capacity by 17 percent.
- United Solar Systems in Michigan pioneered the first commercial use of solar photovoltaics as a building material. The triple-junction, thin-film technology is now sold as flexible solar panels, solar shingles for building roofs, and a peel-and-stick-on variety for standing seam metal roofs. United Solar is now building a larger manufacturing plant in Michigan that is five times the size of its existing manufacturing facility. DOE collaborates with United Solar on research and development helping overcome hurdles in manufacturing. As a result, United Solar is able to provide unique solar electric products using a unique roll-to-roll manufacturing process.

• In partnership with DOE, NREL, Battelle Lab, Burlington Electric and others, Future Energy Resources Corporation of Norcross, Georgia, was able to build, test, and operate the world's first biomass gasification system. The McNeil Plant, located in Burlington, Vermont, gasifies rather than combusts wood chips to power a gas boiler. The technology has shown itself to be commercially viable, and is being considered worldwide by industries as a way of upgrading existing inefficient and aging boilers.

Improved renewable and alternative energy technologies are becoming increasingly attractive to a number of energy companies seeking to build new business opportunities for the future (Figure 6-3). Following are a few examples:

Figure 6-1
Increases in U.S. Energy Production: 1990–1999
(Quadrillion Btus)



During the last decade, renewable energy sources contributed substantially to the growth in U.S. energy production, outpacing all fuel sources except for nuclear energy.

Source: U.S. Department of Energy, Energy Information Administration.

Table 6-2

Electricity Generated by Renewable Energy Sources: 1999

	Solar	Wind	Geothermal	Biomass	Hydropower
Current net summer capacity (MW)	350	2,600	2,870	6,170	79,130
Annual generation (millions of kWh)	940	4,460	13,070	36,570	312,000
Expected growth in generation (%)	PV: 19.3 Thermal: 21	5.3	3.3	3.0	-0.1
Cost (cents/kWh)	20	4–6	5–8	6–20	2–6

Renewable energy has become a significant source of electric power in the United States.

Note: Capacity, generation, and growth data do not include off-grid electricity, thermal, or other nonelectricity energy production, municipal solid waste, or methane from landfills.

Sources: U.S. Department of Energy, Energy Information Administration and Office of Power Technologies.

- FPL Group announced in January 2001 the construction of two major wind farms: a 300 MW facility on the Washington–Oregon border, and a 25.5 MW facility in Wisconsin. The company now has more than 1,000 MW of wind generating capacity in operation or under construction in seven states.

- CalEnergy Company has made renewable and alternative energy generation a central focus of its power portfolio. The company operates 1,300 MW of geothermal, natural gas, hydropower, and other power facilities in the U.S. and abroad, with an other 750 MW currently under construction.

- General Motors, Ford, DaimlerChrysler, Texaco, BP/Amoco, and Shell are collectively spending between \$500 million and \$1 billion dollars a year on fuel cells, hydrogen storage, and infrastructure development for passenger vehicles. Ongoing bus demonstrations in the United States and Europe are expected to commercialize fuel cell power hydrogen buses in the next five years.

Because alternative and renewable energy resources can be used in so many different ways throughout the economy to produce so many combinations of energy types, their total use is often difficult to measure precisely. As of 1996, California alone had over 10 MW of installed distributed energy, a large increase in generating

capacity during a period of otherwise limited growth in generation (Figure 6-3). In 1999, several types of renewable energy were used to produce electricity (Table 6-2).

On the transportation side, there are approximately 450,000 alternative fuel vehicles in the United States. Additionally, there are more than 1.5 million flexible-fuel vehicles that can use gasoline or a high mixture of ethanol and gasoline. These include the Ford Taurus, the DaimlerChrysler Caravan, and the General Motors S10 pickup. Ethanol is the most widely used biofuel, and its production is currently 1.9 billion gallons a year, representing a nearly ten-fold growth from about 200 million gallons a year in 1980.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles.-

Hybrid Electric Vehicles

Hybrid electric vehicles (HEVs) combine the internal combustion engine of a conventional engine with the battery and electric motor of an electric vehicle, resulting in twice the fuel economy of conventional vehicles. This combination offers the extended range and rapid refueling that consumers expect from a conventional vehicle, with a significant portion of the energy and environmental benefits of an electric vehicle. The practical benefits of HEVs include improved fuel economy and lower emissions compared to conventional vehicles. The car's flexibility will mean convenient use for individuals as well as businesses.

Removing Barriers to Renewable and Alternative Energy Growth

Perhaps the greatest barrier to growth of renewable energy is cost. Currently, the cost of renewable energy generation fre

quently exceeds the costs of conventional electricity generation. In recent years, though, the costs of renewable energy have declined substantially. For example, the cost of wind energy has declined by more than 80 percent over the past twenty years and is increasingly competitive with conventional electricity generation sources. Wind, biomass, and geothermal are all in creasingly competitive with conventional electricity generation.

The ability of these technologies to meet specific market needs is another factor in how quickly their market share will grow. These technologies and energy sources provide multiple benefits to the energy producer and the consumer. For example, many of these technologies are modular and can be constructed rapidly, adding an immediate source of new power in areas that otherwise might face a short fall. Distributed renewable energy resources can enhance the reliability and quality of power.

Cogeneration uses of waste products and heat can increase profits by reducing purchased electricity costs, as well as costs for process steam and heating or cooling. Several sectors, including lumber and paper, steel, and chemical manufacturing, are exploring the increased use of cogeneration. With the technological development of biomass gasification, the lumber and paper industry could become a seller of electricity.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

Renewable technologies can help provide insurance against price volatility. In addition, many renewable technologies can help industry achieve compliance with the Clean Air Act and other environmental regulations. In some cases, renewables can be more readily located in urban areas whose air quality does not meet regulatory requirements.

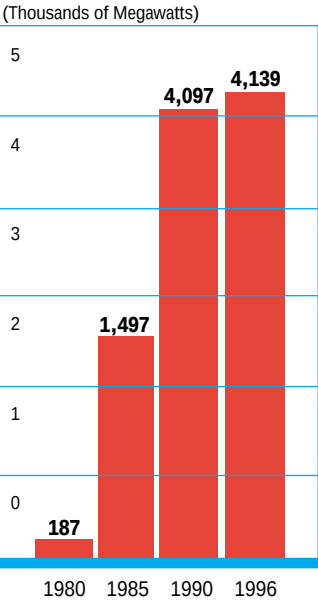
With the growth rate for non-hydro power renewable electricity generation more than doubling the expected growth in overall electricity capacity, these energy sources will play a more significant role in electricity markets in the next two decades. However, the extent to which these domestic resources are successfully tapped will depend in large part on continued technological development.

For renewable and alternative energy to play a greater role in meeting our energy demands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary interface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.

Promising technologies exist that will improve the transmission, storage, and reliability of renewable energy. An example of recent technological success that will allow for increased access to all forms of energy, including renewable energy, is the high-temperature superconducting underground power transmission cables that the Department of Energy is developing in partnership with industry. These cables will allow a 300 percent increase in capacity without excavation to lay new transmission lines. This summer, Detroit Edison is demonstrating this commercially viable high-temperature superconducting cable system in an application that serves 14,000 customers.

Renewable and alternative energy technologies, such as wind energy and combined heat and power could be significantly expanded, given today's technologies. They could be further expanded with added investment in technology. For example, wind energy could be developed that could be adapted to sites with lower wind speeds than is feasible today. Combined heat and

Figure 6-3
Growth in California's Renewable Energy Capacity



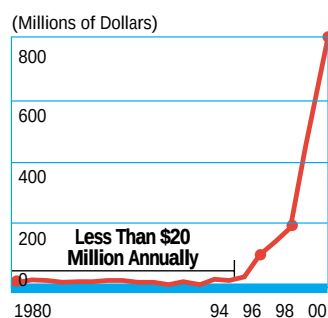
Source: U.S. Department of Energy, Energy Information Administration.



While solar energy technologies have undergone technological and cost improvements, and are well established in high value markets like remote power, satellites, communications, and navigational aids continued research is needed to reduce costs and improve performance.

U.S. DEPARTMENT OF ENERGY

Figure 6-4
Investors Are Betting on Distributed Energy



In the last few years, surging venture capital investments showed strong support for distributed energy technologies.

*Note: Data for 2000 are projected investments.
Source: Nth Power via the Economist, August 5, 2000.*

power in buildings offers great potential for increased system efficiencies and lower costs. New developments in microturbine and fuel cell technologies are also highly promising. Performance improvements of other technologies, such as photovoltaic systems, would facilitate much wider use. In addition to technological performance, attention to several key market and regulatory constraints would accelerate the development and use of renewable and alternative energy in the marketplace.

Because many renewable and alternative energy technologies do not fit into traditional regulatory categories, they are often subjected to competing regulatory requirements or to requirements that were never designed to address them. For example, much of the current Clean Air Act does not specifically address the use of new, more efficient renewable energy technologies. Consequently, the Act does not provide significant incentives for the development of such technologies.

The lack of interconnection standards or guidelines for electricity supply and loads impedes the use of distributed energy technologies. As a result, developers of small renewable energy projects must negotiate interconnection agreements on a site-by-site basis with local distribution companies that are often opposed to distributed energy projects because of the increased competition. Although a few states have established interconnection standards, there is no national standard to facilitate development of distributed energy (Figure 6-4).

New combined heat and power facilities may face air permitting hurdles when they replace marginally dirty boilers. The Clean Air Act does not recognize the pollution prevention benefits of the increased efficiency of combined heat and power units. At the same time, these combined heat and power investments are taxed at the industry's tax rate, not at the rate they would receive if they were considered part of the utility sector for tax purposes.

In addition, modifications to permitting and siting requirements may be necessary to facilitate the incorporation of these technologies into buildings.

The infrastructure needed for increasing the use of renewable and alternative energy varies considerably. In particular, the alternative fuels infrastructure lags far behind the existing infrastructure for conventional fuels. The lack of infrastructure for alternative fuels is a major obstacle to consumer acceptance of alternative fuels and the purchase of alternative fuel vehicles. It is also one of the main reasons why most alternative fuel vehicles actually operate on petroleum fuels, such as gasoline and diesel. In addition, a considerable enlargement of ethanol production and distribution capacity would be required to expand beyond their current base in the Midwest in order to increase use of ethanol-blended fuels.

The use of natural gas or electricity for vehicles requires enhancements to these distribution systems, such as compression stations for natural gas. While many alternative fuels can be shipped by pipeline, they may require separation within the pipeline to avoid mixing different energy products. Geographically dispersed renewable energy plants often face significant transmission barriers, including unfavorable grid schedule policies and increased embedded costs.

Uncertainty regarding the tax treatment of these technologies and energy sources can discourage long-term investment. Though existing tax credits provide an incentive for investing in some types of renewable energy, the limited scope of the credit and its frequent expiration discourages investment.

Summary of Recommendations

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.
- ★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

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- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
 - Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
 - Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
 - Support legislation reauthorizing the Hydrogen Energy Act.
 - ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.
 - ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

America's Energy Infrastructure

A Comprehensive Delivery System

One of the greatest energy challenges facing America is the need to use 21st-century technology to improve America's aging energy infrastructure. Americans need a comprehensive, long-term solution to deliver energy to industry and consumers in a reliable and safe manner.

Our energy infrastructure is comprised of many components, such as the physical network of pipes for oil and natural gas, electricity transmission lines and other means for transporting energy to consumers. This infrastructure also includes facilities that turn raw natural resources into useful energy products. The rail network, truck lines, and marine transportation are also key components of America's energy infrastructure.

The energy industry has undergone major changes in the last two decades, and more are expected. These changes affect how our energy infrastructure operates. For example, while the electricity industry was once vertically integrated, it is increasingly separated into three isolated segments: generation, transmission, and distribution.

Our energy infrastructure has failed to keep pace with the changing requirements of our energy system. Domestic refining capacity has not matched increases in demand, requiring the United States to import refined products. Natural gas pipelines have not expanded sufficiently to meet demand. The electricity transmission system is constrained by insufficient capacity. Rail capacity was significantly increased during the 1970s when rail facilities were improved to move more coal. Since then, however, few additions to the coal transportation rail network have been built.

The United States needs to modernize its energy infrastructure. One sign of a lack of an energy policy in recent years has been the failure to maintain the infrastructure needed to move energy where it is needed most.

Electricity

The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, as well as the local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear, natural gas, water and, to a lesser extent, oil. Coal, natural gas and oil powered plants require a dependable transportation infrastructure to deliver the fuels necessary for the production of electricity. A transportation network for waste disposal is also necessary for power plants that create by products.

Restructuring

The electricity industry has undergone considerable changes in the last two decades. These changes affect how our electricity infrastructure operates. Major industry restructuring has separated once vertically integrated electric utilities that supplied generation, transmission, and distribution services into distinct entities. To facilitate competition at the wholesale level, in 1996, the Federal Energy Regulatory Commission (FERC) required transmission-owning utilities to "unbundle" their transmission and power marketing functions, and provide nondiscriminatory, open access to their transmission systems by other utilities

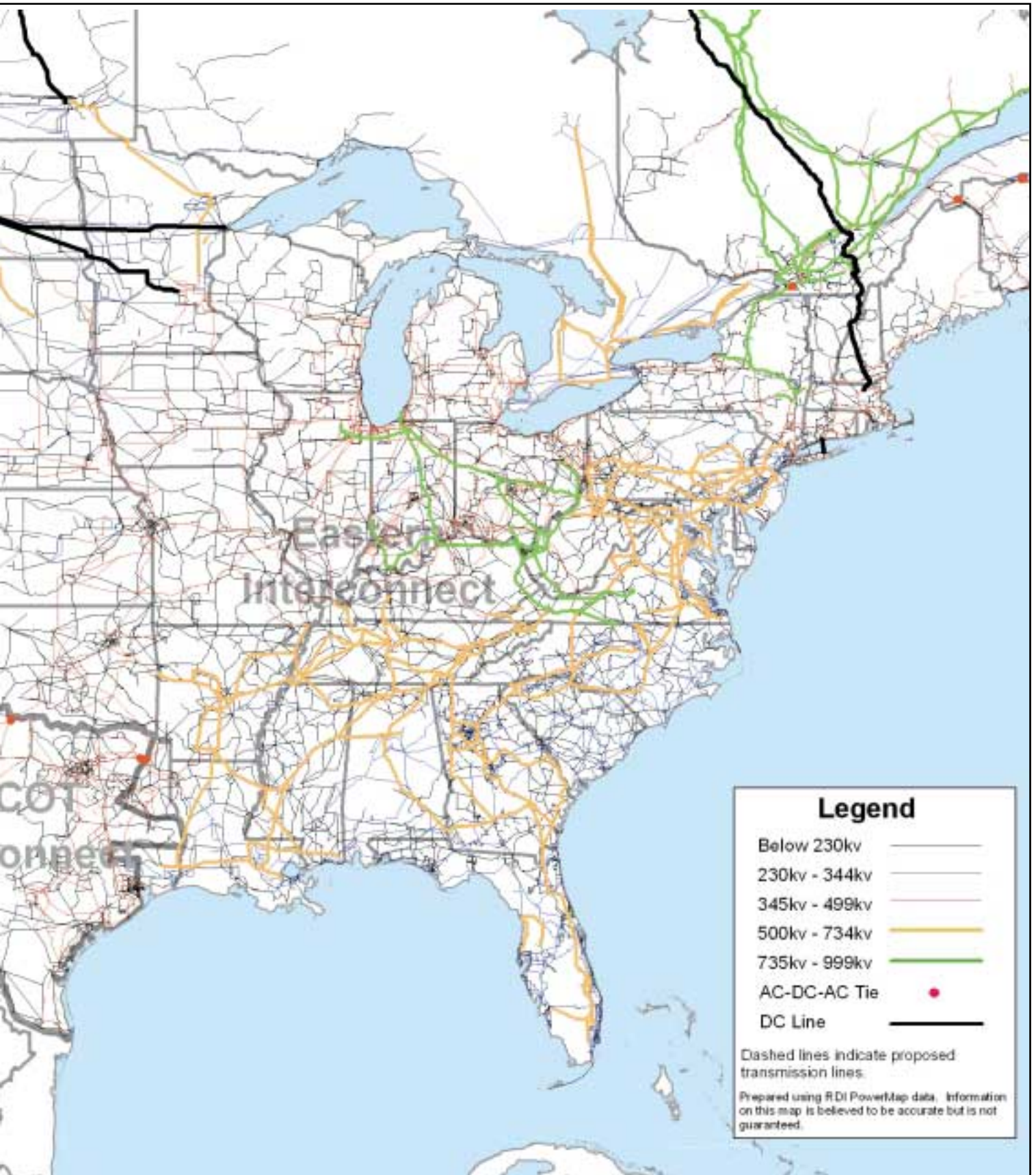


FIGURE 7-1
**North American
Transmission Lines**

About 204,000 miles of long-distance transmission lines move power from region to region. The four integrated transmission grids serving North America are the Western Interconnection, Eastern Interconnection, Electric Reliability Council of Texas, and Province of Quebec.

Source: PA Consulting Group





and independent power producers. At the retail level, some states have required utilities to divest their generation assets as part of restructuring. These utilities currently supply only transmission and distribution services for customers who purchase electricity (i.e., generation services) from other firms. In addition, power marketers—who often do not own generation, transmission, or distribution facilities—buy and sell power on wholesale markets and market electricity directly to customers.

Electricity competition has led to significant changes in the operation of the bulk power grid, which are the power plants and high-voltage transmission facilities that make up the wholesale power market. More electricity is being shipped longer distances over a transmission system that was initially designed only to provide limited power and reserve sharing among neighboring utilities. Electric utilities that were once solely responsible for ensuring that adequate generation was available to meet demand now purchase a substantial amount of the power they need from the wholesale market, relying on independent power producers to build and operate plants.

Electricity Generation

There are roughly 5,000 power plants in the United States, and they have a total generating capacity of nearly 800,000 megawatts. Over the past few years, there has been an explosion of “merchant” power plants proposed by independent power producers seeking to sell into wholesale markets. In spite of this interest, a number of regions of the country are experiencing capacity shortages as a result of wholesale market design problems and barriers to siting and building new power plants.

Over the next ten years, demand for electric power is expected to increase by about 25 percent, and more than 200,000 megawatts of new capacity will be required. However, under current plans electric transmission capacity will increase by only 4 percent. This shortage could lead to serious transmission congestion and reliability problems.

Transmission Grid

The United States does not have a national transmission grid. Instead, there are four integrated transmission grids serving North America: the Western Interconnection, Eastern Interconnection, Electric Reliability of Council of Texas, and the Province of Quebec (Figure 7-1). These regional grids themselves are international, encompassing the United States, Canada, and part of Mexico.

Transactions between the four integrated transmission grids are very limited because they are interconnected at only a few locations through interties, so for all practical purposes they can be viewed as separate transmission grids. The four integrated transmission grids break down into a series of smaller regions, largely defined by transmission constraints. Altogether, 204,000 miles of transmission lines in North America move power from the point of generation to where electricity is needed. There are 157,810 miles of transmission lines in the United States. Transmission grid expansions are expected to be slow over the next ten years, with additions totaling only 7,000 miles.

The transmission system is the highway system for interstate commerce in electricity. Transmission allows the sale of electricity between regions. In a particular region, transmission can be a substitute for generation, allowing that region to import power that otherwise would have to be generated within that region. In some cases, transmission expansion may be more cost effective than generation additions, allowing a region better access to lower-cost generation.

Transmission constraints limit these power flows, and result in consumers paying higher prices for electricity. The electricity price spikes in the Midwest in the summer of 1998 were caused in part by transmission constraints limiting the ability of the region to import electricity from other regions of the country that had available electricity. During the summer of 2000, transmission constraints limited the ability to sell low-cost power from the Midwest to the South during a period of peak demand,

resulting in higher prices for consumers. Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England (Figure 7-2).

Regional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country and are reducing the quality of power delivered to end users. Power quality is becoming an increasingly important issue as our digital economy continues to grow.

One factor limiting reliability is the lack of enforceable reliability standards. Since 1968, the reliability of the U.S. transmission grid has depended entirely on voluntary compliance with reliability standards. There is a broad recognition that voluntary adherence with reliability standards is no longer a viable approach in an increasingly competitive electricity market. There is a need to provide for enforcement of mandatory reliability standards. Broad support has emerged for development of these standards by a self-regulating organization overseen by FERC.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with FERC to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.

Transmission constraints were also a primary factor in blackouts in northern California, which imports power from both the Northwest and southern California. When resources are not available in the Northwest, electricity supply must come

Figure 7-2

Current Electric Power Bottlenecks



Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England. The arrows in this figure depict the locations and directions of current transmission congestion.

Source: North American Electric Reliability Council.

from southern California's Path 15 transmission route. Path 15 does not have sufficient capacity to provide all of the power needed in northern California.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

Transmission constraints have been a persistent cause of price spikes in New York City in recent years. The New York Independent System Operator (the grid operator in that state) estimates that the city will be short about 400 MW below their desired reserve margin of power during the summer peak. To fill this gap, the New York Power Authority is trying to install additional generation capacity in the city. Market-oriented approaches could also be used to create additional capacity and alleviate some of the potential problems.

If transmission constraints are not removed, the result can be higher prices and

lower reliability. There are various reasons why transmission constraints exist. One is the lack of sufficient investment in transmission. Transmission investment has lagged dramatically over the past decade (Figure 7-3). There is a need to ensure that transmission rates create incentives for adequate investment in the transmission system, especially as restructuring leads to the creation of transmission companies whose only business is operation of transmission facilities. FERC recognizes this need and has expressed a willingness to consider innovative transmission pricing proposals.

Another cause of transmission constraints is the siting process. Under current law, siting of transmission facilities is a responsibility of state governments, not the federal government, even though the transmission system is not only interstate but also international, extending into both Canada and Mexico. This stands in stark contrast to siting of other interstate facilities, such as natural gas pipelines, oil pipelines, railroads, and interstate highways.

Federal law governing the responsibility for siting transmission facilities was written in 1935, nearly 80 years ago. At the time, transmission facilities were not inter-

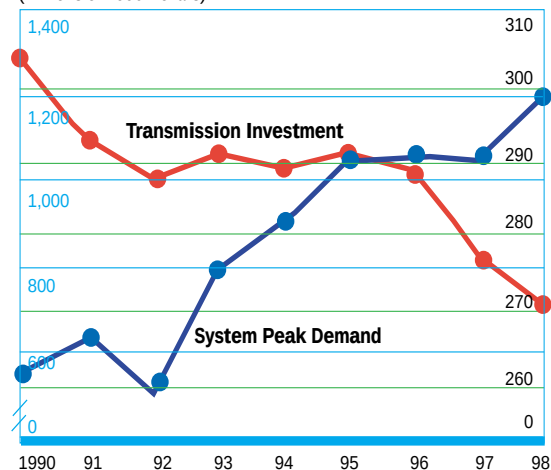
state, and there was virtually no interstate commerce in electricity. Congress did not anticipate the development of an interstate and international transmission system.

State decisions on where to locate transmission lines often do not recognize the importance of proposed transmission facilities to the interstate grid. For example, a recent decision by regulators in Connecticut to block a proposed transmission line to Long Island did not recognize the need for electricity on Long Island. Some state siting laws require that the benefits of a proposed transmission facility accrue to the individual state, resulting in the rejection of transmission proposals that benefit an entire region, rather than a single state.

Much has changed since 1935. The transmission system is the highway for interstate commerce in electricity. Transmission constraints are resulting in higher prices for consumers and lower reliability. The siting process must be changed to reflect the interstate nature of the transmission system.

Figure 7-3

U.S. Investment in New Electric Power Transmission (Millions of 1990 Dollars)



Growth in peak demand for electricity has far outstripped investment in transmission capacity. As a result, transmission constraints could aggravate already limited supplies of power and could result in high prices in some areas of the country.

Source: PA Consulting Group, based on data from the UDI data base.

Recommendations:

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate-transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.-

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and



financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.

- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

Another cause of transmission constraints is limited access to federal lands. The federal government is the largest land owner in the United States and owns most of the land in some western states. Limited access to federal lands can block needed transmission expansion. A case in point is a transmission line being built from West Vir-

ginia to Virginia. Five years ago, the Department of Energy identified that line as critical to the reliability of the transmission system on the East Coast. Five years later, the line is still not complete. Improved access to federal land can help remove transmission constraints.

Rights-of-Way on Federal Lands

The Bureau of Land Management (BLM) estimates that 90 percent of the oil and natural gas pipeline and electric transmission rights-of-way in the western United States cross federal lands. These lands are principally lands managed by either the BLM or the U.S. Forest Service. Rights-of-way are authorized through an approval process that allows the public to comment on proposals to locate infrastructure items, like utility poles, on these rights-of-way. As part of this process, proposals are examined for resource and other use conflicts, and a national interest test is applied prior to approval.

The BLM administers 85,000 rights-of-way, including 23,000 for oil and gas pipelines and 12,000 for electric transmission lines. It processes over 1,200 pipeline and electric system right-of-way applications a year, with an increase in applications of

The electric power infrastructure includes a nationwide "power grid" of long-distance transmission lines that move electricity from the point of generation to where the electricity is needed. Over the next ten years, U.S. demand for electric power is expected to increase by 25 percent, while transmission capacity is expected to increase by only 4 percent.



Virtually all natural gas in the United States is moved via pipeline. The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

over 10 percent a year in recent years. The demand for additional energy and electricity is expected to increase the need for rights-of-way across federal lands.

Other federal entities also deal with rights-of-way, each approaching the issue from a unique perspective. The National Park Service is authorized to grant leases and permits, but discourages rights-of-way corridors unless there are no practical alternatives. The U.S. Fish and Wildlife Service manages National Wildlife Refuge lands for wildlife and habitat values, and allows corridors where they were pre-existing or are determined to be compatible with the purposes for which a refuge was established. The Bureau of Reclamation is authorized to grant rights-of-way over lands acquired or withdrawn for reclamation purposes, if compatible with authorized project purposes. The Bureau of Indian Affairs and tribal governments are authorized to grant rights-of-way across both tribal and individually owned Indian lands.

Pipelines

After being pumped from the ground in domestic oil fields, oil travels through gathering lines to pipelines, which bring it to refineries, where it is transformed into petroleum products like gasoline, diesel fuel, or heating oil. These products then travel through pipelines and tanker trucks to distribution outlets for purchase by consumers. Natural gas must similarly travel from gas fields through gathering lines to processing facilities, and then into pipelines

and local distribution lines to its final destination. These pipeline systems involve a complex infrastructure of their own, including pump stations or compressor stations, and control systems that open and close valves and switch product flow through pipes, often with the use of computer technology.

Oil Pipelines

The two million miles of oil pipelines in the United States are the principal mode for transporting oil and petroleum products such as gasoline. They account for about 66 percent of domestic product movements (Figure 7-4). Increases in the demand for oil and changes in where it is supplied will lead to the need for more pipeline capacity.

Pipelines are less flexible than other forms of oil transport, because they are fixed assets that cannot be easily adjusted to changes in supply and demand. Once built, they are an efficient way to move petroleum and petroleum products. A modest sized pipeline carries the equivalent of 750 tanker truckloads a day—the equivalent of a truckload leaving every two minutes, 24 hours a day, 7 days a week. Replacing the same pipeline with a railroad train of tank cars, carrying 2,000 barrels each, would require a 75-car train to arrive and be unloaded every day. Pipelines are relatively inexpensive to operate and are generally quiet and safe. Ensuring pipeline safety requires careful management, as multiple products move through a single pipeline system at the same time.

Insufficient domestic pipeline capacity has caused peak-load problems in moving oil and petroleum products such as gasoline from one region of the country to another. For example, many energy analysts forecasted the possibility of a shortage last winter in the upper Midwest of liquefied petroleum gas used for heating and for drying crops. Others were concerned about possible shortages of heating oil in New England.

Energy supply shortages can create operational difficulties for the pipelines themselves. The complex interrelationship

of our energy infrastructure is evident, since pipelines have been shut down for varying time periods due to regional electricity shortages.

For example, fuel supplies to Las Vegas and Phoenix became dangerously low when blackouts in California shut down the main pipeline serving those areas. The California Public Utilities Commission (CPUC) has granted a waiver of penalties to oil pipelines that have interruptible contracts for electricity to help ensure the uninterrupted flow of motor fuel supplies to California. The California Energy Commission asked the CPUC to grant the waiver in order to minimize the threat to public health due to disruptions of fossil fuel supplies. While the waiver of penalties does not guarantee that disruptions of power to petroleum product pipelines will not occur, it diminishes the threat by allowing disruptions to occur only when they are coordinated with the entire petroleum product delivery system, from refiner to pipeline to terminals. Both Phoenix and Las Vegas would benefit from this decision because refineries and pipelines from California supply the two cities.

Much of the existing oil pipeline infrastructure is old, requiring regular safety and environmental reviews to ensure its reliability. The potential risk of pipeline accidents to human health and safety is of grave concern. In June 1999, a petroleum product pipeline ruptured and caught fire in Bellingham, Washington. In addition to tragic loss of life, the pipeline's 18-month shutdown caused an economic hardship to the Seattle-Tacoma Airport and other local businesses that relied on the pipeline for aviation and diesel fuels. To avoid similar crises, the Department of Transportation, which has responsibility for pipeline safety, has adopted regulations and other risk management approaches to ensure safety in pipeline design, construction, testing, operation, maintenance, and emergency response.

Recommendation:

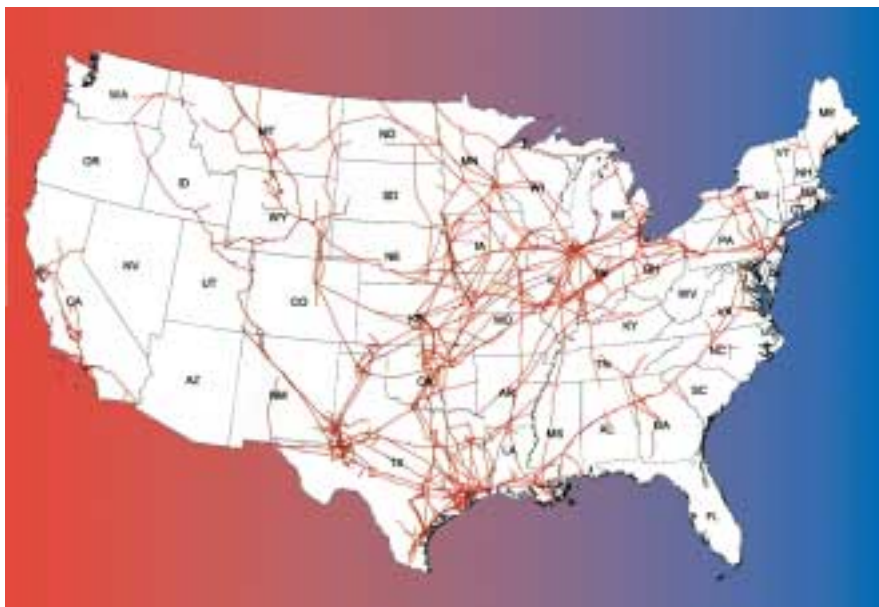
★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.-

The Trans-Alaska Pipeline System is the single most important crude oil pipeline in the United States, and is perhaps the most regulated oil pipeline in the world. The pipeline system has carried nearly one-fifth of all domestically produced oil for the last two decades. Since beginning operations in 1977, it has transported more than 13 billion barrels of oil from Alaska's North Slope across 800 miles to the Port of Valdez. Since the pipeline began operation, only 0.00014 percent of the total amount of oil transported through it has been spilled.

The pipeline's federal grant and state lease for right-of-way expires in 2004 and will require renewal. That process will in-

Figure 7-4

U.S. Oil Pipelines



The two million miles of oil pipelines in the United States are the principal mode for transporting crude oil and refined products. They account for about 66 percent of domestic product movements.

Source: U.S. Department of Transportation, Office of Pipeline Safety.



Several federal agencies are authorized to grant rights-of-way for oil and gas pipeline and electric transmission systems on federal lands, and each approaches the issue from a unique perspective. Authorizing agencies include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, the U.S. Fish and Wildlife Service, the Bureau of Reclamation, and the Bureau of Indian Affairs.

volve a thorough review of compliance with federal laws and regulations, including those related to safety and environmental impacts. Because nearly 50 percent of the right-of-way is owned by the State of Alaska, they must also renew the applicable state permits. To commence the formal portion of the federal renewal process, regulations require a renewal application to be filed with the Alaska Office of the BLM of the Department of the Interior. To the extent possible, a single, joint federal/state approach should be considered.

Natural Gas Pipelines

Virtually all natural gas in the United States is moved via pipeline (Figure 7-5). The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

Some parts of the country, such as California and New England, already face capacity shortages. Several pipeline opera-

tors have applied for permits to increase their delivery of natural gas to California, but right-of-way issues and local permitting delays have constrained the ability to transport natural gas to California, contributing to high prices. In addition, the natural gas pipeline connections from Canada are near capacity, so any greater U.S. reliance on Canadian natural gas will require increased pipeline capacity.

One of the largest known reserves of natural gas in the United States has been found in the Arctic, associated with the development of oil at Alaska's Prudhoe Bay. These known gas reserves, over 35 tcf, would make a significant long-term contribution to the nation's energy supplies if delivered to the lower 48 states. It is estimated there may be an additional 100 tcf on the North Slope of Alaska. Recently, as the energy supply situation has changed, interest has renewed in tapping into Alaska's natural gas supplies. Over the past year, the Alaska North Slope gas producers have been reviewing whether projected market conditions will make transportation of this natural gas economically feasible. The North Slope gas producers are scheduled to complete that review by the end of 2001.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

America needs the energy that Alaska's North Slope natural gas can provide. The Administration seeks to expedite the construction of a pipeline to deliver this natural gas to the lower 48 states.

In addition to shortfalls in capacity, sources of natural gas have shifted from the Southwest to the deep water of the Gulf of Mexico, the Rocky Mountains, western Canada, and the Canadian Atlantic. At the same time, demand has shifted from the industrial Midwest to the growing population centers in the South and the West. An additional 263,000 miles of distribution pipelines and 38,000 miles of new transmission pipelines will be necessary to meet increased consumption and the new geographic realities of supply and demand.

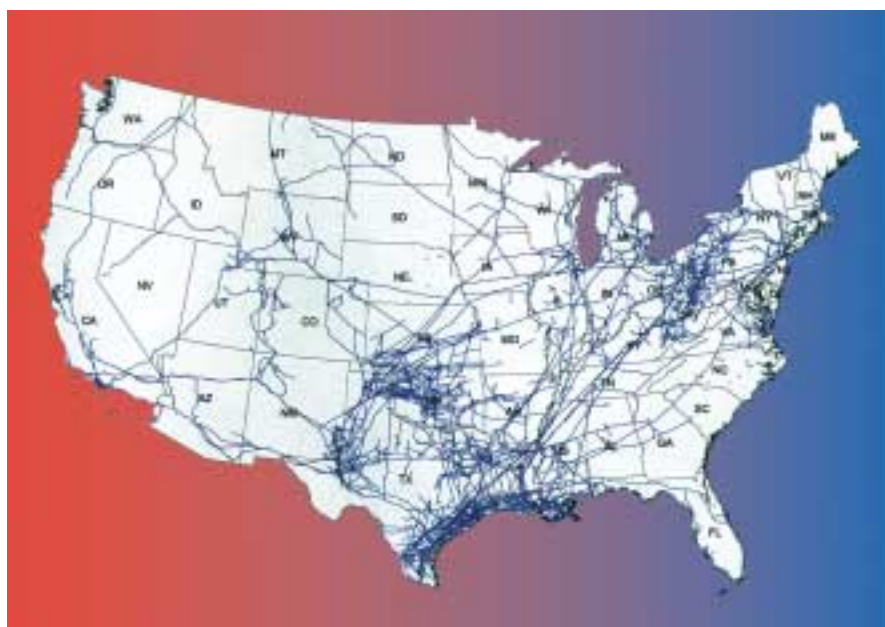
Several factors complicate efforts to meet the need for increased pipeline capacity, including encroachment on existing rights-of-way and heightened community resistance to pipeline construction. Currently it takes an average of four years to obtain approvals to construct a new natural gas pipeline. In some cases it can take much longer.

The projected growth in energy demand has called into question whether regulatory actions and permitting processes can keep pace with the necessary construction of new facilities for storage and delivery. Consistent federal, state, and local government policies, and faster, more predictable regulatory decisions on permitting for oil and natural gas pipelines are needed to enable timely and cost-effective infrastructure development. The permitting process has a positive role in protecting the environment, public health, and safety by allowing all interested parties an opportunity to participate effectively and fully in the deliberations prior to the permit issuance.

Recent pipeline ruptures involving a natural gas pipeline near Carlsbad, New Mexico, and an underground natural gas storage facility near Hutchinson, Kansas, highlight the need to develop technologies and policies that protect people, environment, and the safety of the nation's energy infrastructure. The federal government has an important role in ensuring and improving the safety of these gas pipelines. New technologies need to be developed to improve monitoring and assessment of system integrity, improve data quality for system

Figure 7-5

U.S. Natural Gas Transmission Pipelines



Virtually all natural gas in the United States is moved via pipeline. The forecast of a doubling in the number of new natural gas wells drilled annually and an 80 percent increase in the number of active drilling rigs will require new pipelines.

Source: U.S. Department of Transportation, Office of Pipeline Safety.

planning, extend the serviceability and life of the national natural gas transmission and distribution network, provide safer transport of energy products, and lessen the impacts of the energy infrastructure on the environment.

Recommendations:

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally-sound manner and encourage the Federal Energy Regulatory Commission to consider improvements in the regulatory process governing approval of interstate-natural gas pipeline projects.



U.S. demand for refined petroleum products currently exceeds its domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season.

Oil Refineries

U.S. demand for refined petroleum products, such as gasoline and heating oil, currently exceeds our domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season and is producing record levels of needed products at other times. The excess demand has recently been met by increased imports.

The U.S. refining industry has experienced a decade of low profitability and rates of return on investment. This has discouraged investment in new refineries. In fact, almost 50 U.S. refineries closed over the last ten years, and no major refineries have been built in the last twenty-five years.

During the last ten years, overall refining capacity grew by about 1 to 2 percent a year as a result of expansion in the capacity of existing, larger refineries. Although there was a significant, sustained improvement in margins during 2000, those gains arose out of a very tight supply situation and high, volatile prices. Industry consolidation has been a key response to this poor profitability.

The U.S. refining industry is also facing major infrastructure problems. While the industry expanded steadily through the 1970s, it went through a period of consolidation after the oil shocks of 1973 and 1978.

Ongoing industry consolidation, in an effort to improve profitability, inevitably leads to the sale or closure of redundant facilities by the new combined ownership. This has been particularly true of terminal facilities, which can lead to reductions in inventory and system flexibility. While excess capacity may have deterred some new capacity investments in the past, more recently, other factors, such as regulations, have deterred investments.

Refiners are subject to significant environmental regulation and face several new clean air requirements over the next decade. Refiners will face many clean fuel production standards, which require the production of many different kinds of gasoline and diesel fuel for different parts of the country. New Environmental Protection Agency rules will require refiners to produce gasoline and diesel fuel with significantly lower sulfur content. New clean air requirements will benefit the environment, but will also require substantial capital investments and additional government permits. The proliferation of distinct regional and state gasoline and diesel product standards, the significant permitting needed, and the downtime to make the needed physical and operational changes will challenge refiners and governments to effectively coordinate in order to reduce the likelihood of supply shortfalls and price spikes.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

Since 1990, refiners have met growing demand by increasing the use of existing equipment and increasing the efficiency and capacity of existing plants. Even with these efforts, however, refining capacity has begun to lag behind peak summer demand. Price volatility and the cyclical nature of oil markets inhibit investment in supply infrastructure. While investors can withstand market fluctuations for some commodities, large investments in oil exploration and development—such as for drilling required to maintain a steady supply and the pipelines needed to bring supply to market—are often curtailed during times of low oil prices. The outcome of this lack of steady investment is less supply, higher prices, and the abandonment of marginal oil resources that may never be recovered.

Recommendations:-

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.-

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations

(covering more than one pollutant and requirement) and consider the rules’ cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

- The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

Energy Transportation Infrastructure

The infrastructure used to transport energy products includes ocean tankers; in land barges; specialized trucks for oil and refined products, such as gasoline and heating oil; railroad tank cars and coal cars; and the waterways, highways, and railroads upon which they travel. There is also a substantial inventory of river and oceanside port facilities that are used for moving energy materials.

Marine Transportation

Marine transportation of oil and refined products accounts for nearly one-third of domestic shipments. Approximately 3.3 billion barrels of oil and petroleum products and 229 million short tons of coal move through the nation’s ports and waterways every year.

There are three kinds of ship transport of domestic energy products. Tankers



Double-hulled tank barges provide distribution of petroleum products.

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primarily carry Alaskan oil to the West Coast. Product tankers transport refined products from the Gulf of Mexico to the Atlantic Coast, from the Gulf to the West Coast, and between ports within the West Coast. Tank barges provide coastwise distribution of refined product imports, distribution from pipeline terminals, and inland distribution. In addition, 477 foreign tankers and 64 U.S. flag tankers deliver oil and petroleum products to the United States. They deliver approximately 2.1 million barrels a day, for a total of 770 million barrels a year.

Ships are also used to import liquefied natural gas (LNG). With increasing demand for natural gas for electricity generation, there is a potential for substantial growth in the demand for LNG imports. From 1998 to 1999, the number of LNG carrier arrivals in Boston increased by 350 percent. In addition, mothballed terminals at Elba Island, Georgia, and Cove Point, Maryland, may reinstate LNG imports by 2002.-

Winter storms, extended darkness, and ice formation disrupt barge and tanker movements. The U.S. Coast Guard's fleet of ice breakers has become an important component of the energy infrastructure for the New England, Mid-Atlantic, and Great Lakes regions.

U.S. COAST GUARD



Unlike pipelines, water transportation requires the positioning of vessels to where cargoes are located. For example, it can take three weeks to move a tanker from the Gulf of Mexico to the West Coast. Consequently, tanker markets do not respond quickly to temporary surges in demand, which typically result in price spikes.

Safety

In accordance with the Oil Pollution Act of 1990, a timeline has been established to replace all single-hulled vessels with double-hulled vessels. Many have already been replaced. Modern navigation and port services also help to prevent maritime oil spills. Spill-response technologies and coordinated response plans are key to minimizing damage to property and the environment. Oil spill technology has improved during the last decade and will continue to do so. Risk assessments, preparedness drills, and cleanup strategies are all necessary safeguards for transporting energy goods. As maritime transportation grows, port and waterway infrastructure, as well as the availability of accurate and timely navigation information, will continue to be important for the safe, efficient delivery of energy.

New England's Dependence on Marine Transportation

New England has no refineries, and its small oil pipeline system is not connected to the interstate pipeline system. As a result, New England must rely on tanker and barge shipments of petroleum products from the south as well as direct imports from overseas. There is some question as to whether this distribution system is sufficient to meet the future needs of the region and, if not, what steps need to be taken to ensure future economical, reliable energy supplies.

In recent years, lower national inventories, market forces, and other factors have combined to create much lower inventories for petroleum products such as heating oil in the Northeast. A supply system with less capacity in reserve is more vulnerable to variations in product delivery, and is less capable of absorbing the disruptions in barge and tanker movements that inevitably come

with winter storms, extended darkness, and ice formation. A rapid change to colder weather affects both supply and demand: households need more fuel at the same time that harbors and rivers experience severe ice conditions.

For the New England and Mid-Atlantic seaboards, U.S. Coast Guard icebreakers have become an important component of the infrastructure necessary to provide energy to the region.

The Department of Energy established the Northeast Heating Oil Reserve to ensure heating oil supplies in the region. This emergency buffer can support a shortage for approximately ten days, which is the time required for ships to carry heating oil from the Gulf of Mexico to New York Harbor.

Even with the Reserve in place, marine transportation remains the only source of heating oil for the New England's winter months.

Recommendation:

★ The NEPD Group supports the President's budget proposal to provide \$8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Rail Transportation

Coal, which provides about 52 percent of America's electricity, is the most important single commodity carried by rail. Over the past ten years, the rail share of coal transportation has increased, primarily as a result of increases in low-sulfur western coal, which moves long distances over rail. In 1999, domestic railroads carried 68 percent of the nation's coal, and in 2000, they transported an average of 14.4 million tons of coal a week.

Transportation costs account for 30 to 50 percent of the final delivered price of coal to utilities. About 74 percent of U.S.

low-sulfur coal reserves are located in Montana and Wyoming. Demand for clean coal from Wyoming's Powder River Basin is expected to increase because of its environmental benefits. However, rail capacity problems in the Powder River Basin have created a bottleneck in the coal transportation system.

With little excess capacity in the rail lines supporting the Powder River Basin, expected increases in demand could result in capacity shortfalls and delays in providing coal to power plants that are relying increasingly on "just-in-time" shipments to reduce inventory costs. Additionally, delays in other parts of the rail network, such as at key rail facilities, can undermine the efficiency and reliability of the system. There is a need to eliminate bottlenecks in the coal transportation system.

Infrastructure Security

The energy infrastructure is vulnerable to physical and cyber disruption that could threaten its integrity and safety. Disruptions could come from natural events, like geomagnetic storms and earthquakes, or could come from accidents, equipment failures, or deliberate sabotage. In addition, the nation's transportation and power infrastructures have grown increasingly complex and interdependent. Consequently, any disruption can have extensive consequences.

Transportation facilities have weathered relatively short interruptions in power as a result of natural disasters and accidents, with varying degrees of impact. In a few instances, they have experienced intermittent, lengthy outages that have affected not only primary systems, but integrated services as well, such as voice, data, Internet, and wireless networks that may be used to transmit control information. The growing reliance on computer technologies, automated monitoring and control systems, and electronic commerce makes the system more efficient and vibrant, but also requires a greater level of diligence and use of safeguards.

Accurate weather and climate forecasting can prevent millions of dollars in

damage to U.S. energy infrastructure. For example, the interaction of geomagnetic storms with the Earth's magnetic field can cause additional current to enter transmission lines, which at times has caused regional grid collapse and has destroyed power plant electrical transformers. Given sufficient warning, the industry can initiate protective countermeasures, such as when several northeastern power plants shed 20 percent of their load during a July 2000 geomagnetic storm.

Improvements in forecasting can further assist in the management of energy resources and materials, can prevent power outages in many cases, and can accelerate restoration of power after outages that do occur. Also, data from extreme weather events can be used to design and build infrastructure, such as transmission lines, pipelines, and hydropower dams.

Summary of Recommendations

America's Energy Infrastructure: A Comprehensive Delivery System

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.
- ★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.
 - Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
 - Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
 - Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
 - Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules’ cumulative impacts and benefits.

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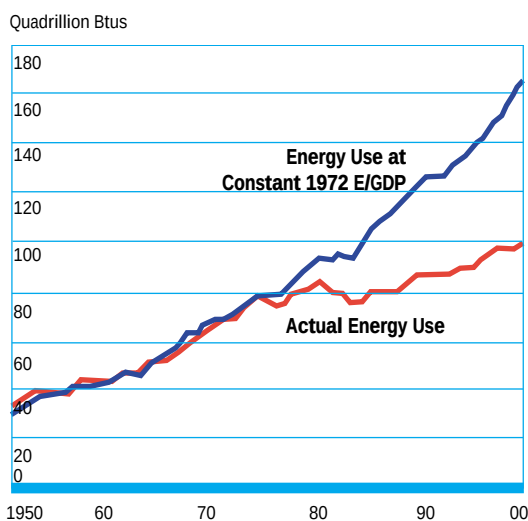
Strengthening Global Alliances

Enhancing National Energy Security and International Relationships

U.S. national energy security depends on sufficient energy supplies to support U.S. and global economic growth. Energy policies that have emphasized reliance on market forces have led to major energy security gains over the past two decades. Major improvements in exploration and production technology, as well as the trend toward opening new areas around the globe for exploration and development, have yielded significant dividends:

- The U.S. and world economies have diversified their sources of oil supplies, largely through increased production in the Western Hemisphere, the North Sea, and Africa.
- The world's fuel mix is also more diverse, primarily because of greater reliance on natural gas and nuclear power.
- The rate of growth in U.S. oil demand has slowed significantly since the first oil shocks of the 1970s because of more energy-efficient industries, structural changes in the economy, and greater efficiencies in vehicles, appliances, and buildings.

Figure 8-1
The U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

Since 1970, as the economy has shifted toward greater use of more efficient technologies, U.S. energy intensity (the amount of energy it takes to produce a dollar of GDP) has declined by 30 percent (Figure 8-1). However, energy use per person in the United States is expected to rise as is overall demand for energy.

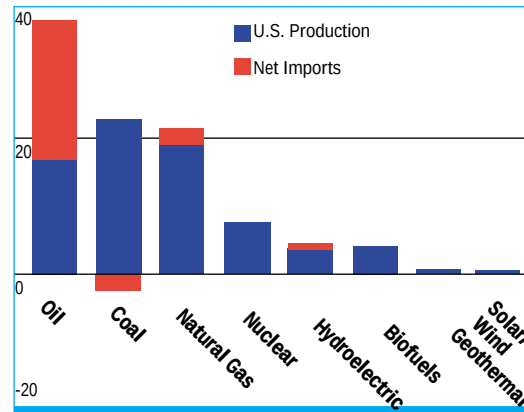
Measures to enhance U.S. energy security by meeting this increased demand must begin at home. The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner. Market solutions to limit the growth in our oil imports would reduce oil consumption for our economy and increase our economic flexibility in responding to any domestic or international disruption of oil or other energy supplies. The United States produces 72 of the 99 quadrillion British thermal units (Btus) of



Figure 8-2

Sources of U.S. Fuel Consumption in 1999

(Quadrillion Btus)



The United States produced 72 of the 98 quadrillion Btus of energy that it consumed in 1999. We are self-sufficient in virtually all our energy resources, except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15–16 percent net, primarily from Canada.

Source: U.S. Department of Energy, Energy Information Administration.

energy that it consumes (Figure 8-2). We are self-sufficient in virtually all our energy resources except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15 to 16 percent of our net requirements, primarily from Canada.

We should not, however, look at energy security in isolation from the rest of the world. In a global energy marketplace, U.S. energy and economic security are directly linked not only to our domestic and international energy supplies, but to those of our trading partners as well. A significant disruption in world oil supplies could adversely affect our economy and our ability to promote key foreign and economic policy objectives, regardless of the level of U.S. dependence on oil imports.

Our energy security also depends on an efficient domestic and international infrastructure to support all segments of the energy supply chain. We can strengthen our own energy security and the shared prosperity of the global economy by working cooperatively with key countries and institutions to expand the sources and types of global energy supplies. We can also advance these goals by increasing the effi

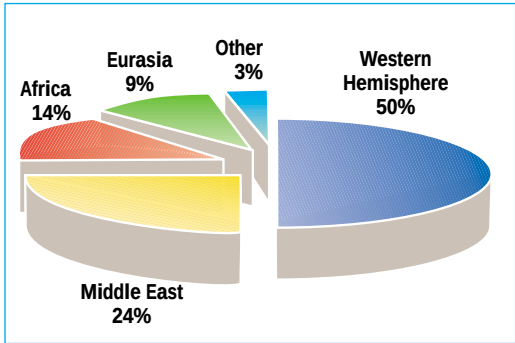
ciency of energy consumption, enhancing the transparency and efficient operation of energy markets, and strengthening our capacity to respond to disruptions of oil supplies. Energy is fundamental to economic growth, and we believe that economic growth and environmental protection can be mutually achieved.

We need to strengthen our trade alliances, to deepen our dialogue with major oil producers, and to work for greater oil production in the Western Hemisphere, Africa, the Caspian, and other regions with abundant oil resources. Greater cooperation with our allies in addressing the growth in oil demand in the transportation sector is particularly important, given the growing demand for oil and other energy resources. Significant economic and environmental benefits can be realized from increased energy efficiency and from the use of clean energy technologies. We need to ensure that our partners in the International Energy Agency (IEA) continue to meet their obligations for emergency supply reserves. Finally, we must continue to work with the IEA, the Asia-Pacific Economic Cooperation (APEC) forum, and others to encourage other large importers to consider measures to augment their oil reserves

Oil Imports and Global Reserves

The U.S. influence on overall world markets is substantial in terms of production and consumption. The United States is the world's second largest natural gas producer and its third largest oil producer. The United States consumes over 25 percent of the oil produced worldwide, slightly more than half of which it imports. Nevertheless, because the price of our domestic and imported oil is determined by a world market, our energy security interests transcend the source of our physical energy supplies (Figure 8-3). Given the large and projected growing volume of U.S. oil imports, our energy and economic security will increase if we take the steps necessary to realize America's potential as a major world oil and natural gas producer.

Figure 8-3
Regional Sources of U.S. Oil Imports in 2000



Slightly over half of the oil the United States imports every day comes from the Western Hemisphere. Canada, Venezuela, and Mexico account for the bulk (41%) of these imports.

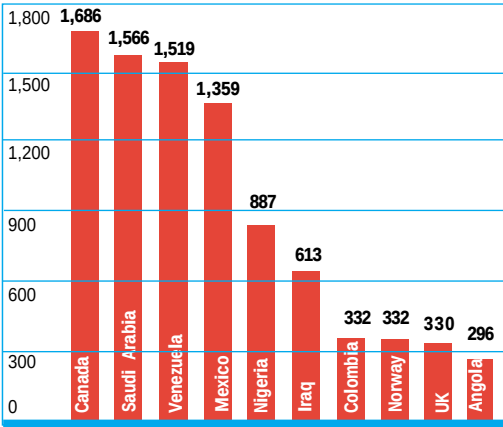
Source: U.S. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign-policy.-

In 2000, nearly 55 percent of U.S. gross oil imports came from four countries: 15 percent from Canada, 14 percent each from Saudi Arabia and Venezuela, and 12 percent from Mexico (Figure 8-4). The security of U.S. energy supply is enhanced by

Figure 8-4
Top 10 Suppliers of U.S. Oil Imports in 2000



In 2000, nearly 55 percent of gross U.S. oil imports came from four leading suppliers: Canada (15%), Saudi Arabia (14%), Venezuela (14%), and Mexico (12%).

Source: U.S. Department of Energy, Energy Information Administration.-

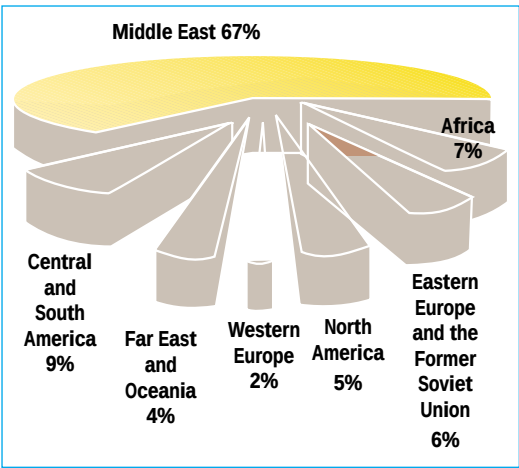
several factors characterizing our diplomatic and economic relationships with our four top suppliers. These factors range from geographic proximity and free trade agreements to integrated pipeline networks, reciprocal energy-sector investments, shared security commitments, and, in all cases, long-term reliable supply relationships (Figure 8-5).

Saudi Arabia and the Middle East Oil Supplies

By 2020, Gulf oil producers are projected to supply between 54 and 67 percent of the world's oil. Thus, the global economy will almost certainly continue to depend on the supply of oil from Organization of Petroleum Exporting Countries (OPEC) members, particularly in the Gulf. This region will remain vital to U.S. interests. Saudi Arabia, the world's largest oil exporter, has been a linchpin of supply reliability to world oil markets.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the

Figure 8-5
Proven World Oil Reserves in January 2000



The world's proven crude oil reserves remain relatively concentrated. The Middle East holds 664 billion barrels, or roughly two-thirds of the world's conventional oil reserves, followed by the Western Hemisphere (14%) and Africa (7%).

Source: U.S. Department of Energy, Energy Information Administration.

energy sector's capacity and its infrastructure. Both producers and consumers will benefit from ensuring that the global energy infrastructure is sufficient and flexible to meet growing global demand.

American energy firms remain world leaders, and their investments in energy producing countries enhance efficiencies and market linkages while increasing environmental protections. Expanded trade and investment between oil importing and exporting nations can increase shared interests while enhancing global energy and economic security. Promoting such investment will be a core element of our engagement with major foreign oil producers.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.

Reviewing and Reforming Sanctions

Economic sanctions include U.S. unilateral sanctions as well as multilateral sanctions, such as United Nations (UN) Security Council Resolutions. Sanctions can advance important national and global security objectives and can be an important foreign policy tool, especially against nations that support terrorism or seek to acquire weapons of mass destruction. Nevertheless, sanctions should be periodically reviewed to ensure their continued effectiveness and to minimize their costs on U.S. citizens and interests.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.-

Diversity of Supply

Concentration of world oil production in any one region of the world is a potential contributor to market instability, benefiting neither oil producers nor consumers. Periodic efforts by OPEC to maintain oil prices above levels dictated by market forces have increased price volatility and prices paid by consumers, and have worked against the shared interests of both producers and consumers in greater oil market stability. This remains a policy challenge, which we will meet over the longer term through a comprehensive energy policy that addresses both supply and demand, as well as through increased engagement with all our major suppliers. Greater diversity of world oil production remains important.

Encouraging greater diversity of oil production and, as appropriate, transportation, within and among geographic regions has obvious benefits to all market participants. Technological advances will enable the United States to accelerate the diversification of oil supplies, notably through deep-



The United States is helping developing countries use energy efficient technologies. Photovoltaic-powered pumps are being used in many wells throughout rural India for collecting potable water.

U.S. DEPARTMENT OF ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY

water offshore exploration and production in the Atlantic Basin, stretching from off shore Canada to the Caribbean, Brazil, and West Africa. The Caspian Sea can also be a rapidly growing new area of supply.

The ongoing development of so-called “heavy oil” reserves in the Western Hemisphere is an important factor that promises to significantly enhance global oil reserves and production diversity. Recent Canadian and Venezuelan success in making heavy oil deposits commercially viable suggests that they will contribute substantially to the diversity of global energy supply, and to our own energy supply mix over the medium to long term. Leading non-OPEC oil exporters, such as Mexico and Norway, remain critical to the diversity of global energy supply.

Growing levels of conventional and heavy oil production and exports from the Western Hemisphere, the Caspian, and Africa are important factors that can lessen the impact of a supply disruption on the U.S. and world economies. Overall U.S. policies in each of these high-priority regions will focus on improving the investment climate and facilitating the flow of needed investment and technology.

Bilateral energy working groups, such as the U.S.-Kazakhstan Oil, Gas and Commercial Energy Working Group and the U.S.-Russian Oil and Gas Working Group, can improve the trade climate in high-priority countries. In addition to seeking new sources of oil, the United States is helping developing countries use energy efficient technologies to mitigate the environmental impacts of energy use, and to improve access to energy resources.

WTO members are beginning to examine global trade in energy services. The United States has called on WTO members to open markets eligible for private participation in the entire range of energy services, from exploration to the final customer. The energy service proposal would attempt to ensure nondiscriminatory access to foreign providers of energy services. Equally important, the U.S. proposal suggests that WTO members consider how to best create a pro-competitive regulatory en-

Figure 8-7

Canada–U.S. Natural Gas Pipelines: 2001



Canada–U.S. Oil Pipelines: 2001

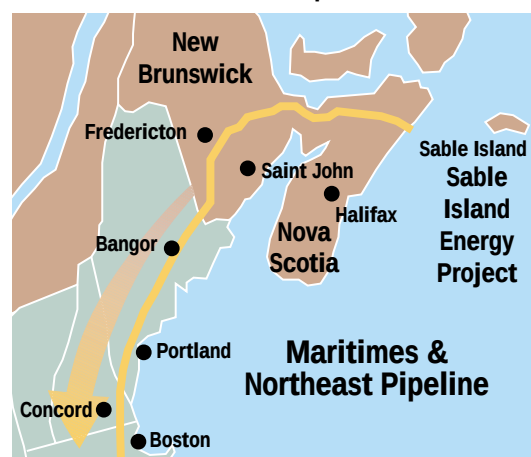


An integrated network of oil and gas pipelines demonstrates the seamless nature of North American energy trade.

Sources: Lakehead Pipe Line Company, Inc., and Canadian Association of Petroleum Producers.

Figure 8-8

Maritimes and Northeast Pipeline: 2000



New England's geography made it the “last stop” for natural gas pipelines stretching thousands of miles across the continent from the South and the West. Consequently, the region became the most oil-dependent area in the country, particularly for home heating and electricity. With the January 1, 2000, inauguration of Atlantic Canada's Maritimes and Northeast Pipeline, New England is now at the beginning of the line for natural gas flowing across the border from Canada at Calais, Maine. Overall, the region's fuel mix is becoming increasingly diversified, with natural gas demand slated to increase by 2.4 percent a year through 2020.

Source: Maritimes and NorthEast Pipeline.

environment for energy services, so that opaque or discriminatory regulatory practices do not undermine commitments to open their domestic markets to foreign service providers. Such objectives can also be pursued in the FTAA and APEC.

Toward a North American Energy Framework

Increased U.S., Canadian, and Mexican energy production and cooperation would enhance energy security and, through our economic links in the North America Free Trade Agreement (NAFTA) economy, fundamentally advance each country's economic security. As state and federal governments consider energy reforms, there will be a need to ensure compatible regulatory frameworks with our neighbors while recognizing differences in jurisdictions.

Canada

Canada's deregulated energy sector has become America's largest overall energy trading partner, and our leading foreign supplier of natural gas, oil, and electricity. Canada's sustainable development based energy strategies contribute to the health of the NAFTA economy and of our shared environment.

Canada provided 14 percent of U.S. natural gas supply last year. An integrated network of pipelines demonstrates the seamless nature of North American energy trade (Figure 8-7). Estimated natural gas deposits in Alaska and Northwest Canada exceed 70 trillion cubic feet, representing over three years of total U.S. consumption at present levels.

To advance shared economic and environmental objectives, the private sector is poised to develop the continent's northern gas reserves, with pipeline linkages between both countries. To the east, recent development of Canada's Atlantic offshore energy reserves has made significant strides, with major offshore natural gas and oil production now available. Canada's Atlantic energy development is now providing previously untapped sources of clean-burning natural gas not only to Nova Scotia and New Brunswick but also to heating oil-de-



pendent New England (Figure 8-8).

Our large cross-border electricity trade flows in each direction. Our electricity imports from Canada are derived largely from hydropower produced in eastern Canada, Canadian and American hydropower projects in the Pacific Northwest operating pursuant to the Columbia River Treaty, and a nuclear power plant in New Brunswick. All of these sources provide important trade and clean air benefits, while allowing both countries to benefit from load sharing and integration. The reliability of the North American electricity grid can be enhanced yet further through closer coordination and compatible regulatory and jurisdictional approaches.

Canada's oil trade, responding to market signals, increased 4 percent worldwide and 10 percent with the United States last year. Estimates of Canada's recoverable heavy oil sands reserves are substantial, and new technologies are being deployed to develop their potential. Production from these promising areas now approaches 600,000 barrels a day. Their continued development can be a pillar of sustained North American energy and economic security.

Mexico

Our energy relationship with Mexico reflects the increasingly interrelated character of NAFTA economies and our contiguous border. U.S. natural gas reserves, pipe-

Offshore oil platform near Campeche, Mexico. Mexico's large crude oil reserves—approximately 25 percent larger than our own proven reserves—makes it a likely source of increased oil production over the next decade.

U.S. EMBASSY, MEXICO CITY

Figure 8-9

Mexican Oil and Gas Resources: 2001



Mexico's large oil reserves—approximately 25 percent larger than U.S. proven reserves—make it a likely source of increased oil production over the next decade.

Source: U.S. Central Intelligence Agency.

A carrier transports liquefied natural gas (LNG) from Trinidad and Tobago—our largest LNG supplier—to Boston harbor. LNG currently represents 16 percent of New England's natural gas supply.

CABOT LNG

lines, and industries are closer to the growing border area than some of Mexico's reserves. The United States is a net exporter of refined petroleum products and natural gas to Mexico, primarily through pipeline connections to northern Mexico. Mexico is a leading and reliable source of imported oil, and its large reserve base, approximately 25 percent larger than our own proven reserves, makes Mexico a likely source of increased oil production over the

next decade (Figure 8-9).

Mexico began exporting 50 megawatts of electricity from Baja to California in January 2001. However, the transmission infrastructure on both sides of the border is insufficient for greater flows of energy in either direction without expansion. In the United States, our process for "Presidential Permitting" of cross-border infrastructure linkages needs to be updated and streamlined.

Mexico will make its own sovereign decisions on the breadth, pace, and extent to which it will expand and reform its electricity and oil and gas capacities. Where the country has opened its energy sector to private investment, such as in natural gas transmission, distribution, and storage, investments have been made to our mutual benefit. To the extent Mexico seeks to attract additional foreign investment consistent with its Constitution, which reserves exploration and production rights to the Mexican government, the United States should actively encourage the U.S. private sector to consider market-based investments.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.



★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

South America: Latin America and the Caribbean

Latin America and the Caribbean are growing not only as major producing regions, but also as major consumers of oil and natural gas. Trinidad and Tobago's progressive investment code has made it the hemisphere's largest exporter of LNG and the largest supplier of LNG to the United States in 2000. Unprecedented development of Central and South America's vast natural gas reserves—222.7 trillion cubic feet as of January 2000, illustrated by transcontinental pipelines linking Bolivia, Brazil, Argentina, Chile, Paraguay, and Uruguay—increase regional self-reliance, affirm economic integration, aid the environment, and stem the growth in oil demand. Colombia has also become an important supplier of oil to the United States.

The United States, with Venezuela, is a co-coordinator of the Hemispheric Energy Initiative process. In March 2001, a Summit of the Americas Hemispheric Energy Ministerial meeting was hosted by the Government of Mexico. At the meeting, the region's energy ministers pledged to support integration and sustainable development in the hemisphere, recognizing the need to foster stable and transparent regulatory frameworks. In April 2001, the thirty-four democratically elected leaders of the Western Hemisphere met in Quebec City for the Third Summit of the Americas. They called for a renewed effort to strengthen the hemisphere's energy cooperation and integration.



Venezuela is the world's fifth largest oil exporter, and the third largest oil supplier to the United States. Its energy industry is increasingly integrated into the U.S. marketplace. Venezuela's downstream investments in the United States make it a leading refiner and gasoline marketer here. Growing U.S. and international investments in Venezuela's energy sector, particularly in its resource-rich heavy oil sector, are enhancing the country's ability to meet its development goals and to keep pace with a growing world energy marketplace. Venezuela is also moving to liberalize its natural gas sector, which will increase opportunities for foreign investment to expand Venezuelan natural gas production. These positive steps along with conclusion of a Bilateral Investment Treaty, which is now being negotiated, would provide investors from both the United States and Venezuela incentives for increased investment.

Brazil has long been a pioneer in the development of deep-water offshore oil and gas resources. Its world-class oil industry is now moving to become a partner with U.S. and international investors to more fully develop its prolific offshore oil reserves. This welcome development will enhance hemispheric energy production from well-established sedimentary basins.

U.S. Secretary of Energy Spencer Abraham listens to his colleagues at the Summit of the Americas Hemispheric Energy Ministerial meeting in Mexico City on March 9, 2001.

U.S. EMBASSY, MEXICO CITY

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

Africa

Sub-Saharan Africa holds 7 percent of world oil reserves and comprises 11 percent of world oil production. Along with Latin America, West Africa is expected to be one of fastest-growing sources of oil and gas for the American market. African oil tends to be of high quality and low in sulfur, making it suitable for stringent refined product requirements, and giving it a growing market share for refining centers on the East Coast of the United States.

In 2000, OPEC member Nigeria exported an average of 900,000 barrels of oil per day to the United States, out of its total production of 2.1 million barrels of oil per day. Nigeria, in partnership with the private sector, has set ambitious production goals as high as 5 million barrels of oil per day over the coming decade.

Angola's growing offshore oil industry, with participation by U.S. and international oil firms, is also a major source of growth. In 2000, Angola exported 300,000 barrels of oil per day out of its 750,000 barrels of oil per day of total production to the United States, and is thought to have the potential to double its exports over the next ten years. Other significant exporters to the United States included Gabon and the Congo-Brazzaville.

The World Bank has supported Chad's efforts to begin ambitious oil development. This year an international consortium that includes U.S. firms began investing \$3.5 billion in this pipeline from Chad to Cameroon, the largest infrastructure project in Africa to day. When complete, the pipeline will allow Chad to export up to 250,000 barrels of oil per day.

The U.S. Agency for International Development (USAID) has provided technical assistance in support of a West Africa Power Pool and associated pipeline project involving a number of U.S. oil companies, and is providing assistance for the creation of a regional regulatory framework that will enable Ghana and Nigeria to become major exporters of natural gas and electricity.

The West Africa Gas Pipeline is a 161 mile (1,000-kilometer), \$400 million on shore/offshore natural gas pipeline connecting Nigeria with Benin, Togo, and Ghana. The pipeline is being built by a consortium of companies, and includes financing by the U.S. Export-Import Bank.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to rein-vigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to recast the Joint Economic Partnership Committee with Nigeria to improve the climate for U.S. oil and gas trade, investment, and operations and to advance our shared energy interests.
- ★ The NEPD Group recommends that the President direct the Secretaries of

State, Energy, and Commerce to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

The Caspian

Proven oil reserves in Azerbaijan and Kazakhstan are about 20 billion barrels, a little more than the North Sea and slightly less than the United States. Exploration, however, is continuing, and proven reserves are expected to increase significantly.

For example, initial results of the exploration well at Kazakhstan's Kashagan field indicate the find is one of the most important in thirty years, and is comparable to Prudhoe Bay in size. Current exports from the region are only about 800,000 barrels of oil per day, in part due to limited export route options. However, potential exports could increase by 1.8 million barrels of oil per day by 2005, as the United States works closely with private companies and countries in the region to develop commercially viable export routes, such as the Baku-Tbilisi-Ceyhan (BTC) and Caspian Pipeline Consortium oil pipelines (Figure 8 10). Moreover, there is considerable optimism that exports could grow even more substantially in subsequent years because of positive prospects for new oil and gas finds as additional geologic structures undergo exploration, and the development of new export routes.

Foreign investors and technology are critical to rapid development of new commercially viable export routes. Such development will ensure that rising Caspian oil production is effectively integrated into world oil trade. U.S.-supported East-West pipeline routes will add substantial new oil transportation capacity to allow continued expansion of production and exports. Over land routes via pipeline, such as the planned BTC oil pipeline, will also help mitigate maritime risks in the crowded Bosphorus Straits. To help countries prepare for increased oil production within the re-

Figure 8-10

Caspian Energy Export Pipelines: 2001



gion, the United States is working with Black Sea and Caspian Sea border states to ensure that they develop adequate oil spill response capabilities.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.-
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.-
- ★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.-
- ★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.-

Russia

Russia has about 5 percent of the world's proven oil reserves. In 2000, Russia produced an average of 6.7 million barrels of oil and natural gas liquids per day, making it both the world's third largest producer and second largest exporter at 4.2 million barrels of oil per day. Russia's oil production in 2000 represented an increase of 7 percent over 1999, the first increase since the dissolution of the Soviet Union. A similar rate of increase is projected for 2001. New fields are being developed, including those with U.S. and other foreign investors.

Nevertheless, substantial infrastructure investment is still needed, as well as legislation and a stable and reliable regime of contracting to finalize the Production Sharing Agreement (PSA) mechanism for private-sector participation and actions to improve the general investment climate. Russian oil firms are increasingly active on a global scale, with upstream and downstream investments in the Caspian, the United States, Africa, South Asia, and Europe, enhancing Russia's ability to develop its own and international oil reserves.

Russia holds 33 percent of the world's natural gas reserves, exporting a full 35 percent of its production to Europe and Central Asia in 1999. Russian natural gas exports can increase regional fuel diversification and advance environmental goals. With production declines now evident in existing fields, development of new reserves that require substantial new investments will be necessary.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with-

Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

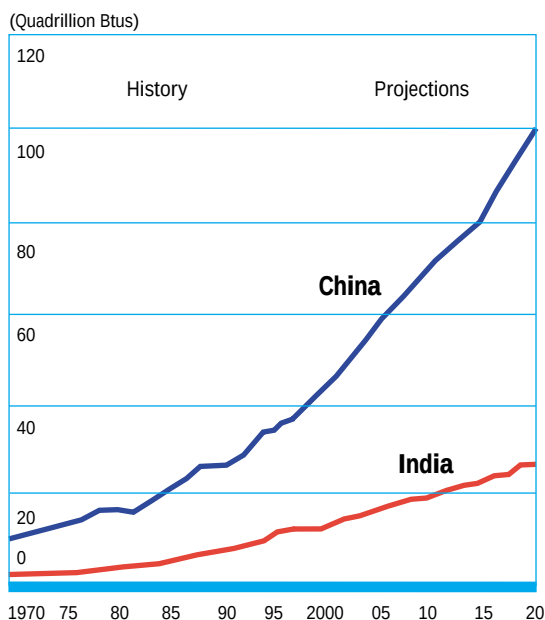
Asia

Asia holds less than 5 percent of world proven oil reserves, but accounts for more than 10 percent of oil production and about 30 percent of world oil consumption. The developing countries of the Pacific Rim are expected to increase their total petroleum imports by almost 43 percent between 1997 and 2020. The developing countries of Asia are expected to remain heavily dependent on Middle East imports.

China is a critical player in global energy security issues, since its net oil imports are expected to rise from approximately 1 million barrels of oil per day at present to possibly 5 to 8 million barrels of oil per day by 2020, with a predominant (over 70 percent) dependence on Middle East imports. China moved in the mid-1990s from being a net oil exporter to a net oil importer.

About 7 percent of the world's proven natural gas reserves are located in Asia. Asian gas production represents about 11 percent of the world total, and consumption is less than 3 percent of world natural gas demand. Other natural gas producers, such as Malaysia, Myanmar, and Australia, are net gas exporters. Currently Japan, South Korea, and Taiwan are the major gas importers in Asia. China, in addition to accelerating domestic exploration and development of natural gas resources, is planning to import gas via pipeline from Central Asia. India, likewise, is considering several potential LNG import projects (Figure 8-11).

Figure 8-11
Energy Consumption in China and India: 1970–2020



China and India account for the bulk of projected growth in oil demand in non-OECD countries.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy-Working Group to examine oil market-data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.-
- ★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.-

Diversification of Fuel Mix

The growing demand for more fuel efficient technologies offers U.S. businesses significant trade and investment opportunities overseas, while addressing rising world oil demand. The United States supports a practical, market-based approach that en

courages the adoption of efficient technologies, including those relating to natural gas, nuclear energy, and renewable energy. This approach takes into account existing national and international programs and has the potential to energize both public action and private involvement. Introduction of these technologies abroad also supports U.S. national interests by reducing competition for the oil resources on which the global economy continues to rely. Overall, the U.S. government's goal is to adopt policies that support innovative finance and market mechanisms that will provide U.S. businesses and consumers greater incentives to make more cost effective, energy efficient investment and consumption decisions.

Increased use of renewable energy technologies would improve U.S. energy security, yield global environmental benefits, improve social and economic stability in the developing world, and provide significant trade and investment opportunities to U.S. businesses. Promotion of clean energy technology exports can mitigate international dependence on oil supplies from volatile regions, help lower energy costs for U.S. consumers, bring U.S. firms greater access to large foreign markets, and enhance U.S. integration with global sources of innovation. In consultation with U.S. industry, the U.S. government is participating in efforts of the IEA, the G-8, the OECD, the United Nations, and multilateral development banks to formulate effective strategies for accelerated market penetration of renewable energy technologies. Significant market penetration will depend on further reducing the costs of deploying these technologies.

The Clean Energy Technology Exports Working Group, a Federal interagency task force comprised of USAID and the Departments of Commerce and Energy, is creating a strategic plan that will provide a roadmap for future exports of U.S. clean energy technologies. Through its international trade programs, the Department of Commerce will showcase market-ready U.S. technologies that generate a cleaner environment and increase energy efficiency.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy efficient technologies; and explore innovative programs to support the global adoption of these technologies.

Climate Change

The President is committed to addressing the issue of global climate change in a manner that protects our environment and economy. Toward this end, the Administration is undertaking a Cabinet-level review of domestic and international policies for addressing this issue.

The United States invited other nations to re-examine global climate change issues, including technologies and market-based systems. Increasing our understanding of the most recent science and further research into the science of climate change will be essential to developing the optimal strategy.

There is increasing awareness of global competition for fossil fuels and their potential threats to the global environment. The United States can diminish both risks by becoming more energy efficient at home, by working with other nations, and by encouraging developing countries to use the cleanest and most energy-efficient technologies. Through educational programs, the United States can encourage developing countries to use advanced U.S. energy technologies, energy management practices, and market-based policies. The United States is uniquely positioned to help emerging nations build energy and institutional capacity and to finance energy-related activities and services. Doing so could prove to be a cost effective investment, for both the United States and emerging economies.

Recommendation:

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

Oil Consumption

Although U.S. energy security can be reinforced by domestic efforts to enhance supply and use energy more efficiently, growth in international oil demand will exert increasing pressure on global oil availability. Worldwide oil consumption is projected to grow by 2.1 percent a year over the next two decades. However, oil demand is projected to grow three times as fast in non-OECD countries as in OECD countries, which will increase worldwide competition for global oil supplies and put increased pressure on our shared environment. Accordingly, non-OECD countries' share of oil demand is expected to rise from 41 percent to 52 percent (Figure 8-12). China and India will be major contributors to this growth in demand and will rely heavily on imports to meet their needs. This growth will increase the stake that many developing countries have in ensuring access to significant energy resources, as well as their incentive to pursue energy efficiency.

Transportation has been responsible for nearly all the growth in OECD oil consumption over the last twenty years, and is projected to be the leading source of future growth in oil consumption through 2020. Transportation-related fuel consumption in the developing world is expected to more than double by 2020, growing at an annual average rate of 4 percent. Therefore, both OECD and developing countries will need

to increase their focus on efficiencies in the transportation sector. The momentum to create market mechanisms supporting alternative-fuel vehicles will increase. Best practices that seek to reduce the cost of these technologies and to promote market penetration should be pursued. Without additional efforts to reduce this growth in consumption, the transportation sector's fuel needs will force an increasing dependence on oil in the developed and developing worlds.

Recommendations:

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.-

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.-

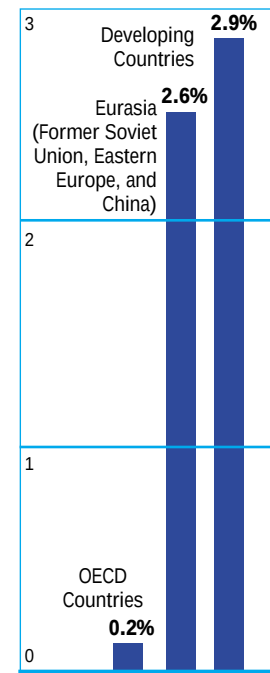
★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.-

Emergency Preparedness for Oil Supply Disruption

U.S. and world exposure to oil supply disruptions increases as the size of strategic and commercial stocks relative to demand declines. This vulnerability is a result of rising global demand, tight supplies, and inadequate efforts to establish or expand oil stockpiles. Such a situation magnifies the importance of U.S. coordination with other members of the IEA, comprised of most OECD member governments. Each IEA member that is a net oil importer is required to hold stocks equal to 90 days or more of its net imports. The IEA maintains agreed mechanisms for coordinating the use of these stocks in responding to a physical supply disruption. Collectively, the net oil-importing members of the IEA currently hold

Figure 8-12
Projected Oil Consumption Rates in Three Economic Regions: 1999–2020

(Percent)



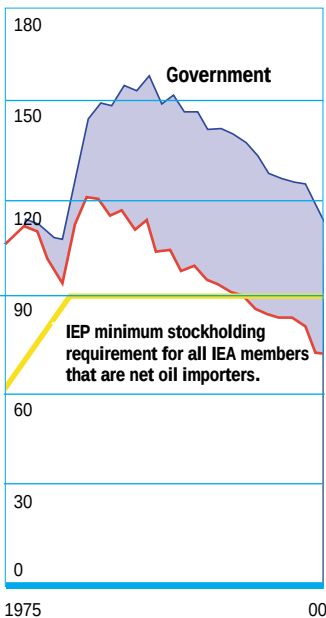
Over the next two decades, oil consumption in developing countries and Eurasia will grow three times faster than in the rest of the world.

Source: U.S. Department of Energy, Energy Information Administration.

Figure 8-13

Stocks of IEA Net Importers: 1975–2000

(Days Of Net Imports)



The International Energy Agency, of which the United States is a member, closely tracks the amount of strategic and commercial petroleum stocks maintained by its member states. The International Energy Program (IEP) Agreement “binds Participating Countries to make specific measures to meet any oil supply emergency and, over the long term, to reduce dependence on oil.”

Source: International Energy Agency.

approximately 113 days worth of strategic and commercial stocks. U.S. stocks, which include both government and commercial stocks, are slightly above the IEA average. While this is more than required, it is far below the peak coverage of 157 days reached in 1986. Moreover, several member states have fallen below the 90-day threshold (Figure 8-13).

The United States meets part of its IEA obligation through government-owned stocks held in the U.S. Strategic Petroleum Reserve (SPR). The SPR currently holds 541 million barrels of oil, which is enough to cover the loss of all U.S. imports for 54 days or a partial disruption for much longer. Close to 33 million barrels of oil will be deposited in the SPR by the fourth quarter of 2002, returning oil that had been “exchanged” out of the reserve last year. SPR oil can be withdrawn at a maximum rate of over 4 million barrels of oil per day initially and could reach the market within fifteen days of a Presidential directive. Because of increased net oil imports, the days of oil import coverage provided by the SPR have declined considerably over the past decade. In 1990, the SPR contained enough oil to compensate for the loss of 82 days worth of U.S. imports—substantially more than today’s 54-day supply. As domestic production and import patterns evolve, the Administration will work to inform Congress about changing coverage levels provided by the SPR. It should be noted that the United States also counts on the SPR as a national defense fuel reserve.

The oil market’s day-to-day operation and its ability to respond to supply problems depend heavily on the availability of information on supply, demand, and price. The oil market volatility of the past two years has emphasized the need for more comprehensive and timely oil market information.

Recommendations:

- ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
- ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stock holding.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
- ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Summary of Recommendations

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

- ★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.
- ★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

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- ★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.
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 - ★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

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- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.
 - ★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.
 - ★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.
 - ★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

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- ★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.
 - ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
 - ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stockholding.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
 - ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

CHAPTER ONE

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy and explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

CHAPTER TWO

Striking Home The Impacts of High Energy Prices on Families, Communities, and Businesses

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

CHAPTER THREE

Protecting America's Environment: Sustaining the Nation's Health and Environment

- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.
 - Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
 - Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
 - Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
 - Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

- ★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”
 - This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
 - This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

- ★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy related project approvals on a national basis. This order would establish an inter agency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

CHAPTER FOUR

Using Energy Wisely: Increasing Energy Conservation and Efficiency

- ★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.
 - Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
 - Extend the Energy Star labeling program to additional products, appliances, and services.
 - Strengthen Department of Energy public education programs relating to energy efficiency.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.
 - Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
 - Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing investment tax credits.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

CHAPTER FOUR

- ★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

- ★ The NEPD Group recommends that the President direct the Secretary of Transportation to:
 - Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
 - Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
 - Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

- ★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

- ★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.
 - The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
 - The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
 - The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

- ★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low emission-idling technologies.

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

- ★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about \$400) a year on their home energy bill by using Energy Star labeled products.

Chapter Five Energy for a New Century: Increasing Domestic Energy Supplies

- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).
 - Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
 - Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste intensive, and more proliferation-resistant.

CHAPTER FIVE

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydro power licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts to ward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

CHAPTER SIX

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.
- ★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

CHAPTER SIX

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
 - Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
 - Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
 - Support legislation reauthorizing the Hydrogen Energy Act.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

CHAPTER SEVEN

America's Energy Infrastructure: A Comprehensive Delivery System

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottle neck through transmission expansion financed by nonfederal contributions.
- ★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.
 - Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
 - Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
 - Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
 - Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System lease to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.
- ★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

CHAPTER SEVEN

- ★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.
- ★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.
 - Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
 - Adopt comprehensive regulations (covering more than one pollutant and require ment) and consider the rules’ cumulative impacts and benefits.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.
- ★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.
- ★ The NEPD Group supports the President’s budget proposal to provide \$8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

CHAPTER 8

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

- ★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.
- ★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that

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may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable-business climate for energy and related infrastructure projects.-

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.-

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.-

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.-

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.-

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.-

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.-

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.-

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.-

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.-

CHAPTER EIGHT

- ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
- ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stockholding.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
- ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Glossary

Barrel (Oil): A unit of volume equal to 42 U.S. gallons.

Barrels per Day (Operable Refinery Capacity): The maximum number of barrels of input that can be processed during a 24-hour period after making allowances for the following limitations: the capability of downstream facilities to absorb the output of crude oil processing facilities of a given refinery (no reduction is made when a planned distribution of intermediate streams through other than downstream facilities is part of a refinery's normal operation); the types and grades of inputs to be processed; the types and grades of products to be manufactured; the environmental constraints associated with refinery operations; the reduction of capacity for scheduled downtime, such as routine inspection, mechanical problems, maintenance, repairs, and turnaround; and the reduction of capacity for unscheduled downtime, such as mechanical problems, repairs, and slowdowns.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

British Thermal Unit (Btu): The quantity of heat needed to raise the temperature of 1 pound of water by 1°F at or near 39.2°F.

Coal: A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time.

Cogeneration: The production of electricity and another form of useful energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Commercial Building: A building with more than 50 percent of its floor space used for commercial activities. Commercial buildings include stores, offices, schools, churches, gymnasiums, libraries, museums, hospitals, clinics, warehouses, and jails. Government buildings are also included, except buildings on military bases or reservations.

Commercial Sector: Business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (agriculture, mining, or construction). Commercial establishments include hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; religious and nonprofit organizations; health, social, and educational institutions; and federal, state, and local governments. Streetlights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial.

Conversion Factor: A number that translates units of one system into corresponding values of another system. Conversion factors can be used to translate physical units of measure for various fuels into Btu equivalents.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casing head) gas in lease separators and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil, such as sulfur and other compounds

Crude Oil Stocks: Stocks of crude oil and lease condensate held at refineries, in pipelines, at pipeline terminals, and on leases.

District Heat: Steam or hot water from an outside source used as an energy source in a building. The steam or hot water is produced in a central plant and is piped into the building. District heat may be purchased from a utility or provided by a physical plant in a separate building that is part of the same facility (for example, a hospital complex or university).

Electric Power Plant: A station containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electricity Generation: The process of producing electric energy or transforming other forms of energy into electric energy. Also, the amount of electric energy produced or expressed in watt-hours (Wh).

End-Use Sectors: The residential, commercial, industrial, and transportation sectors of the economy.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy), or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours, while heat energy is usually measured in British thermal units.

Energy Consumption: The use of energy as a source of heat or power or as an input in the manufacturing process.

Energy Source: A substance, such as oil, natural gas, or coal, that supplies heat or power. Electricity and renewable forms of energy, such as wood, waste, geothermal, wind, and solar, are considered to be energy sources.

Exports: Shipments of goods from the 50 states and the District of Columbia to foreign countries and to Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Federal Energy Regulatory Commission (FERC): The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission.

Fossil Fuel: Any naturally occurring organic fuel formed in the Earth's crust, such as oil, coal, and natural gas.

Fuel Ethanol: An anhydrous, denatured aliphatic alcohol intended for motor gasoline blending.

Gas-Turbine Electric Power Plant: A plant in which the prime mover is a gas turbine. A gas turbine typically consists of an axial-flow air compressor and one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases expand to drive the generator and then are used to run the compressor.

Geothermal Energy: Energy from the internal heat of the Earth, which may be residual heat, friction heat, or a result of radioactive decay. The heat is found in rocks and fluids at various depths and can be extracted by drilling or pumping.

Gross Domestic Product (GDP): The total value of goods and services produced by labor and property located in the United States.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Hydropower: The production of electricity from the kinetic energy of falling water.

Hydropower Plant: A plant in which the turbine generators are driven by falling water.

Independent Power Producer: Wholesale electricity producers (other than qualifying facilities under the Public Utilities Regulatory Policies Act of 1978) that are unaffiliated with franchised utilities in the area in which the independent power producers are selling power and that lack significant marketing power. Unlike traditional electric utilities, independent power producers do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise.

Industrial Sector: Manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry. Establishments in this sector range from steel mills, to small farms, to companies assembling electronic components.

Jet Fuel: A refined petroleum product used in jet aircraft engines. It includes kerosene type jet fuel and naphtha-type jet fuel.

Methane: Hydrocarbon gas, which is the major component of natural gas.

Methanol: A light, volatile alcohol eligible for motor gasoline blending.

Methyl Tertiary Butyl Ether (MTBE): An ether, intended for motor gasoline blending.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, delivered via pipeline for consumption. It is used as a fuel for electricity generation, a variety of uses in buildings, and as raw material input and fuel for industrial processes. *Note:* This product, also referred to as *dry natural gas* or *consumer-grade natural gas*, is the product that remains after *wet natural gas* has been processed at lease facilities and/or natural gas processing plants. This processing removes nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen) that would otherwise make the gas unmarketable and natural gas liquids.

Natural Gas, Dry: The marketable portion of natural gas production, which is obtained by subtracting extraction losses, including natural gas liquids removed at natural gas processing plants, from total production.

Natural Gas, Wet: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with oil and are not distinguishable at the time as separate substances.

Nitrogen Oxides (NO_x): Compounds of nitrogen and oxygen produced by the burning of fossil fuels.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC consists of ten regional reliability councils and encompasses essentially all the power systems of the contiguous United States and Canada.

Nuclear Electric Power: Electricity generated by an electric power plant whose turbines are driven by steam generated in a reactor by heat from the fissioning of nuclear fuel.

Organization for Economic Cooperation and Development (OECD): Current members are Australia, Austria, Belgium, Canada, Czech Republic, Denmark and its territories (Faroe Islands and Greenland), Finland, France, Germany, Greece, Greenland, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, South Korea, Spain, Sweden, Switzerland, Turkey, United Kingdom, and United States and its territories (Guam, Puerto Rico, and Virgin Islands).

Organization of Petroleum Exporting Countries (OPEC): Countries that have organized for the purpose of negotiating with oil companies on matters of oil production, prices, and future concession rights. Current members are Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid state semiconductor devices that have no moving parts.

Pipeline, Natural Gas: A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural gas and/or supplemental gaseous fuels from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

Pipeline, Oil: Oil and product pipelines (including interstate, intrastate, and intracompany pipelines) used to transport oil and petroleum products, respectively, within the 50 states and the District of Columbia.

Proved Reserves, Oil: The estimated quantities of all liquids defined as crude oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Reserves, Natural Gas: The estimated quantities of natural gas that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Refinery (Oil): An installation that manufactures finished fuels from oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Renewable Energy: Energy obtained from sources that are essentially inexhaustible (unlike, for example, fossil fuels, of which there is a finite supply). Renewable sources of energy include conventional hydroelectric power, wood, waste, geothermal, wind, photovoltaic, and solar thermal energy.

Spot Price: The price for a one-time open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Strategic Petroleum Reserve (SPR): Petroleum stocks maintained by the federal government for use during periods of major supply interruption.

Stocks: Supplies of fuel or other energy source(s) stored for future use. Stocks are reported as of the end of the reporting period.

Sulfur Dioxide (SO₂): A toxic, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate in paper pulping and ore refining, and as a solvent.

Transportation Sector: Private and public vehicles that move people and commodities. Included are automobiles, trucks, buses, motorcycles, railroads, and railways (including streetcars), aircraft, ships, barges, and natural gas pipelines.

Wellhead Price: The price of oil or natural gas at the mouth of the well.

Wind Energy: The kinetic energy of wind converted into mechanical energy by wind turbines (i.e., blades rotating from a hub) that drive generators to produce electricity.

Wood Energy: Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-120:
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C



Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE’s Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE “shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE].” 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department “may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.” *Id.*

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) “is a Canadian Corporation with its principal place of business in Toronto, Ontario” that is “organized under the *Business Corporations Act* of the Province of Ontario, Canada.” *Id.* The Applicant states that it “does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility.” *Id.* at 1-2. The applicant further represents that it is a “[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or

virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations.” App at 2.

Research Power Corporation represents that it “has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact.” App. at 3. The Applicant states that it “has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations.” *Id.* The Applicant further affirms that it “will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA” and that “such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S.” *Id.*

The applicant states that it “will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports.” *Id.* The Applicant further states that it will “schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]” *Id.* Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id.* at 1. On June 16, 2025, DOE published notice of Centre Lane’s Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane’s corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application “unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States” 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including

serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g., BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed*, Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application “unless, after opportunity for hearing, it finds that the proposed transmission would ... impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE].” 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g., Order No. EA-314-C*, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government’s commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers¹ and to ensure that these markets are functioning properly.² As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

¹ *See, e.g., Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh’g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh’g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh’g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

² *See, e.g., Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh’g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh’g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,³ DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.⁴ Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,⁵ all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 “establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act.”⁶ Requirement R1 states that “[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions.”⁷ Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.⁸ Reliability Standard IRO-014-3 R1 provides that “[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

³ A related reliability analysis follows in the next section of this Order.

⁴ This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

⁵ The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

⁶ Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

⁷ *Id.* ¶ B.R1.

⁸ See Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.”⁹

DOE finds that NERC’s FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation’s proposed export authorization.

DOE’s sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility¹⁰ with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility’s native load obligations and reserve margins. As explained in DOE’s notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.

Since marketers generally could not be seen as having any “native load” requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation’s exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

⁹ *Id.* ¶ B.R1.

¹⁰ The Supreme Court of the United States has explained: “In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems...[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were ‘bundled,’ meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent.” *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that “[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area.”¹¹

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 (“Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions”), R2 (“Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator’s Operating Instructions unless compliance with the

¹¹ EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements”), and R3 (“Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1”).

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation’s export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States’ electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE’s reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.,* <http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework>.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit¹² to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,¹³ DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC’s reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

¹² DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

¹³ *See, e.g., AEP Tex. Cent. Co.*, Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq.* DOE's NEPA [Implementing](#) Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id.* DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at electricity.exports@hq.doe.gov. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

- (A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:^{14, 15}

<u>Owner</u>	<u>Location</u>	<u>Voltage</u>	<u>Permit No.</u> ¹⁶
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481 ¹⁷

¹⁴ This Order authorizes the export of electricity over any “authorized international transmission facility,” which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

¹⁵ The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant’s submission to reflect those changes.

¹⁶ These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

¹⁷ Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412 ¹⁸
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438 ¹⁹
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299 ²⁰
TDI New England	Alburgh, VT	±320 kV DC	PP-400 ²¹

¹⁸ These transmission facilities have been authorized but not yet constructed or placed into operation.

¹⁹ These transmission facilities have been authorized but not yet constructed or placed into operation.

²⁰ These transmission facilities have been authorized but not yet constructed or placed into operation.

²¹ These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

- (a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.
- (b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.
- (c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.
- (d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).
- (e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.
- (f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities

authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

- (g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.
- (h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.
- (i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.
- (j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.
- (k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.
- (l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.
- (m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

- (n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

- (o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

NEPOOL		
Exports Through	Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

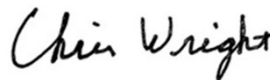
- (p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.
- (q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.
- (r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299

(issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

- (s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.
 - (t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.
- (B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.
- (C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.
- (D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.
- (E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.
- (F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.
- (G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

- (H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.
- (I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.
- (J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.
- (K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.



Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-121:
Mercury Mortality Risks of Coal



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Environment & Climate Health

Particulate pollution from coal associated with double the risk of mortality than PM2.5 from other sources

By Staff Writer • November 23, 2023

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For immediate release: November 23, 2023

Exposure to fine particulate air pollutants from coal-fired power plants (coal PM2.5) is associated with a risk of mortality more than double that of exposure to PM2.5 from other sources, according to a new study led by George Mason University, The University of Texas at Austin, and Harvard T.H. Chan School of Public Health. Examining Medicare and emissions data in the U.S. from 1999 to 2020, the researchers also found that 460,000 deaths were attributable to coal PM2.5 during the study period—most of them occurring between 1999 and 2007, when coal PM2.5 levels were highest.

The study was published on November 23, 2023, in Science.

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much more harmful than we thought, and its mortality burden has been seriously underestimated,” said lead author Lucas Henneman, assistant professor in the Sid and Reva Dewberry Department of Civil, Environmental, and Infrastructure Engineering at Mason. “These findings can help policymakers and regulators identify cost-effective solutions for cleaning up the country’s air, for example, by requiring emissions controls or encouraging utilities to use other energy sources, like renewables.”

Using emissions data from 480 coal power plants in the U.S. between 1999 and 2020, the researchers modeled where wind carried coal sulfur dioxide throughout the week after it was emitted and how atmospheric processes converted the sulfur dioxide into PM2.5. This model produced annual coal PM2.5 exposure fields for each power plant. They then examined individual-level Medicare records from 1999 to 2016, representing the health statuses of Americans ages 65 and older and representing a total of more than 650 million person-years. By linking the exposure fields to the Medicare records, inclusive of where enrollees lived and when they died, the researchers were able to understand individuals’ exposure to coal PM2.5 and calculate the impact it had on their health.

They found that across the U.S. in 1999 the average level of coal PM2.5 was 2.34 micrograms per cubic meter of air (ug/m³). This level decreased significantly by 2020, to 0.97 ug/m³. The researchers calculated that a one ug/m³ decrease in annual average coal PM2.5 was associated with a 112% decrease in mortality. The researchers also found that coal PM2.5 was associated with a 112% increase in mortality for every 1 ug/m³ increase in annual average coal PM2.5.

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The researchers were also able to quantify deaths attributable to specific power plants, producing a ranking of the coal-fired power plants studied based on their contribution to coal PM2.5's mortality burden. They found that 10 of these plants each contributed at least 5,000 deaths during the study period. They visualized the deaths from each power plant in a publicly available online tool (<https://cplaatgt.github.io/cpie/>).

The study also found that 390,000 of the 460,000 deaths attributable to coal-fired power plants took place between 1999 and 2007, averaging more than 43,000 deaths per year. After 2007, these deaths declined drastically, to an annual total of 1,600 by 2020.

"Beyond showing just how harmful coal pollution has been, we also show good news: Deaths from coal were highest in 1999 but by 2020 decreased by about 95%, as coal plants have installed scrubbers or shut down," Henneman said.

"I see this as a success story," added senior author Corwin Zigler, associate professor in the Department of Statistics and Data Sciences at UT Austin and founding member of the UT Center for Health & Environment: Education & Research. "Coal power plants were this major burden that U.S. policies have already significantly reduced. But we haven't completely eliminated the burden—so this study provides us a better understanding of how health will continue to improve and lives will be saved if we move further toward a clean energy future."

The researchers pointed out the study's continuing urgency and relevance, writing in the paper that coal power is still part of some U.S. states' energy



"As countries debate their energy sources—and as coal maintains a powerful, almost mythical status in American energy lore—our findings are highly valuable to policymakers and regulators as they weigh the need for cheap energy with the significant environmental and health costs," said co-author Francesca Dominici, Clarence James Gamble Professor of Biostatistics, Population, and Data Science at Harvard Chan School and director of the Harvard Data Science Initiative.

Funding for the study came from the National Institutes of Health (grants R01ES026217, R01MD012769, R01ES028033, 1R01ES030616, 1R01AG066793, 1R01MD016054-01A1, 1R01ES 034373-01, 1RF1AG080948, and 1R01ES029950); the Environmental Protection Agency (grant 835872); the EmPOWER Air Data Challenge (grant LRFH); the Alfred P. Sloan Foundation (grant G-2020-13946); and the Health Effects Institute (grants R-82811201 and 4953).

"Mortality risk from United States coal electricity generation," Lucas Henneman, Christine Choirat, Irene Dedoussi, Francesca Dominici, Jessica Roberts, Corwin Zigler, *Science*, online November 23, 2023, doi: [10.1126/science.adf4915](https://doi.org/10.1126/science.adf4915).

Image: iStock/Triton_Tree

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Harvard T.H. Chan School of Public Health brings together dedicated experts from many disciplines to educate new generations of global health leaders and produce powerful ideas that improve the lives and health of people everywhere. As a community of leading scientists, educators, and students, we work together to take innovative ideas from the laboratory to people's lives—not only making scientific breakthroughs, but also working to change individual behaviors, public policies, and health care practices. Each year, more than 400 faculty members at Harvard Chan School teach 1,000-plus full-time students from around the world and train thousands more through online and executive education courses. Founded in 1913 as the Harvard-MIT School of Health Officers, the School is recognized as America's oldest professional training program in public health.

George Mason University is Virginia's largest public research university. Located near Washington, D.C., Mason enrolled over 40,000 students from 130 countries and all 50 states for the fall 2023 semester. Mason has grown rapidly over the last half-century and is recognized for its innovation and entrepreneurship, remarkable diversity, and commitment to accessibility. Also in 2023, the university launched Mason Now: Power the Possible, a \$1 billion comprehensive campaign to support student success, research, innovation, community, and sustainability. Learn more at gmu.edu .

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-122:
Energy Reliability and Resilience

U.S. DEPARTMENT
of **ENERGY**[Office of Energy Efficiency & Renewable Energy](#)[Resources](#)[Why Energy Innovation Matters](#)[Energy Reliability and Resilience](#)

Energy Reliability and Resilience



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Energy reliability is the ability of a power system to consistently deliver power to homes, buildings, and devices—even in the face of instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Energy resilience is the ability of the grid, buildings, and communities to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services. Energy resilience increases energy reliability and renewable energy sources can help support a resilient, reliable energy system.

Resilient, reliable energy is critical to the well-being of every American. It keeps life-saving hospital equipment and communications systems operating, buildings at safe temperatures with good ventilation, and American workers to go about their business without interruption. Energy infrastructure—facilities or equipment used to generate, deliver, process, or produce energy—that can withstand and quickly recover from disruptions is resilient and reliable infrastructure.

A resilient and reliable power system reduces the likelihood of long-duration outages over large service areas, limits the scope and impact of outages when they do occur, and rapidly restores power after an outage.

What Makes Energy Resilient?

Power outages can be caused by extreme weather, breaches in cybersecurity, high energy demand that overloads the electric grid, failure of aging equipment, and physical interference with equipment. Grid disturbances are changes in electrical voltage and frequency on the grid that can lead to power outages.

A resilient electric grid distribution system uses local resources, such as solar panels and battery storage in homes and buildings, to quickly reconfigure power flows and recover electricity services during a disturbance. The approach to modernize the grid and increase resilience focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale.

Strong resilience measures in building energy codes can also ensure that new construction and major renovation projects minimize energy use, maximize comfort, and enhance potentially life-saving resilience benefits. Building owners and operators, communities, and local and state governments can strategically plan to increase resilience using these resources.

What Makes Energy Reliable?

When we diversify our energy mix by adding more types of energy to the grid, we increase our energy reliability. The rise of renewable power, which comes from unlimited energy resources, like wind, sunlight, water, and the Earth's natural heat, has the potential to vastly improve the reliability of the American energy system. Currently, renewable energy generates about 21% of all U.S. electricity, and that percentage is rising quickly.

A reliable electric grid distribution system can continue to deliver electricity to homes and buildings regardless of any disruptions or disturbances. The approach to modernizing the grid to increase resilience and reliability focuses on integrating distributed energy resources, advanced controls, grid architecture, and emerging grid technologies at a regional scale. DOE efforts, like the Energy Storage Grand Challenge Roadmap, will increase resilience. DOE's Grid Modernization Initiative works with public and private partners to develop concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future.

Improving Reliability Through Energy Storage

[Energy storage](#) technologies can improve energy reliability by making surplus energy available whenever it is needed, such as during a power outage.

[Pumped storage hydropower](#) is responsible for most U.S. commercial energy storage capacity and has been used for more than 100 years. [Wind energy](#) and [solar energy](#) can be captured and stored for later use with batteries, and researchers are investigating [geothermal energy storage](#).

Energy storage is also essential to efficient transportation. EERE invests in research and development of [hydrogen storage](#) and [batteries](#) to ensure on- and off-road vehicles can reliably move people and goods from one place to another.

The U.S. Department of Energy's [Energy Storage Grand Challenge](#) is a comprehensive program to accelerate the development, commercialization, and use of next-generation energy storage technologies. As part of this program, the Long Duration Storage Shot™ aims to, within the decade, reduce the cost of grid-scale energy storage by 90% for systems that can provide energy for at least 10 hours in duration.

Energy Reliability and Resilience News



Advanced by Americans: A Year of Energy Innovation

EERE invests in research, development, and technology-validation to help modernize the...

[Learn More](#)

DOE Invests \$68 Million in Innovative Heavy-Duty Electri...

SuperTruck Charge projects will accelerate deployment of large-scale public EV charging...

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-123:
EPA COBRA Health Effects Estimate

COBRA Web Edition



CO-Benefits Risk Assessment (COBRA) is a screening tool that enables state, local, and tribal government staff and others interested in the effects of air pollution to estimate the air quality and health benefits of different emissions scenarios.

You are using the web-based version of COBRA. For the COBRA desktop application, visit the [COBRA download page](#).

Step 1: Build Scenario

Complete the sections below and click "Add to Scenario."

A. Select Location REQUIRED

Select the states or counties where the emissions changes will occur. [i](#)

- ☐ Las Animas
- ☐ Lincoln
- ☐ Logan
- ☐ Mesa
- ☐ Mineral
- ☒ Moffat
- ☐ Montezuma
- ☐ Montrose
- ☐ Morgan

[Select All](#) | [Deselect All](#)

B. Select Sector REQUIRED

Select the industry or sector where the emissions changes will occur. [i](#)

Sector

Fuel Combustion: Electric Utility

Subsector (optional)

Coal

Subsector (optional)

All subsectors

C. Modify Emissions REQUIRED

Enter emissions changes for **at least one** of the four pollutants below. [i](#)

PM_{2.5} (Baseline = 93.48 tons)

reduce by

increase by

enter #



tons



percent

SO₂ (Baseline = 1,824.34 tons)

reduce by

increase by

enter #



tons



percent

NO_x (Baseline = 4,756.47 tons)

reduce by

increase by

enter #



tons



percent

VOC (Baseline = 114.8 tons)

reduce by

increase by

enter #



tons



percent

NH₃ [i](#) (Baseline = 1.08 tons)

reduce by

increase by



tons



percent

ADD TO SCENARIO

Step 2: Review Scenario

Review the scenario below. To add changes to more locations or sectors, repeat Step 1 to continue building your scenario.

Location(s)	Sector	Emissions Modification(s)	
Moffat, Colorado	Fuel Combustion: Electric Utility Coal	PM _{2.5} reduce by 13 tons SO ₂ reduce by 335.43 tons NO _x reduce by 2,211.57 tons	✕

Discount rate: [i](#)

2%

Custom: **RUN SCENARIO**

Step 3: View Results

BUILD NEW SCENARIO

A. Summary of Health Effects Results

Below is a table with the health effects results based on your scenario.

You are viewing results for all contiguous U.S. states. This is because changes in air quality can impact health endpoints in multiple locations due to the transportation of emissions across state and county lines.

Use the filters below to see health effects for a specific state or county.

1. Filter by state:

All contiguous U.S. states

2. Filter by county: (optional)

All counties

Results for: All Contiguous U.S. States

 Export: [All results](#) | [Current filter](#)

Health Endpoint 	Pollutant	Change in Incidence  (cases, annual)		Monetary Value  (dollars, annual)	
		Low	High	Low	High
✓ Mortality *	PM _{2.5} O ₃	3.4	4.4	\$50,000,000	\$64,000,000
Nonfatal Heart Attacks	PM _{2.5}	0.54	0.54	\$46,000	\$46,000
Infant Mortality	PM _{2.5}	0.0077	0.0077	\$120,000	\$120,000
✓ Hospital Admits, All Respiratory	PM _{2.5} O ₃	0.36	0.36	\$7,300	\$7,300
✓ Emergency Room Visits, Respiratory	PM _{2.5} O ₃	7.3	7.3	\$12,000	\$12,000
✓ Asthma Onset	PM _{2.5} O ₃	22	22	\$1,700,000	\$1,700,000
✓ Asthma Symptoms	PM _{2.5} O ₃	3,400	3,400	\$1,100,000	\$1,100,000
Emergency Room Visits, Asthma	O ₃	0.036	0.036	\$30	\$30
Lung Cancer Incidence	PM _{2.5}	0.061	0.061	\$2,700	\$2,700
Hospital Admits, Cardio-Cerebro/Peripheral Vascular Disease	PM _{2.5}	0.1	0.1	\$3,000	\$3,000
Hospital Admits, Alzheimers Disease	PM _{2.5}	0.36	0.36	\$8,200	\$8,200

Hospital Admits, Parkinsons Disease	PM _{2.5}	0.052	0.052	\$1,200	\$1,200
Stroke Incidence	PM _{2.5}	0.053	0.053	\$3,300	\$3,300
✓ Hay Fever/Rhinitis Incidence	PM _{2.5} O ₃	140	140	\$150,000	\$150,000
Cardiac Arrest, Out of Hospital	PM _{2.5}	0.013	0.013	\$780	\$780
Emergency Room Visits, All Cardiac	PM _{2.5}	0.26	0.26	\$550	\$550
Minor Restricted Activity Days	PM _{2.5}	690	690	\$87,000	\$87,000
School Loss Days	O ₃	1,800	1,800	\$3,100,000	\$3,100,000
Work Loss Days	PM _{2.5}	120	120	\$37,000	\$37,000

Total Health Effects from PM_{2.5} **\$12,000,000 \$27,000,000**

Total Health Effects from O₃ **\$44,000,000 \$44,000,000**

♥ Total Health Effects **\$56,000,000 \$71,000,000**

Note: Dollar amounts shown are based on 2023 currency values. Additionally, all values have been rounded to 2 significant figures. Please [export the results](#) in order to see values prior to rounding.

* The Low and High values represent differences in the methods used to estimate some of the health impacts in COBRA. For example, high and low results for avoided premature mortality are based on two different epidemiological studies of the impacts of PM_{2.5} on mortality in the United States.

B. Map of Health Effects and Air Quality Results

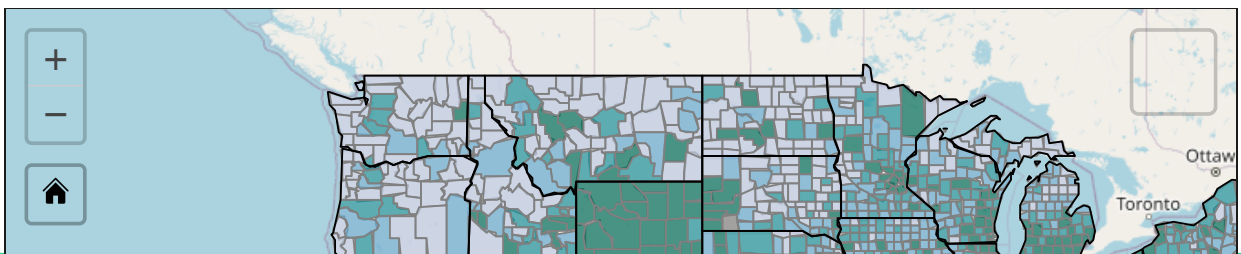
Below is a map showing health effects and air quality data based on your scenario.

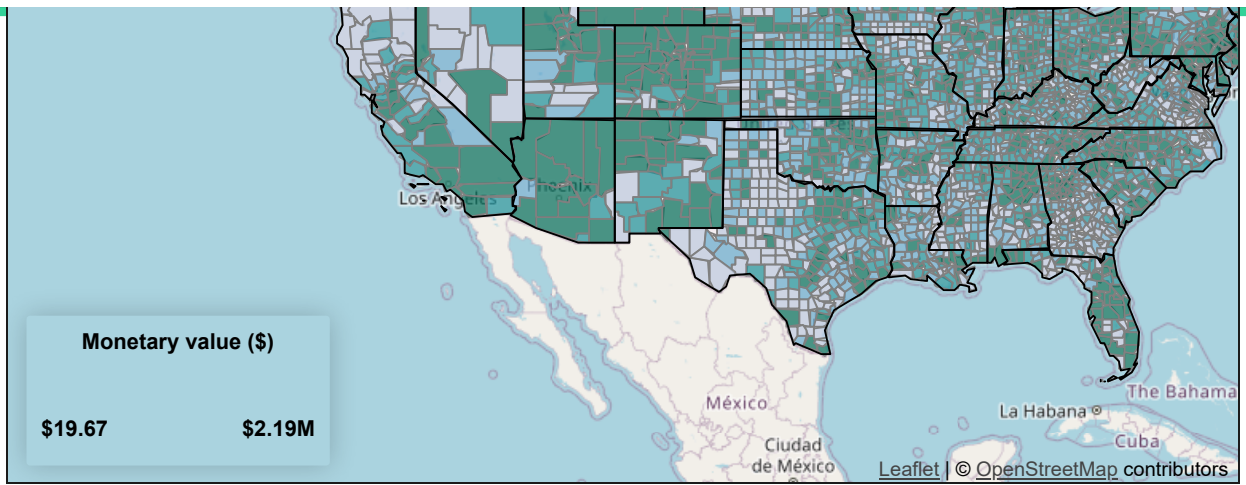
Use the filter below to change the map's data layer. Click on a county on the map to explore the data.

Select the map's data layer:

Total Health Benefits (\$, low estimate)

Displaying: Total Health Benefits (\$, low estimate)





LAST UPDATED ON APRIL 12, 2021

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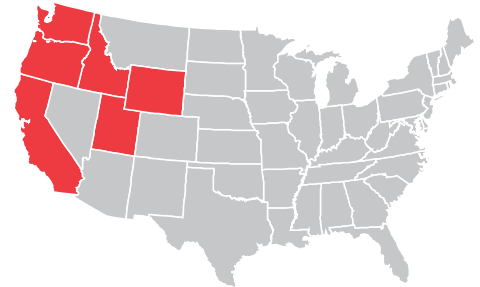
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-124:
2025 PacifiCorp Fact Sheet

JUST THE **FACTS**

PacifiCorp

SERVICE AREA	141,500 square miles
ELECTRIC CUSTOMERS SERVED	2.1 million
NET OWNED GENERATION CAPACITY	11,700 megawatts
NET OWNED RENEWABLE AND NONCARBON CAPACITY	3,410 megawatts
RENEWABLE PROJECTS UNDER CONSTRUCTION, CAPACITY	531 megawatts
ELECTRIC TRANSMISSION LINE MILES	17,500 miles
ELECTRIC DISTRIBUTION LINE MILES	66,900 miles



- PacifiCorp owns and operates a diverse portfolio of generation resources in eight states comprised of coal, natural gas, hydroelectric, solar, geothermal and the largest owned wind fleet by a regulated utility in the Western U.S. The company also owns and operates the largest transmission system in the Western U.S., with 17,500 miles of transmission lines across 10 states. PacifiCorp serves customers through its two divisions:
 - Rocky Mountain Power is based in Salt Lake City, Utah, and serves customers in Utah, Wyoming and Idaho.
 - Pacific Power is based in Portland, Oregon, and serves customers in Oregon, Washington and California.
- PacifiCorp's Energy Gateway transmission expansion project is the largest of its kind in the U.S. The \$13 billion investment totals 2,300 miles, provides access to the West's abundant and diverse energy resources, and is the foundation for a more resilient, reliable Western grid.
- As a founding partner in the Western Energy Imbalance Market in 2014, PacifiCorp has saved customers \$938 million and significantly reduced emissions in the region. To further magnify the benefits of market collaboration, PacifiCorp plans to join the Extended Day-Ahead Market in 2026.
- Through investments of \$1 billion through 2024 and another \$2 billion planned through 2027, PacifiCorp continues to strengthen its system to reduce the risk of and prevent wildfires.
- PacifiCorp owns and manages 46,000 acres of lands reserved for wildlife habitat, forestry and recreation.



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Exhibit 2-125:
Service Area and Territory (Electric Power and Water) SRP

Service Territory

As a community-based not-for-profit water and energy company, SRP provides reliable, affordable water and power to more than 2 million people living in central Arizona.

Enter your address to see the SRP services available at your location

SRP delivers affordable water and power to more than 2 million customers living in and around the Valley. Our service territory is broad and covers much of central Arizona. Some addresses receive only one of our services while others are provided both water and power.

Find address or place



Esri, TomTom, Garmin, FAO, NOAA, USGS, Bureau of Land Management, EPA, NPS, USFWS

Powered by [Esri](#)



Search for an address to learn more about the location and its surrounding area.

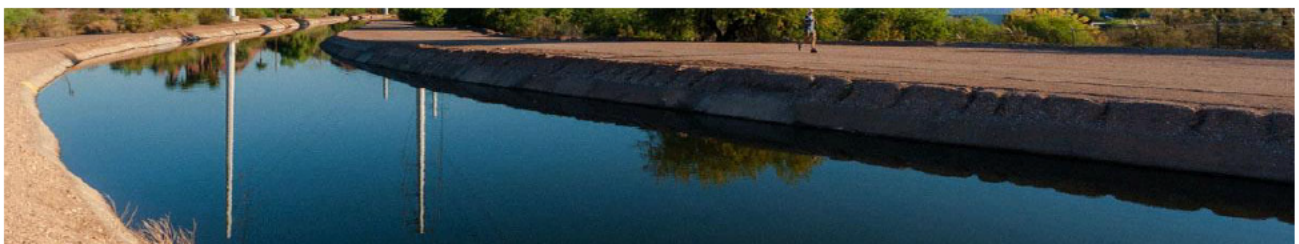
If you don't know the address, use one of these search methods:

Click the search box and type in an address or choose **Use current location**.

Be sure to click within the map.

Feedback

RELATED TOPICS



[About Salt River Project | SRP](#)

SRP is a community-based, not-for-profit organization providing affordable water and power to more than 2 million people in central Arizona. Read more here.



[History of Salt River Project | SRP](#)

Since 1903, Salt River Project has helped shape our state. Learn about our history of service to the people who call Arizona home.



[Future plan for energy | SRP](#)

Ensuring that the Valley's energy future remains reliable requires energy experts and communities working together. Learn about SRP's energy plan for the future.

SUPPORT

Contact us

Residential electric: (602) 236-8888

Business electric: (602) 236-8833

SRP irrigation: (602) 236-3333

La Línea: (602) 236-1111

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Exhibit 2-126:
Xcel, List of Towns Receiving Electric Service in Colorado

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

INFORMATION SHEET
COLORADO



🔥 = Gas only ⚡ = Electricity only 🔥⚡ = Gas and Electricity

A Alamosa 🔥⚡	C Campion 🔥⚡	Edgewater 🔥⚡	Glendale 🔥⚡
Alma ⚡	Canfield 🔥⚡	Eldora ⚡	Glenwood Springs ⚡
Antonito 🔥⚡	Canon ⚡	Eldorado Springs ⚡	Gold Hill ⚡
Arvada 🔥⚡	Canyon Creek ⚡	Empire 🔥⚡	Golden 🔥⚡
Aspen Park 🔥	Capulin 🔥	Englewood 🔥⚡	Granby 🔥
Atwood 🔥⚡	Carbondale ⚡	Erie 🔥⚡	Grand Junction 🔥⚡
Ault ⚡	Castle Pines ⚡	Estes Park 🔥	Grand Lake 🔥
Aurora 🔥⚡	Centennial ⚡	Evans ⚡	Greeley ⚡
Avon 🔥	Center ⚡	Evergreen 🔥⚡	Greenwood Village 🔥⚡
Avondale 🔥	Central City 🔥⚡	F Fairplay ⚡	Guadalupe 🔥⚡
B Barnesville ⚡	Chama ⚡	Farmers Spur ⚡	H Hideaway Park 🔥
Battlement Mesa 🔥	Cherry Hills Village 🔥⚡	Federal Heights 🔥⚡	Highlands Ranch 🔥⚡
Beaver Creek 🔥	Clifton 🔥⚡	Fort Collins 🔥⚡	Hillrose ⚡
Bellvue 🔥⚡	Climax 🔥⚡	Fort Garland ⚡	Homelake ⚡
Bergen Park 🔥⚡	Cody Park 🔥⚡	Fort Lupton 🔥	Hooper ⚡
Berthoud 🔥⚡	Columbine Valley 🔥⚡	Fort Morgan 🔥⚡	Horca ⚡
Berthoud Falls 🔥	Commerce City 🔥⚡	Fosston ⚡	Hot Sulphur Springs 🔥
Black Hawk 🔥⚡	Conejos 🔥⚡	Foxfield ⚡	Hygiene 🔥
Blanca ⚡	Conifer 🔥	Fraser 🔥	I Idaho Springs 🔥⚡
Blue River ⚡	Copper Mountain 🔥	Frisco 🔥⚡	Idledale 🔥⚡
Bonanza ⚡	Cornish ⚡	Fruita 🔥⚡	Indian Hills 🔥⚡
Boone 🔥	Crisman ⚡	Fruitvale 🔥⚡	J Jamestown ⚡
Boulder 🔥⚡	D De Beque 🔥⚡	G Galeton ⚡	Johnstown 🔥⚡
Bountiful ⚡	Del Norte 🔥⚡	Garden City ⚡	K Kelim 🔥⚡
Bow Mar 🔥⚡	Denver 🔥⚡	Garfield ⚡	Kersey ⚡
Bracewell ⚡	Dillon 🔥⚡	Georgetown 🔥⚡	Keystone 🔥
Breckenridge 🔥⚡	Downieville 🔥⚡	Gilcrest ⚡	Kittredge 🔥⚡
Briggsdale ⚡	Dumont 🔥⚡	Gill ⚡	Kremmling 🔥
Brighton 🔥	E Eastlake 🔥⚡	Gilman ⚡	Kuner ⚡
Broomfield 🔥⚡	Eaton ⚡		
Brush 🔥⚡			

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

🔥 = Gas only 🔌 = Electricity only 🔥🔌 = Gas and Electricity

L La Jara 🔥🔌	Minturn 🔥🔌	R Raymer 🔌	Stoneham 🔌
Laporte 🔥🔌	Moffat 🔌	Raymond 🔌	Stringtown 🔌
La Salle 🔌	Mogote 🔌	Red Cliff 🔥🔌	Sugarloaf 🔌
La Valley 🔌	Monarch 🔌	Redlands 🔌	Summitville 🔥🔌
Lafayette 🔥🔌	Monte Vista 🔥🔌	Richfield 🔥🔌	Sunshine 🔌
Lakeside 🔥🔌	Montezuma 🔌	Rifle 🔥🔌	Superior 🔥🔌
Lakewood 🔥🔌	Morrison 🔥🔌	Riverside 🔌	T Tabernash 🔌
Las Mesitas 🔌	Mosca 🔌	Romeo 🔥🔌	Thornton 🔥🔌
Lawson 🔥🔌	Mountain View 🔥🔌	Rulison 🔌	Timnath 🔥🔌
Leadville 🔥🔌	Mount Vernon 🔥🔌	Russell Gulch 🔥🔌	Tiny Town 🔌
Leyden 🔌	N Nederland 🔥🔌	S Saguache 🔥🔌	V Vail 🔌
Littleton 🔥🔌	New Castle 🔥🔌	Salida 🔌	Valmont 🔌
Lobatos 🔌	Niwot 🔥🔌	Salina 🔌	Vineland 🔌
Lochbuie 🔌	North Avondale 🔌	San Antonio 🔌	W Wah Keeney Park 🔥🔌
Log Lane Village 🔥🔌	Northglenn 🔥🔌	San Francisco 🔌	Wallstreet 🔌
Lone Tree 🔌	Nunn 🔌	San Luis 🔌	Ward 🔌
Longmont 🔥🔌	O Orchard Mesa 🔥🔌	San Pablo 🔌	Watkins 🔌
Lookout Mountain 🔌	Ortiz 🔌	San Pedro 🔌	Weldona 🔥🔌
Louisville 🔥🔌	P Paisaje 🔌	Sanford 🔥🔌	Wellington 🔌
Louviers 🔌	Palisade 🔥🔌	Sargent 🔥🔌	West Vail 🔌
Loveland 🔥🔌	Parachute 🔥🔌	Sedalia 🔌	Westminster 🔥🔌
Lucerne 🔌	Parker 🔌	Severance 🔥🔌	Wheat Ridge 🔥🔌
Lyons 🔥🔌	Parshall 🔌	Sheridan 🔥🔌	Wiggins 🔌
M Magnolia 🔌	Peaceful Valley 🔌	Silt 🔥🔌	Willard 🔌
Malta 🔌	Peckham 🔌	Silver Plume 🔌	Windsor 🔥🔌
Manassa 🔥🔌	Peetz 🔌	Silverthorne 🔥🔌	Winter Park 🔌
Marshall 🔌	Pierce 🔌	Smeltertown 🔌	
Marshdale 🔌	Platoro 🔌	Snyder 🔌	
Maysville 🔌	Platteville 🔌	Springdale 🔌	
Mead 🔌	Poncha Springs 🔌	Sprucedale 🔌	
Merino 🔥🔌	Pueblo 🔌	Sterling 🔥🔌	
Milliken 🔥🔌	Purcell 🔌	Sterling Ranch 🔥🔌	



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Exhibit 2-127:
Who we serve - Platte River Power Authority

Our communities

Platte River Power Authority is a Colorado political subdivision established to provide wholesale electric generation and transmission to the utilities of its owner communities – Estes Park, Fort Collins, Longmont and Loveland.



Town of Estes Park

Estimated population*: 6,426

Utility: Estes Park Power and Communications, established in 1945

[Source to Switch](#)



City of Fort Collins

Estimated population*: 170,243

Utility: Fort Collins Utilities, established in 1938

[Source to Switch](#)



City of Longmont

Estimated population*: 97,261

Utility: Longmont Power & Communications, established in 1912

[Source to Switch](#)



City of Loveland

Estimated population*: 78,877

Utility: Loveland Water and Power, established in 1925

[Source to Switch](#)

*Based on the U.S. Census Bureau

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Exhibit 2-128:
Order No. 24-073 OR PUC on Pac 2023 IRP

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 82

In the Matter of

PACIFICORP, dba PACIFIC POWER,

2023 Integrated Resource Plan.

ORDER

DISPOSITION: STAFF’S RECOMMENDATION ADOPTED.

In this order, we adopt the recommendations made by Staff of the Oregon Public Utility Commission to acknowledge in part and not acknowledge in part PacifiCorp, dba Pacific Power’s Integrated Resource Plan (IRP). We do not acknowledge PacifiCorp’s Clean Energy Plan (CEP). We also adopt Staff’s 21 recommendations, which set firm direction for what we require to be provided with PacifiCorp’s 2025 IRP.

While we understand that development of PacifiCorp’s 2025 IRP is a multi-stakeholder, multi-state process in which the company might reasonably seek our flexibility in setting requirements for the analysis, we are reacting to the rigidity PacifiCorp has displayed in responding to Oregon Staff and stakeholders’ reasonable requests for adjustments and additional analysis during our review of its filed IRP and CEP, and even in its forthcoming IRP Update. We expect PacifiCorp to embrace the letter and spirit of the Staff recommendations that we adopt here, to follow them assiduously in developing its 2025 IRP, and to return to us for clarification if there is any doubt about what we require. With the urgency of reliability, cost control, and House Bill (HB) 2021 compliance challenges upon us, we would rather review any emerging questions or uncertainty about our direction before an IRP is locked down rather than find the IRP deficient and the company unwilling to adjust until the next cycle.

I. INTRODUCTION

The purpose of the IRP review process is to provide the utility with the input of the Commission, Commission Staff, and stakeholders on the reasonableness of the plan

presented. Our acknowledgment decision provides PacifiCorp with guidance to consider in taking resource actions that, ultimately, rest with the company.¹

We take seriously our role in informing PacifiCorp's direction, but also reinforce that we do not control PacifiCorp's resource decisions and that any risks associated with carrying out even acknowledged actions rest with the company.

Our goal in an IRP proceeding is to acknowledge that a utility's action plan and preferred portfolio represent the least-cost, least-risk strategy for meeting customer needs, based on the best data available at the time and using the best available tools to analyze and review that data. In this particular IRP proceeding, we are asked to review a plan and portfolio that PacifiCorp had already abandoned by suspending the 2022 All-Source RFP, and that was further impacted by the stay of the federal Ozone Transport Rule. We are left without a plan that reflects PacifiCorp's reality, and without any willingness by PacifiCorp to adjust its action plan to reflect that reality. Therefore, we have no basis on which to acknowledge the majority of PacifiCorp's IRP, nor can we acknowledge its CEP without the foundation of a viable IRP action plan. We expect that, in 2025, we will be given a plan that follows Staff's recommendations and reflects both updated operating circumstances and an action plan that the company can stand behind. Recognizing that circumstances are rapidly evolving, that plan may describe action items and the key factors that would instigate a change in course. We also invite the company to present an IRP Update with revised actions that can serve as the foundation for a refiled CEP, which we will consider for acknowledgment and as a demonstration of continual progress.

II. IRP AND CEP PROCESS

A. Overall Purpose of the IRP

The IRP is a road map for providing reliable and least-cost, least-risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.² The primary outcome of the process is the "selection of a

¹ See *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 6 (Apr. 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission* * *").

² *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A, Guidelines 1-13 (Jan. 8, 2007) corrected by Order No. 07-047 (Feb. 9, 2007); *In the Matter of Investigation into the Treatment of CO₂ Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs.).

portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.”³

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.⁴ Consistent with our guidelines, which require modeling of at least a 20-year time horizon, a utility’s IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources;
- Identification and estimated costs of all supply-side and demand-side resource options;
- Construction of a representative set of resource portfolios;
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and
- Creation of a two- to four-year Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

In reviewing an IRP, we assess reasonableness based on the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our examination of whether the costs associated with a utility’s resource investment should be recovered in customer rates. The question of whether a specific utility investment or procurement decision was prudent and reasonable will be examined in the subsequent rate proceeding.

B. Overall Purpose of the CEP

The Commission is tasked with ensuring progress towards, and evaluating compliance with, the emissions reductions targets required by HB 2021. Oregon electric companies subject to HB 2021 must file clean energy plans (CEPs), which we are charged with evaluating for acknowledgment pursuant to ORS 469A.415(6).⁵ CEPs must meet statutory requirements set forth in ORS 469A.415, and also must demonstrate continual

³ Order No. 07-002 at Appendix A, Guideline 1.

⁴ Order No. 07-002 and Order No. 07-047 (adopting 13 IRP Guidelines); Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs).

⁵ ORS 469A.410(1) lists the required greenhouse gas emission reductions; the Commission’s required evaluation is described in ORS 469A.415(4)(e) and (6).

progress towards meeting the HB 2021 targets in a way that results in “an affordable, reliable and clean electric system.”⁶

Oregon electric companies subject to HB 2021’s requirements must submit a CEP to the Commission concurrent with the development of each IRP.⁷ CEPs “must be based on or included in an [IRP] filing,” and must be filed concurrently with the IRP.⁸

Each CEP must:

- (1) incorporate the clean energy targets articulated in ORS 469A.410;
- (2) “[i]nclude annual goals set by the electric company for actions that make progress towards meeting the clean energy targets * * * including acquisition of nonemitting generation resources, energy efficiency measures and acquisition and use of demand response resources;”
- (3) “[i]nclude a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards;”
- (4) “[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;”
- (5) “[d]emonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets * * * including demonstrating a projected reduction of annual greenhouse gas emissions;” and
- (6) “[r]esult in an affordable, reliable[,] and clean electric system.”⁹

The actions and investments proposed in a CEP can include “the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response * * * development of new transmission * * * retirement of existing generating facilities, changes in system operation and any other necessary action.”¹⁰

The CEP must also “present annual goals for actions that balance expected costs and associated risks and uncertainties for the utility and its customers, including a demonstration of making continual progress towards meeting the clean energy targets, the

⁶ ORS 469A.415(4)(f).

⁷ ORS 469A.415(1).

⁸ ORS 469A.415(3).

⁹ ORS 469A.415(4)(a) - (f).

¹⁰ ORS 469A.415(5).

pace of greenhouse gas emissions reductions, and community impacts and benefits.”¹¹ The CEP must be “written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public.”¹²

III. PACIFICORP’S 2023 IRP AND CEP

After PacifiCorp filed its amended IRP and CEP in May 2023, we adopted a procedural schedule. This schedule allowed numerous opportunities for submission of written comments from Staff and intervenors, as well as opportunities to obtain feedback from PacifiCorp. On January 24, 2024, Staff filed its Round 2 Comments and Recommendations, in which it recommended truncating the schedule and bringing PacifiCorp’s IRP to the February 20 regular public meeting for decision. Due to changed circumstances, including suspension of PacifiCorp’s 2022 All-Source RFP and stay of the federal Ozone Transport Rule, Staff recommended only partial acknowledgment of the IRP and that instead of finishing the established procedural schedule, stakeholder and Staff attention should instead turn to the IRP update, to be filed in April 2024. On January 30, 2024, Staff filed a motion to modify the procedural schedule consistent with that recommendation, which was granted. After engagement with parties and Commissioner deliberation on February 20, we adopted the decision memorialized in this order at our March 5 regular public meeting.

C. PacifiCorp’s Preferred Portfolio and Action Items

PacifiCorp states its preferred portfolio includes “substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.”¹³ Among other things, PacifiCorp states that it plans 1,792 MW of wind, and 495 MW of solar additions with 200 MW of battery storage capacity from the 2020 All-Source RFP, as well as resource selections from the 2022 All-Source RFP. It also includes 1500 MW of advanced nuclear resources, including the 500 MW Natrium demonstration project. PacifiCorp asks for acknowledgment of the preferred portfolio, as well as a variety of actions, specifically:

- Existing Resource Actions – PacifiCorp seeks to exit Colstrip Units 3 and 4, and Craig Unit 1. It seeks to convert Naughton Units 1 and 2 and Jim Bridger Units 1 and 2 to gas. Finally, it seeks acknowledgment of its compliance plans for Wyoming House Bill 200 (Carbon Capture, Utilization, and Storage); regional haze; and the Ozone Transport Rule.

¹¹ OAR 860-027-0400(5).

¹² *Id.*

¹³ Amended IRP at 10 (May 31, 2023).

- New Resource Actions – PacifiCorp seeks acknowledgment of its customer preference RFP; its 2024 All-Source RFP; and its 2022 All-Source RFP (now suspended).
- Transmission Action Items – PacifiCorp seeks acknowledgment for three long transmission segments – Energy Gateway South, Segment F; Energy Gateway West, Segment D.1; and Boardway-to-Hemingway – and for local reinforcement projects. It also seeks acknowledgment of continued permitting activities for Gateway West Segments D.3 and E.
- Demand-Side Management (DSM) Actions – PacifiCorp seeks acknowledgment of its energy efficiency targets.
- Market Purchases – PacifiCorp seeks acknowledgment of its intent to acquire short-term firm market purchases for on-peak delivery from 2023-2025.
- Renewable Energy Credit (REC) Actions – PacifiCorp seeks acknowledgment of its intent to pursue unbundled REC RFPs and purchases to meet state compliance obligations and to sell RECs that are not required to meet state RPS obligations.

D. PacifiCorp’s CEP

PacifiCorp’s CEP first discusses its community engagement strategy, community benefit indicators and metrics, local resiliency, and community-based renewable energy. It then discusses the company’s procurement strategy and the IRP’s projection that the company will need to acquire over 30 GWs of new resources, including over 800 MW of small-scale renewables. PacifiCorp’s CEP finally lays out two pathways for complying with HB 2021: Pathway 1 achieves compliance by allocating the company’s gas resources in such a way that the amount allocated to Oregon is capped; Pathway 2 achieves compliance by assuming that new large commercial load is 100 percent served with non-emitting generation through voluntary renewable options.

E. Stakeholder Engagement

Numerous stakeholders filed comments and otherwise participated in this proceeding. Some of their recommendations were incorporated by Staff into their initial and supplemental Staff Reports. Participating stakeholders were: the Oregon Citizens’ Utility Board; Energy Advocates; Columbia River Inter-Tribal Fish Commission; NewSun Energy LLC; Renewable Northwest; Swan Lake North Hydro, LLC and FFP Project 101, LLC; Alliance of Western Energy Consumers; Fervo Energy; Sierra Club; Cascade Policy Institute; and Community Advocates.

F. Staff Report

On February 7, 2024, Staff submitted an extensive Staff Report, in which it reiterated its recommendation for partial acknowledgment. That Staff Report is attached as Appendix A. In it, Staff recommends acknowledging eleven action plan items and the company's load forecast. It recommends not acknowledging nine action plan items, the preferred portfolio, and the company's long-term IRP/CEP strategy. It also makes thirteen recommendations that it asks the Commission to adopt and lists over 50 expectations that it intends to work with the company on for the IRP Update or 2025 IRP; it states that it does not seek the Commission impose those expectations.

Staff recommends this course of action because “the 2023 IRP/CEP would not be revised to reflect major events—like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027”—and therefore “Staff and stakeholders lack the shared analytic foundation from which most of the important acknowledgment decisions could be made.”¹⁴ Staff's recommendations are also premised on the fact that “the IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner.”¹⁵

On March 1, 2024, Staff filed a report containing an updated set of recommendations, responding to Commissioner deliberation in the February 20 public meeting, including some edited recommendations and a number of new ones. This report is attached as Appendix B and stands as Staff's final recommendations in this proceeding. It did not change Staff's acknowledgment recommendations but did provide specific expectations for PacifiCorp's 2025 IRP and the analyses that PacifiCorp is to provide with that document.

IV. DISCUSSION

We adopt the recommendations set forth in Staff's March 1 report. We acknowledge certain elements and action items in the IRP, but do not acknowledge many other action items. Moreover, we do not acknowledge PacifiCorp's preferred portfolio or the CEP. The plans and many of the action items simply no longer reflect PacifiCorp's reality; most significantly, when PacifiCorp suspended the 2022 All-Source RFP and declined to update its analysis or the further procurement actions set forth in its action plan, we were left with few reality-based actions to acknowledge. Also, when the decision not to take those actions fundamentally undermines a preferred portfolio that was already substantially altered by the federal Ozone Transport Rule, we find it curious that PacifiCorp continues to assert that we should acknowledge its IRP and CEP. In short,

¹⁴ Staff Report at 4.

¹⁵ *Id.*

when the IRP and CEP are superseded by events, and the company makes no effort or space to adjust and provide visibility into what actions it is actually planning to take, acknowledgment is not appropriate. Much in the way we would not acknowledge actions that PacifiCorp has already taken, we do not see a point in acknowledging actions that PacifiCorp has already abandoned.

In saying this, we recognize that not all of these changed circumstances are in the company's control—there are real changes in federal regulations, real operating circumstances and pressures affecting the company, and some inflexibility in PacifiCorp's six-state IRP structure. Nonetheless, we expect PacifiCorp to design its IRP process so that Oregon-specific analysis is upfront and visible to us in our review. If IRP timelines in other states do not allow for testing assumptions and making adjustments during review of the filed IRP and CEP, we expect the company to make an extra effort to ensure a full exploration of alternatives for Oregon.

As to the CEP specifically, the elements that made up the basic actions that would move the company toward the HB 2021 targets were removed at the company's discretion and there has been no engagement around how those can be revised. PacifiCorp chose to pull back on the actions on which the CEP relied as the foundation for movement toward the clean energy targets—movement toward resource acquisitions that would reduce emissions but also, importantly, reduce customers' exposure to electricity market price volatility, for instance.

Beyond the changed circumstances, we are concerned that the CEP was treated as a manual or outboard adjustment to the preferred portfolio development and analysis in the IRP. Without alternative portfolio testing that incorporates state policy requirements, we are unable to see alternatives to the company's allocation-only approach. Had PacifiCorp's plans stayed on track, this approach may have been acceptable for a first iteration given PacifiCorp's persuasive assertion that the IRP preferred portfolio with reallocation was least cost for HB 2021 compliance, and we are not concluding that an allocation approach is legally invalid. It may well be a viable pathway, but going forward, we expect the company to integrate the requirements of state policies into the IRP itself. We need modeling of state policy in order to be able to see, among other things, achievement of the small-scale resource requirement in context of other resources and as a relative cost driver. As we understand it, a key element of HB 2021 is to be able to use the planning process to see tradeoffs and alternative paradigms, and we conclude that adopting requirements for 2025 is necessary to be able to understand PacifiCorp's alternatives for progress to HB 2021 compliance.

To that end, we are approving Staff's clear recommendations laying out a roadmap for the company's next IRP and we emphasize the importance of the company following

these recommendations in its 2025 IRP. At the same time, we invite the company to find a way to include in its 2024 IRP update some of the items that Staff is looking for and to update the CEP. We also voice our support for Staff continuing to pursue its non-binding “expectations;” it is not our intention to only support the items that have been formed into recommendations for our adoption.

We particularly want to call out Recommendations 15, 16, and 17 as difficult but important analyses. Stakeholders have worked with the company over successive IRP cycles to effectively model the comparative economics and flexibility of the many resource options, including careful analysis of when it is cost effective to retire a thermal facility. This rigor must continue as cost pressures mount. Recommendation 16, derived from CUB’s comments, is a sound recommendation to incorporate actual carbon prices from California and Washington as PacifiCorp is modeling the cost of resources and the resulting dispatch. PacifiCorp has historically put a long-term price on carbon as a proxy for future regulatory requirements. HB 2021 requires a specific carbon budget and a carbon price, and without it, the CEP is not precise enough to establish compliance. Remedying this is especially important so that the CEP can test how much the portfolio as a whole will meet the Oregon requirements, how much will need to be solved with allocation, and what the cost will be. It will also help us determine whether the company is on a least-cost path to compliance. We also note that analysis of the federal loan program is a critical, near-term priority given capital constraints and rate pressure.

In general, we expect to see more cost information in the course of PacifiCorp’s planning, both due to affordability concerns and because we need the company to be clearer about constraints that may be impacting their progress and how they are allocating their resources among their many priorities. The company should be transparent with stakeholders if the IRP Update or the 2025 IRP action plan are being driven by constraints that are not visible in the modeling. The company needs to do more to communicating the many moving parts in the company’s planning and procurement landscape.

We recognize that we committed in our order in docket UM 2273 to consider, alongside IRP and CEP review processes, whether utilities have demonstrated continual progress.¹⁶ We are not doing so here simply because we expect, in a matter of weeks, to have a more realistic view of PacifiCorp’s status with the IRP/CEP Update that are to be filed in April 2024. We will assess continual progress in connection with our review of the update. If we do not find that PacifiCorp has demonstrated “continual progress [toward the HB 2021 targets] and [that it] is taking actions as soon as practicable that facilitate

¹⁶ *In the Matter of Public Utility Commission of Oregon, Investigation of House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 23-465 (Dec. 4, 2023).

rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers,” we will consider in a holistic manner whether we need to take actions to fulfill our responsibility to ensure this progress.

V. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by PacifiCorp, dba Pacific Power, is acknowledged in part to the extent and with the conditions contained in Staff’s February 7, 2024, and March 1, 2024 reports attached as Appendix A and Appendix B.

Made, entered, and effective Mar 19 2024.

Megan W. Decker

Megan W. Decker
Chair

Letha Tawney

Letha Tawney
Commissioner



ITEM NO. RA4

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: FEBRUARY 20, 2024**

REGULAR X CONSENT _____ EFFECTIVE DATE _____ N/A

DATE: February 7, 2024

TO: Public Utility Commission

FROM: JP Batmale

THROUGH: Kim Herb **SIGNED**

SUBJECT: PACIFICORP:
Docket No. LC 82
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PGE's CEP or decline to acknowledge the CEP and direct the Company to revise and resubmit certain portions of the plan.
Whether the Commission should direct PGE to take any additional actions prior to filing its next IRP or IRP Update or CEP.

Applicable Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.¹ In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of “IRP Guidelines” to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon’s regulated utilities before the Commission considers acknowledgement of a utility’s resource plan.² These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.³ Further, the IRP must also include an “Action Plan” with resource activities that the utility intends to take over the next two to four years.⁴ The utility’s IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the “portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.”⁵ This is often referred to as the “least cost/least risk portfolio.”

The Commission reviews the utility’s plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.⁶ However, the Commission explains: “We may also decline to acknowledge specific action items if we question whether the utility’s proposed resource decision presents the least cost and risk option for its customers.”⁷ The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.⁸

¹ Order No. 89-507.

² Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).

³ Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.

⁴ Order No. 14-415 at 3.

⁵ Order No. 07-002 at 1-2.

⁶ *Id.* at 1.

⁷ *Id.*

⁸ OAR 860-027-0400(7), (10).

In 2021, the legislature passed Oregon House Bill (HB) 2021, codified as ORS 469A.400 to 469A.475, which requires the state's large investor-owned electric utilities (IOUs) and electricity service suppliers (ESSs) to decarbonize their retail electricity sales with consideration for direct benefits to local communities.

ORS 469A.415 requires large electric IOUs to, “develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 concurrent with the development of each integrated resource plan,” and file the plan with the Commission and Oregon Department of Environmental Quality (DEQ).

ORS 469A.420 outlines the requirements and considerations for the Commission to acknowledge the CEP “...if the commission finds the plan to be in the public interest and consistent with the clean energy targets....”

In addition, ORS 469A.415(6) requires the Commission to ensure that the utilities demonstrate continual progress within the CEP planning period toward meeting the clean energy targets and are taking actions as soon as practicable to reduce emissions at reasonable cost to retail electricity consumers.

Additional requirements for the filing, review, and update of IRPs and CEPs are provided in OAR 860-027-0400.

Finally, PacifiCorp's previous IRP, LC 77, resulted in Order No. 22-178, which provided specific direction to the Company on analytic matters for this IRP.

Analysis

Background

PacifiCorp filed its 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or Plans) with PUC on May 31, 2023. PacifiCorp's filing shortly followed PGE's filing of the first IRP/CEP on March 31, 2023, both of which followed from the passage of HB 2021 and direction from Docket UM 2225.

Originally three rounds of comments had been planned in the lead up to a final Staff memo for an April 2024 Special Public Meeting to acknowledge PacifiCorp's 2023 IRP/CEP. Round 0 comments provided preliminary notes about improvements PacifiCorp could make in advance of participants' in-depth review of the IRP/CEP. Round 1 comments evaluated the reasonableness of the plan and explored acknowledgement considerations. Round 2 comments were meant to focus on Staff's draft recommendations for Commission acknowledgement of the IRP/CEP. The Company would respond with a final set of comments, typically including a final set of

revisions to the IRP. Then in March a public meeting memo from Staff with final acknowledgement recommendations was to be published, giving stakeholders and the Company a final opportunity to make written comments to the Commission.

Round 1 comments by Staff and stakeholders reflected the fact that there had been material changes impacting the IRP/CEP analysis since the documents were filed in May 2023. These changes rendered moot most of the IRP's Action Plan and Preferred Portfolio. The changes also undermined PacifiCorp's CEP and plan to meet the HB 2021 targets. Of particular concern, PacifiCorp confirmed in response to an information request that the Company will not be able to procure the clean energy additions included in the Preferred Portfolio through 2028 given the suspension of the 2022 All-Source RFP.⁹

In PacifiCorp's December 2023 LC 82 Round 1 reply comments, PacifiCorp made it plain that changes would not be made to the 2023 IRP/CEP, despite Staff and stakeholders' requests. Instead, the Company pointed toward the IRP Update – planned for April 2024 – for any revisions of the Company's now obsolete IRP analysis. PacifiCorp reinforced this position several information request responses.

As the 2023 IRP/CEP would not be revised to reflect major events – like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027 – Staff and stakeholders lacked the shared analytic foundation from which most of the important acknowledgement determinations could be made. Given this threshold issue, Staff saw little value in continuing multiple rounds of comments on the plan as filed. Staff's Round 2 comments included proposed final recommendations, rather than draft recommendations, and a request to shorten the procedural schedule and end LC 82 in February, rather than April.¹⁰ A revised schedule consistent with Staff's request was adopted by the ALJ in a ruling on February 5, 2024.

Staff sees benefits to an abbreviated schedule, and non-acknowledgment as proposed by Staff followed by revision and resubmission of the CEP and additional actions for the IRP Update. The first, the Company's planned IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner. Second, by directing a revised and resubmitted CEP in mid-2024, the Commission can avoid an extensive delay in the acknowledgment of a CEP the Company to implement, given the looming emissions reductions targets in HB 2021, rather than stalling consideration of the CEP to 2025. Finally, the Commission could consider providing

⁹ PacifiCorp response to OPUC Staff Information Request No. 243.

¹⁰ LC 82, OPUC Staff Second Round Comments, January 24, 2024, pg. 4 and Staff procedural motion on January 30, 2024 to change the schedule.

direction to shape PacifiCorp's quickly moving small-scale renewable request for proposal (SSR RFP).

Staff's redacted Round 2 comments are included with this memo as Attachment A. The Round 2 comments provide more details to Staff's recommendations. The Round 2 comments also include more background information on the IRP itself and stakeholder comments than is contained in this memo. This public meeting memo includes no new analyses. It does, however, seek to reemphasize and clarify the positions taken by Staff in the Round 2 comments and address potential shortcomings in the SSR RFP currently under development.

Acknowledgement Recommendations for the IRP and CEP

Staff made thirteen acknowledgement recommendations in our Round 2 comments.¹¹ They spanned the IRP and CEP. Staff also listed over fifty expectations for the IRP Update or the 2025 IRP. These expectations amounted to issues that did not require Commissioner deliberation and would not require an order. Instead, Staff plans to work with PacifiCorp and stakeholders to meet these expectations.

The table below summarizes the recommendations from Staff's comments regarding the IRP.¹²

Table 1

	Acknowledge	Not Acknowledge
IRP	- Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) - Load Forecast	- Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) - Preferred Portfolio - Long-Term IRP/CEP Strategy

With regard to the CEP, Staff believes that the necessary changes to the Preferred Portfolio in the IRP Update will significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies needed for PacifiCorp to comply with HB 2021. Staff does not believe the CEP is consistent with the emissions reduction targets of HB 2021, given the present circumstances. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

With regard to PacifiCorp's allocation approach to CEP compliance pathways, Staff stated previously that we find the approach of testing hypothetical allocations to be a reasonable approach to forecasting future Oregon-allocated emissions in years beyond

¹¹ LC 82, OPUC Staff Second Round Comments, January 24, 2024, Appendix A, pgs. 55-56.

¹² *Id.*, pg. 4.

the current allocation agreement. It would, however, generate more insight if PacifiCorp tested more options and was more transparent about those options and their tradeoffs. Additionally, Staff is clear in our Round 2 comments that the Company is not expected to make significant revisions in community-focused areas of the CEP as part of a revised filing; only the CEP Compliance pathways and demonstration of continual progress on emission reductions. With that said, Staff did include four CEP, community-focused recommendations:

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Recommendation 7. Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Beyond these recommendations, to the extent that the CEP's community-based activities or strategies have changed since it was filed in May 2023, the Company should provide new information in the revised CEP filing. Otherwise, Staff expects PacifiCorp to leverage the CBIAG and 2025 IRP process to continue to improve the community-based elements of the CEP.

Minimum Changes Sought by Staff in the IRP Update and Revised CEP

Staff's Round 2 comments identified four analytic threshold issues that would need to be addressed in the IRP Update and reflected in the revised and resubmitted CEP for

Staff to consider recommending acknowledgment of the revised and resubmitted CEP.¹³ These were in addition to the thirteen acknowledgement recommendations.

1. Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
2. Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
3. Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
4. Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

On January 31, 2024, PacifiCorp released a draft of the IRP Update. This draft outlined eight areas that PacifiCorp planned to revise with new information in the IRP Update. They are:

- System coincident peak load forecast,
- Natural gas and power market price updates,
- Stay of the ozone transport rule,
- Suspension of the 2022 all-source RFP,
- Natural gas generation and the use of either green hydrogen or green ammonia,
- Preference for peaking type resources,
- Demand-side management,
- Front office transactions,
- Contracted resources, and
- Transmission option updates.

It appears that PacifiCorp plans to update the Preferred Portfolio and Action Plan in the IRP Update, though these updates were not completed and included in the draft document. PacifiCorp makes no mention of Staff's other three recommendations. Further, the draft IRP Update outline included no mention of seeking acknowledgement of a revised Preferred Portfolio and Action Plan as part of the IRP Update. All of these things are crucial.

If Staff's additional analyses are not addressed as part of the April 2024 IRP Update, Staff is concerned that the basis from which to assess the acknowledgability of a revised and resubmitted CEP will be compromised and more time wasted. Thus, Staff

¹³ *Id.*, pg. 3.

requests that the Commission order PacifiCorp to conduct Staff's recommended analyses within the IRP Update, in addition to all thirteen recommendations from Staff's Round 2 comments.

Timing of Resubmission of Revised CEP

Due to the circumstances surrounding this IRP and CEP, Staff finds that PacifiCorp should seek to resubmit its revised CEP with the IRP update. However, given that April is less than two months away, Staff is open to PacifiCorp filing a request in its reply comments for an extended CEP filing date of four to eight weeks.¹⁴ Regardless of the timing, Staff plans to work quickly to review the CEP once it is filed.

SSR RFP

The 2023 IRP/CEP forecasted a need of approximately 490 MW of new, renewable capacity – all less than 20 MW in size – to meet HB 2021's 2030 SSR requirement. Because the Company believes acquiring this volume and type of capacity by 2030 may be difficult, PacifiCorp plans to move rapidly. On January 24, 2024, PacifiCorp held a bidders workshop for its SSR RFP. The workshop outlined the Company's initial approach to acquiring the SSR resources necessary to meet a key component of HB 2021. Per the bidders conference presentation, the RFP will be finalized and issued by March 29, 2024. Staff appreciates the Company's sense of urgency on this topic.

However, Staff is concerned about the strategic choices made by PacifiCorp in designing this RFP. First, the timing was such that the bidders conference was the same day as Staff's comments were due. Staff did include two SSR RFP recommendations that were not part of the RFP. They were:

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Should the Commission choose to accept Staff recommendation we would hope to see the SSR RFP be updated accordingly.

¹⁴ OAR 860-027-0400(9)(c).

Beyond this, the Company also appears to be establishing RFP parameters that limits the pool of potential resources, drives up SSR project costs borne by Oregon ratepayers, and/or limits insights into the community benefits of projects. Specifically:

- The RFP bars energy storage from being paired with eligible renewable systems.
- No RFP mechanism like non-price scoring or sensitivities to identify, track, and/or allow for project selection that accounts for community benefits.
- Premium peak hour pricing, like what was approved for Oregon PURPA projects, is not allowed. Only flat pricing and on-peak/off-peak.
- Requiring ODOE RPS certification, which includes WREGIS certification and metering.
- Requiring CAISO EIM visibility and dispatchability.

Staff has included two attachments associated with the SSR RFP. Attachment B is the bidders conference presentation and Attachment C Staff's response.

Time permitting at the Public Meeting, Staff suggests that it may be productive to discuss with PacifiCorp their SSR acquisition strategy. The SSR RFP represents one of the first actions by PacifiCorp to meet the HB 2021 targets. As such, a better understanding of PacifiCorp's strategy and approach to SSR acquisition could help all parties learn more about balancing tradeoffs around the economic and technical feasibility of HB 2021 actions.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

LC 82

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

Docket No. LC 82

In the Matter of

PACIFICORP, dba PACIFIC POWER,

2023 Integrated Resource Plan.

OPUC STAFF ROUND 2 COMMENTS AND
RECOMMENDATIONS

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Executive Summary

In this second round of comments on the PacifiCorp (PAC or Company) Integrated Resource Plan (IRP) and Clean Energy Plan (CEP), the Oregon Public Utilities Commission (OPUC) Staff puts forth draft recommendations for acknowledgment and future expectations. Our recommendations and expectations cover this IRP, the planned IRP Update (April 2024), and the next IRP (April 2025). As detailed below – and throughout this document – Staff also puts forth a plan and rationale to revise the current IRP/CEP process to enable the Commission to consider the significant changes to the Preferred Portfolio and Action Plan that PacifiCorp plans to include in the IRP Update to be filed in April 2024.

Staff finds the 2023 IRP was an insightful first attempt at putting forth a comprehensive resource plan to meet HB 2021's decarbonization targets and community benefit goals while accomplishing traditional IRP analysis. PacifiCorp staff conducted more complex modeling than in any previous IRP and demonstrated a commendable level of engagement and candor with Staff and stakeholders. However, Staff has determined that a change of course in this IRP is necessary. This is spurred by two developments.

First, events outside the LC 82 process profoundly changed the relationship between this IRP/CEP's conclusions, action plan, and the market and policy realities faced by PacifiCorp. The two most notable of these events were the judgment against PacifiCorp in the wildfire lawsuits in August 2023 and the Tenth Circuit Court of Appeals' stay of the Ozone Transport Rule in July 2023. The combination of these two events, along with other events, led PacifiCorp to suspend its 2022 AS RFP in September 2023. As noted by many stakeholders in the first round of comments, the RFP suspension, which removed approximately 1.5 GW of new, non-emitting capacity by 2027 from the Preferred Portfolio, cast into doubt several important elements of the IRP/CEP. These included the Preferred Portfolio itself, many action plan items, and any understanding of the potential of forecasted emissions reductions to achieve CEP compliance. In short, the IRP/CEP map no longer matches the territory of operational and market realities. Thus, Staff and stakeholders argued in the first round of comments that additional analysis within this IRP/CEP was necessary in order for several elements to be acknowledged. Independent of these outside events, Staff and stakeholders also noted in Round 1 comments the need for improvements to the IRP/CEP to consider acknowledgement. These included:

- Including Oregon's Small Scale Renewable (SSR) requirement in the Preferred Portfolio in 2030 to capture the portfolio benefits of SSRs.
- Adding more energy efficiency (EE) in Oregon to reflect the higher value that EE brings to Oregon in the context of HB 2021.
- Utilizing more reasonable resource cost estimates.
- Addressing any identified errors with the granularity adjustments that PacifiCorp applied within its PLEXOS modeling.
- Analyzing the sufficiency of the Preferred Portfolio to enable simultaneous compliance with clean energy and GHG policies in Oregon, Washington, and California.
- Reoptimizing select portfolios for a clearer understanding of portfolio NPVRR and the ability to compare actions.

- Articulating more clearly the Oregon implication of coal-to-gas conversions vis-à-vis emissions, decarbonization efforts, and future MSP allocations.

While PacifiCorp has signaled an openness to eventually considering the improvements listed above, the Company was also clear that it would not conduct additional analysis to revise its filed IRP/CEP.¹ The Company has pushed all additional analysis or changes to this IRP/CEP to either the IRP Update or the next IRP.

While it would be unwieldy to constantly revise a filed IRP/CEP, additional analysis has been done in the past when staff or stakeholders indicate they cannot support acknowledgement without material revisions. Conducting additional analysis within the IRP/CEP timeframe to adjust to large-scale and material events impacting the Preferred Portfolio – or in response to stakeholder insights and requests – is reasonable. The IRP process is designed for rounds of comments to consider, discuss, and debate changes to achieve acknowledgement. Accordingly, the IRP/CEP is deemed reasonable to acknowledge at the end of the process, not upon filing.

Because PacifiCorp will not voluntarily make changes to this IRP/CEP, some of the most important issues before us lack a shared analytic foundation from which an acknowledgement determination can be made. As such, Staff does not see a path to recommending acknowledgment of PacifiCorp's current IRP/CEP. At the same time, Staff is concerned that non-acknowledgement and reconsideration at an undetermined future date could delay important activities that the Company must or should undertake to comply with HB 2021. Time is limited for the utility to adopt a CEP that can be acknowledged and successfully implemented before the first emissions reduction target in 2030. Given this tension and the indications from PacifiCorp that there will be significant changes to the Preferred Portfolio and Action Plan in the IRP Update to be filed in April 2024, Staff recommends that the schedule be updated to allow the Commission to consider the information in the forthcoming IRP Update. Staff also recommends that PacifiCorp be directed to address, within the IRP Update, a limited number of threshold issues that have been raised within this docket.

Specifically, Staff recommends that PacifiCorp be directed to, at a minimum:

- Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
- Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
- Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
- Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

With regard to the CEP, Staff believes that the changes to the Preferred Portfolio in the IRP Update may significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies

¹ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 96. "Pertaining to the 2022 AS RFP, PacifiCorp has no revised plan or substantive updates available at this time and is actively working to incorporate a number of updated assumptions as part of portfolio development for its 2023 IRP Update, anticipated to be filed April 1, 2024. The result will be comprehensive changes to the portfolio, and not just specific line items that could be modified in a few figures in the filed 2023 IRP."

needed for PacifiCorp to comply with HB 2021. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

Staff also describes in these comments a number of issues regarding PacifiCorp's efforts to incorporate community impacts into planning decisions and presents a number of expectations regarding community engagement, community benefit indicators (CBIs), community-based renewable energy (CBREs), and resiliency. Staff views PacifiCorp's efforts on these fronts as important first steps upon which to build in future planning cycles. Staff does not expect the Company would make significant revisions in these areas prior to filing a revised CEP, but does expect the Company would update information in a revised CEP filing to the extent that their plans have changed.

To accommodate the timing of PacifiCorp's planned IRP Update filing, Staff proposes that the Commission take up these recommendations at the February 20, 2024, Public Meeting. This will allow Staff and stakeholders to focus the remaining efforts for this IRP/CEP on reviewing the April 2024 IRP Update and a revised and resubmitted CEP. Staff believes a revised CEP should be submitted with the IRP Update.

The table below summarizes those IRP items that Staff plans to recommend and not recommend for acknowledgement in LC 82:

Table 1: IRP Elements Recommended for Acknowledgement

	Acknowledge	Not Acknowledge
IRP	Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) Load Forecast	Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) Preferred Portfolio Long-Term IRP/CEP Strategy

Finally, Staff is incredibly grateful to the following stakeholders for their work in LC 82: Alliance of Western Energy Consumers (AWEC); Community Advocates; Columbia River Inter-Tribal Fish Commission (CRITFC); Oregon Citizens' Utility Board (CUB); Energy Advocates; Fervo; NewSun Energy LLC (NewSun); Renewable Northwest (RNW); Sierra Club; and Swan Lake and FFP Project 101. The comments and overall engagement throughout this IRP have deepened Staff's understanding of the issues surrounding HB 2021. They have also improved this IRP/CEP and future filings by PacifiCorp as they chart a pathway to a reliable, affordable, equitable and decarbonized system.

Key Challenges & Vulnerabilities

In Round 1 comments, Staff identified key challenges and key vulnerabilities to LC 82. The challenges represented issues within IRP and CEP that would require more explanation of the near-term resource strategy and general implementation. Staff's identified vulnerabilities represented more critical issues that called into question the ability to acknowledge a particular aspect of LC 82. While all of the identified topics from Round 1 are covered in these comments, we revisit the most pressing or unresolved items below.

Composition and Costs of Small-Scale Renewables and Community-Based Renewable Energy (Challenge)

In Reply comments, PacifiCorp addressed questions around costs and composition of SSRs. While the Company reasserted that SSRs remain uneconomic, the Company is clearly committed to trying to meet the 2030 SSR target in HB 2021.² Staff appreciates PacifiCorp's approach of letting the RFP run its course and then pivot to other methods of acquiring SSRs based on the RFP results.³ Staff also appreciates PacifiCorp's thorough response on the potential barriers in Oregon rule to SSR procurement.⁴ The Company's four suggestions provide a solid basis for fruitful public dialogue. Staff will not address each of the Company's suggestions in its comments, but would be open to participating or leading an informal public discussion on PacifiCorp's suggestions.

Both Staff and the Company see some overlap between CBRE and SSR projects.⁵ However, PacifiCorp has modeled CBRE Projects and SSR projects separately, most notably with CBRE projects having a higher cost per MWh. PacifiCorp plans to acquire CBRE projects through a grant pilot program rather than an RFP.⁶

Staff would note the initial SSR RFP filing limits the range of projects from 3 MW to 20 MW. We think the bound at the low-end of the range may unnecessarily exclude potential CBRE projects that are smaller in nature. Staff will work to expand this range in the SSR RFP so that it can potentially capture these projects and establish two channels for acquiring this resource.

State Policy Compliance in IRP Portfolios (Vulnerability)

In Round 1 Comments, Staff raised a central concern to PacifiCorp's CEP compliance allocation methodology: would the Preferred Portfolio contain a sufficient amount of non-emitting resources in 2030 to simultaneously comply with the clean energy and GHG policies of Oregon, Washington, and California? Staff is concerned that if PacifiCorp continues to evaluate compliance with each state-level policy in separate analyses outside of the IRP, resources could be erroneously double-counted toward policy compliance in multiple states.

Staff requested that PacifiCorp demonstrate in this IRP that the Preferred Portfolio could simultaneously comply with clean energy and GHG policies in Oregon, Washington, and California and that, in future IRPs, the Company to constrain the Preferred Portfolio to ensure that simultaneous policy compliance is feasible.

PacifiCorp's Response Comments noted that, "there is no feasible single-pass modeling solution that guarantees Oregon compliance while simultaneously meeting all other portfolio requirements."⁷

PacifiCorp also suggested that Staff's request to demonstrate simultaneous compliance of state-level policies would not be possible due to limitations of PLEXOS and the fact that resource allocations have not yet been determined.⁸

² LC 82, PacifiCorp Reply Comments, December 1, 2023, page 53.

³ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 52.

⁴ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 85.

⁵ LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 36.

⁶ LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 54.

⁷ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 24.

⁸ *Ibid.*

Yet elsewhere in PacifiCorp comments, the Company expresses openness to developing a more “unified” portfolio that integrates systemwide and state-level constraints.⁹

From Staff’s perspective, ensuring that PacifiCorp can simultaneously comply with all state-level policies to which it is bound should be foundational to the Company’s IRP process. Staff appreciates PacifiCorp’s concern that a “single pass” modeling solution to this problem may not be available through the PLEXOS model. However, this limitation does not prevent PacifiCorp from demonstrating that simultaneous state-level policy compliance is feasible or ensuring that portfolios meet this requirement. PacifiCorp already uses multiple modeling passes to make adjustments to portfolios to respect other complicated constraints (e.g. the reliability and granularity adjustments). PacifiCorp could similarly adopt an iterative process within the IRP in the event that a portfolio was found not to comply with one or more state-level policies simultaneously.

Staff also appreciates PacifiCorp’s concern that evaluating state-level policy compliance may require the Company to make assumptions regarding future allocation. However, Staff does not see this as an impediment to testing the feasibility of simultaneous policy compliance. PacifiCorp could, for example, demonstrate that there is some feasible allocation (i.e. all allocation factors fall between 0 and 1 and sum to 1) that achieves simultaneous policy compliance, without adopting that allocation strategy. Such an exercise could be used to test the limitations of what can be achieved through allocation and to identify if there are high-level constraints that could inform allocation discussions in MSP.

Because PacifiCorp would not or could not conduct this analysis – and given its centrality to the IRP and CEP – Staff conducted a high level and approximate exercise to make a “back of the envelope” determination of the non-emitting sufficiency of the Preferred Portfolio in 2030. Staff’s simple analysis, which was based on public information from PacifiCorp’s IRP and CEP workpapers, identified multiple energy allocation strategies for the Preferred Portfolio that would likely result in simultaneous policy compliance in Oregon, Washington, and California in 2030.

Further, the policy-feasible allocations that Staff tested also resulted in the majority of the load in Idaho, Utah, and Wyoming being met with non-emitting generation by 2030 under the Preferred Portfolio.

Staff’s findings are in fact consistent with PacifiCorp’s assertion that the proposed renewable additions originally proposed in this IRP are primarily being driven by economics, rather than policy compliance. Staff’s analysis also bolstered Staff’s view that it is reasonable for PacifiCorp to incorporate this type of analysis into future IRPs and IRP Updates.

Staff Expectations:

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

⁹ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 54.

CEP Compliance Pathways (Vulnerability)

Staff finds that considering the effect of allocation pathways in the CEP on HB 2021 compliance is an acceptable, flexible approach to beginning a conversation about HB 2021 compliance that reflects how DEQ conducts annual emissions compliance evaluation. However, Staff also recognizes that it represents a complete departure from the allocation methodology approved in the 2020 MSP. Staff agrees with CUB that this was done with limited discussion outside of MSP. CUB observed that, beyond comparing compliance costs across portfolios, PacifiCorp's approach to developing CEP pathways – along with changes in coal retirements and this IRP's quick pivot to coal-to-gas conversions – represent a fundamental break from the approach of the 2020 Multi-State Protocol (MSP) with no transparent discussion or analytic demonstration of how these changes to the allocation methodology are in the best interest of Oregon.¹⁰ Further, AWEC speculated that PacifiCorp's proposed pathways most likely exceeded HB 2021's incremental cost cap, that neither pathway can be enforced or guaranteed, and that because both pathways do not reflect the current MSP allocation they should be prohibited.¹¹ Both RNW and the Energy Advocates generally objected to PacifiCorp's approach as just an allocation exercise with no meaningful emission reductions and little chance of being accomplished within the MSP framework.

The Company's response points out that CEP pathways are compliant with the 2020 MSP prior to its expiration at the end of 2024, and that no MSP has been agreed upon for the time period after 2024 when most CEP cost will be incurred. Further, PacifiCorp counters CUB that the CEP does include cost analysis. The CEP pathways also represent issues to be considered in the current MSP negotiations, not actual positions that must be taken. To this end, PacifiCorp notes that the pathways were not the primary means to achieve CEP compliance. Rather, the IRP's proposed system-wide, Preferred Portfolio would in fact achieve 98 percent of the Oregon CEP emission reduction targets by 2030.¹² Finally, PacifiCorp argues for a narrow interpretation of HB 2021's cost cap that should be applied once costs are incurred and to conduct such an analysis in a rate case.¹³

Staff agrees with PacifiCorp that the expiration of the 2020 MSP provides a level of flexibility in proposing CEP compliance pathways. Yet the analysis in this CEP – while instructive and insightful – falls short of providing actionable insights *and* a forum to discuss the tradeoffs for Oregonians around MSP allocation methodologies capable of meeting HB 2021's goals. In this sense Staff agrees with CUB: by limiting the CEP pathways to only “illustrate” what could eventually occur in MSP, the IRP/CEP falls short of providing an actionable “plan” around which to debate the costs and risks of various CEP Compliance Pathways. Finally, Staff agrees with the Company's assertion that UM 2273 will be the best place to address policy issues around HB 2021's cost cap, not this IRP/CEP.

Staff Expectations:

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP “actions,” Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.

¹⁰ LC 82, CUB Round 1 Comments, October 25, 2023, page 5.

¹¹ LC 82, AWEC Round 1 Comments, October 25, 2023, page 3-5.

¹² LC 82, PacifiCorp Reply Comments, December 1, 2023, page 23.

¹³ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 26.

- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions (Vulnerability)

In Opening Comments (Round 1), Staff recognized that PacifiCorp's 2023 IRP makes a significant departure from its 2021 IRP in its plans to retire coal-fired generation resources. Specifically, while the 2021 IRP only included gas conversions of Jim Bridger Units 1 and 2, the current plan adds Jim Bridger Units 3 and 4 and Naughton Units 1 and 2 to the list.

PacifiCorp's analysis shows that the conversions are selected by its optimization model based on economics. Staff appreciated this analysis and sought more information from the Company to better understand the cost and risks associated with these conversions for Oregon customers as well as the consistency of these actions with HB 2021 emissions reduction targets. Staff appreciates PacifiCorp's responses to some of the questions posed by Staff, however, expresses disappointment that the Company did not answer most of the questions posed by Staff.

In response to Staff's question regarding the prominence of gas conversions in this plan compared to the 2021 IRP, PacifiCorp explains that the previously realized benefits from Bridger 1 and 2 conversions in the 2021 IRP portfolio analysis prompted the Company to explore this option for the other coal plants, and the conversions were endogenously selected within its optimization model. The Company also points out that gas conversions identified in the 2021 and 2023 IRP are a better outcome compared to a new gas plant selected in its 2019 IRP. Further, the Ozone Transport Rule limiting nitrous oxide emissions also favors gas conversions over coal. PacifiCorp also sees benefits in using the converted plants as a backup resource to be used in "limited circumstances" as it integrates clean energy resources into its system. The delay in the Natrium demonstration project has further necessitated the conversion of the Naughton Units 1 and 2.

PacifiCorp did not provide explanations in its Reply Comments to Staff's other requests in which Staff sought to understand if the Company has evaluated the risks of these converted units becoming stranded assets, or what factors could alter the decisions around future coal plant retirement and conversions. Staff had also asked for an analysis with a portfolio variant that does not allow any conversion beyond Jim Bridger 1 and 2, and to test this variant across various gas and CO₂ price options. Staff expected PacifiCorp to either include this portfolio in its CEP alongside other high-performing portfolio variants or introduce constraints related to HB 2021 in its IRP analysis. PacifiCorp indicated that more detailed analysis around coal retirement and conversion options will be provided in its 2023 IRP Update due to be filed in April 2023. Staff looks forward to receiving the updated analysis and expects PacifiCorp to include a detailed analysis of risk of regrets, potential changes in future retirement and conversion plan and the portfolio variant that Staff suggested.

CUB pointed out that coal to gas conversions nullify the agreement reached in the 2020 Multi-State Protocol regarding Oregon's exit from these coal plants, which was key to the determination of the 2020 MSP agreement. CUB had also expressed concerns with the implications of coal to gas conversion for decommissioning and cost allocation to Oregon customers. PAC is inclined to address MSP issues in the MSP process. PacifiCorp indicated that the main component of gas conversion costs is the cost of natural

gas pipeline transport and therefore there is no significant impact on depreciation and decommissioning costs.

Energy Advocates commented that coal to gas conversion is not shown to be least cost least risk in the presence of HB 2021. PacifiCorp indicated that they provided economic analysis showing system benefits from conversion of all Bridger units and Naughton units (in both 2021 (JB1 and 2) and 2023 IRPs). Conversion should be consistent with HB 2021, since these plants would have lower emissions compared to before and will be operated with low-capacity factor but meet peak and reliability needs. In response to Energy Advocates' comments on whether the benefits from these conversions and costs will only be limited to Oregon customers, PacifiCorp replied that these plants will retire in 2037, before HB 2021's 2040 timeline, hence Oregon is not the only one sharing costs. Moreover, conversion costs are much lower than cost of new renewables.

Sierra Club had expressed concern around availability of firm gas capacity for the converted units. PacifiCorp did not disclose the pipeline information in its Reply Comments due to confidentiality agreements with third parties.

Staff believes that the Company's decision to continue to operate coal generation units as natural gas plants must be evaluated in the light of HB 2021. Staff understands that inter-state protocol and cost allocation concerns raised by CUB are vital and expects the Company to respond to those in the appropriate docket. Further, Staff understands that the conversions of Jim Bridger 1 and 2 was acknowledged in the 2021 IRP and the conversion plan for Naughton 1 and 2 is also well under way, and therefore these items are not appropriate action items for acknowledgement in this IRP.¹⁴

Staff Expectations:

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the Action Plan because the Company has already taken these actions.

RFP Suspension

As previously noted in Staff's Round 1 comments, PacifiCorp recently suspended its 2022 All Source Request for Proposals (2022 AS RFP), which sought bids from resources capable of coming online by the end of 2026. The suspension raises concerns around the Company's ability to execute certain Action Plan items in the 2023 IRP and procure sufficient near-term resources to meet Oregon's HB 2021. RNW's Round 1 comment similarly noted the risk from this suspension and encouraged PacifiCorp to resume the RFP as soon as possible or have the Commission to direct the Company to do so.¹⁵

PacifiCorp's Round 1 Response Comments did not provide much information to assuage 2022 AS RFP suspension concerns. The Company failed to address many of the questions raised by Staff and stakeholders. Despite stating previously in LC 82 that the greatest risk to the IRP was under procurement of resources, the Company now stated that it did not have any revised plan or substantive updates available that reflected the impacts of the RFP suspension.¹⁶ However, the Company did state that it had

¹⁴ PacifiCorp Response to Staff DR Nos. 222 and 223.

¹⁵ LC 82, Renewable Northwest, Round 1 Comments, October 25, 2023, page 7.

¹⁶ LC 82, PacifiCorp Reply Comments, page 96.

engaged in a bilateral effort to procure battery storage technology by June 1, 2026, and that in the IRP Update a new RFP may be put forth.

Given that the Preferred Portfolio included 2,531 MW of wind, 6,383 MW of solar, and 6,411 MW of battery capacity on the system by 2028, the impact of suspending a near-term RFP puts these builds at risk. In response to discovery, PacifiCorp confirmed that it is unable to procure the amount of wind and solar included in the Preferred Portfolio in years leading up to 2028.¹⁷ Table 2 summarizes the difference in installed capacity between the Preferred Portfolio and the additions that may actually occur if PacifiCorp is unable to procure any additional new renewables, other than the bilateral storage mentioned above.

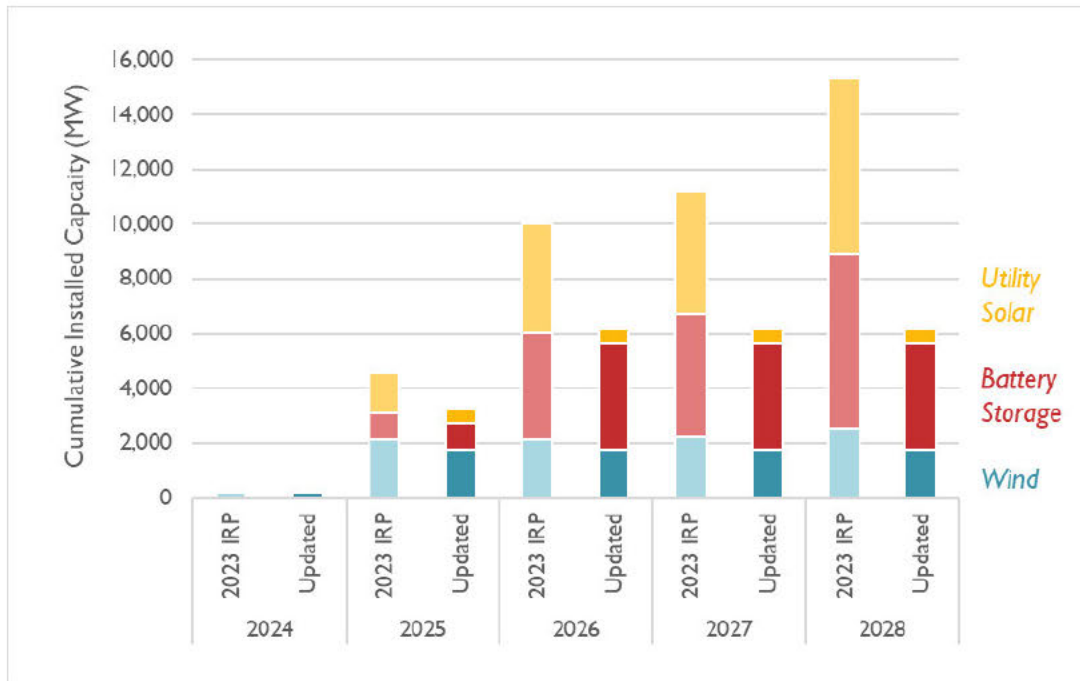
Table 2: Difference in Installed Capacity Between 2023 IRP Preferred Portfolio and Current Reality

Cumulative Installed Capacity Delta (MW)	2024	2025	2026	2027	2028
Renewable- Utility Solar	0	-974	-3,498	-3,981	-5,888
Renewable- Battery	0	0	0	-628	-2,528
Renewable- Wind	0	-339	-339	-439	-739
Total	0	-1,313	-3,837	-5,048	-9,155

The figure below demonstrates the impact that this delayed procurement could have on renewable resource builds over the next five years. The “2023 IRP” chart series on the left represents the data as presented in the Preferred Portfolio. The “Updated” chart series on the right represents capacity that PacifiCorp has currently indicated it can procure based on the 2020AS RFP and bilateral storage contracts. Solar is the resource that is most at risk due to the 2022AS RFP suspension, as the 2020AS RFP did not result in a large number of solar additions and PacifiCorp has not indicated any alternative procurement processes for solar.

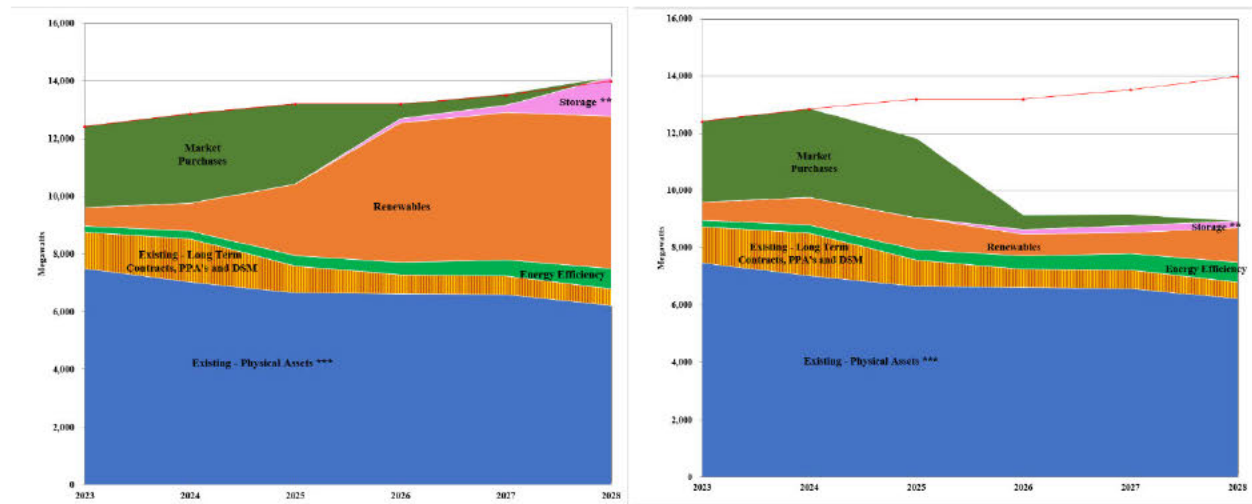
¹⁷ PacifiCorp Response to Staff DR No. 243.

Figure 1. Difference in Installed Cumulative Capacity Between 2023 IRP Preferred Portfolio and Current Reality



This delay will also have a significant impact on the generation mix of the system. Figure 9.60 in the IRP shows the projected generation by resource type for the Preferred Portfolio. Over the next five years, PacifiCorp's Preferred Portfolio relied heavily on market purchases (also referred to as front office transactions or FOTs) and existing resources in the near-term while transitioning to rely more and more on new renewable resources. The left side of the figure below is a reproduction of Figure 9.60 as published in the IRP for years through 2028. The right side of the figure below demonstrates what the generation mix could look like if PacifiCorp does not procure new renewables and instead has a capacity mix that resembles the "Updated" chart series in Figure 9 above.

Figure 2. Reproduction of Figure 9.60 in IRP, with and without 2022AS RFP Suspension Impacts



Without the guarantee of additional solar, storage, and wind resources coming online over the next few years, PacifiCorp may end up relying more heavily on FOTs or delaying thermal resource retirements relative to the Preferred Portfolio. This could lead to decarbonization risks, which the Company has not adequately addressed in the current IRP.

As PacifiCorp will not remove the Action Plan items related to the 2022 and the proposed 2024 AS RFP from the filed IRP, nor update any analysis in this IRP/CEP to reflect the indefinite suspension of these procurements, the filed plans do not appear feasible. Staff finds little value in continuing to review this IRP/CEP. Too much is indeterminate and unknown. Further, as the CEP compliance pathways, and thus any determination of continual progress of emission reductions and compliance with the reduction targets, rests so squarely upon the IRP's Preferred Portfolio, without a revised analysis and procurement plan by PacifiCorp, Staff cannot determine the extent to which the CEP demonstrates compliance with the emissions reduction targets or can be substantiated to meet most if not all of the public interest factors detailed in HB 2021.¹⁸

Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes

PacifiCorp reply comments did not offer alternatives or revisions to the following Action Plan items that were impacted by events external to the IRP/CEP.

¹⁸ See ORS 469A.420(2).

- Action Plan Item 1h: Per the non-confidential response to Sierra Club Information Request (IR) No. 37, the very near-term installation of the proposed selective, non-catalytic reduction (SNCR) installations at several coal plants is being paused and reevaluated due to the Federal Court stay of the Ozone Transport Rule.
- As noted previously all Action Plan Items Under Category 2 involve the acquisition of new resources either through the suspended 2022 AS RFP or through a proposed, new 2024 AS RFP. No alternatives or revisions to these activities were offered by the Company. Instead, PacifiCorp points to the potential for new procurements to be proposed with the April 2024 IRP Update.

Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments

CEP acknowledgement hinges upon a finding that the CEP is, “in the public interest and consistent with the clean energy targets...” of HB 2021.¹⁹ The recent order in UM 2273 provides an excellent overview of the public interest factors for valuating a CEP.²⁰ As noted above, given the Company’s unwillingness to revise its analysis, Staff recommends not acknowledging the CEP. In the sections below, Staff details its determination that the community-focused elements of the LC 82 CEP appear reasonable with certain recommended changes, while the GHG emission reduction related portion of the CEP is not consistent with the clean energy targets nor does it appear to meet most if not all of the public interest factors detailed in HB 2021. For this reason, Staff does not recommend acknowledgement, but identifies portions of the CEP that may be included and/or improved in the revised and resubmitted CEP.

Community Benefits Indicators (CBI)

In Round 1 Comments Staff expressed concern that the interim CBIs provided no incremental information for evaluating the Company’s IRP or CEP portfolios and did not materially affect its plans.²¹ Staff requested that for the next IRP, the Company adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company’s CBRE actions.²²

The Energy Advocates recommend greater granularity for the Company’s CBIs.²³ They also encourage the Company to include better measures of distributional justice when creating CBIs.²⁴ The Energy Advocates then state that the Company’s CBIs do not offer any sense of how PacifiCorp brings economic benefits to communities,²⁵ a sentiment that is echoed by NewSun Energy.²⁶ The Community Advocates Cohort is discouraged by the lack of details in the Company’s proposed CBIs and believes the Company’s CO2 emissions CBI is not an indicator of community benefits.²⁷ Renewable Northwest (RNW) would like more detail about how the Company chose the 17 metrics that were included in the CEP.²⁸ RNW also recommends that the Company adopt additional environmental CBIs and believes that the language the Company uses when describing its resiliency CBIs expresses a hope instead of indicating that it is strongly committed to improvements or has any planned actions.²⁹ CRITFC supports past recommendations by the Energy Advocates to improve CBIs and wants better accounting for tribal needs in the Company’s CEP.³⁰ In particular, CRITFC wants the CBI to incorporate tribal energy metrics and create metrics that target reducing peak loads, maximizing energy efficiency, strategically siting renewable resources, reducing reliance on Federal hydro resources, and minimizing the transmission and distribution system.³¹

¹⁹ ORS 469A.420(2).

²⁰ UM 2273, Investigation into HB 2021 Implementation Issues, Order No. 24-002, Jan. 5, 2024, starting on page 17.

²¹ Staff’s Round 1 Comments, page 19.

²² Staff’s Round 1 Comments, page 21.

²³ Energy Advocates’ Round 1 Comments, page 7-8.

²⁴ Energy Advocates’ Round 1 Comments, page 11.

²⁵ Energy Advocates’ Round 1 Comments, page 12.

²⁶ NewSun Energy’s Round 1 Comments, page 6.

²⁷ Community Advocates Cohort’s Round 1 Comments.

²⁸ RNW’s Round 1 Comments, page 65.

²⁹ RNW’s Round 1 Comments, page 65.

³⁰ CRITFC’s Round 1 Comments, page 4.

³¹ CRITFC’s Round 1 Comments, page 7.

PacifiCorp stated in Round 1 Response Comments that it intends its CBIs to be a holistic representation of all the Company's activities to increase community benefits and highlights that it has added two new draft CBIs through its stakeholder process.³² The Company states that it intends to refine its approach to resiliency and that there is additional work necessary to develop its CBIs.³³ In response to Staff's suggestion to frame CBIs as a metric rather than a goal, the Company states that it would consider it, but anticipates that it may cause confusion.³⁴ The Company did not appear to directly respond to any other concerns raised by Staff or stakeholders regarding CBIs.

Staff finds that the Company failed to fully respond to Round 1 comments by both Staff and stakeholders. In particular, the Company failed to:

- Provide any timeline to refine CBIs or provide any detail about how they could be refined.
- Discuss how it is attempting to implement tribal concerns brought up by CRITFC or greater CBI granularity brought up by Energy Advocates and Staff into CBIs.
- Discuss whether or how it would incorporate additional environmental CBIs into its next CEP.
- Provide any explanation about how the 17 metrics were chosen, as requested by RNW.

Staff agrees with the Company that developing CBIs is an iterative process that should be done in consultation with local communities and tribal governments. Staff is worried by the Company's apparent lack of response to published concerns by stakeholders, lack of record keeping, and lack of target timeline to improve CBIs. Staff would note the importance of maximizing to the extent possible Oregon community benefits across such planning activities such as portfolio development³⁵ and resource selection.³⁶ As such, relying solely on measures of systemwide impacts provides very little value when evaluating whether the Company's IRP and CEP provide tangible benefits to Oregon communities. Staff's Round 1 comments recommended that CBIs better addressing energy efficiency, local emissions, and CBRE impacts were meant to bridge this gap.

With the following draft recommendations and expectations, Staff recognizes that the CBIs in this CEP are interim, but also seeks to stress the importance of using CBIs to meaningfully inform utility decisions and to track progress over time. Staff expects that the further development of CBIs be done in coordination with local communities and tribal governments and describes additional recommendations and expectations regarding this coordination in the Community Engagement section.³⁷

Staff believes that in order to have an effective set of CBIs, it is critical to provide baseline measures of community impact prior to the next IRP/CEP update, and to develop more CBIs that address local non-GHG emissions, energy efficiency, and CBRE actions.

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

³² LC 82, PacifiCorp Reply Comments, page 13.

³³ LC 82, PacifiCorp Reply Comments, page 16-17.

³⁴ LC 82, PacifiCorp Reply Comments, page 18.

³⁵ UM 2225, Order No. 23-060, February 23, 2023, Appendix A, page 5.

³⁶ UM 2273, Order No. 24-002, January 3, 2024, page 23.

³⁷ UM LC 80, Staff's Round 2 Comments, page 31.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Expectations:

In the next IRP/CEP, Staff expects PacifiCorp to:

- Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
- Better inform CBIs and methods with input from stakeholders and community.
- Enhance tribal-focused CBIs.
- Use CBIs to better reflect the health impacts of EE.
- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
- Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
- Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

Community Based Renewable Energy (CBRE)

Staff found PacifiCorp's identified CBRE resources a reasonable starting point, but questioned whether more should be available based on a forecast of market activities not just existing programs. Staff also questioned whether net benefits were appropriately considered. Staff encouraged PacifiCorp to not limit CBRE potential to the activities and resources identified in the CEP and consider energy efficiency and flexible loads as potential valuable contributors. Lastly, Staff drew the connection between CBRE and SSR, and encouraged PacifiCorp to more aggressively pursue CBREs. Further, Staff encouraged PacifiCorp to pursue a CBRE strategy targeted at Oregon load pockets to avoid significant local transmission and distributions system upgrades.

RNW encouraged PacifiCorp to better quantify the benefits of CBRE and identify above market costs. Energy Advocates similarly encouraged PacifiCorp to consider broad benefits of CBRE, beyond a levelized cost of electricity analysis. RNW and Energy Advocates highlighted that PacifiCorp's CBRE potential relied on tallying existing programs which could be counted as CBRE. Both entities encouraged PacifiCorp to take initiative to identify additional CBRE resources. Energy Advocates highlighted that costs are likely inflated due to modeling not considering the IJIA and IRA. CUB raised government funding and questioned how funds may support CBRE development.

In response to Round 1 comments, PacifiCorp emphasized the Company's commitment to launching the CBRE Pilot proposal to external parties in the first quarter of 2024. The Company highlighted some of the ways in which the landscape of CBRE is quickly developing since the initial CEP filing. Of note, PacifiCorp anticipates a larger CBRE potential in Group B, siting 20 new projects in the pipeline. Initially, Group B included 3.5 MW of small-scale and community-focused renewable projects, primarily solar plus storage.

PacifiCorp commented on features of the Company's modeling that were raised by Staff and stakeholders. PacifiCorp clarified that the 10 percent adder was used to treat CBRE resources

commensurately with energy efficiency. For the CBRE scenario, PacifiCorp clarified that the Company had to force the model to acquire CBRE resources as the model would not have otherwise done so for cost reasons. Finally, PacifiCorp emphasized the dynamic nature of the planning environment for CBRE and committed to ongoing refinement of CBRE Pilot Approach. In particular, the Company resolved to support projects that are “in-flight” via other co-funding mechanisms and programs. PacifiCorp contends that despite commitment to ongoing improvement, costs were not inflated in this first round of analysis even though large federal legislation, namely the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), were not included in initial analysis.

CBRE Resource Potential

Staff recommends that PacifiCorp consider more ambitious CBRE potential than the 95 MW identified, including 92 MW of which are in existing programs. The initial potential study tallied pending projects, and did not rely on forecasting sophistication of consumer adoption curves, historical cost declines, or enabling funding and programs. Staff appreciates PacifiCorp’s acknowledgement that the 3.5 MW, Group B, potential is likely much greater due to new funding and programs. Due to rapid increases in renewable energy acquisition, Staff finds that 95 MW could significantly undercount the CBRE potential if effective program designs are deployed that recognize the benefits of CBRE, especially in the preferred portfolio.

Due to the magnitude of the 490 MW SSR requirement and the potential of CBRE resources to grow, Staff would like PacifiCorp to take a more aggressive approach than the “measured and incremental approach to investigating CBREs”.³⁸ Staff encourages a sense of urgency and recommends PacifiCorp immediately publish the CBRE Grant Pilot Proposal to the CBIAG. Feedback should be solicited and processed quickly, such that PacifiCorp files the first round of the CBRE Grant Pilot for Staff approval by the end of Q2 2024. A quick feedback cycle is essential such that PacifiCorp may consider amending its CBRE potential based on feedback and results of an initial CBRE Grant Pilot.

Staff Recommendation 7. Direct PacifiCorp to pursue the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

CBRE Activities

In the upcoming 2024 CEP update, Staff recommends PacifiCorp include an acquisition target of CBRE in its Action Plan. PacifiCorp’s Round 1 comments identified a growing pool of known CBRE resources suggesting that 95 MW is likely a floor for a 2030 acquisition goal.³⁹ Many of PacifiCorp’s CBRE actions are positive steps, but the current Action Plan, with no firm acquisition target, falls short of Staff’s expectations. Staff appreciates that PacifiCorp continues to develop the CBRE Grant Pilot with stakeholders and is prioritizing “in-flight projects”, such that the Company can accelerate how quickly those come online. Further, Staff expects PacifiCorp to be proactive beyond publishing a CBRE Grant Pilot. PacifiCorp should report regularly to the CBIAG on development activities, including on concrete actions PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

Staff Expectation:

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

³⁸ LC 82, PacifiCorp Reply Comments, page 4.

³⁹ LC 82, PacifiCorp Reply Comments, page 92.

CBRE Inclusion in Preferred Portfolio

In Portland General Electric's (PGE) 2023 IRP/CEP, PGE clearly communicated the fixed cost minus the benefit streams of CBRE resources. PGE's modeling selected the entire 155 MW of CBRE potential for the resource's value within the balancing authority.⁴⁰ Acknowledging that PGE and PacifiCorp have different geographic and resource characteristics, PacifiCorp's load pockets are an example where prioritization for CBRE resources would maximize benefits to both individual communities and to all ratepayers.

Staff disagrees with PacifiCorp's blanket characterization that a commitment to pursuing CBRE resources would break from historical least-cost, least-risk paradigm. Much of the CBRE resources identified have complementary, non-ratepayer sources of funding to reduce costs and avoid separate SSR procurement. As PacifiCorp acknowledged, the IRA and IJA incentives were not accounted for in CBRE analysis which both reduces the potential and inflates the cost. Further, as was raised by Energy Advocates and RNW, PacifiCorp did not provide a transparent accounting of the benefits of CBRE resources to the system, particularly with respect to investments that can be avoided as a result. Without this clear articulation of value and despite PacifiCorp's claims of "considerable favor to SSRs" in PLEXOS modeling, Staff is not persuaded that all CBRE resources are as uneconomic as the Company portrays.⁴¹

Also undermining PacifiCorp's argument that pursuing CBRE breaks from the least-cost, least-risk paradigm is the fact that the Company's potential study found 92 MW of CBRE in existing programs. Proper cost consideration should have included these resources in the IRP preferred portfolio. Staff expects PacifiCorp to include these CBRE resources in the 2024 IRP update preferred portfolio and to update the CBRE potential in the 2024 CEP update.

Staff requested PacifiCorp address CBRE's role in minimizing costs in Oregon's load pockets.⁴² PacifiCorp acknowledged the request but failed to respond in a quantitative manner. Staff highlights that PacifiCorp is versed in the dynamics of storage as a tool to manage transmission constraints, as section 6 in Round 1 comments includes robust discussion of specific examples (storage in lieu of B2H) and general agreement that less transmission expense is a "chief advantage of SSR".⁴³ However, it is unclear whether the Company applied a commensurate benefit to small scale and customer sited renewables and storage.

Staff Expectations:

In the IRP/CEP update:

- Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

By the next IRP/CEP:

- Highlight and communicate the relative benefits of CBRE in load pockets.

⁴⁰ See Docket No. LC 80, *Portland General Electric 2023 Integrated Resource Plan and Clean Energy Plan*, Figure 77. Net cost of a microgrid CBRE, page 251, <https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf>.

⁴¹ Id., page 84.

⁴² Staff Round 1 Comments, DR No. 16, page 25, <https://edocs.puc.state.or.us/efdocs/HAC/lc82hac144131.pdf>.

⁴³ LC 82, PacifiCorp Reply Comments, page 53, <https://edocs.puc.state.or.us/efdocs/HAC/lc82hac1546.pdf>.

- Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to “[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy.”⁴⁴
- Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

Staff encourages PacifiCorp to consider CBRE program designs that scale quickly and provide meaningful capacity distributed across the geographically diverse territory and specifically to load pockets. Staff highlights Green Mountain Power’s (GMP) residential storage programs that have 1.1 percent of customers enrolled today and are poised to double annual customer acquisition rates.⁴⁵ A similar program growing at the same, per capita rate as GMP’s could add 200 MW of distributed storage capacity to PacifiCorp’s Oregon territory by 2030.⁴⁶ GMP’s rate-based cost to operate the programs is reduced by the benefit of a 30 percent federal tax credit, monthly customer participation fees, and GMP’s ongoing economic dispatch of the aggregated capacity. Over the system’s lifetime, GMP identifies a positive lifetime net-present value of \$2,749, despite the upfront, fixed cost of \$22,000.⁴⁷

Staff highlights Green Mountain Power as an example of a program design that delivers resilience, helps increase renewables adoptions, and scales quickly. Staff encourages PacifiCorp to be more expansive in its consideration of CBRE resources and consider additional energy efficiency and demand response capacity. For example, many buildings and communities across the state lack basic weatherization and existing programs are not scaled up to meet the need. In one example, the Northwest Energy Efficiency Alliance’s 2016-2017 Residential Building Stock Analysis showed that 11 percent of Oregon’s single family homes have uninsulated walls.⁴⁸ Efficient buildings that can maintain comfort during severe heat and cold events deliver not just energy savings but are better able to participate in demand response programs and deliver capacity savings.

Staff Expectation:

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

In Order No. 22-390, the Commission adopted expectations for PacifiCorp and PGE to furnish details on community engagement.⁴⁹ PacifiCorp used its existing IRP public input process, DSP efforts, and CETA Washington Equity Advisory Group as the basis of its CEP engagement efforts. The Company’s

⁴⁴ ORS 469A.415(4)(d).

⁴⁵ Howland, Ethan, *Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others*, Utility Dive, Aug. 29, 2023, <https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/>.

⁴⁶ Ibid. GMP anticipates growth of 474 residential battery installs per 100,000 customers. At 10 kW capacity per install, PacifiCorp’s 610,000 customers could accumulate 200 MW of capacity by 2030.

⁴⁷ Ibid.

⁴⁸ *Residential Building Stock Assessment II Single Family Report*, Northwest Energy Efficiency Alliance, April 2019, [neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf](https://www.neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf).

⁴⁹ *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (October 25, 2022) corrected, Order No. 22-470 (December 5, 2022).

engagement efforts consist of customer surveys, sharing the Company's planning decisions at public "stakeholder engagement venue" meetings, and a Feedback Tracker to document the Company's response meeting questions and comments. The engagement venues include, among others, a CEP Engagement Series, the Community Benefits and Impacts Advisory Group (CBIAG), and the Oregon Tribal Nations Clean Energy Engagement Series.

Staff Round 1 Comments asserted that PacifiCorp had not successfully articulated the Company's path from engagement and input to planning and action. While the CEP discussed tribal engagement opportunities, Staff found the CEP lacked detail on whether the Company had successfully incorporated Tribal perspectives into the Company's decision making and engagement strategy. Additionally, it was not clear that the Company's plan included the perspectives of environmental justice communities. To this extent, Staff suggested improvements including reevaluating the Feedback Tracker to include a clear description of why feedback was or was not included in IRP/CEP.⁵⁰ Going forward, Staff also recommended a dedicated stakeholder and cross-utility community engagement working group similar to that put forward in LC 80.⁵¹

In Opening Comments, the consensus among CUB, RNW, Energy Advocates, and Community Advocates, was that PacifiCorp had not meaningfully considered input from environmental justice communities. Energy Advocates and Community Advocates further noted that PacifiCorp had not measured the effectiveness of their engagement strategy. CRITFC advanced that there is no indication from the CEP or IRP that PacifiCorp has consulted with affected Tribes prior to making decisions, particularly around hydropower reliance.

In Reply Comments, PacifiCorp did not oppose working with PGE to create a common community engagement strategy group along the lines of Staff's suggestion.⁵² PacifiCorp committed to timely updating the Feedback Tracker following public workshops,⁵³ but did not address Staff's additional suggestions to improve the Feedback Tracker. PacifiCorp stated the Company continues to pursue a dialogue with its sovereign tribal partners across its six-state service area and intends to hire a tribal-affairs representative. The Company further commented that it was developing a Tribal CBI focused on TE. PacifiCorp linked components of its DSP/Clean Energy survey to outreach and accessibility practices. Regarding environmental justice, the Company referenced an educational component at CBIAG meetings.

On December 19, 2023, following Round 1 Reply Comments, PacifiCorp met with Staff informally to explain how the Company had used the community engagement process to develop its Interim CBIs. PacifiCorp explained that, due to time constraints, the Interim CBIs presented in the CEP did not originate with the CBIAG. Instead, PacifiCorp selected CBIs previously developed through Washington's Clean Energy Transformation Act (CETA) engagement process. According to PacifiCorp, CBIAG members had approved of the Washington CBIs and also suggested additional CBIs; however, PacifiCorp stated at the meeting with Staff that it could not provide Staff with documentation of this approval or the

⁵⁰ *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (Oct. 25, 2022) *corrected*, Order No. 22-470 (Dec. 5, 2022).

⁵¹ *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Round 2 Comments and Recommendations at pages 29-30 (October 24, 2023).

⁵² LC 82, PacifiCorp Reply Comments, December 1, 2023, pages 10, 11.

⁵³ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 11.

proposed CBIs from CBIAG members⁵⁴ beyond the map showing the Company had opposed CBIs proposed by Joint Advocates that were not in line with the Washington CBIs.⁵⁵ Going forward, Company representatives committed to:

- Working with the CBIAG to evolve CBIs to be Oregon specific and reflective of CBIAG member feedback;
- Leveraging other efforts to inform and bolster CBIs, including through a 2023 survey and by developing channels to streamline community input from adjacent initiatives to CBIAG members; and
- Making changes to how the Company received and documented input to ensure CBIAG member feedback and knowledge was captured and could be referenced at a later date.⁵⁶

After review of Stakeholder and PacifiCorp comments, Staff has identified the following key adjustments to the Company's platforms and methods that can improve community engagement in future CEP/ IRP processes.

Accountability and Transparency

PacifiCorp's CEP includes available venues for public input, yet the Company's community engagement strategy could be improved and ultimately more effective through better documentation of stakeholder input. This CEP did not provide a clear roadmap of how or why PacifiCorp used stakeholder input to inform the Company's IRP and CEP. Going forward, this documentation can help close the gaps between the Company's interpretation of effective engagement and stakeholders' priorities and expectations. Accordingly, Staff reiterates the need for Feedback Tracker improvements and looks forward to working with PacifiCorp and stakeholders to implement these improvements. Staff also recommends the utility conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts. Additionally, Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document how Environmental Justice community priorities are addressed. Finally, as introduced in Round 1 Comments, Staff believes it is a priority to develop clear, actionable expectations for engagement in future IRP/CEP development and review. Consistent with LC 80, Staff recommends the establishment of a working group that can operate in coordination with the broader investigation into the Commission's planning and procurement policies in 2024.

Cross-venue Engagement Planning

Staff recognizes that stakeholder engagement addressing critical issues, such as wildfire risk, transportation electrification (TE), and energy affordability is occurring in separate dockets and venues outside of the CEP process. As discussed at the informal December 19 meeting with PacifiCorp, Staff is encouraged by the Company's work to streamline input channels. In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in these adjacent dockets and venues to inform CBIs, CBREs, and portfolio decisions.

⁵⁴ Staff and PacifiCorp meeting held December 19, 2023.

⁵⁵ PacifiCorp response to Staff DR 35 Attachment.

⁵⁶ Staff and PacifiCorp meeting held December 19, 2023.

Tribal Engagement

In Opening Comments, Staff recognized that engagement with Tribal Nations requires intentional recognition and a focused approach that the utility and industry as a whole is working to better understand and practice. Staff appreciates PacifiCorp's introduction of a Tribal TE CBI. Going forward, Staff expects the Company to provide updates to the CBIAG and Staff on the Tribal CBI development and strategy to actively increase Tribal Nation priorities in planning conversations and resource decision-making.

Notably, in December 2023, the U.S. Government reached a settlement agreement to support the Columbia Basin Restoration Initiative (CBRI) in partnership with the Six Sovereigns.⁵⁷ This comprehensive agreement leveraged the collective knowledge and priorities of Tribal Nations, Oregon and Washington states, federal agencies, and interest groups. The CBRI anticipates changes to the energy system as part of the work to restore fisheries while supporting decarbonization and resilient communities. For these reasons, Staff views the CBRI as an opportunity for PacifiCorp to improve its engagement strategy with Tribal Nations impacted by the construction and operation of the Columbia River Federal dams.

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Staff Expectations:

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
 - Organization/entity attribution or affiliation.
 - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
 - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp should conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

⁵⁷ See Northwest Power and Conservation Council memorandum, *Report on the US Government Commitments: Power Related Topics*, January 3, 2024, https://www.nwcouncil.org/fs/18579/2024_01_p2.pdf. The Six Sovereigns include the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington.

Resiliency Analysis Framework

PacifiCorp's CEP outlines the beginnings of the Company's Resiliency Analysis Framework. The Resiliency Analysis Framework combines census tract level community⁵⁸ and utility⁵⁹ resilience scores into a composite community-resilience score. The Company plans to use the community-resilience score to identify census tracts for additional analysis and project prioritization.⁶⁰ After identifying threats, probabilities, and consequences, PacifiCorp plans to use a risk-spend efficiency (RSE) or cost-benefit analysis (CBA) to account for the costs at specific project locations. The Company's goal is to include resilience risk scores in project and program prioritization, including when assessing the IRP, CBRE, and SSR.⁶¹

In Opening Comments, Staff requested an update on the Resiliency Analysis Framework timeline, which includes PAC's plan to incorporate community-utility resilience scores and risk drivers into CEP program planning by Q1 2024.⁶² By extension, Staff asked how the Company planned to use the Resiliency Analysis Framework in the IRP, CEP, and/or DSP. Staff also asked for additional information on the resiliency scoring metrics.

Energy Advocates and CRITFC argued that PacifiCorp should improve community resiliency and consider how SAIDI/SAIFI/CAIDI data can be connected with information about lived experiences and community resources that can be used during an outage. Energy Advocates added that PacifiCorp should clearly define resiliency in the CEP and improve the readability of the CEP to include important definitions for SAIDI, SAIFI, and CAIDI. CRITFC discussed the link between healthy salmon ecosystems, utility resource planning to meet HB 2021 requirements, and tribal community resiliency.

In Round 1 Reply Comments, PacifiCorp did not directly respond to requests for information about resiliency planning and community data points. Instead, PacifiCorp stated that much of Staff and stakeholders' comments, questions, and concerns would be addressed in the next CEP.⁶³ PacifiCorp's future planning approach will, "evolve as [the Company] gain[s] experience and receive[s] additional stakeholder input."⁶⁴ PacifiCorp explains that it is still evaluating how to include additional community input.

⁵⁸ To develop the community resilience score, PacifiCorp assigns social vulnerability and community resilience scores to census tracts using FEMA National Risk Index (NRI) values. PacifiCorp response to Staff DR No. 97.

⁵⁹ To develop the utility resilience score, PacifiCorp applies System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) including major events to calculate the annual number of customers and minutes interrupted at each transformer in each census tract. PacifiCorp response to Staff DR No. 97.

⁶⁰ For example, PacifiCorp explains that by sorting the largest census tract CAIDI values first, and then sorting by the lower NRI values the Company can identify customers experiencing longer system outages with lower community resilience or higher social vulnerability. PacifiCorp response to Staff DR No. 99.

⁶¹ LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 29.

⁶² See LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 32; see also PacifiCorp response to Staff DR No. 30.

⁶³ See LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48 (In Round 1 comments Staff requested an updated Table 9 timeline. PacifiCorp acknowledged Staff's request in its Round 1 Reply Comments but did not provide an updated Table 9 timeline.); see also LC 82, PacifiCorp Round 1 Reply Comments, December 1, 2023, page 49 ("PacifiCorp is also evaluating how to apply its resilience analysis to DSP and CEP programs and will provide additional information in its upcoming CEP consistent with Staff recommendations. ... PacifiCorp is currently developing a preliminary resilience cost-benefit analysis and will include this framework in its upcoming CEP.").

⁶⁴ LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48.

PacifiCorp did not address Staff's questions on how the Company's wildfire plan was incorporated into the CEP resiliency analysis beyond directing Staff to review the Company's Wildfire Mitigation Plan. PacifiCorp disagreed with Staff's assessment about its use of the terms "resiliency" and "reliability", but states it will be clearer in the next CEP. In response to Stakeholder requests, PacifiCorp has provided definitions of SAIDI, SAIFI, and CAIDI.

Staff also understands that PacifiCorp is currently evaluating the geographic scope of the Resiliency Analysis Framework to develop more granular resilience scores.⁶⁵ Of note, PacifiCorp's current methodology to calculate SAIDI/SAIFI/CAIDI scores at the census tract level results in higher values than under the traditional use, which applies these metrics to the state or utility level.⁶⁶ As stated in Staff Round 1 Comments, Staff is still interested in understanding how these census-level SAIDI/SAIFI/CAIDI data has been successfully used in the past for resiliency-related planning. Staff expects the Resiliency Analysis Framework to consider direct benefits to Oregon communities. Nevertheless, Staff is concerned that limiting the scope of resilience metrics to transformer outages within Oregon census tracts, as discussed in step two of the Resiliency Analysis Framework, may result in unnecessary grid-hardening at the expense of PacifiCorp's Oregon ratepayers or overlook cross-state resiliency issues such as wildfire, extreme weather, and load pockets.⁶⁷ Given the nascent state of the Resiliency Analysis Framework, Staff sees an opportunity to open discussions with the Company and Stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework.

PacifiCorp states it accounts for non-energy related resilience assets and services in the NRI values.⁶⁸ As noted in Round 1 comments, the NRI values use well known indices and Staff continues to find them helpful. That said, Staff would like further insight on how the Company plans to consider these assets and services to meet its goal to prioritize enhancing community resilience over acquiring additional capacity⁶⁹ and avoid extraneous utility projects and their associated costs. Staff also expects further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.

Staff understands that resiliency analysis is an evolving field and expects that PacifiCorp will significantly improve upon its Resiliency Analysis Framework in the next CEP. In the meantime, Staff recommends that PacifiCorp incorporate resiliency-related factors into the Q1 2024 SSR RFP and the CBRE Grant Pilot so that these efforts can bring tangible community benefits to their system.

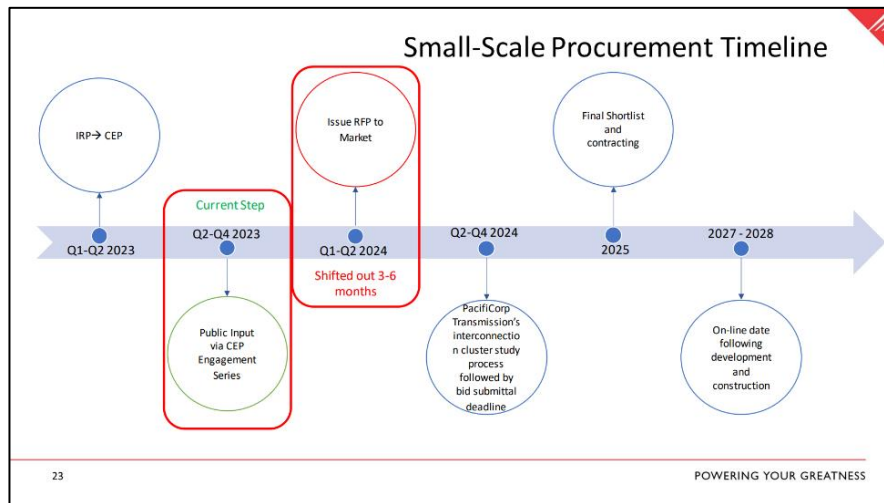
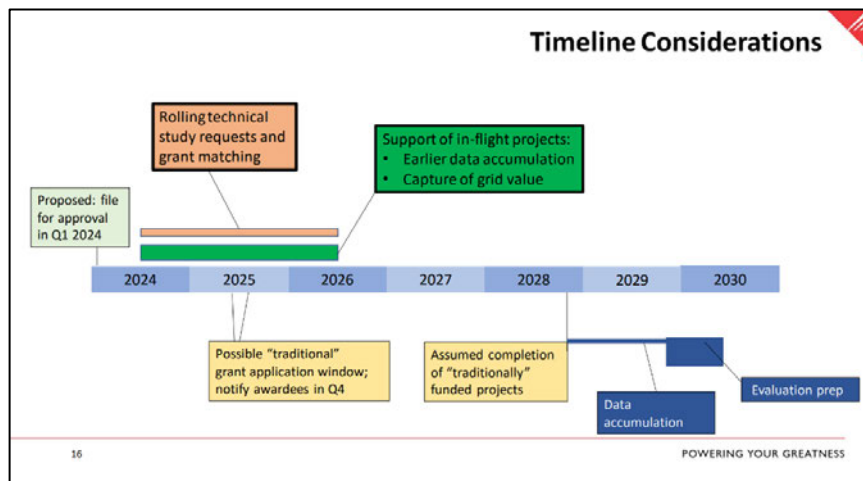
⁶⁵ See e.g., PacifiCorp response to Staff DR No. 96.

⁶⁶ LC 82, PacifiCorp 2023 CEP, CBI, May 31, 2023, page 20.

⁶⁷ See e.g., *In the Matter of Investigation into House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 24-002 at page 25 (January 5, 2024) ("Grid-connected facilities located outside Oregon contribute to reliable service for Oregon electricity customers and to reducing GHG emissions on the grid, and facilities located inside Oregon do not serve Oregon customers exclusively. There may be resiliency benefits to in-state resources and resource strategies that are worthwhile to consider, but those must be based on reliability and resiliency analysis or related valuation methodologies, not assumed based solely on geographic location or the presence of specific electricity market transaction receipts.").

⁶⁸ LC 82, PacifiCorp response to Staff DR Nos. 102, 104.

⁶⁹ LC 82 PacifiCorp 2023 CEP, CBRE, May 31, 2023, page 45; see also PacifiCorp response to Staff DR 109.

Figure 3: SSR RFP Procurement Timeline⁷⁰Figure 4: Timeline Considerations for the CBRE Pilot⁷¹

PacifiCorp's community-utility resilience score accounts for time and duration of outages through SAIDI/SAIFI/CAIDI metrics. It is not clear to Staff what additional information Stakeholders need regarding SAIDI/SAIFI/CAIDI methodologies and definitions. Prior to the next CEP filing, Staff expects PacifiCorp work with Stakeholders to identify gaps in Resiliency Analysis Framework comprehension and the vulnerabilities and complexities of these data sets as a measure of community level impacts.

⁷⁰ PacifiCorp CEP Engagement Series, 4th meeting, slide 23 (August 25, 2023) available at https://www.pacifiCorp.com/content/dam/pcorp/documents/en/pacifiCorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

⁷¹ PacifiCorp CEP Engagement Series, 4th meeting, slide 16 (August 25, 2023) available at https://www.pacifiCorp.com/content/dam/pcorp/documents/en/pacifiCorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Staff Expectations:

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.
- By the next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

One of the specifically enumerated, HB 2021 public interest factors for weighing CEP acknowledgement is the extent to which the availability of federal incentives were considered.⁷² In Round 1 comments Staff joined Sierra Club and CUB in calling for PacifiCorp to fully incorporate the financing opportunities and tax credits made available through the Interest Reduction Act (IRA) more fully into its IRP/CEP analysis. This included rerunning variant portfolios. Specifically: apply a 30 percent reduction to transmission network upgrade costs for low cost, renewable projects in select cluster study areas; and, assuming low cost federal financing and loan guarantees be used for targeted early plant retirements. Suggestions also included regular reporting to the Commission on progress pursuing federal incentives, exploring how Justice 40 incentives could be used for CBREs, and applying tax bonus credits to eligible "energy communities" in Oregon.

PacifiCorp responded that it used the available IRA information at the time of filing and continues to examine evolving legislation for use in future analysis where appropriate. Further, the Company stated that the PLEXOS model did account for federal incentives, as appropriate. The Company also shared that it was actively pursuing EIR programs, financing it can qualify for, and applying for grants and that it will communicate the details of IRA financing and other incentives as they become known. Finally, the Company stated that a variant study can be reported once the IRA financing details are better known.

⁷² ORS 469A.420(2).

Staff appreciates all of the work done by PacifiCorp, stakeholders, and especially Sierra Club, to highlight the enormous cost-saving opportunities available through the federal government's IRA initiatives. However, this funding is limited to \$2 Billion, expires in September 2026, and utilizes a first-come, first-served competitive application process. In short, time is of the essence if PacifiCorp wants to secure low-cost financing for planned investments to replace aging infrastructure.

Staff Expectations:

- The IRP Update includes two variant portfolios that directly reflect Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments

In this section, Staff will not revisit all topics raised in our Round 1 comments on the IRP aspects of LC 82. Rather we have sought to prioritize those items which have the greatest bearing on acknowledgement/non-acknowledgement or are most critical for improvement in the next IRP/CEP.

Preferred Portfolio Modeling Process

Staff, RNW, and Sierra Club included an extensive number of comments on portfolio modeling for both improved development and selection. Most notable were the comments on the granularity adjustment, reliability adjustment, the inclusion of CEP resource additions (i.e., Oregon SSRs and higher levels of EE in Oregon), and the re-optimization of variant portfolios.

In developing the second round of comments, Staff's team explored the extent to which the processes around the granularity adjustment, the reliability adjustment, and portfolio reoptimization may have led to suboptimal portfolio development and selection.

Granularity Adjustment

In Round 1 comments, Sierra Club raised potential issues with PacifiCorp's application of granularity adjustments in their capacity expansion runs. PacifiCorp did not address Sierra Club's methodological questions about why the granularity adjustments did not seem to make sense and instead stated that there are "no logical alternatives" to the granularity adjustments, because they were "dictated by model math."⁷³ The Company's responses to earlier discovery from Sierra Club were similarly unclear.⁷⁴

Staff engaged Synapse to further investigate the development and application of granularity adjustments. Synapse examined the workpaper that the Company used to develop the granularity adjustments,⁷⁵ and it identifies a potential errors and omissions in the calculations. [BEGIN

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[END HIGHLY CONFIDENTIAL]. Thus the

Company may be adding erroneous adjustment factors to its capacity expansion modeling, which should be corrected. While the mistake does not appear to systematically favor [BEGIN CONFIDENTIAL]

⁷³ LC 82, PacifiCorp Round 1 Reply Comments, page 39.

⁷⁴ Sierra Club Round 1 Comments, page 41.

⁷⁵

[REDACTED] [END
CONFIDENTIAL].

[BEGIN HIGHLY CONFIDENTIAL] [REDACTED]

[REDACTED] [END HIGHLY CONFIDENTIAL]. [BEGIN CONFIDENTIAL]

[REDACTED] [END CONFIDENTIAL].⁷⁶ The

inclusion of this adjustment introduces further subjectivity into the LT modeling and highlights the broader shortcomings of PacifiCorp's modeling approach.

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[REDACTED]

[REDACTED] [END HIGHLY CONFIDENTIAL]

The impact of the granularity adjustments, even with the limit of [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL], significantly changes the resource fixed prices. Figure 6 shows the capacity-weighted average fixed cost and granularity adjustments for each category of units. The granularity adjustments reduce fixed prices enough that they could have affected capacity expansion decisions in the model.

Ideally, PacifiCorp should improve the temporal granularity of LT modeling in future IRP proceedings so that granularity adjustments are no longer necessary. If this is not possible, the Company should at minimum revisit its methodology and correct its workpapers if necessary. It should also clearly explain

⁷⁶ PacifiCorp response to OPUC DR No. 240.

its methodology for this adjustment, including clarifying whether it uses the same set of granularity adjustments in each LT model run or whether it adjusts them iteratively. Importantly, PacifiCorp should be able to justify why its results, both with and without the price cap, are reasonable.

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[REDACTED]

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Reliability Adjustment

In Round 1 Comments, Sierra Club also raised concerns with the magnitude and potential subjectivity of the reliability adjustments that PacifiCorp made to optimized portfolios to meet reliability-based constraints. Sierra Club confirmed through discovery that PacifiCorp chooses which reliability adjustments to make based on the duration and timing of the shortage, the maximum size of the shortage in megawatts, and the location of the shortage.⁷⁷ However, the details of the Company's process are not transparent, including which resources it considers eligible for reliability adjustments and how it values eligible resources. As with the granularity adjustments, the Company stated in its Reply Comments that the reliability adjustments were "dictated by model math."⁷⁸ This explanation is even less satisfactory for the reliability adjustments than the granularity adjustments; while it is true that the model determines which hours have unserved energy, the decision about which manual adjustment to make in order to address this problem is at least partially subjective (as illustrated by the alternative portfolio of adjustments that Sierra Club developed for one of the variants in its Round 1 Comments).

⁷⁷ PacifiCorp response to Sierra Club DR No. 27.

⁷⁸ LC 82, PacifiCorp Reply Comments, page 39.

Staff engaged Synapse to further investigate the Company's reliability adjustments. Synapse confirmed Sierra Club's findings and similarly expressed concern regarding the magnitude of and lack of transparency in PacifiCorp's reliability adjustments.

Table 3 and Table 4 below quantify the reliability adjustments that PacifiCorp made in its preferred portfolio. The reliability adjustments more than triple the capacity of non-emitting peakers added during the study period, increase the amount of new batteries by 70 percent, and increase the amount of new solar by 26 percent. PacifiCorp shifted wind builds earlier, increasing the amount of new capacity by 129 percent between 2023 and 2030, but slightly decreasing the amount added over the entire study period.

In discovery, PacifiCorp stated that only non-emitting resources are eligible for reliability adjustments.⁷⁹ However, this is not quite accurate. The Company also manually adjusted the conversion and retirement dates for a number of its thermal resources. In the preferred portfolio, these adjustments took place in two stages. PacifiCorp started with a "Base" scenario, and then it hard-coded coal retirement dates and re-ran PLEXOS to produce a "Base Limited" scenario,⁸⁰ which it identified as the "initial" run used to create the preferred portfolio.⁸¹ It then added further adjustments to produce the "reliable" portfolio. Table 3 compares coal retirement and conversion dates across these three model runs. The large number of changes further underscores the extent to which PacifiCorp produced the preferred portfolio through manual adjustments, rather than configuring PLEXOS in a way that would allow it to optimize builds and retirements.

Table 3: Reliability Adjustments in Preferred Portfolio 2023-2030

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	375	1,770	1,394	371%
Coal – SNCR	(1,380)	-	1,380	-100%
Gas – EOL	247	247	-	0%
Nuclear	500	500	-	0%
Non-emitting peaker	-	606	606	Inf.
Battery	4,359	7,560	3,201	73%
Battery – LDES	482	-	(482)	-100%
Wind	1,934	4,431	2,497	129%
Solar	6,063	6,583	520	9%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

⁷⁹ PacifiCorp response to OPUC DR No. 233.

⁸⁰ PacifiCorp response to Sierra Club DR No. 40.

⁸¹ PacifiCorp response to Sierra Club DR No. 25.

Table 4: Reliability Adjustments in Preferred Portfolio 2023-2042

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	(349)	0	349	-100%
Coal – SNCR	(2,335)	(2,335)	(0)	0%
Gas – EOL	(652)	(595)	57	-9%
Nuclear	1,500	1,500	-	0%
Non-emitting peaker	289	1,240	951	329%
Battery	4,643	7,910	3,267	70%
Battery – LDES	-	350	350	Inf.
Wind	9,251	9,113	(138)	-1%
Solar	6,246	7,855	1,609	26%

Source: “(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx” and “(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx”

Table1 5: Manual Changes to Coal Retirement and Conversion Dates in the IRP Preferred Portfolio

	Base	Base Limited	Reliable
Craig 1	Retires 2026		
Craig 2	Retires 2029		
Dave Johnston 1 and 2	Retires 2029		
Dave Johnston 3	Retires 2028		
Dave Johston 4	Gas conversion, retires 2040	Retires 2040	
Hayden 1	Retires 2029		
Hayden 2	Retires 2028		
Jim Bridger 1	Converts 2024, retires 2031	Converts 2024, retires 2031	Converts 2024, retires 2038
Jim Bridger 2	Converts 2024, retires 2030	Converts 2024, retires 2030	Converts 2024, retires 2038
Jim Bridger 3	Retires 2026	Unclear from workpaper	Converts 2030, retires 2038
Jim Bridger 4	Retires 2032	Unclear from workpaper	Converts 2030, retires 2038
Hunter 1	Retires 2031	SNCR, retires 2031	SNCR, retires 2032
Hunter 2	Retires 2031	SNCR, retires 2032	SNCR, retires 2033
Hunter 3	Retires 2030	SNCR, retires 2030	SNCR, retires 2033
Huntington 1	Retires 2030	SNCR, retires 2030	SNCR, retires 2033
Huntington 2	Retires 2026	SNCR, retires 2028	SNCR, retires 2033
Naughton 1	Converts 2026, retires 2032-2033	Converts 2026, retires 2032	Converts 2026, retires 2037
Naughton 2	Converts 2026, retires 2037		
Wyodak	Converts 2027, retires 2040	SNCR, retires 2040	

Source: “(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx,” “(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xls,” “(P)-LT-6530-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx,” and Sierra Club Round 1 Comments at page 19.

Staff shares Sierra Club's concerns about both transparency surrounding PacifiCorp's process for making reliability adjustments and the magnitude of the adjustments. The reliability adjustments substantially change the resources in the preferred portfolio, calling into doubt the extent to which PacifiCorp's capacity expansion is economically optimized.

Portfolio Reoptimization

Sierra Club's Round 1 comments also raised concerns regarding the inconsistency of PacifiCorp's practice of re-optimizing portfolio variants. Because re-optimization generally finds the lowest cost way to meet a portfolio's constraints, failure to re-optimize a portfolio could lead to an over-estimation of the costs associated with the specific resource variation being examined by that portfolio. This may lead some portfolio variants to appear artificially more expensive than others. In response to this concern, PacifiCorp noted that they have limited time to conduct re-optimization and must prioritize. Additionally, the variant portfolios identified by Sierra Club for re-optimization were generally meant to test through a counterfactual portfolio, a choice within or not included in the Preferred Portfolio (i.e., P-17's exploration of Colstrip's early retirement).

PacifiCorp's decision to not-reoptimize the PLEXOS LT model for variants P13, P18, and P19 causes the resulting portfolios to retain excess capacity that ratepayers do not necessarily need for a reliable system. For example, the resource builds, conversions, and retirements are identical between the Preferred Portfolio and P13– Max DSM, despite this variant installing an additional ~4,000 MW of DSM capacity over the time frame.

Regardless of the ostensible "purpose" of a variant portfolio, this approach fails to allow Staff and stakeholders to properly compare the preferred portfolio to other variants due to the overbuilt nature of the selected variants. As stated above, P18 results in PacifiCorp having an additional 2,000 MW of capacity starting in 2029, and P19 results in additional 500 MW of capacity starting in 2028. Even though PLEXOS ST captures any cost savings associated with dispatch, it is important for PLEXOS LT to be re-optimized as well to give the opportunity for additional cluster resource and DSM capacity to displace other new resource builds and/or identify earlier retirement dates for existing plants. Without re-optimizing PLEXOS LT, stakeholders are unable to easily tease out which resources would be displaced and how that would impact GHG and PVRR outcomes.

In discovery, PacifiCorp stated that three of the variant studies (P13, P18, and P19) were conducted with the understanding that additional resources would likely result in higher cost PVRR outcomes, and that the purpose of these variants is to assess the magnitude of the impact for determining possible least-regret paths to consider for the preferred portfolio.⁸² While the results as presented in this IRP may still be of interest to the Company, PacifiCorp should not be doing this in lieu of re-optimization.

For example, the Max DSM variant as modeled is not currently providing much value for comparison to the preferred portfolio due to the magnitude of the incremental installed capacity that has been required (~4,000 MW) and the magnitude of the PVRR delta (\$3 billion). The benefits of pursuing

⁸² PacifiCorp response to Sierra Club DR No. 43.

ambitious energy efficiency and demand response are to reduce system load, peak demand, and firm capacity reserve requirement, thus avoiding investments in generation and capacity resources and transmission and distribution infrastructure. By not allowing re-optimization of this portfolio, PacifiCorp fails to allow for a significant portion of DSM benefits to be realized in the PVRR result. This variant design also fails to account for the potential of DSM to reduce the SSR and CBRE requirements, further reducing portfolio costs.

In future studies, PacifiCorp should re-optimize all future variant portfolios that add incremental capacity to the preferred portfolio. This will allow the Commission and stakeholders to assess all variant portfolios on an equal playing field. If a variant does not result in the addition or subtraction capacity from the portfolio and can be fully evaluated using PLEXOS ST only, re-optimization may not be necessary. If there is a scenario where PacifiCorp would legitimately be expected to maintain a system with more resources than needed to cost-effectively meet customer needs (e.g. P21), or if there is a legitimate reason the Company could not change its resource plans in time (e.g. P17), then studies without re-optimization could be used. If the Company is still interested in assessing the magnitude of incremental costs from hard-coded resources without re-optimization, this should be done outside of the variant case analysis.

Table 6 below summarizes PacifiCorp's variant portfolios and how they were modeled.

Table 6: Variant Portfolios

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P01-JB3-4 GC	Yes		
P02-JB3-4 EOL	Yes		
P03-Hunter3-SCR	Yes		
P04-Huntington RET28	Yes		
P05-No NUC	Yes		
P06-No Forward Tech	Used P05		
P07-D3-D2 32	Yes		
P08-No D3-D2	Yes		
P09-No WY OTR	No	Used to evaluate the impact on P-MM if Wyoming's OTR was not enforced.	
P10-Offshore Wind	Yes		
P11-Max NG	Yes		
P12-RET Coal 30/33 NG 40	Yes		
P13-Max DSM	No	Used to evaluate the impact on P-MM if all DSM was selected.	Re-optimize capacity mix.
P14-All GW	Yes		
P15-No GWS	Yes		

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P16-No B2H	Yes		
P17-Col3-4 RET25	No	Used to evaluate if earlier retirement of Colstrip 4 would result in energy or capacity shortfalls.	
P18-Cluster East	No	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P19-Cluster West	No	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P20-JB3-4 CCUS	Used P02		
P21-DJ2 CCUS	No	Used to evaluate the impact of installing CCUS at DJ2.	
P22-DJ4 CCUS	No	Used to evaluate the impact of installing CCUS at DJ2.	
P23-RET Coal 30/33	Used P12		
P24-Gas 40-year Life	Yes		

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Staff Expectations:

Before the next IRP, PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP, PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In its Round 1 Comments, Sierra Club raised concerns about the coal prices that PacifiCorp used in its modeling, which may have erroneously delayed the economic retirement date for Jim Bridger 3 and 4.⁸³ These units, which are co-owned by PacifiCorp (67 percent) and Idaho Power Company (33 percent)

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Fuel costs influence unit economics, so it is important for PacifiCorp to represent them correctly within PLEXOS so that the model is able to determine economic retirement and/or conversion dates. [BEGIN HIGHLY CONFIDENTIAL]

2023			
2024			
2025			
2026			
2027			
2028			

Sources: [END HIGHLY CONFIDENTIAL]. [BEGIN CONFIDENTIAL] [END CONFIDENTIAL].

PacifiCorp's Round 1 Response Comments suggested that the Company accounted for the full cost of coal in the IRP, but represented some of the costs as fixed, rather than modeling all coal costs as variable.⁸⁸ [BEGIN HIGHLY CONFIDENTIAL]

[END HIGHLY CONFIDENTIAL].

⁸³ Sierra Club Round 1 Comments, page 44.

⁸⁴ [REDACTED]
⁸⁵ [REDACTED]
⁸⁶ [REDACTED]
⁸⁷ *Id.*

⁸⁸ LC 82, PacifiCorp Reply Comments, page 82: "PacifiCorp did incorporate significant fixed costs for coal supply to Jim Bridger units 3 & 4."

However, PacifiCorp added the fixed costs for coal supply at Jim Bridger in post-processing rather than modeling them within PLEXOS.⁸⁹ As a result, PLEXOS sees only the variable portion of the coal cost (blue line in [REDACTED] [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL]). Unrealistic coal prices within PLEXOS may make Jim Bridger 3 and 4 appear more economic than they are in actuality, which could result in PLEXOS selecting a delayed economic retirement date. In the future, PacifiCorp should correct its PLEXOS modeling so that the full cost of coal at Jim Bridger is represented within the model.

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[REDACTED]

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Sources: [BEGIN CONFIDENTIAL] [REDACTED]

[REDACTED] [END CONFIDENTIAL].

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Hunter and Huntington

Two of PacifiCorp's coal plants, Hunter and Huntington, are located in Utah and have experienced the impact of disruptions to the Utah coal market for reasons such as the Lila Canyon mine fire and unfavorable coal mining conditions. While it can be hard to fully predict future disruptions to coal markets and resulting impact on fuel prices, it is important to incorporate as much up-to-date information as possible in order to ensure model results are reasonably similar to reality. Synapse, on behalf of Staff, reviewed federal Department of Energy EIA 923 fuel receipts data for 2023 and determined that PacifiCorp paid between \$1.79 and \$4.19 per MMBTU for coal at Hunter. At Huntington, Synapse determined that PacifiCorp paid between \$2.18 and \$2.54/MMBTU.

⁸⁹ PacifiCorp response to Staff DR No. 228.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[END CONFIDENTIAL].

On April 3, 2023, PacifiCorp filed its Transition Adjustment Mechanism in Docket No. UE 420 to update its net power costs for 2024. In Witness Owen’s testimony, he states that “the significant production shortfall due to the Lila Canyon mine fire negatively affected all large coal consumers including PacifiCorp. Unfortunately, this negative impact is expected to continue into the foreseeable future.”⁹² If this is PacifiCorp’s current position, then the 2023 IRP Update should incorporate the lasting impacts of unfavorable market conditions into its coal price forecast for these Utah plants.

⁹⁰ Confidential Attachment OPUC 229, “HTR-HTG Coal Update_2022 12 21 CONF”.

⁹¹ US Bureau of Land Management. 2022. *The Bureau of Land Management issues decision on Lila Canyon Mine*. Available at: <https://www.blm.gov/press-release/bureau-land-management-issues-decision-lila-canyon-mine>.

⁹² *In the Matter of PacifiCorp’s 2024 Transition Adjustment Mechanism*, Docket UE 420, Exhibit PacifiCorp/200, Owen/4.

Staff Expectation:

In the next IRP PacifiCorp should:

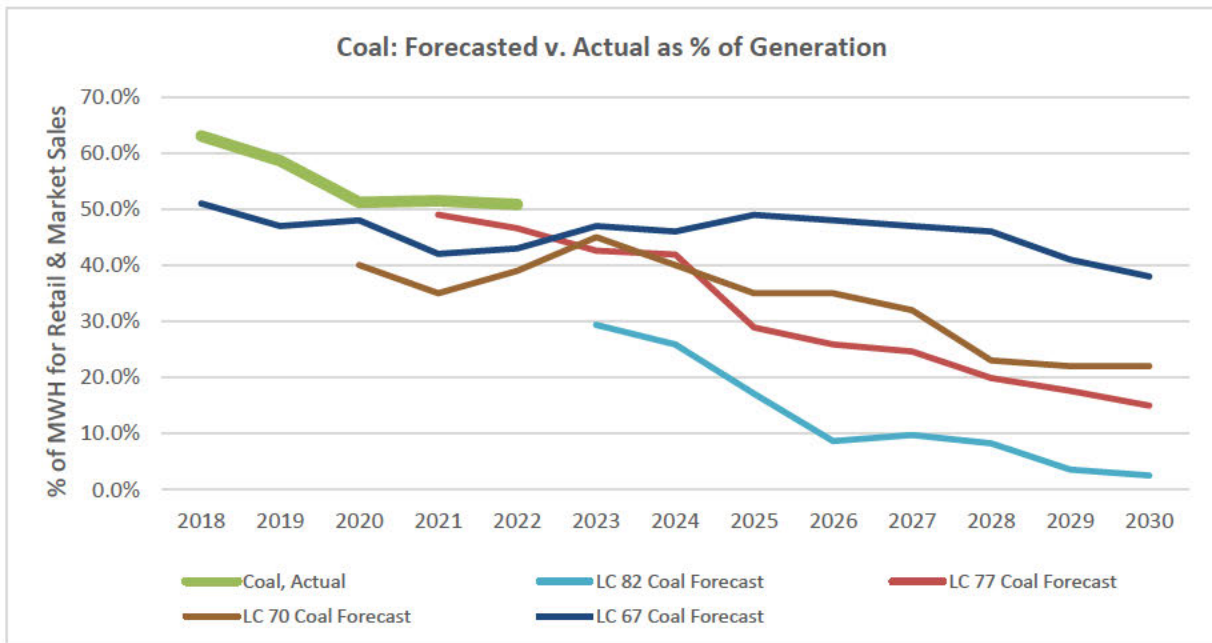
- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

At the LC 82 Special Public Meeting on December 12, 2023, Bob Jenks of CUB raised an interesting point regarding PacifiCorp's use of carbon pricing. He noted that PacifiCorp's IRPs generally begin to apply a price to carbon two years after the IRP. This has the effect of reducing forecasted emissions in the IRP, especially from coal plants, as PacifiCorp's models internalized this carbon price into simulated, future operations. CUB suggested that because a true carbon price has never actually internalized into operations, real-life emissions are systematically higher than IRP modeled GHG emissions. CUB also noted in its Round 1 comments that an effective GHG price could be developed by forecasting, "...the annual cost of carbon from wildfires (prevention and insurance), divide that by its carbon emissions, and allocate the costs of emissions directly to the emissions themselves."⁹³

Staff conducted a brief analysis forecasted to actuals in an attempt to substantiate CUB's comments regarding the disconnect between planning that uses a carbon price and actual coal operations.

Figure 8: 3Comparison of Forecasted v. Actual Coal Use as Percent of Generation



Staff's simple analysis would seem to corroborate CUB's concerns regarding the realism of PacifiCorp's modeled coal dispatch in the IRP. Staff raised a similar concern in UM 2225 in discussing the role of

⁹³ CUB Round 1 Comments, October 25, 2023, page 8.

operational changes in achieving GHG reductions and the Commission adopted the following expectation:

For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:

- *Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and*
- *Describe how the utility intends to implement those operational changes (e.g. through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.⁹⁴*

Accordingly, if the GHG emissions reductions in the CEP depend on the reduction in coal generation that results from applying carbon prices to dispatch, Staff would expect PacifiCorp to quantify those impacts in terms of both generation and GHG emissions, relative to an assumption of economic dispatch without carbon prices.

Importantly, PacifiCorp removes all coal from Oregon rates prior to 2030 per SB 1547 and so Staff expects this issue may only affect the Oregon-allocated GHG emissions in the 2020s. Nevertheless, PacifiCorp's use of GHG prices in modeling operations could be resulting in an unrealistic trajectory of GHG emissions reductions and the lack of an operationalized carbon price could therefore affect PacifiCorp's ability to demonstrate continual progress in the 2020s.

Staff fully supports PacifiCorp's use of GHG prices in portfolio design to capture the risk of future GHG policies. However, Staff is concerned that including GHG prices in the dispatch simulation that informs the Company's Oregon-allocated GHG emissions could be resulting in an unrealistic GHG reduction trajectory.

Staff Expectation:

In the next IRP/CEP PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

⁹⁴ Order No. 22-446, Appendix A at page 21.

Candidate Resource Costs

In Round 1 comments, stakeholders raised concerns that PacifiCorp incorporated unreasonable price escalations for renewable resources. RNW's Round 1 Comments raised concerns on the cost assumptions PacifiCorp applied to its clean energy and energy efficient technologies, which include solar, wind (land-based and offshore), and storage resources.⁹⁵

PacifiCorp sourced its cost data from WSP, an engineering and professional services firm, and later made some adjustments to the cost data to align with its view of future renewable resources market conditions.⁹⁶ WSP had relied primarily on the 2022 NREL ATB study to formulate renewable cost forecasts. The IRP states that PacifiCorp's cost-escalation curve differs from the NREL ATB forecast to account for observed market conditions, such as supply chain issues and long construction lead times.⁹⁷ RNW found that the company's ambiguous modifications to WSP's renewable resource cost estimates results in cost escalations that are 15-50 percent higher through the years 2023-2030.⁹⁸ PacifiCorp's sources or methodology behind large price escalations remain unclear. PacifiCorp has not clearly explained its resource cost modifications besides the "recent tighter trade tariff and inflation" observed in 2022.⁹⁹

Staff agrees with RNW that the long duration of these high prices assumptions are concerning and not well proven. Manual adjustment of cost assumptions most likely affects resource selection and the preferred portfolio's economics.^{100, 101} Due to the high capital cost forecast for renewable resources in PacifiCorp's IRP, the model selects over a GW of nuclear and non-emitting peaking resources through the years of cost escalations.¹⁰²

While it is reasonable to assume cost escalations due to recent market conditions, PacifiCorp's estimates are far above the consensus. Compared to other studies that have adjusted for the recent market changes in renewable energy, PacifiCorp's adjustments have overstated the effects of inflation. Recently published studies have shown that cost increases may not be as persistent as PacifiCorp assumes. Lazard's most recent Levelized Cost of Energy Analysis from 2023 provides recent capital cost comparisons for renewable energy technologies based on a detailed analysis of observed new renewable builds across best-in-class renewables companies. This source provides a thoroughly vetted set of actual costs from newly installed projects.¹⁰³ Lazard's report states that "Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies."¹⁰⁴

⁹⁵ Renewable Northwest, Round 1 Comments, page 31.

⁹⁶ *Ibid.*

⁹⁷ *Ibid.*

⁹⁸ Renewable Northwest, Round 1 Comments, page 31.

⁹⁹ LC 82, PacifiCorp Reply Comments, page 47.

¹⁰⁰ Renewable Northwest, Round 1 Comments, page 32.

¹⁰¹ *Id.*, page 32.

¹⁰² *Id.*, page 32.

¹⁰³ <https://www.lazard.com/media/20zoovyg/lazards-lcoeplus-april-2023.pdf>.

¹⁰⁴ Lazard. Levelized Cost of Energy Analysis-version 16.0. April 2023. Available at: <https://www.lazard.com/media/20zoovyg/lazards-lcoeplus-april-2023.pdf>.

Regulators in other states are also assessing the reasonableness of using NREL ATB studies for the purposes of resource planning.¹⁰⁵ One South Carolina study found that relying on NREL ATB was reasonable and anticipates, "...a gradual decline in real-dollar costs due to industry learning curves and economies of scale, especially as renewable adoption accelerates. Therefore, we encourage Santee Cooper to remain open to upward adjustments in future procurement targets to capitalize on these anticipated cost reductions."¹⁰⁶ Staff finds this sentiment to be similarly relevant to PacifiCorp's resource cost methodology and would also encourage the Company to reassess overly conservative costs and monitor the market for anticipated cost reductions.

For example, PacifiCorp estimates a 34 percent increase in the cost for solar starting in 2023 and persisting for five years after, until cost declines in 2029. This results in a projected cost of \$1,533/kW for a 200MW PV installation in Utah for 2023 through 2028.¹⁰⁷

PacifiCorp's capital cost forecast for land-based and offshore wind is also unsupported by the 2023 NREL ATB and Lazard. For 2023 through 2028, PacifiCorp assumes roughly \$2,000/kW for land-based wind and \$5,900/kW for offshore wind. According to Lazard's 2023 Levelized Cost of Energy Analysis, capital costs for land-based and offshore wind reaches a high of \$1,700/kW and \$5,000/kW, respectively.¹⁰⁸

Finally, PacifiCorp's resource storage assumptions are also significantly higher than NREL's projections. PacifiCorp's battery storage capital costs estimates are \$454 and \$477/kWh in 2022 and 2023 respectively, with no projected cost declines until 2029.¹⁰⁹ NREL 2023 study estimates capital cost of approximately \$470/kW but assumes step cost decline afterwards with capital cost reaching a low \$320/kW in 2032.

Staff, through its consultant, Synapse, conducted a high-level analysis to estimate the difference in the Preferred Portfolio's build costs if the utility had instead relied on NREL's 2023 ATB. This analysis relies on the current levels of near-term renewable builds presented in the 2023 IRP Preferred Portfolio and does not attempt to re-optimize the renewable builds based on these lower costs. This analysis reflects the situation where PacifiCorp conducts resource planning using elevated prices, and is able to procure renewable resources for lower cost in actuality.

Additionally, we highlight here that if PacifiCorp had incorporated supply-side costs for renewables that were more in line with PGE, CPUC, and NREL ATB, it is likely that PLEXOS LT would select more of these resources ***instead of*** higher-cost alternatives, such as nuclear, non-emitting peakers, and fossil units. It is important to note that the build costs shown in the PLEXOS LT outputs are shown pre-tax credits and without annualization, rate of return, or depreciation. This means that the final impact on the Preferred Portfolio revenue requirement will be different than the total cost delta presented below.

¹⁰⁵ See South Carolina Public Service Commission, Report by PA Consulting *Independent Review of Santee Cooper's 2023 Integrated Resource Plan*. December 2023.

¹⁰⁶ *Ibid.*

¹⁰⁷ PacifiCorp file "(P)-Figure 7.3-7.5 History of IRP Renewables Cost Curves 2023 0119.xlsx".

¹⁰⁸ <https://www.lazard.com/media/202002/lazards-lcoeplus-april-2023.pdf>.

¹⁰⁹ Renewable Northwest, Round 1 Comments, page 38.

Table 9: Renewable Build Costs Summary Results

Category	Resource Type	NPV (2023-2030) (\$M)	2023	2024	2025	2026	2027	2028	2029	2030
Capacity (MW)	Solar	n/a	-	-	1,069	2,524	483	1,907	-	-
2023 IRP Build Costs (\$)	Solar	\$7,037	-	-	\$1,687	\$4,020	\$790	\$2,946	-	-
ATB Build Costs (\$M)	Solar	\$6,034	-	-	\$1,474	\$3,440	\$650	\$2,530	-	-
Delta (\$M)	Solar	\$1,003	-	-	\$213	\$580	\$140	\$416	-	-
Capacity (MW)	Wind	n/a	-	43	296	-	100	300	1,900	-
2023 IRP Build Costs (\$M)	Wind	\$3,317	-	\$85	\$644	-	\$212	\$613	\$3,394	-
ATB Build Costs (\$M)	Wind	\$2,427	-	\$59	\$405	-	\$138	\$414	\$2,631	-
Delta (\$M)	Wind	\$890	-	\$26	\$240	-	\$75	\$199	\$763	-
Capacity (MW)	BESS	n/a	-	-	754	2,929	628	1,900	1,149	-
2023 IRP Build Costs (\$M)	BESS	\$9,594	-	-	\$1,364	\$5,300	\$1,136	\$3,416	\$2,009	-
ATB Build Costs (\$M)	BESS	\$8,590	-	-	\$1,240	\$4,767	\$1,010	\$3,018	\$1,800	-
Delta (\$M)	BESS	\$1,004	-	-	\$124	\$533	\$126	\$398	\$209	-
Total Delta (\$M)	All	\$2,897								

Staff Expectation:

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

In Opening Comments, Staff raised concerns about the permitting timeline and fuel availability of nuclear resources in the Company's preferred portfolio.¹¹⁰ Staff concerns about reactor fueling risks and permitting were shared in comments from the Sierra Club,¹¹¹ NewSun,¹¹² and Renewable Northwest.¹¹³ As an example RNW documented the lengthy six-year timeline to final approval by the NRC of the only other small modular reactor (SMR) design to date, developed by TerraPower competitor NuScale Power Company.¹¹⁴ RNW follows this discussion with a request for the Company to identify offramps that would provide adequate lead time for replacement of the Natrium facility with clean energy resources with comparable attributes, a request that Staff finds to be reasonable.

¹¹⁰ LC 82 – Staff's Round 1 Comments, page 44.

¹¹¹ LC 82 – Sierra Club's Round 1 Comments, page 58.

¹¹² LC 82 – NewSun Energy's Round 1 Comments, page 5.

¹¹³ LC 82 – Renewable Northwest's Round 1 Comments, page 21-22.

¹¹⁴ Id.

In PacifiCorp's December reply comments, the Company stated that its consideration of nuclear resources in the 2023 IRP are consistent with Oregon IRP Guidelines 1(a), 1(b), and 1(c), and therefore those resources are limited to years outside of the action plan and CEP planning windows and require continued evaluation of their potential.¹¹⁵ The Company further stated that it "cannot provide meaningful tracking and reporting" on the Natrium facility's NRC Construction Permit Application due to there being no commercial agreement with the facility's developer, TerraPower. The Company did provide that a construction permit (CP) is targeted for submission to the Nuclear Regulatory Commission (NRC) by Q1 2024, stating a generic timeframe for issuance of the CP by the NRC is 36 months.¹¹⁶ Staff, assuming a similar 36-month timeline for issuance of the separate operating license (OL) for the Natrium facility from the NRC, contemplates substantial risk in selecting this resource in the preferred portfolio for inclusion in the year 2030. Staff finds comments from the Sierra Club, NewSun, and RNW regarding fueling cost and risk, permitting timeline risks, and the lack of adequate alternatives should permitting issues arise, to be compelling.

The Company's timelines for the availability of non-emitting peaking resources and nuclear resources have both been modelled for portfolio consideration in the year 2030 or beyond, intentionally outside of the action plan window and the current CEP compliance window.¹¹⁷ As the Company states that it anticipates that non-emitting peaking resources will improve in performance and cost-effectiveness, Staff believes that the Company should also prepare for the possibility that both non-emitting peaking resources and nuclear resources may potentially fail to materially improve in those regards before the year 2030.¹¹⁸

In short, Staff finds that the overly optimistic timeline for both the Natrium nuclear technology and any potential non-emitting peaking technology - given both what is known and unknown - requires planning more reflective of implementation risks. Staff is not opposed to either technology per se and believes they may both be necessary to achieve HB 2021's 2040 target and for the broader region to decarbonize. However, we agree with RNW's observation that the 2021 IRP selection of Natrium in 2028, which was due in part to overly optimistic assumptions, impacted both the action plan and the scope of the subsequent RFP (UM 2193).¹¹⁹ Staff finds that PacifiCorp appears to be repeating the same process in LC 82 with these long lead time resources. An additional implication of this approach in LC 82 is that it puts Oregon's decarbonization efforts at risk.

Per a December filing, NRC has scheduled a readiness assessment meeting for the TerraPower permit application on January 10, 2024.¹²⁰ The process to conduct the assessment will take four weeks and 45 calendar days, following which NRC staff will issue a public report on their findings. The approximate date for the publication of this report will be approximately around March 20, 2024. At the point of the NRC report's publication, the Company should have a clear understanding if the Natrium project is on track to begin construction under the very tight timelines found in LC 82.

In variant portfolio P06 – No Forward Tech, PacifiCorp explored the risk of neither the nuclear facility **nor** the non-emitting peaker being operational by the end of 2030. This portfolio showed no impact to

¹¹⁵ LC 82 – PacifiCorp Reply Comments, page 94-95.

¹¹⁶ PacifiCorp response to Staff DR No. 118.

¹¹⁷ LC 82 – PacifiCorp Round Reply Comments, page 93-95.

¹¹⁸ LC 82, PacifiCorp Reply Comments, page 93.

¹¹⁹ Renewable Northwest, Opening Comments, page 20.

¹²⁰ See Filing in NRC Docket 99902087, "Preapplication Construction Permit Readiness Assessment Plan," December 20, 2023.

the timing of the planned retirements of approximately 2.5 GW of coal generation capacity between 2028 and 2032. Instead this variant portfolio showed more some additional solar and wind but most notably an additional 1.2 GW of batteries by 2033. This portfolio had some of the highest emissions compared to all other portfolios.¹²¹

As RNW notes, the Company's plan to replace SMRs should they not be viable is to largely replace them with non-emitting peakers.¹²² The Company states that non-emitting peakers' limited presence in the 2023 IRP preferred portfolio supports the Company's position that the risks associated with these resources are reasonable.¹²³ Given the potential for neither to emerge and both the higher cost and higher emissions associated with this outcome – as evidenced by P-06 – the Preferred Portfolio's reliance on emergent nuclear and non-emitting peaking resources may prove to be an outsized risk.

Staff would note that in LC 80 the procurement of long lead time (LLT) resources posed a similar set of risks and procurement challenges for PGE. Given the uncertainty around timelines for both nuclear and non-emitting peaking resources, Staff believes that the Company should issue a request for information (RFI) for LLT resources. The RFI should be used to inform placement of LLT emergent resources in a preferred portfolio more realistically by accurately comparing them against more traditional, matured, resources. To gain a more accurate view of the entire resource landscape, the Company's RFI could also study advanced geothermal, pumped hydro storage, transmission costs associated with offshore wind, and any other resources identified by the Company or stakeholders. The Company might even coordinate with PGE in developing this RFI for a streamlined approach.

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Staff Expectations:

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Small Scale Renewables

In Opening Comments, Staff expressed an interest in exploring options to facilitate the development and acquisition of small scale renewables (SSRs) in a cost-effective manner, highlighting the RPS certification process in particular.¹²⁴

¹²¹ LC 82, PacifiCorp 2023 IRP, page 268, Table 9.14.

¹²² Renewable Northwest, Opening Comments, page 22.

¹²³ LC 82, PacifiCorp Reply Comments, page 93.

¹²⁴ LC 82 – Staff's Opening Comments, page 46.

Staff greatly appreciates the Company's efforts to offer regulatory recommendations toward easing the acquisition of SSRs in its reply comments. Regarding the Company's recommendation that the OPUC amend or waive OAR 860-091-0030(1), Staff finds that this may be an unnecessary solution to a barrier that remains, in Staff's view, to be largely informational. The Company specifically cites an additional ODOE regulation, OAR 330-160-0035(2), that "may require...an explanation of the relationship between the applicant and the WREGIS account holder."¹²⁵ Staff does not understand how this requirement, nor RPS certification as a whole, are meaningful barriers to potential SSR project financing.

Staff agrees with the Company's recommendation that incentives might be refined or updated to better reflect system SSR needs through updated PURPA policies in the OPUC's UM 2000 proceeding.¹²⁶ Should these policies be updated to better reflect SSR acquisition costs, Staff would urge the Company to utilize PURPA policies to the greatest extent possible to streamline its SSR acquisition process, and additionally facilitate modelling of SSR acquisition in portfolio modelling as the SSR mandate will remain an ongoing compliance obligation. The ability to model SSR acquisition costs reliably and accurately will facilitate the modelling of marginal SSR needs and associated costs when system capacity acquisitions are made.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

In Opening Comments, Staff found that the Company's current resource adequacy and capacity valuation approaches are lacking necessary sophistication and should be updated with both more data and methodologies that better conform to best practices. Staff recommended that the Company incorporate WRAP into its next IRP, update its resource capacity contribution methodology, add more weather data, and perform a Loss of Load Expectation (LOLE) analysis on the preferred portfolio.²

RNW has a host of recommendations for the Company to modernize its reliability and resource adequacy modeling that are largely in line with Staff's opening comments. Among them, RNW recommends that the Company move beyond its current capacity factor method to something an Effective Load Carrying Capability (ELCC) method or something similar, such as the "Global Slicing Block" that is available in PLEXOS.³ RNW also believes that the Company's 13 percent Planning Reserve Margin is unfounded.⁴ Of greater concern to them, RNW finds that the Company's deterministic look at Loss-of-load-probability (LOLP) modeling is lacking and recommends that the Company incorporate stochastic parameters for weather risk factors that correlate with supply and demand.⁵ Given that the Western Resource Adequacy Program (WRAP) may become binding as early as 2026, RNW also advocates that the integrate WRAP into the IRP process.⁶

The Company responded to comments made by both Staff and RNW in its Round 1 Reply Comments. Staff recommended that the Company update its capacity valuation methodology to incorporate multiple years of weather data, calculate and report the LOLE of the preferred portfolio in each year and explain why the Company chose to plan to its current level of reliability. PacifiCorp agrees with Staff and RNW that incorporating stochastic conditions is a necessary part of identifying supply and demand risks and notes that neither wind nor solar nor energy efficiency savings were modeled stochastically in the 2023 IRP. The Company also agrees that the value of stochastic analysis is higher when multiple years of data are used but also notes that incorporating this is a significant undertaking. The Company states that it looks forward to further improvements to the LOLP and that it is always open to improvements in its RA modeling.⁷ In response to Staff's and RNW's

¹²⁵ LC 82 – PacifiCorp Reply Comments, page 85.

¹²⁶ Id, page 86.

comments on WRAP, the Company states that it is actively evaluating the WRAP program and considering how to implement it in the IRP as early as 2026.⁸ The Company did not appear to directly respond to RNW's recommendation to conduct an ELCC style analysis.

Staff recognizes that updating LOLP, capacity valuation, and RA modeling is a large undertaking that may take many months. While Staff continues to advocate for the use of more years of weather, load and generation data, Staff is supportive of these things being included in the Company's next IRP. Staff also agrees with RNW's comments advocating for stochastic modeling of supply and demand variable in LOLP analysis and recommends that wind and solar resources be modeled stochastically using observed weather and load correlation. Staff also agrees with RNW that switching to an ELCC style analysis of capacity valuation is a necessary modeling improvement that should be integrated into the next IRP. Staff reiterates its past recommendation that the Company model and report the LOLE of the preferred portfolio in a future IRP.

Staff continues to recommend that PacifiCorp consider WRAP participation, including potential future obligations and benefits, in the next IRP. Staff notes that another Oregon-regulated utility, Idaho Power, has chosen to model the benefits of WRAP in its current IRP, LC 84, and assumes that WRAP's operational program would provide some system capacity benefit starting in 2027.¹²⁷ While Idaho Power presents this merely as a first attempt at modeling WRAP benefits, Staff feels it necessary to point out that one of the Company's Oregon peer utilities has already begun incorporating WRAP into its IRP.

Front Office Transactions

Staff is concerned by the Company's reliance on FOTs in its IRP.¹²⁸ PacifiCorp's IRP allows for a certain amount of market purchases to contribute to system capacity needs. These purchases are referred to as Front Office Transactions (FOTs) and they have limits as shown in Table 5.8 in the IRP and reproduced below as Table 10.

Table 10: Reproduction of Table 5.8 of IRP¹²⁹

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042)		Summer	Winter
		Summer	Winter		
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
<i>Total</i>	3326	500	1000	500	1000

In the IRP, FOTs are modeled as short-term purchases that can be made with little or no notice. However, this may be an oversimplification. Staff also notes that in order to demonstrate compliance with WRAP, an entity has to secure resources and contracts with a lead time of multiple months,

¹²⁷ LC 84, Idaho Power IRP Initial Filing, page 8.

¹²⁸ LC 82, PacifiCorp 2023 IRP, page 33, Action item 5a.

¹²⁹ 2023 IRP at 126.

meaning that the Company's choice to rely on short-term purchases may lead to the Company being out of compliance with WRAP's forward showing requirements. Further, given the suspension of the Company's RFP, UM 2193,¹³⁰ Staff anticipates that the Company will need to rely further on FOTs to offset resources that may come on later than what was expected at the beginning of LC 82.

In other proceedings, the Company has noted that the volume of transaction in regional wholesale markets has been steadily declining in recent years.¹³¹ The Company models a constant level of FOT availability at its main five market hubs through 2027, which is incongruous with its operational realities of the last few years. Staff worries that the failure to align its action plan assumptions with the operational realities it uses as evidence in its power cost dockets could lead to a situation in which it neither has resources available to meet its load nor a viable counterparty to buy energy in a peak load hour.

Renewable Northwest also expressed concern with PacifiCorp's assumptions regarding future reliance on regional markets. RNW notes that near-term reliance on market purchases for capacity in this IRP is high. In addition, RNW notes that the Load and Resource Balance table in the IRP includes market purchases well above the stated FOT limits in Table 5.8. RNW notes, "regional markets are likely to experience increasing uncertainty in both depth and availability due to environmental policies and regional market initiatives, which increases the importance of hedging against the continued risk of high market reliance in the future." RNW recommends that PacifiCorp work with other regional planning organizations such as the Western Power Pool (WPP) to develop "a detailed, quantitative analysis on the likelihood of regional markets to provide reliable power at non cost-prohibitive prices." Staff acknowledged that a regional study could provide value in long-term planning, but notes that there are currently multiple organizations that already look at resource adequacy to assess whether there is a surplus of energy available in the region. For example, WECC releases frequent studies of regional capacity availability. The 2023 WECC Western Assessment of Resource Adequacy (WARA) finds that total planned resources in the WECC are not adequate to prevent substantial "Demand at Risk" hours in 2026-2028.¹³² Demand at risk hours are defined as the number of hours in a year that are at risk for loss of load exceeding the one-day-in-ten-year outage threshold. As Figure 9 below shows, in August 2028, the WARA finds on average about 500 MW of Demand at Risk over 25 hours.¹³³ We note, however, that shortage predictions five years out can often change, as both demand and supply side resources respond in advance to potential shortfalls with incremental development activity.

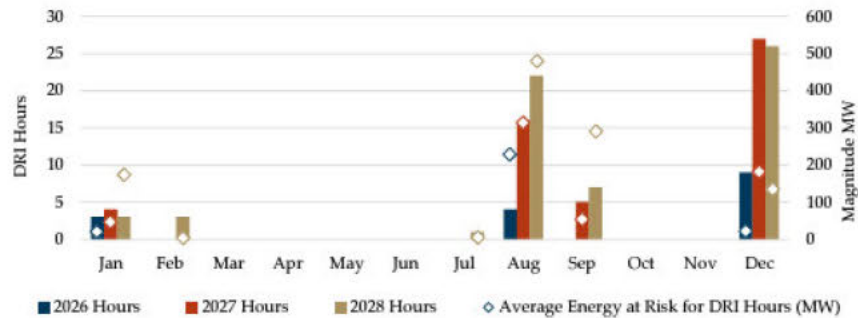
Figure 9: Mid-term DRI Hours and Magnitude for the Western Interconnection

¹³⁰ [See the Company's September 29, 2023 filing in UM 2193.](#)

¹³¹ See UE 420, PAC/400, Mitchell/59 [here](#).

¹³² WECC. [2023 Western Assessment of Resource Adequacy](#), page 17.

¹³³ WECC. [2023 Western Assessment of Resource Adequacy](#), page 16.



The WARA finds that a significant increase in Demand at Risk hours in December can be attributed to increased load forecasts in the Northwest, while there are relatively few utility-scale resource additions planned in the Northwest. The WARA concludes that load serving entities may need to delay resource retirements if they cannot mitigate these risky hours in the next two years. However, we note that WARA may have less visibility into local small-scale supply and demand resource activity that could reduce the at-risk hours in those out years.

Notably, PacifiCorp's IRP relies on 944 MW of summer market purchases in 2027 and 493 MW in 2028.¹³⁴ Given WECC's showing of regional resource adequacy risk during August in those years (red bars in Figure 4 above), the expectation of nearly 1 GW of market energy being available for purchase during summer peak hours seems potentially risky. Further, PacifiCorp has suspended the 2022AS RFP that would have brought resources online from 2025 through 2027, further increasing the region's resource adequacy risk.

These findings are concerning and indicate that PacifiCorp should look seriously at reducing market reliance in the near term, whether through longer-term contracts or resource procurements. If PacifiCorp continues to plan its system around procuring capacity from the market that may not be available and is forced to delay fossil retirements as a result, the Company could be at risk for failing to meeting its HB 2021 Oregon emissions reductions targets and much higher power costs. To address this, PacifiCorp should consider actions to reducing near-term market reliance in the next IRP.

Staff also expects PacifiCorp to consider how WRAP participation might affect the Company's reliance on FOTs in the next IRP. The WRAP forward showing program will require PacifiCorp to secure enough resources to meet their obligations seven months in advance. Staff's understanding is that this requirement may limit FOTs to transactions that can be secured on that timeline. Staff also expects that information from the WRAP program may bring additional transparency into the depth of regional markets during constrained periods and that this information could help to inform future assumptions regarding FOT availability.

Staff Expectations:

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.

¹³⁴ LC 82, PacifiCorp 2023 IRP, page 325.

- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

Transmission & Storage

In Round 1 Comments, Energy Advocates recommends, "PacifiCorp should expand future CEP/IRP's to look beyond storage co-location near generation sites and to identify substations and transmission lines that can use storage to flatten load peaks and avoid congestion and costly transmission and distribution upgrades."

In Reply Comments, PacifiCorp responded that the 2023 IRP allows standalone storage to be selected at generator and load locations, in addition to co-location near generation sites. PacifiCorp states, "Additionally, storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed anywhere on the system."¹³⁵

PacifiCorp also notes that "[t]he specific substation and transmission would be identified in the request for proposals process after the 2023 IRP."¹³⁶ We note, however, that PacifiCorp should reconcile this statement with its unambiguous indication in the IRP itself that battery storage resource options are limited to co-location at generation sites.¹³⁷

PacifiCorp's explanation partially addresses Energy Advocates' recommendation, although it does not directly explain how PacifiCorp considers the ability of storage to avoid transmission and distribution upgrades. PacifiCorp applies a Transmission and Distribution deferral credit to DSM resources in the IRP; however, it does not appear that PacifiCorp has used a T&D deferral value for storage in PLEXOS IRP modeling.

In evaluating PacifiCorp's consideration of T&D deferral value, it may be valuable to consider transmission deferral separately from distribution deferral. Regarding transmission, the PLEXOS modeling logic should be able to assess the potential for storage to reduce or defer the need for endogenously selected transmission resources. The model can generally make economic decisions about whether to upgrade the system with storage or to select a major new transmission investment.¹³⁸ However, there may be some transmission deferral value that is not considered in the IRP PLEXOS modeling. For transmission system investments that cannot be selected by the model, and are instead hard-coded, the model will not be able to see any opportunities to defer these resources by acquiring storage.

¹³⁵ LC 82, PacifiCorp Reply Comments, page 73.

¹³⁶ LC 82, PacifiCorp Reply Comments, page 72.

¹³⁷ LC 82, PacifiCorp 2023 IRP, Chapter 8, page 233: "Batteries are assumed to **always** be co-located with other resources, enabling them to shift energy..." Emphasis added.

¹³⁸ PacifiCorp response to OPUC DR 190.

The IRP generally states that transmission resources are available for endogenous selection.^{139,140} However, further clarification from PacifiCorp to verify whether this applies to all or only some planned transmission resources that could be deferred by storage would be valuable. There may be some transmission expenses that can be deferred by strategically located storage but are not included in the PLEXOS model. If these costs are significant, then applying a transmission deferral credit to storage resources in the IRP could be appropriate.

Staff Expectation:

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Management

Staff's Round 1 Comments supported PacifiCorp's plan to include near-term cost-effective EE in the Company's preferred portfolio. The long-term EE modeling however, appeared insufficient. Staff's analysis found that PacifiCorp had not included available and low-cost EE in the preferred portfolio after 2025.¹⁴¹ Accordingly, Staff requested that PacifiCorp allow optimization of EE in the CEP to inform whether EE could reduce HB 2021 costs allocated to the CEP portfolio. Staff also requested PacifiCorp reoptimize the Max DSM scenario. Additionally, Staff found opportunities to improve PacifiCorp's avoided costs, such as including avoided planning reserve margin costs and considering HB 2021's emissions constraints.¹⁴² Finally, Staff found PacifiCorp's short-term DR acquisition strategy reasonable but recommended additional measures to reduce NPVRR.

In Round 1 Comments CRITFC, CUB, Energy Advocates, and Sierra Club saw room for additional DSM measures in the preferred portfolio. By extension, they questioned whether PacifiCorp's long-term planning recognized the full implications of HB 2021. CRITFC, CUB, and Energy Advocates voiced concerns that the existing cost-effectiveness tests overlooked EE's non-energy values of improved community resiliency and reduced environmental and ratepayer burdens.

In Round 1 Reply Comments PacifiCorp did not allow the Max DSM Scenario to reoptimize the resource selections around the additional EE. PacifiCorp also declined to reoptimize EE in the CEP. According to PacifiCorp, this request was unnecessary because the model had selected an average of 91 percent of potential EE between 2023 to 2030, with few remaining potential EE measures to meet system needs. PacifiCorp further argued there is no statutory or regulatory mechanism requiring the Company to optimize EE for CEP requirements. Similarly, PacifiCorp argued it lacked Commission guidance to include HB 2021's constraints in avoided cost data. PacifiCorp stated that the Company's method is like the traditional concept of "capacity cost" with the added component of renewable energy compliance. PacifiCorp's standard renewable avoided costs reflect the cost of a renewable wind proxy starting in 2026; prices after that date would not include a forward market component. PacifiCorp further explained that calculating the avoided planning reserve margin cost was difficult due to the addition of

¹³⁹ LC 82, PacifiCorp 2023 IRP, page 221.

¹⁴⁰ LC 82, PacifiCorp 2023 IRP, page 213.

¹⁴¹ LC 82, Staff Round 1 Comments, October 15, 2023, page 58, Figure 12.

¹⁴² For example, in using the existing avoided cost method, Staff found the Company overlooked the need to purchase non-emitting resources rather than the least-cost market resources. These comments mirrored Staff's comments to PGE in LC 80. See *In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Corrected Opening Comments at pages 27-30 (July 27, 2023).

variable energy resources. Finally, PacifiCorp provided an update on its electrification modeling and agreed to consider DR measures encouraged by Stakeholders.

Staff's review of OPUC DR 80-1 found that the preferred portfolio selected only 80 percent of available EE between 2023 and 2030, which contradicts PacifiCorp's claim of 91 percent.¹⁴³ In either case, the model selected EE *without considering HB 2021*, which suggests that the model would select more EE once HB 2021 strategy is considered. Staff requests that the 2024 IRP Update address the discrepancy in EE acquisition and ensure that the model considers HB 2021 compliance in the preferred portfolio.

Further, PacifiCorp's 2023 IRP analysis relied on an Energy Trust potential study which used avoided costs from the 2019 IRP.¹⁴⁴ If the Company's long-term planning were to indicate that greater amounts of efficiency at higher avoided costs would benefit the system, Energy Trust could perform a new potential estimate that would likely result in a higher amount of available efficiency in Oregon. Therefore, Staff concludes that PacifiCorp's least cost, preferred portfolio likely includes more EE from the previously identified potential, plus additional new23 potential that may have been screened out of Energy Trust's potential study.

Given the impactful new requirements of HB 2021, the value of efficiency in Oregon should diverge substantially from the value of efficiency to some other states on PacifiCorp's system. Under Senate Bill 1547 (2016) and codified in ORS 757.054(3)(a), investor-owned utilities are required by law to acquire all cost-effective energy efficiency and demand response prior to acquiring new generating resources.¹⁴⁵ To meet this requirement, new approaches to avoided costs must be explored and Staff expects PacifiCorp to help update the accounting in UM 1893 to reflect current state policy. Staff expects that Oregon-specific avoided cost analysis will be included in PacifiCorp's IRP Update and future IRPs. The acquisition of higher-value Oregon EE in light of HB 2021 requirements, should be part of PacifiCorp's preferred portfolio in both IRP and CEP planning, not relegated to one or the other.

Staff will consider approaches to avoided cost valuation from other regions, such as the method used by New England energy efficiency program administrators.¹⁴⁶ PacifiCorp's current IRP modeling approach for calculating avoided energy costs has similarities with the New England AESC modeling construct and could be improved to better represent Oregon-specific benefits.

Staff reiterates prior recommendations from Round 1 Comments regarding demand response resources. Staff recommends acknowledgement of DR acquisition to 2026, but encourages the Company to consider additional classes of DR as part of the least cost, least risk portfolio in future analysis. Staff again cites the Northwest Power and Conservation Council's 2021 Power Plan recommendations for utilities to pursue frequently deployable, low-cost measures with minimal customer impact, including time-of-use rates and demand voltage reduction.¹⁴⁷ PacifiCorp did not respond to this request in Round

¹⁴³ See PacifiCorp response to Staff DR No. 80-1.

¹⁴⁴ Under OAR 860-030-011(2), utilities must provide energy efficiency avoided cost data based on the utility's most recently acknowledged IRP or update, or from the energy utility's most recent general rate case that has been resolved by a final order of the Commission.

¹⁴⁵ ORS 757.054(3)(a), https://oregon.public.law/statutes/ors_757.054.

¹⁴⁶ For every planning period (3 years), the efficiency program administrators sponsor an avoided energy supply components (AESC) study to determine the value of energy efficiency and other demand-side measures. Avoided costs are calculated for each New England state under a hypothetical future in which New England program administrators do not install any new demand side measures in future years.

¹⁴⁷ See 2021 Northwest Power Plan, page 47. https://www.nwccouncil.org/fs/17680/2021powerplan_2022-3.pdf.

1 Reply Comments. Staff expects future IRP analyses will consider these two resources to help manage power costs and reduce emissions.

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Staff Expectations:

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

Conclusion

Despite the good work and hard effort of PacifiCorp staff, the decisions to both suspend the 2022 AS RFP and push all necessary revisions of LC 82 analysis to the IRP Update mean Staff and stakeholders lack the shared analytic understanding for making many of the needed acknowledgement recommendations required of this IRP/CEP. Until additional analysis is done, and the Preferred Portfolio is revised, many aspects of this IRP and the CEP cannot be acknowledged.

Staff proposes to truncate the LC 82 review process. Staff will file a motion to update the schedule so as to bring the recommendations from these comments forward for acknowledgement at the public meeting on February 20, 2024. Staff will seek a Commission order on those items that it believes can be acknowledged and on minimum analytic requirements for the IRP Update. Further, we recommend that the CEP be revised and resubmitted, per Staff's suggestions, with the IRP Update so that it has the potential to be acknowledged.

Dated at Salem, Oregon, this January 24th, 2024.



JP Batmale
Administrator
Energy Resources and Planning Division

Appendix A: Summary of Recommendations

RFP Suspension

Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes

Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments:

Community Benefit Indicators

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

CBRE Resource Potential

Staff Recommendation 7. Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

Community Engagement

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Resiliency Analysis Framework

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

IRP Comments:

Preferred Portfolio Modeling Process

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Natrium and Non-Emitting Peaking Resources

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Demand Side Resources

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Appendix B: Staff Expectations

State Policy Compliance in IRP Portfolios

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

CEP Compliance Pathways

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP “actions”, Oregon’s CEP requirements, and Oregon’s DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.
- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon’s SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the action plan because the Company has already taken these actions.

CEP Comments:

Community Benefit Indicators

- In the next IRP/CEP, Staff expects PacifiCorp to:
 - Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company’s CBRE actions.
 - Better inform CBIs and methods with input from stakeholders and community.
 - Enhance tribal-focused CBIs.
 - Use CBIs to better reflect the health impacts of EE.
 - Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
 - Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
 - Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company’s CBRE actions.

CBRE Activities

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

CBRE Inclusion in Preferred Portfolio

- In the IRP/CEP update:
 - Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.
- By the next IRP/CEP:
 - Highlight and communicate the relative benefits of CBRE in load pockets.
 - Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to “[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy.”¹⁴⁸
 - Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

- Staff expects PacifiCorp’s CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
 - Organization/entity attribution or affiliation.
 - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
 - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp to conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company’s engagement strategy efforts.

Resiliency Analysis Framework

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021’s requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to

¹⁴⁸ ORS 469A.415(4)(d).

identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.

- By next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

- The IRP Update includes two variant portfolios that directly reflects Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments:

Preferred Portfolio Modeling Process

Before the next IRP PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In the next IRP, PacifiCorp should:

- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

In the next IRP/CEP, PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

Candidate Resource Costs

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Sodium and Non-Emitting Peaking Resources

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Sodium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Sodium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.
- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Resources

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

PacifiCorp 2024 Oregon Small-Scale Renewable Request for Proposal

Pre-Issuance Bidder Workshop

January 24, 2024



2024 Oregon Small-Scale Renewable RFP

ORDER NO.
4-0

Logistics

Workshop Date and Time

- Wednesday, January 24, 2024
- 2:00 – 4:00 PM (Pacific Standard Time)

Location

- Microsoft Teams meeting
- Join on your computer or mobile app
- [Click here to join the meeting](#)
- Or call in (audio only)
- tel:+15632755003,,979257373# United States, Davenport
- Phone Conference ID: 979 257 373#

2024 Oregon Small-Scale Renewable RFP

Agenda

- Purpose/Resource Types
- Eligibility Requirements
- Contract Considerations
- Interconnection and Transmission Requirements
- Proposed RFP Schedule
- Evaluation and Selection Methodology
- Role of Independent Evaluator (IE)
- Next Steps
- Questions and Comments

2024 Oregon Small-Scale Renewable RFP

ORDER NO.
4-07

Purpose of Request for Proposal (RFP)

- To enable PacifiCorp to obtain, by 2030, approximately 490 megawatts (MW) of additional electrical capacity from small-scale renewable energy projects.
- The RFP supports PacifiCorp compliance with Oregon House Bill 2021 (OR HB2021) Section 37 and furthers PacifiCorp's Clean Energy Plan goals.

Energy sources accepted into the 2024 Oregon Small-Scale Renewable RFP must

- **Have a nameplate capacity of at least 3 MW but no greater than 20 MW *and***
- **Generate electricity utilizing one of the following sources:**
 - Wind energy
 - Solar photovoltaic and solar thermal energy
 - Wave, tidal and ocean thermal energy
 - Geothermal energy
 - Hydroelectric energy
 - Biomass that generates thermal energy for a secondary purpose
 - Biomass energy sources larger than 20 MW will be accepted, but only the first 20 MW of the energy source counts toward OR HB2021 requirement.
 - Energy sources listed above will be accepted to the 2024 Oregon Small-Scale Renewable RFP only if they meet the Renewable Portfolio Standard (RPS) criteria outlined in ORS 469A.025.

Note: Information in this presentation is subject to further change until RFP is issued.

2024 Oregon Small-Scale Renewable RFP

Minimum Resource Eligibility Requirements

- Eligible technologies consistent with ORS 469A.025.
- Eligible resources cannot be behind-the-meter, energy storage, microgrids or demand response technologies.
- Minimum 3 MW (ensures Energy Imbalance Market (EIM) eligibility); maximum 20¹ MW (supports Oregon HB2021 compliance).
- Possess Oregon Department of Energy Renewable Portfolio Standard (RPS) certification at time of commercial operation for contract effectiveness.
- Off-system bids not accepted; projects must be planned to interconnect to PacifiCorp transmission or distribution system in Oregon, Washington, California, Idaho, Utah or Wyoming.
- Completed interconnection study, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
 - <https://www.oasis.oati.com/ppw/index.html>; [https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Transmission Wall Map, E-Size.pdf](https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Transmission_Wall_Map_E-Size.pdf)
- Site control required.
- Commercial Operation Date (COD) by December 31, 2028.
- Comply with co-location/proximity criteria based on Oregon OAR 860-089-0100, applied to a 20 MW threshold level.
- Bids for new and existing resources will be accepted provided the existing resources are not obligated in a contract effective as of the COD date above.
- Bid fee will be required for each bid proposal. Details provided at RFP issuance.
- All PPA bids must be fixed-price for the full term.

¹ As previously noted, Biomass resources larger than 20 MW *will* be considered, but only the first 20 MW will count toward OR HB2021 capacity requirement.

2024 Oregon Small-Scale Renewable RFP

Minimum Eligibility Criteria

1. Receipt of bid by deadline
2. Receipt of bid fee by deadline
3. Completed provided Bid Summary and Pricing Input Sheet, without modification
4. Capacity interconnected to PacifiCorp's transmission or distribution system
5. Completed PacifiCorp Transmission Interconnection Study or signed PacifiCorp Transmission Interconnection Study Agreement
6. Interconnection study results and/or executed Large Generator Interconnection Agreement (LGIA) consistent with and supports bid
7. Demonstrated ability to achieve COD deadline
8. Execute Confidentiality Agreement and allow appropriate disclosures to agents, contractors, regulators, etc.
9. No attempts to influence PacifiCorp
10. Entire bid held firm through Q2 2025
11. No commitments of all or part of bid to another entity
12. Must disclose real parties of interest
13. Compliance with Prohibited Vendors List (see pro forma PPA)
14. Bidder's credit information
15. Ability to meet credit security requirements
16. Non-modifiable standard pro-forma contract
17. Bidder not in bankruptcy proceedings
18. Proposal cover letter signed by authorized officer
19. Renewable Portfolio Standard (RPS) certification from Oregon Department of Energy
20. Performance report and model output including hourly output values; bid resource assumption (12X24 or 8760) includes all planned outages and losses, including planned and maintenance outages and curtailment due to protected species such as bats; third-party provided performance report preferred
21. Adherence to all applicable permits prior to and after construction. If applicable, Seller will also agree to Eagle Take Permit or alternative mitigation measures
22. Ownership of, leasehold interest in, or right to develop site, or valid title to property
https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230823_OATTMaster.pdf
23. Oregon bidder agrees to the contractor labor standards attestation in OR HB2021, Section 26
<https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled>
24. Compliance with OR HB2021 reporting requirements, including contractor diversity reporting requirement
<https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled>

2024 Oregon Small-Scale Renewable RFP

Key Contract Considerations

- **Contract form.** PacifiCorp's pro forma power purchase agreement (PPA) will be provided.
 - Standard-form power purchase agreement (PPA). **The PPA will be standard for all bidders with no individual form modifications permitted.**
 - Seller develops, operates and owns resource; PacifiCorp buys the output for a specific term.
- **Ownership.** PacifiCorp takes ownership of all capacity, energy and associated environmental attributes after delivery to PacifiCorp.
- **Contract pricing.** Fixed pricing for term of contract (flat or on-peak/off-peak).
- **Credit requirements.** Letter of credit or approved parental guarantee will be required.
 - **Project development security.** Seller security is required to support delay damages and/or default damages for failure to reach commercial operation date (COD).
 - **Default security.** Seller security is required to support default damages in the event of breach of contract.
- **Commercial Operation Date delay.** Seller will have up to 365 days to cure a delay in scheduled commercial operation date; delay damages will be assessed.
- **Post-execution Condition Precedent.** Agreement language will ensure PacifiCorp's ability to obtain designated network resource (DNR) transmission service at no additional cost.
- **Annual Performance Guarantee.** Agreement will require annual resource mechanical availability guarantee and threshold percentage.
- **Benchmarks.** To support 2030 OR HB 2021 compliance PacifiCorp may offer benchmark bids.
 - PacifiCorp develops, constructs, owns and operates a bid project.
 - Benchmark bids will be evaluated using methodology consistent with market bid evaluation.

2024 Oregon Small-Scale Renewable RFP

Interconnection and Transmission

On-system resources (Off-system resources not accepted)

- PacifiCorp Transmission interconnection studies and agreements should be consistent with the bid proposal's technology, size and commercial operation date. If studies and agreements are not consistent with the proposal, bidder will provide documentation from PacifiCorp Transmission that a material modification to their interconnection documentation is not required.
- Bidders are financially responsible to PacifiCorp Transmission for all interconnection costs as identified in their generator interconnection agreement.
- After a PPA is executed, PacifiCorp's merchant function is responsible for requesting and arranging transmission from the Point of Interconnection (POI) to load.

Acceptable Documentation of Interconnection

- Completed PacifiCorp Transmission Interconnection Study (system impact study and/or facilities study) or signed PacifiCorp Transmission Interconnection Agreement is due when bid is submitted.
- An *Informational* Interconnection Study is NOT sufficient interconnection documentation to be considered eligible for the 2024 SSR RFP.

Questions

- For questions regarding PacifiCorp Transmission's interconnection study process, please visit the PacifiCorp Transmission website and contact Generation Interconnection at:
www.pacificorp.com/transmission/transmission-services.html

2024 Oregon Small-Scale Renewable RFP

ORDER NO.
4-0

Equity Questionnaire

Facility proximity to community
Census track in which facility is located
Distance from facility to nearest residential home
Number of residential homes within 1 mile of facility
Number of residential homes within 6 miles of facility
How does this resource serve or otherwise impact vulnerable populations?
Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels?
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).
Population characteristics of community where facility is proposed
To be completed based on census track in which facility is located
Race and ethnicity
White (%)
Black or African American (%)
American Indian and Alaska Native (%)
Asian (%)
Native Hawaiian and Other Pacific Islander (%)
Two or More Races (%)
Hispanic or Latino (%)
Population 25 years and over with no high school diploma
Unaffordable housing
Population five years and older that speak English less than "very well" and "not at all"
Population with income 185% below poverty
Population 16 years and older unemployed

Facility Job Creation
Total hires (number of jobs)
Will there be an apprenticeship or training program?
Will there be a project labor agreement (PLA)?
Will Bidder have a plan for outreach, recruitment and retention of women, minority individuals, veterans and people with disabilities to perform work under the contract?
Projected local hires from nearby communities (number of jobs)
Expected total employment (hires) of fossil fuel construction workers (number of jobs)
Duration of work (months of construction / years of operation)
Total Recordable Incident (TRI) of Bidder
Industry Average TRI for type of business (OSHA)
Bidder agrees to use Veriforce, or equivalent, to report safety
Estimate projected economic benefits to the local economy (direct and indirect) (annual \$ from payroll taxes, property taxes, other taxes, services)
Minority-owned businesses (percentage of contractors and subcontractors)
Woman-owned businesses (percentage of contractors and subcontractors)
Service-disabled veteran-owned businesses (percentage of contractors and subcontractors)
LGBT firms (percentage of contractors and subcontractors)
What percent of total work hours does Bidder target to be performed by women, minority individuals, veterans and people with disabilities?
Local Impacts
Is Facility a distributed energy resource?
Duration of construction
Source of water used during construction
Source of water used during operations
Is water a permitted or public source
Site disturbance - amount of disturbed soil during construction
Tree and pollinator seed re-planting after construction

Note: Above questionnaire was requested in the 2022AS RFP.

2024 Oregon Small-Scale Renewable RFP

Proposed RFP Schedule

Event	Date
Pre-issuance bidder workshop	1/24/2024
Independent Evaluator (IE) hired	2/16/2024
RFP issued to market and publicized	3/29/2024
PacifiCorp OATT ¹ cluster study window open	4/1/2024
PacifiCorp OATT ¹ cluster study window closed	5/16/2024
Bidder workshop No. 1	6/27/2024
Bidder workshop No. 2	TBD (September 2024)
Last day for bidder questions to PacifiCorp and IE	11/1/2024
Cluster study results posted to OASIS	~11/12/2024
Benchmark bid submissions due	11/15/2024
Benchmark final bid financial analysis provided to IE	12/20/2024
Market bid submissions due	12/23/2024
Bid eligibility screening complete	1/17/2025
Market bid evaluations complete	2/14/2025
IE final report	3/17/2025
Potential 2025 SSR RFP	3/28/2025
Contracts finalized and executed	TBD (June 2025)
Guaranteed commercial operations date (COD)	12/31/2028

10 ¹ PacifiCorp's Open Access Transmission Tariff (OATT)

2024 Oregon Small-Scale Renewable RFP

Price Proposal – Bidder Inputs

Each Proposal is required to include a completed Bidder Inputs form, which provides PacifiCorp a “numbers based” overview of the bid offering:

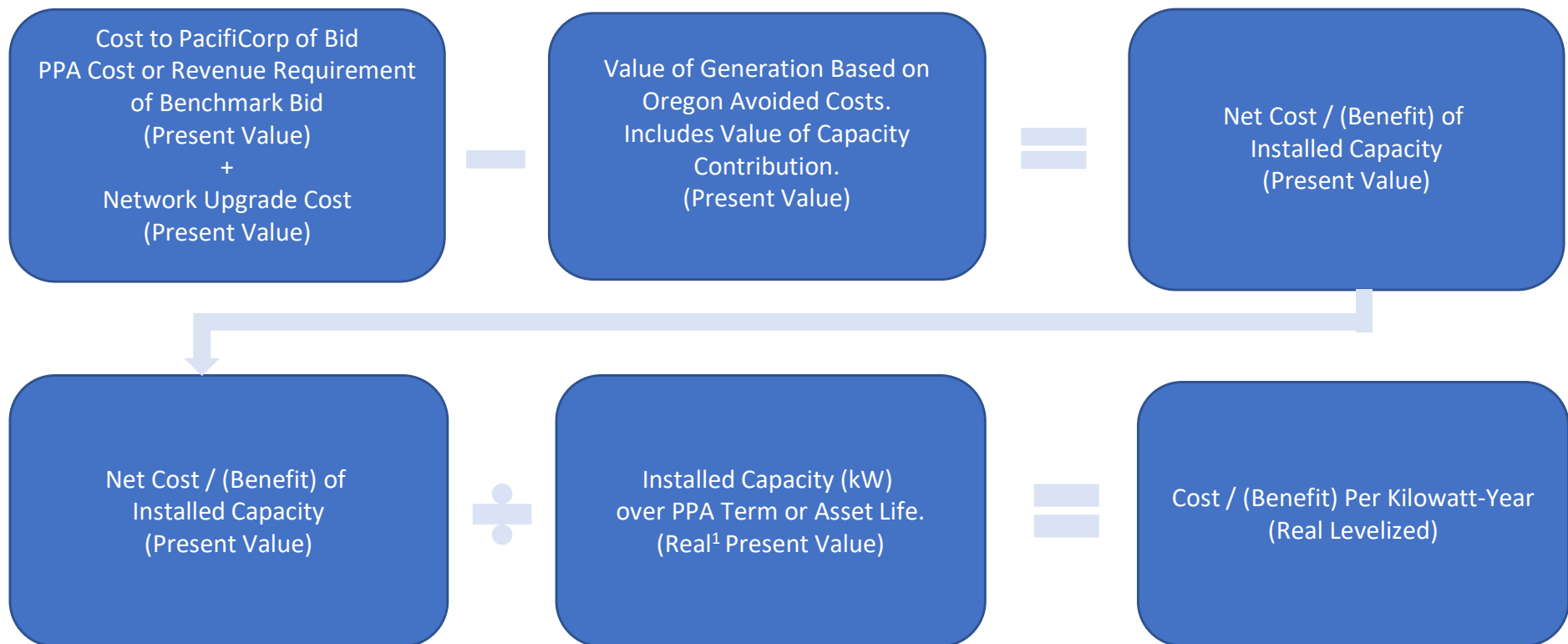
Price Proposal - Bidder Inputs (Required for Bid Submittal)	Location
➤ Bid Summary ▪ Type of Bid: PPA or Benchmark ▪ Project Specifics (Generator Type, location, capacity, annual degradation) ▪ Bidder Contact Information ➤ PacifiCorp Interconnection/Transmission Information ▪ Queue Number or Cluster Study ▪ Cost of Interconnection Facilities and Network Upgrades ➤ Purchase Power Agreement Terms ▪ Start/End Dates ▪ \$/MWh Price¹ (Flat or On- and Off-Peak Pricing) ➤ Benchmark Terms ▪ Date Operational ▪ Initial Capital Cost (Detail on Tab 3) ▪ ITC/PTC Qualification Questions	Tab 1
Expected First-Year Generation Inclusive of Degradation – 50th Percentile Estimate ➤ 8,760 hourly generation profile, OR ➤ 12 month by 24-hour generation profile (“12X24”)	Tab 2a, or Tab 2b
Benchmark Pricing (Not Applicable to Market Bids)	Tab 3
Benchmark Additional Information (Annual Operating and Capital Costs)	Tab 4

¹ Bid prices include direct interconnection costs. PacifiCorp includes network upgrade costs from PacifiCorp Transmission interconnection studies in the financial valuation model.

2024 Oregon Small-Scale Renewable RFP

Evaluation and Ranking of Bids

- Objective is to acquire 490,000 kilowatts (490 MW) of new capacity from small-scale renewable energy projects at the lowest cost to Oregon customers
- Acceptable Bid Criteria:
 - Power purchase agreement and benchmark bids
 - Fixed pricing for Term of PPA (flat or on-peak/off-peak)
- Bids will be ranked based on the LOWEST Real Levelized Cost per Kilowatt of installed Capacity



¹Discussion of Real Levelized valuation methodology will be provided in June bidder workshop.

2024 Oregon Small-Scale Renewable RFP

ORDER NO.
4-0

Role of the Independent Evaluator (IE)

PacifiCorp is seeking the services of an Independent Evaluator to provide independent validation that:

- PacifiCorp's screening of eligible bidders based on published minimum eligibility requirements was consistently applied to all submitted market and benchmark bids; and
- PacifiCorp's cost valuation of all submitted market and benchmark bids was consistently applied.

2024 Oregon Small-Scale Renewable RFP

Next Steps

1. Questions or comments regarding this pre-issuance bidder conference should be sent to the following mailbox, even if an answer was provided verbally in today's meeting, to ensure all bidders receive responses: 2024SSR_RFP@pacificorp.com.
2. Responses to questions (Q&As) received will be posted anonymously on PacifiCorp's 2024 Small-Scale RFP website.
3. 2024 Small-Scale RFP information will be provided it is developed and Q&As will be posted to: www.pacificorp.com/suppliers/rfps/2024-small-scale-renewable-rfp.html.

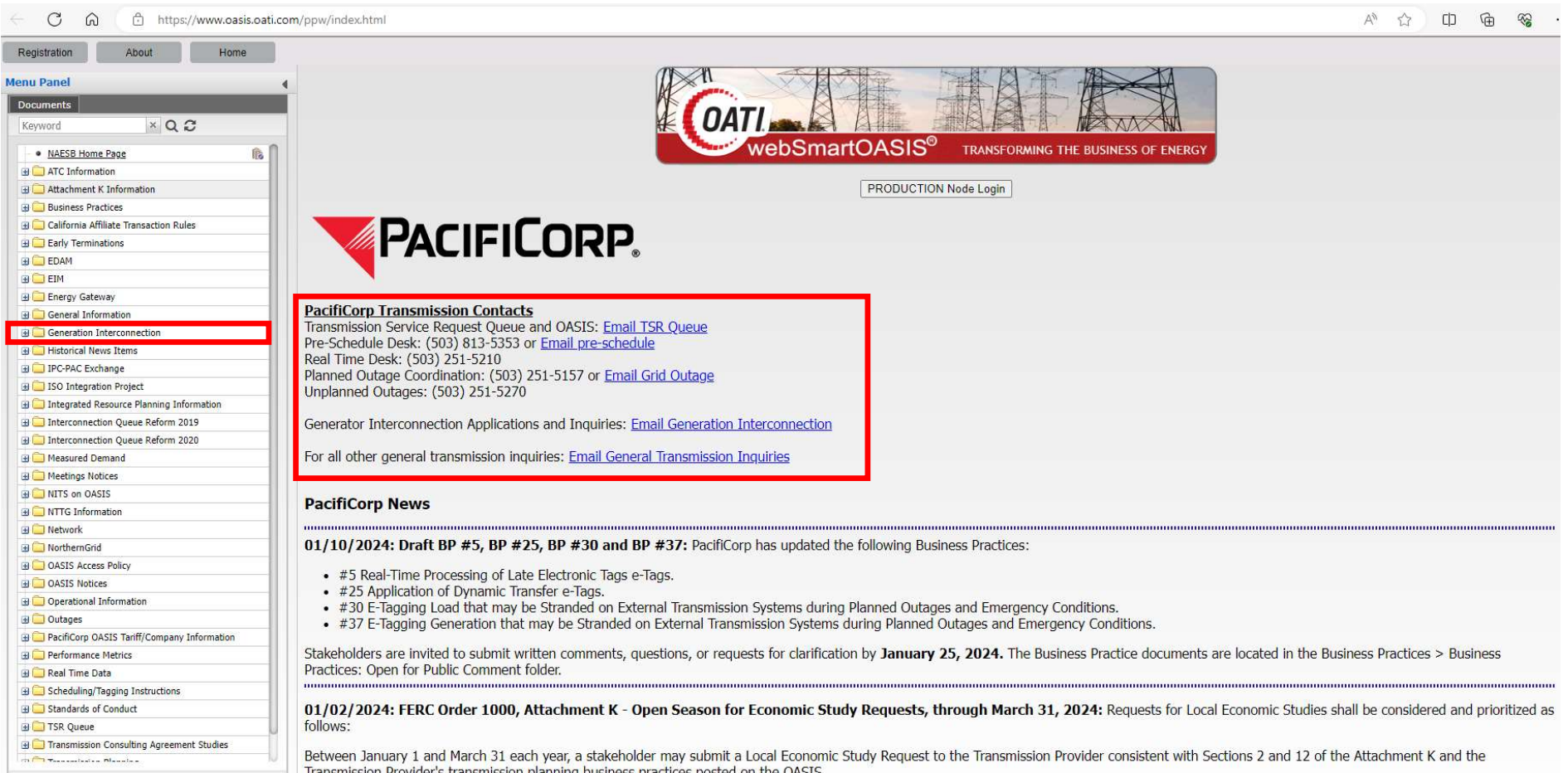
Supporting Materials

2024 Oregon Small-Scale Renewable RFP

PacifiCorp Transmission OASIS Interconnection Requests

Information on new generator interconnection requests and general interconnection and cluster study information please visit:

<https://www.oasis.oati.com/ppw/index.html>



The screenshot shows the webSmartOASIS portal. The left sidebar contains a 'Menu Panel' with various categories. The 'Generation Interconnection' item is highlighted with a red box. The main content area features the PacifiCorp logo, a banner for OATI webSmartOASIS, and a 'PRODUCTION Node Login' button. Below the logo, there is a red-bordered box containing contact information for PacifiCorp Transmission, including links for TSR Queue, pre-schedule, real time, and grid outage coordination. Below this, there is a section for 'PacifiCorp News' with two updates: one from 01/10/2024 regarding Business Practices and another from 01/02/2024 regarding FERC Order 1000 and Open Season for Economic Study Requests.

PacifiCorp Transmission Contacts
Transmission Service Request Queue and OASIS: [Email TSR Queue](#)
Pre-Schedule Desk: (503) 813-5353 or [Email pre-schedule](#)
Real Time Desk: (503) 251-5210
Planned Outage Coordination: (503) 251-5157 or [Email Grid Outage](#)
Unplanned Outages: (503) 251-5270

Generator Interconnection Applications and Inquiries: [Email Generation Interconnection](#)

For all other general transmission inquiries: [Email General Transmission Inquiries](#)

PacifiCorp News

01/10/2024: Draft BP #5, BP #25, BP #30 and BP #37: PacifiCorp has updated the following Business Practices:

- #5 Real-Time Processing of Late Electronic Tags e-Tags.
- #25 Application of Dynamic Transfer e-Tags.
- #30 E-Tagging Load that may be Stranded on External Transmission Systems during Planned Outages and Emergency Conditions.
- #37 E-Tagging Generation that may be Stranded on External Transmission Systems during Planned Outages and Emergency Conditions.

Stakeholders are invited to submit written comments, questions, or requests for clarification by **January 25, 2024**. The Business Practice documents are located in the Business Practices > Business Practices: Open for Public Comment folder.

01/02/2024: FERC Order 1000, Attachment K - Open Season for Economic Study Requests, through March 31, 2024: Requests for Local Economic Studies shall be considered and prioritized as follows:

Between January 1 and March 31 each year, a stakeholder may submit a Local Economic Study Request to the Transmission Provider consistent with Sections 2 and 12 of the Attachment K and the Transmission Provider's transmission planning business practices posted on the OASIS.

Question & Comments

ORDER NO.
24-073



To: PacifiCorp SSR RFP Team (2024SSR_RFP@pacificorp.com)

Subject: Oregon PUC Staff Initial Comments on SSR RFP

PUC Staff appreciates PacifiCorp releasing a draft of the Small Scale Renewable request for proposal (SSR RFP) for comments and the speed with which the Company is pursuing these resources. Staff's comments are organized around two themes. First, PacifiCorp's chosen SSR project characteristics are too narrow, leaving value on the table, driving up project costs, and failing to leverage the RFP as a market discovery mechanism. Second, Staff has suggestions for the structure of the RFP itself, based on our experience, that should help the Company meet its goals and the goals of the state while also assisting potential bidders.

Project Characteristics

Issue: Energy storage ineligibility

Staff position: Energy storage paired with renewable energy projects should be eligible.

Staff rationale:

- Allowing for the pairing of energy storage with renewables and dispatched as a single project enhances capacity value of SSR projects to system peak. Barring energy storage from SSRs appears to make projects less economic than other renewable systems and potentially drives up total costs of CEP compliance for Oregon ratepayers.
 - o Energy storage allows for renewable projects to be dispatched in a way that better aligns with system need and to offset fossil fuel use (i.e., summer peak, after 6pm).
- PAC has outstanding capacity need that SSR projects with energy storage can help meet.

Evidence:

 - o Per the 2023 IRP, the Company has a 2028 summer capacity deficit over 6,000 MW.¹
 - o Per the Draft IRP Update, peak capacity will grow at an average annual rate of 1.7%.²
 - o Company is seeking 100s of MW of energy storage by 2026 through bilateral contracts in wake of UM 2193 RFP suspension.

Given the outstanding capacity need, Staff questions why PacifiCorp would limit dispatchable load.

- PacifiCorp staff stated on the January 24, 2024 conference call that the Company had determined that the economics of SSR projects with energy storage would be uncompetitive. There is no data to substantiate this argument. Further, the purpose of an RFP is to discover what is available in the market. If project bids are uneconomic due to inclusion of energy storage that should be apparent in their RFP score.
 - o Based on PacifiCorp's evaluation and ranking of bids, projects paired with storage will most likely provide more value and thus provide a higher benefit to ratepayers.
- CAISO and WREGIS allow for renewable projects to be paired with energy storage and to be dispatched as a single system.
- ODOE certifies RPS projects paired with energy storage.

¹ LC 82, PacifiCorp IRP, May 31, 2023, pgs. 165 – 172, specifically Table 6.11 and Figure 6.4.

² LC 82, Draft IRP Update, January 31, 2024, pg. 2.

Issue: 3 MW floor

Staff position: Allow for project sizes down to 25 kW.

Staff rationale:

- 25 kW is smallest size for Community Solar Program. A lower bid threshold allows for projects such as those waitlisted in the CSP to participate in the SSR RFP.
- Based on the size of PacifiCorp's CSP queue there are clearly many projects less than 3 MW in size that could submit viable bids.
- Function of an RFP is to discover what is available in the market. If project bids are uneconomic due to their smaller size, that will be apparent in the RFP scoring.
- WREGIS allows for renewable projects of any size to be registered.

Issue: CAISO EIM eligibility

Staff position: Should be optional for projects, not a requirement.

Staff rationale:

- Eliminates the potential for smaller projects.
- Imposes unnecessary costs on all projects.
- Reinforces need to allow batteries to be paired with projects as it would increase value of projects to ratepayers.

Issue: Required ODOE RPS Certification at time of commercial operation date (COD)

Staff position: Should be required only after COD and should be optional for projects, not a requirement.

Staff rationale:

- Timing is off. ODOE does not issue RPS certifications until after COD.
- Project does not need ODOE certification to be considered renewable energy resource. Just needs to be one of the technologies listed in ORS 469A.025. Imposes unnecessary costs on all projects.
- ODOE RPS certification requires WREGIS issuing a generating unit id. This requires equipment that is expensive for smaller projects. It also requires more time and raises project costs.
 - o The largest benefit to registering with WREGIS is the ability to generate RECs. As HB 2021 does not require REC retirement to demonstrate emission reductions – and as PacifiCorp will have over 50 million RECs in excess of its Oregon RPS needs by 2030³ – Staff finds little to no value in requiring PAC SSRs to be WREGIS certified, even if the ODOE RPS verification is waived.

Issue: Contract pricing limited to flat or on-peak/off-peak.

Staff position: Contract pricing should include flat, on-peak/off-peak, or premium peak hours

Staff rationale:

- Projects with associated storage should have a contract pricing structure which incentivizes and rewards its dispatchable nature. More targeted hours will maximize the capacity value derived from these projects at little to no cost to the project.
- Hour derivation could be based on projected market prices or utility capacity needs.
- Structure could follow UM 1729 Solar+Storage rate with minor modifications.

³ LC 82, PacifiCorp IRP, May 31, 2023, pg. 321, Figure 9.59.

RFP Structure Issue

Issue: Lack of non-price scoring.

Staff position: Include non-price scoring that captures information about benefits to Oregon communities.

Staff rationale:

- Staff appreciates the inclusion of the Equity Questionnaire from the 2022 AS RFP. However, the equity questionnaire is not mandatory in the SSR RFP and answers do not impact project selection.
- Elements should be improved (*see below*) and converted into non-price scoring or sensitivity that captures community benefits.
- The Commission stated that it will want information about direct benefits to communities in Oregon.⁴ In fact, capturing more information about benefits and impacts to Oregon communities was identified as a necessary first step in impacting near-term decisions around utility procurement.⁵
- PacifiCorp and Oregon PUC staff agree that many projects could easily qualify as both SSR and as Community Based Renewable Energy (CBRE) projects, under HB 2021.

Issue: Equity questionnaire

Staff position: Equity questionnaire needs more explicit linkages to PacifiCorp's CBIs and reflect input from the Company's CBIAG.

Staff rationale:

- Staff appreciates the inclusion of the 2022 AS RFP Equity Questionnaire. However, the equity questionnaire does not necessarily reflect the Company's evolving CBIs from LC 82 and input from community members in both LC 82 and in the CBIAG.
- Some portion of the equity questionnaire should become the non-price scoring element to the RFP. (*See above.*)
 - o These can reflect the Company's evolving CBIs and/or attempt to capture insights into elements like positive impacts to community resiliency or the offsetting of fossil fuels.
 - o HB 2021 requires consideration of community benefits in meeting the emissions reduction targets, vis-à-vis offsetting fossil fuels, increasing community resiliency, and even economic development.⁶

Issue: Lack of locational value in evaluating and ranking of bids.

Staff position: PacifiCorp's evaluation and ranking of bids needs to explicitly take into account the locational value of capacity and energy from proposed SSR projects when assessing bids.

Staff rationale:

- Given that PacifiCorp has multiple load pockets across its system (e.g., five in Oregon) and uneven growth across its system (e.g., northeast Oregon load will grow incredibly fast over the next five years), the methodology to determine net cost/benefit of installed capacity needs to explicitly account for locational value.

⁴ UM 2273, Order No. 24-002, January 3, 2024, pg. 23

⁵ *Ibid.* Pg. 24-25.

⁶ ORS 469A.400(2)(a),(b) and 469A.415(4)(d)

- This will encourage the selection of bids with the lowest realized cost to Oregon ratepayers while better capturing the value to the PacifiCorp system.

Issue: No contract negotiations or redlines

Staff position: Redlines should be allowed.

Staff rationale:

- In UM 2274, contract redlines will be used by IE to illuminate bid nuances and pricing so as to make project selection more transparent and so the IE can comment around tradeoffs or irregularities in ISL or FSL project selection.⁷
- Contract redlines allows for projects with more unique attributes to potentially offer lower cost bids and provide necessary flexibility.

Issue: IE Scope

Staff position: Include information that compares and contrasts IE scope and staff interaction in the SSR RFP to UM 2193.

Staff rationale:

- Staff appreciates the inclusion of an IE for this RFP but needs a clearer understanding of the IE's scope and ability to interact independently with stakeholders, and how similar the role will be to an IE selected for a procurement under Oregon's competitive bidding rules.
- Will the IE be responsible for responding to bidder questions?
- Will the IE be responsible for establishing the scoring rules, as well as scoring all, or a subset of bids?
- Will the IE be working for/reporting to PAC or OPUC staff?

Issue: Separation of PacifiCorp RFP and Benchmark staff in establishing scoring system, reviewing bids and contract negotiations.

Staff position: The final RFP needs to clearly state how PacifiCorp RFP and Benchmark staff will be entirely screened from one another throughout this RFP process. This includes naming all employees working as part of the RFP team or the Benchmark team, including their roles and associated dates of their work; ensuring Benchmark staff have had no access to 3rd party project information during this RFP and for at least two years after bids are submitted; and developing and enforcing separation protocols to ensure no confidentiality breach or anti-competitive use of confidential data.

Staff rationale:

- If PacifiCorp's SSR benchmark project development team has any access to RFP bidder information they will have an unfair advantage in their bids.
- All other RFPs require a separation of staff.
- It is standard practice in Oregon to name utility staff on RFP and Benchmark teams so the IE, Staff, and/or stakeholders can verify that a separation between RFP and Benchmark teams was maintained.
- Bidders who receive confidential utility information are embargoed from using it for two to five years after an RFP. The same should be true for utility staff.

⁷ UM 2274, Order No 24-011 at 1.

In closing, an RFP functions as a market discovery mechanism. In Staff's experience, an RFP with too many restrictions on project eligibility limits the Company's and stakeholder's insights into available, competitive options. And for this RFP, Staff finds no downside to removing many restrictions (e.g., energy storage, RPS certification, size limit, two-types of pricing, etc.) if project selection still rests mainly on price and the determination of value as proposed in the RFP's evaluation and ranking methodology. If acquiring 490 MW by 2030 is truly an "all hands on deck" moment, restricting participation – as this RFP currently does – would appear to be counterproductive.

Further, HB 2021's direction to consider community benefits by understanding what they are necessitates some evaluation of a bid's community benefits and impacts. However, the equity questionnaire does not reflect recent developments and is not mandatory. Without some sort of non-price scoring or sensitivity that attempts to capture/understand community benefits we lose a unique opportunity in this RFP to understand and learn while also undermining a key rationale for including SSRs in HB 2021.

Finally, Staff encourages the utility to adopt the changes proposed above and to make any additional improvements necessary to clarify the community benefits and impacts of SSR procurement and ensure a fair, competitive process that reflects HB 2021's evolving approach to the public interest, especially with regards to technical and economic feasibility. Such efforts will be necessary for the Commission to evaluate the prudence of any acquisition and to evaluate the steps PacifiCorp is making to demonstrate continual progress towards the HB 2021 reduction targets at reasonable costs to customers.

ITEM NO. RA1

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MARCH 5, 2024**

REGULAR X CONSENT EFFECTIVE DATE N/A

DATE: March 1, 2024

TO: Public Utility Commission

FROM: JP Batmale

SUBJECT: PACIFICORP:
(Docket No. LC 82)
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP). Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PacifiCorp's CEP or decline to acknowledge the CEP.

Whether the Commission should adopt Staff's recommendations for additional direction to PacifiCorp.

Applicable Law

See Staff's February 20, 2024 public meeting memo for a full description of the Applicable Law to this docket.

Analysis

Purpose of Memo

The memo provides a final set of Staff recommendations to aid in Commissioner deliberation at the March 5, 2024 public meeting. These final recommendations are informed by the February 20, 2024 public meeting, the discussion of the Commissioners in that meeting, and subsequent review of the issues. For more background information behind these recommendations, please see Staff's previous public meeting memo, filed February 7, 2024, and associated comments from Stakeholders and PacifiCorp.

The approach guiding Staff's final suggested recommendations for Commissioner consideration are as follows:

- Elements of the IRP can be acknowledged in part.
- Based on Staff's interpretation of statute, the CEP cannot be acknowledged – in whole or in part – due to the CEP's failure to meet the standard in ORS 469A.420 to be in the public interest and consistent with the emissions reduction targets.
- Based on comments made by PacifiCorp at the February 20, 2024 public meeting, the April 2024 IRP/CEP Update is not a viable vehicle for any substantial new or revised analysis.
- All recommendations for any new or revised IRP/CEP analysis should focus on the 2025 IRP/CEP, which PacifiCorp plans to file in April 2025, and are based on an expectation that that IRP/CEP will be timely filed.
- Recommendations for the 2025 IRP/CEP should be kept to a minimum. The focus is on identifying the least number of analytic improvements or qualitative additions necessary to develop an IRP/CEP that leads to an acknowledgeable CEP.
- Additional recommendations are not new to this proceeding, but instead are drawn from previously stated expectations or stakeholder comments. Staff will continue to work with the Company and Stakeholders in the lead up to the 2025 IRP/CEP to implement the expectations identified in Staff's Round 2 comments.

Staff's final, suggested recommendations for Commissioner consideration are organized into two parts:

1. **Original Recommendations**: These come from Staff's Round 2 Comments. They are also included as Attachment A to Staff's February 20, 2024 public meeting memo. The recommendations include suggested strike throughs.
2. **Additional Recommendations**: There are three sources for these new recommendations. The first is Staff's stated expectations. The second is utility and stakeholder final comments and/or suggestions at the February 20, 2024 Public Meeting. The final source is the PacifiCorp IRP/CEP.

Original Recommendations

Table 1 below details Staff's original thirteen recommendations and includes Staff's suggested redlines as of the date of this memo.

Table 1, Revised Original Recommendations from Staff

Recommendation Description	Suggested Commissioner Action on March 5
# 1: Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.	Retain in full.
#2: Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.	Remove in full
#3: Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.	Change.
#4: Do not acknowledge Action Plan items s 1h and 2a.	Change.
#5: Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.	Retain in full.
#6: Direct PacifiCorp to provide specific baseline metrics prior to filing its next in the 2025 IRP/CEP to allow for measured progress towards CBI goals. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.	Change.

Recommendation Description	Suggested Commissioner Action on March 5
#7: Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG and environmental justice groups.in Q1 2024	Change.
#8: Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.	Change.
#9: The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.	Retain in full.
#10: Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.	Remove in full. Staff will have more specific directions in next table.
#10 (Formerly #11): Direct PacifiCorp to update Action Plan Item 1g (Natrium) to reflect actual events since the IRP/CEP was filed in May 2023. In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	Revise.
#11 (Formerly #12): Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.	Retain in full.
#12 (Formerly #13): Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.	Retain in full.

Additional Recommendations

Table 2 below details additional recommendations Staff believes the Commissioners should consider in the acknowledgement order. Recommendations number 13 and 14 are recommendations that should have been included with the original thirteen but were

not due to a Staff oversight. We apologize for the error and seek to correct that by including those recommendations below.

The other seven remaining recommendations are all forward looking. They are designed to help the PacifiCorp IRP team by providing clear expectations for the 2025 IRP/CEP.

The table below also includes the source of the recommendation and a short summary of the rationale behind the recommendation's inclusion. While the text may not exactly match a recommendation attributed to a stakeholder, Staff sought to capture the essence of the recommendation. Finally, many stakeholders made outstanding contributions to this IRP/CEP in written and verbal comments, which Staff greatly appreciates. Staff apologizes in advance for any potential oversights in recognizing the contribution of a stakeholder organization toward these additional recommendations.

Table 2, Additional Recommendations

New Recommendation Description	Source and Rationale
#13: Do Not Acknowledge Action Items 1c and 1d from the action plan because the Company has already taken these actions.	Source: Staff expectations. Rationale: Should have been included in original recommendation. Do not acknowledge action items already undertaken and not already acknowledged.
#14: Acknowledge Action Plan Items 3a through 3e, 5a, 6a, and 6b.	Source: PacifiCorp IRP Action Plan. Rationale: Should have been included in original recommendation.

New Recommendation Description	Source and Rationale
# 15: In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocation paradigms; (2) include expected CBREs in the Preferred Portfolio and ensure that the Preferred Portfolio meets Oregon's Small Scale Renewable Requirement; (3) adopt best practices in resource adequacy modeling, including consideration of load and resource performance under multiple weather years and calculation of loss of load expectation and capacity contributions using probabilistic analysis.	Source: Staff's expectations; CUB, Sierra Club, and RNW comments. Rationale: An optimized preferred portfolio that reflects law and best practices.
#16: In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	Source: CUB comments. Rationale: Better forecast of actual emissions. Provides insight into the potential continuation of historical underperformance of the fleet's emission reductions relative to IRP forecasts.
#17: In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions.	Source: Staff expectations. Rationale: Improve understanding of tradeoffs in CEP construction.
#18: In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard.	Source: RNW comments Rationale: Improve transparency of resource costs in portfolio development.

New Recommendation Description	Source and Rationale
#19: In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	Source: Sierra Club Rationale: Improved transparency in pricing of coal resources.
#20: In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk.	Source: Sierra Club, RNW, and Staff Rationale: Improve modeling and portfolio transparency.
#21: In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing.	Source: Sierra Club Rationale: Very low-cost financing for renewables should be pursued. Future resources – for either the System or for Oregon ratepayers – will be less costly due to EIR financing.

Conclusion

The twenty-two final proposed recommendations above are designed to aid in Commissioner deliberation at the March 5, 2024 public meeting. The memo includes updated recommendations from Staff's previous memo **and** updated recommendations based on various sources and in response to learnings from the February 20, 2024 public meeting.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's 2023 IRP, per Staff's recommendations. Decline to acknowledge PacifiCorp's CEP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-129:
Utah PSC on Pac 2023 IRP

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

PacifiCorp's 2023 Integrated Resource
Plan

DOCKET NO. 23-035-10

ORDER

ISSUED: April 17, 2024

SHORT TITLE

PacifiCorp's 2023 Integrated Resource Plan

SYNOPSIS

We acknowledge that PacifiCorp's 2023 Integrated Resource Plan ("2023 IRP") substantially complies with the IRP Standards and Guidelines, with certain important exceptions. Most notably, PacifiCorp's inconsistent and disparate evaluation of the Natrium Demonstration Project ("Natrium"), non-emitting (hydrogen) resource technologies, Carbon Capture, Usage, and Storage ("CCUS") technologies, and new natural gas resources produced a preferred portfolio that likely does not identify the least-cost, least-risk resources. Consequently, we decline to acknowledge the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan.

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I. INTRODUCTION AND PROCEDURAL HISTORY

On May 31, 2023,¹ PacifiCorp filed with the Public Service Commission (PSC) its seventeenth Integrated Resource Plan (“2023 IRP”), pursuant to the IRP Standards and Guidelines (“Guidelines”) adopted in Docket No. 90-2035-01.² PacifiCorp requests the PSC acknowledge the 2023 IRP in accordance with PSC rules and fully support the 2023 IRP conclusions, including the proposed action plan (“Action Plan”).

The Division of Public Utilities (DPU) and the Office of Consumer Services (OCS) participated in the docket and the following parties intervened: the Utah Association of Energy Users (UAE), Utah Clean Energy (UCE), Western Resource Advocates (WRA), the Interwest Energy Alliance (“Interwest”), Sierra Club, Fervo Energy Company, and Utah Citizens Advocating Renewable Energy.

¹ On March 28, 2023, the PSC granted PacifiCorp’s Request for a two-month extension and preliminary comment phase to file its final 2023 IRP due to changed model inputs that were driven by then-recent material changes, including the Ozone Transport Rule (the “OTR”), the Inflation Reduction Act (“IRA”), resource interconnection rules, the Oregon Clean Energy Plan, and Washington’s Clean Energy Transformation Act. According to PacifiCorp, the changes required additional time to implement the accuracy of the model’s outputs and did not allow stakeholders to review the model’s results, including the Preferred Portfolio, before the 2023 IRP March 31, 2023 deadline. The PSC authorized a preliminary IRP and comment phase to accommodate the filing of a preliminary 2023 IRP on March 31, 2023 (PacifiCorp’s submission was filed after business hours on Friday, March 31, 2023 and therefore it was submitted April 3, 2023), comments on the preliminary IRP by April 30, 2023, and the final 2023 IRP filing by May 31, 2023.

² See *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, (Report and Order on Standards and Guidelines, issued June 18, 1992), Docket No. 90-2035-01. Future references to Guidelines contained in that order will be referred to by the Guideline number. For example, “Guideline 3” will refer to Guideline 3 from page 19 of that order, without referencing the 1992 order each time the Guideline is referred to in this order.

By December 12, 2023, the following parties filed comments: DPU, OCS, UAE, WRA, Interwest, Sierra Club, and UCE. On January 31, 2024, PacifiCorp, DPU, UCE, and WRA filed reply comments.

A. Summary of the 2023 Integrated Resource Plan

The 2023 IRP presents PacifiCorp's plan to supply energy and capacity to provide for and manage the growing electricity demand in its six-state service territory over the next 20 years. The report identifies PacifiCorp's preferred least-cost, least-risk plan ("Preferred Portfolio") to invest in a portfolio of power plants, transmission facilities, firm power purchases, and demand side management (DSM) resources, including energy efficiency and direct load control. The 2023 IRP identifies the type, timing, and magnitude of resource additions and provides a short-term Action Plan.

The 2023 IRP includes modeling advancements such as a Targeted Portfolio Reliability Analysis that allows the assessment of the reliability of resource portfolios by performing subsequent modeling of renewable resources that are selected in the portfolios that can identify capacity shortfalls. It also includes supplemental studies such as, among others, an energy storage potential evaluation that provides details on energy storage grid services and how they can be configured and sited to maximize benefits.

PacifiCorp selected its Preferred Portfolio,³ which it asserts is the least-cost plan, adjusting for risk and uncertainty. To serve system-wide peak hour demand over the next 20 years, the Preferred Portfolio identifies cumulative supply additions (both long- and short-term resources) of 1,240 MW of non-emitting peaker resources, 9,113 MW of new wind resources, 7,855 MW of new utility solar resources, approximately 8,260 MW of battery storage, inclusive of 350 MW of long duration battery storage, 4,953 MW of incremental energy efficiency, 929 MW of new direct load control resources, 35 MW of pumped hydro storage, 1,500 MW of nuclear, and, through the 20-year horizon, approximately 390 MW of summer and winter firm power purchases, also referred to as front office transactions (FOT).⁴

The 2023 IRP Preferred Portfolio includes the end-of-life retirement of 1,141 MW of existing coal resources, the retirement of 2,335 MW of coal-fueled capacity with selective noncatalytic reduction retrofits, the transition of 1,770 MW of coal resources to other types of fuel, the end-of-life retirement of 595 MW of natural gas resources, the retirement of 23 MW of non-thermal resources, and the expiration of 22 MW of other resources.

The Preferred Portfolio and Action Plan include the retirement of co-owned coal units, the conversion of several coal units to natural gas, the closure of the Naughton South Ash pond, the development of Natrium, new resource acquisitions

³ See 2023 IRP, Volume I, at 307-324.

⁴ See *id.*, Table 9.31 at 325.

through the 2022 and 2024 All Source Requests for Proposals, as well as continuing development and construction of the Boardman-to-Hemingway 500 kV transmission line, among other action items.⁵

Planned investment in the Preferred Portfolio differs from PacifiCorp's Fall 2022 Business Plan ("Business Plan") primarily due to reductions or delays in the 2020 All Source Request for Proposals wind, solar, and battery storage resources in the Business Plan.⁶ The Preferred Portfolio also reflects lower reliance on FOTs. In addition, CO2 emissions over the study period decreased by 9 million tons relative to the Business Plan.⁷

B. The IRP Process and Standard of Evaluation

Utah Code Ann. § 54-1-10 requires the PSC to "engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources." The PSC relies in part on PacifiCorp's IRP process to fulfill this planning requirement to meet the electrical needs of PacifiCorp's Utah service territory. In 1992, the PSC developed and approved the Guidelines that govern the IRP process.⁸ PSC acknowledgment of an IRP means it substantially complies with these Guidelines. Such acknowledgment, however, does not constitute PSC approval of any specific PacifiCorp resource acquisition decision or

⁵ See *id.*, at 27-33.

⁶ See *id.*, at 335-336.

⁷ See *id.*

⁸ Information on historic PacifiCorp Integrated Resource Plans can be found at the following link: <https://psc.utah.gov/electric/historic-integrated-resource-plans/>.

strategy for meeting its obligation to serve. Resource approval and cost recovery are addressed in dockets separate from the IRP.

II. SUMMARY OF ISSUES ADDRESSED IN COMMENTS

As discussed in more detail below, several parties urge us not to acknowledge this IRP. Many express serious concerns regarding the limited time afforded for their review, evaluation, and meaningful input. The challenges PacifiCorp has faced meeting IRP schedule deadlines are evident in the fact it has requested substantial extensions in each of the last three IRP cycles. Parties contend there was no opportunity for their review and feedback on modeling results and the P-MM Preferred Portfolio before the preliminary 2023 IRP was filed. Consequently, some dispute that the P-MM Preferred Portfolio represents the least-cost, least-risk resource portfolio. Additionally, many parties expressed concern over the suspension of the 2022 All Source Request for Proposals (the “2022 AS RFP”) and its impact on the Action Plan. Finally, several parties, including the DPU and OCS, challenged various specific modeling inputs, assumptions, and studies, asserting:

- a) inconsistent or insufficient analysis, or disparate treatment, of resources;
- b) insufficient analysis of federal and state incentives and potential savings opportunities from the IRA and the Energy Infrastructure Reinvestment (“EIR”) program;
- c) insufficient discussion and analysis of regional transmission planning;

d) inadequate modeling and evaluation of advanced transmission technologies, grid-enhancing technologies (“GET”), and other alternatives to new transmission construction; and,

e) inadequate transparency and discussion related to PacifiCorp’s reliability and granularity adjustments.

III. PARTIES’ POSITIONS ON ACKNOWLEDGMENT OF THE 2023 IRP

Parties’ Comments

DPU, OCS, and UAE recommend the PSC not acknowledge the 2023 IRP. DPU argues 1) its submission was two months late with the last of the supporting documents filed on June 20, 2023;⁹ 2) Natrium was included in the Preferred Portfolio without sufficient analysis of costs, timing, and risks to customers in light of the large costs and schedule overruns of other nuclear projects in the country; 3) the 2022 AS RFP was suspended without explaining its impact on the Action Plan;¹⁰ 4) the assumption that non-emitting peaker plant technology will be commercially available by 2030 is inappropriate given the technology is unproven and its operating costs are unknown; and 5) some resources and technologies, like nuclear and non-emitting

⁹ DPU Comments, at 2 and 4, filed December 12, 2023 (“DPU Comments”). DPU comments this is the third straight instance the IRP was filed two or more months after the March 31 deadline.

¹⁰ DPU explains the assumptions that served as model inputs may change significantly by the time PacifiCorp performs more modeling, reiterating that “[t]hrough the end of 2026, the 2023 IRP Preferred Portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 AS RFP [was] ... soliciting and evaluating resources to fulfill.” *Id.*, at 15 (quoting the IRP, at 35).

peakers, are unjustifiably favored and others, like new natural gas resources and CCUS technologies, are unjustifiably excluded.¹¹

OCS argues PacifiCorp failed to meet Guidelines 3, 4.b., 4.e., 4.g., and 4.h. OCS states PacifiCorp did not provide any modeling results to stakeholders for review and feedback until after it had filed the preliminary IRP.¹² Additionally, OCS joins DPU in asserting natural-gas-fired resources were not evaluated on a comparable and consistent basis relative to unproven technologies like Natrium and non-emitting hydrogen peakers. OCS also objects that an appropriate customer rates impact analysis was not provided. Finally, OCS notes the suspension of the 2022 AS RFP may negatively impact system reliability within the next four years, leading OCS to challenge whether the Action Plan reflects least-cost, least-risk resources.

UAE comments PacifiCorp withheld the results of any modeling runs, including the Preferred Portfolio, from stakeholders before filing its preliminary 2023 IRP, contrary to Guideline 3. UAE believes PacifiCorp's actions prevented UAE's reasonable and meaningful participation in the selection of the Preferred Portfolio.¹³

¹¹ DPU notes that the CCUS technology was the top-performing variant case using medium gas/medium CO₂ assumptions, with a present-value revenue requirement ("PVRR") of \$507m under the P-MM Preferred Portfolio. It was also a top performer under various other scenarios. Regarding new gas resources, DPU explains PacifiCorp assumed a 10-year cost recovery period rather than a typical 40-year period (DPU Comments, at 24). This unusual assumption was made without stakeholder input and, to DPU's knowledge, was first announced after PacifiCorp submitted the preliminary IRP.

¹² OCS Comments, at 1-2, filed December 12, 2023 ("OCS Comments").

¹³ UAE Comments, at 3, filed December 12, 2023 ("UAE Comments").

UAE also expresses concern about the inclusion of Natrium in the Preferred Portfolio. UAE explains the lack of information about Natrium's cost and performance assumptions impeded any independent evaluation. UAE states PacifiCorp in effect forced the model to select Natrium. This modeling approach cannot be viewed as providing consistent and comparable treatment of competing resources.¹⁴

UCE recommends the PSC acknowledge the 2023 IRP and explains UCE is encouraged by PacifiCorp's planned increases in wind, solar, and storage resources in the 2023 IRP.¹⁵

WRA takes no position regarding the acknowledgment of the 2023 IRP. But it joins other parties in asserting that time constraints negatively impacted the accuracy of the modeling and the opportunity for public input. WRA explains that the preliminary 2023 IRP, the final 2023 IRP, and the accompanying supporting workpapers include significant errors — far more than is typical. In WRA's view, many portfolio results don't make sense.¹⁶ These discrepancies, according to WRA,

¹⁴ *Id.*, at 9.

¹⁵ UCE Comments, at 3, filed December 12, 2023 ("UCE Comments").

¹⁶ As an example, WRA described that several portfolios show inexplicable disparities particularly in early years where system resources should be more or less identical including a comparison of portfolio variant P05-No Nuclear and P06-No Forward Technology. WRA explains that given nuclear and non-emitting peakers are not selected in either portfolio until 2030, the expectation was that the portfolios would differ only in future years but that there were large discrepancies in market purchases appearing in the first three years of the modeling period, despite no difference in system need or expansion options in those early years. WRA Comments, at 11, filed December 12, 2023 ("WRA Comments").

undermine its confidence in the results and support its view the IRP was filed before it was ready for stakeholder analysis.

Interwest recommends either the PSC decline to acknowledge the 2023 IRP or conditionally acknowledge certain parts thereof and the Action Plan.¹⁷ Interwest states the 2022 AS RFP's suspension casts extreme uncertainty over the Action Plan. Interwest calls for increased scrutiny of Natrium and non-emitting peaker resource technologies in the Preferred Portfolio, as they "do not reflect the least cost/least risk" resources".¹⁸ Interwest also recommends the PSC direct PacifiCorp to resume the 2022 AS RFP as soon as possible.

Sierra Club recommends the PSC acknowledge the planned new renewable resources in the 2023 IRP but argues the Plan's coal retirement timelines, gas conversions, and nuclear additions "are extremely risky for ratepayers" and do not warrant acknowledgement.¹⁹ Sierra Club also expresses concern about the suspension of the 2022 AS RFP.²⁰

PacifiCorp's Reply

PacifiCorp asserts its 2023 IRP and Action Plan comply with the Guidelines and were developed after substantial stakeholder input. PacifiCorp asserts it held eleven public-input meetings and six state-specific input meetings.²¹ The 2023 IRP public-

¹⁷ Interwest Comments, at 3, filed December 12, 2023 ("Interwest Comments").

¹⁸ *Id.*, at 6.

¹⁹ Sierra Club Comments, at 3, filed December 12, 2023 ("Sierra Club Comments").

²⁰ *Id.*

²¹ PacifiCorp Reply Comments at 12, filed January 31, 2024 ("PacifiCorp Reply Comments").

input process materials covered inputs, assumptions, risks, modeling techniques, and analytical results. PacifiCorp states it considered and implemented the PSC's direction in developing the 2023 IRP. It further asserts the Preferred Portfolio is supported by a detailed analysis of: 1) key inputs and assumptions to inform the modeling and portfolio-development process; 2) a wide range of resource portfolios; 3) a targeted reliability analysis to ensure portfolios have sufficient flexible capacity to meet reliability requirements; 4) evaluation of the resource portfolios to measure comparative costs, risks, reliability, and emission levels; and 5) development of a near-term resource Action Plan required to deliver resources in the Preferred Portfolio.²²

PacifiCorp asserts the 2023 IRP benefited from various modeling advancements²³ and that through an extensive IRP process PacifiCorp was able to develop a Preferred Portfolio that meets its long-term goals of providing reliable and affordable service to its customers.

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS

A. SUSPENSION OF THE 2022 ALL SOURCE RFP

OCS, DPU, Interwest, and Sierra Club assert the suspension of the 2022 AS RFP in September 2023 is problematic and, according to OCS, violated Guideline 4.e. OCS explains, and DPU agrees, the 2022 AS RFP suspension directly impacts the

²² *Id.*, at 4.

²³ See 2023 IRP, Volume I, at 18-19.

assumptions and selection of resources in the 2023 IRP because the types of resources that were expected to emerge from the 2022 AS RFP may no longer be available and may not be ready for commercial operation by the date required. According to OCS, this could result in increased exposure to market price risks, especially in the event of extreme weather like the September 2022 western heatwave.²⁴

DPU and Interwest assert the suspension of the 2022 AS RFP raises serious doubts as to whether the 2023 Action Plan can be implemented.²⁵ Likewise, Sierra Club states it is highly concerned over PacifiCorp's decision to pause the 2022 AS RFP, especially after the 2023 IRP shows an even greater need for new renewable resources than was forecast in the 2021 IRP.²⁶

PacifiCorp responds it suspended the 2022 AS RFP in September 2023, after it had filed the 2023 IRP.²⁷ It explains its decision was based on a stay of the U.S. Environmental Protection Agency's ("EPA") proposed OTR; ongoing EPA rulemaking on greenhouse gas emissions; wildfire risk and associated liability; and, evolving extreme weather risks.²⁸ It argues that it complied with Guideline 4.e. and that IRP acknowledgment means not that the Action Plan or Preferred Portfolio selections are

²⁴ OCS Comments, at 4.

²⁵ DPU Comments, at 14; and Interwest Comments, at 5-6.

²⁶ Sierra Club Comments, at 3.

²⁷ PacifiCorp Reply Comments, at 16.

²⁸ The OCS argues that all of these factors were known and included in the final 2023 IRP when it was filed on May 31, 2023; and therefore, was surprised PacifiCorp named the same factors as the reason for suspending the 2022 AS RFP in September 2023.

valid into perpetuity but rather, that the IRP and resulting Action Plan are appropriate given the conditions at the time of filing.

We conclude PacifiCorp's decision to pause the 2022 AS RFP substantially impacts the Action Plan and greatly reduces its value and trustworthiness. The PSC recognizes at least some of the reasons PacifiCorp offers for pausing the RFP were known to PacifiCorp at the time it filed its final 2023 IRP in May 2023. Nevertheless, while certain parties recommend the PSC direct PacifiCorp to reinstate the 2022 AS RFP, such proposals are outside the scope of this docket.

B. MODELING ISSUES, ASSUMPTIONS, AND RESOURCE SELECTIONS

1. Consistent and Comparable Treatment of Resources

a. *Natrium*

DPU, OCS, UAE, and Interwest argue that PacifiCorp either forces the selection of Natrium in the Preferred Portfolio or inputs favorable assumptions to ensure the model always selects Natrium. For example, UAE notes that unlike every other generation resource considered in Table 7.1 of Chapter 7 of the 2023 IRP (showing costs and performance information for all supply-side resources), Natrium is not included.²⁹ Rather, PacifiCorp's cost and performance assumptions for Natrium are unknown to stakeholders. According to UAE, this allows the assumed costs of Natrium to "move" in the model such that they purportedly always provide benefits to

²⁹ UAE Comments, at 7.

customers.³⁰ UAE contends this also ensures that Natrium is always selected by the model.³¹ PacifiCorp justifies this treatment by stating that it is in commercial discussions with TerraPower and will not move forward unless there are benefits for customers. UAE concludes Natrium's treatment in the model is not consistent and comparable with the treatment of other resources.

DPU states PacifiCorp has never responded to requests for 1) Natrium's costs and performance factors and 2) a timeline with major milestones that shows a path to achieving an online service date of 2030.³² DPU also contends that since no details are available to stakeholders, it is impossible to evaluate Natrium on a comparable and consistent basis with other resources. DPU concludes that until an agreement is finalized, federal funding is certain, and a timeline is provided, Natrium is a speculative resource that should not be in the Preferred Portfolio.³³

PacifiCorp responds that its selection of Natrium in the P-MM Preferred Portfolio was based on substantial grants from the Department of Energy (DOE), Natrium's development by TerraPower, the alternative path analysis, the OTR and other federal regulatory requirements, and the obligation to provide least-cost, least-risk portfolios.³⁴ It explains TerraPower bears all development risks and asserts it has not signed any agreements with TerraPower. It reiterates it will only move forward if

³⁰ *Id.*, at 9.

³¹ *Id.*

³² DPU Comments, at 21.

³³ *Id.*, at 19.

³⁴ PacifiCorp Reply Comments, at 35.

Natrium brings value to customers. PacifiCorp indicates the risks associated with Natrium are mitigated because Natrium alternatives require much shorter lead-times than nuclear projects and ample opportunities to meet future electric demand will emerge, before it commits to Natrium.³⁵ PacifiCorp also reiterates the potential realization of Natrium does not fall within the two- to four-year Action Plan window and explains that Natrium was intentionally limited to years outside of the Action Plan.³⁶

b. *Non-Emitting Peaker Plants*

DPU, OCS, and Interwest contend that PacifiCorp favors non-emitting peaker resources (turbines running on 100 percent hydrogen) by assuming they will be available and commercially viable by 2030 even though no such utility scale technology is currently operating. Both DPU and Interwest note the production and transportation plans for hydrogen for utility-scale energy generation are also currently only in the design phase.³⁷ They explain that while hydrogen could be delivered using a pipeline network from a centralized remote facility, these pipelines do not currently exist. Given these facts, the parties question the selection of the resource for the P-MM Preferred Portfolio.³⁸ DPU comments it is impossible to

³⁵ *Id.*, at 36.

³⁶ *Id.*, at 37.

³⁷ DPU comments, at 3 and 22.

³⁸ In response to a data request, PacifiCorp responded that its modeling of this technology assumes 1) the expense of the needed pipeline, as well as 2) its ability to procure hydrogen at market prices based on forward price curves and projections showing low hydrogen production costs and federal tax credits for 100 percent hydrogen. DPU Comments, at 22-23.

analyze PacifiCorp's cost information since such plants are not commercially operating, and DPU has no way to test any data supporting PacifiCorp's assumptions.³⁹ DPU adds that the timelines PacifiCorp uses for availability of non-emitting peakers may also be optimistic, and argues that assuming a specific date for this non-emitting resource is speculative.

Interwest criticizes non-emitting peaking resources' selection in the Preferred Portfolio stating that a 20 percent hydrogen blending ratio is inadequate to achieve emission performance requirements because it achieves only a marginal decrease of 6-7 percent in carbon emissions at the gas generating unit.⁴⁰ Additionally, there is evidence a sustained green hydrogen supply-chain does not exist.

In response, PacifiCorp states that its main goal is selecting a Preferred Portfolio with the best combination of expected costs and associated risks and uncertainties.⁴¹ Thus, in creating a 20-year plan, it does not limit resources to only those currently estimated to be commercially viable within the planning horizon. Rather, it considers associated risks when it includes resource options. PacifiCorp believes non-emitting peakers, like nuclear, will achieve wider commercial use outside of the two- to four-year Action Plan window and restricts their selection on that basis. PacifiCorp also explains that the alternative path analysis indicates ample

³⁹ *Id.*, at 22.

⁴⁰ Interwest Comments, at 11.

⁴¹ PacifiCorp Reply Comments, at 41.

opportunity for adjustment to these proxy resource selections based on future analysis.

c. CCUS Technology

DPU contends PacifiCorp's planning is biased against CCUS technologies. For example, DPU states that variant P20 JB3-4 CCUS ("P20") (which includes CCUS technology), was the top-performing variant case using the medium gas/medium CO2 assumptions, with a PVRR of \$507 million *under* the P-MM Preferred Portfolio variant (using short-term ("ST") value).⁴² Variant P20 was also the top performer under a risk-adjusted cost metric and was third in the CO2 emissions category.⁴³ It was also the top ST cost performer under both the medium gas/zero CO2 scenario and the high gas/high CO2 scenario, and was the top emission performer under both of these scenarios.⁴⁴

PacifiCorp responds that CCUS technologies have shown significant cost uncertainty and only two major utility-scale CCUS retrofit projects are commercially operating.⁴⁵ PacifiCorp conceded the P20 variant was the top performer under both ST and risk-adjusted evaluations, but explained it did not choose it for the Preferred Portfolio because 1) the CCUS assumptions are not based on bids or proposals from CCUS technology companies but are proxy assumptions for project-specific costs and

⁴² DPU Comments, at 24.

⁴³ *Id.*

⁴⁴ *Id.*

⁴⁵ PacifiCorp Reply Comments, at 39.

operational characteristics; 2) the scale of the proposed CCUS technology has never been demonstrated on a coal plant operating commercially anywhere in the world; 3) while feasibility studies for amine-based CCUS at Jim Bridger (“JB”) units 3 and 4 have been done, PacifiCorp currently does not have evaluation or equivalent cost data to that of a front-end engineering and design study; 4) the updated fueling strategy to source coal for JB exclusively from the Powder River Basin has not been previously attempted by PacifiCorp; and 5) other limitations, challenges, and risks. In response to a question about whether these risks were analyzed by its model, PacifiCorp indicated its rejection of the P20 variant in the Preferred Portfolio was more of a judgment call.⁴⁶

d. *New Natural Gas Plants*

According to DPU and OCS, PacifiCorp’s planning is also biased against generating facilities fueled by natural gas and coal. For example, DPU states PacifiCorp informed stakeholders for the first time in the April 13, 2023 public input meeting that in most scenarios, the recovery period for the costs of new gas resources is assumed to be 10 years to account for PacifiCorp’s perceived risks in investments in new carbon emitting resources.⁴⁷ DPU requested results from a portfolio variant assuming instead a 40-year cost recovery horizon as realistically in line with new natural gas resources and PacifiCorp responded by producing variant

⁴⁶ DPU Comments, at 24-25.

⁴⁷ *Id.*, at 30.

“P24-Gas 40-year Life” (“P24”). PacifiCorp describes it as a variant of the P-MM Preferred Portfolio that changes the technical life assumption for proxy gas resources from 10 years in the base study to 40 years. According to PacifiCorp, this change produced different results. First, the model selected gas units as replacements for any coal retirements, instead of the nuclear or non-emitting peaking options in the P-MM Preferred Portfolio.⁴⁸ Second, the “cost of gas pipelines led the model to keep” the Hunter 2 and 3 coal plants running through 2042.⁴⁹ Third, the model selected significantly less early DSM.⁵⁰ DPU criticizes PacifiCorp’s arbitrary decision to change the expected life of new natural gas plants arguing several natural gas plants are currently in different stages of development across the country.⁵¹ DPU also notes the PSC declined to acknowledge the 2021 IRP for a similar reason — PacifiCorp’s unilateral decision to force the model to exclude new natural gas plants altogether. DPU explains the decision to constrain the life of a new natural gas plant resulted in an inappropriate Preferred Portfolio. PacifiCorp responds that for the first time, it allowed the model to endogenously select natural gas conversions for a broader set

⁴⁸ *Id.*, at 26-27.

⁴⁹ *Id.*

⁵⁰ *Id.*, at 27 (DPU referencing the 2023 IRP, Volume I, at 305).

⁵¹ DPU presents a map showing natural gas plants that were announced, in early development, in advanced development and under construction in 2023 which DPU states illustrates that many utilities do not attribute the same risks to natural gas plants that PacifiCorp does. DPU Comments, at 29 (Figure 5 – Planned New Natural Gas Plant (S&P)).

of units. According to PacifiCorp, this enhancement expands opportunities for natural-gas-fired operation compared to prior IRPs.⁵²

DPU also challenges the final step PacifiCorp used to select the Preferred Portfolio. After all of the variants were run through the model, PacifiCorp explains its decision to select the P-MM variant as the Preferred Portfolio was driven by “consideration of current policies in motion and unmodeled risks for which ongoing trends recommend the adoption and development of tax-supported renewable projects”⁵³ In response to a request for calculations or other supporting data for these subjective criteria, PacifiCorp stated there were no records or calculations to review.

e. We Find and Conclude PacifiCorp Failed to Treat Resources on a Consistent and Comparable Basis.

Guideline 4.b. requires “[a]n evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.” In addition, 4.b.iii. states “resource assessments should include: life expectancy of the resources... .”

We find, based on the evidence, that PacifiCorp overlooked the negative attributes of Natrium in its analysis and withheld confidential costs and performance information that were necessary to compare Natrium on a consistent and comparable

⁵² PacifiCorp Reply Comments, at 37-38.

⁵³ 2023 IRP, Volume I, at 306.

basis relative to other resources. Natrium certainly has potential due to its unique characteristics as described in PacifiCorp's reply comments.⁵⁴ However, the IRP contains no discussion of the potential for significant cost overruns or delayed construction timelines typical to the development and construction of nuclear projects. Natrium was selected as a least-cost, least-risk resource in the Preferred Portfolio based solely on its positive, unique attributes. We recognize the sensitivity of PacifiCorp's costs and performance assumptions for Natrium; however, our process provides protections for highly confidential information that may have allowed parties to perform at least a general cost analysis, and PacifiCorp failed to use it. We find it is impossible to compare Natrium with other resources on a comparable and consistent basis without cost and performance assumptions and a realistic assessment of all the potential attributes of Natrium, both positive and negative.

We also find disparate treatment by PacifiCorp of non-emitting resource technologies relative to CCUS technologies. For example, despite the P20 CCUS variant being the top or near the top-performing variant under five different scenarios,⁵⁵ PacifiCorp did not select it as a least-cost, least-risk resource in the Preferred Portfolio. The reasons PacifiCorp argues for rejecting CCUS, e.g., that cost assumptions are not based on bids and commercial operation is unproven, apply with

⁵⁴ PacifiCorp Reply Comments, at 36.

⁵⁵ See DPU Comments, at 24.

equal, if not greater, force to the Natrium and non-emitting resource technologies PacifiCorp includes in the P-MM Preferred Portfolio.

Finally, the use by PacifiCorp of a 10-year life for new natural gas plants was arbitrary and unjustified, and prevented their consistent and comparable treatment relative to other resources. The PSC recognizes risks may exist to natural gas plant lifespans attendant to the OTR and other federal regulations. Such risks are inherent in the planning process and require analysis and articulated reasoning on how best to measure and account for them. In this instance, however, the restriction on useful life is unilateral and arbitrary. Neither the OTR nor any other federal regulation changes the depreciable lives of natural gas plants from 40 to 10 years. Moreover, any Oregon, Washington, and California laws that may impact the lives of new natural gas plants do not apply in Utah. Accordingly, the PSC finds that PacifiCorp did not treat natural gas plant options on a comparable and consistent basis relative to other resources, contrary to Guidelines 4.b., 4.b.iii., and 4.h.

2. Reliability and Granularity Adjustments

Sierra Club requests PacifiCorp clarify its methodology for its reliability adjustments and explain the reason the long-term model produces significant energy shortfalls that must be manually addressed. Sierra Club also requests an opportunity to recommend alternative reliability adjustments, and clarification of the values

PacifiCorp uses in the granularity adjustments.⁵⁶ Sierra Club suggests that PacifiCorp base its coal units' granularity adjustments on total fuel costs.⁵⁷

PacifiCorp explains that both reliability and granularity adjustments are specific measures that address specific enhancements and there are no logical alternatives because both procedures are dictated by model math.⁵⁸ It further explains that in extreme cases where the adjustments exceed plus or minus \$100/kW-year, it limits the adjustment to plus or minus \$100/kW-year to prevent the granularity adjustment from overwhelming long-term outcomes based on extreme values driven by conditions that will not be relevant in final reliable portfolios.⁵⁹ PacifiCorp comments it makes resource adjustments on the basis of measured deficiencies and by applying calculated resource values to determine the appropriate action to cover deficiencies. It states its approach is specific to stated goals and a direct application of model outcomes to improve results. We find PacifiCorp's explanations to be reasonable and sufficiently responsive to Sierra Club's requests. Therefore, we find that no additional information related to its reliability and granularity adjustments is necessary.

⁵⁶ Sierra Club Comments, at 4.

⁵⁷ *Id.*, at 4 and 42.

⁵⁸ PacifiCorp Reply Comments, at 19.

⁵⁹ *Id.*, at 20.

3. Customer Rate Impact Analysis

In response to OCS's claim that PacifiCorp failed to comply with Guideline 4.g. by not including a customer rate impact analysis, PacifiCorp states that the IRP includes an indicator of customer rate pressure over time among the initial portfolios relative to the P-MM Preferred Portfolio. It explains that Volume II, Appendix J, stochastic simulation results show incremental and cumulative estimated customer rate impacts over the 20-year planning period that apply equitably across all classes of ratepayers.⁶⁰ PacifiCorp indicates that while the approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for ratemaking purposes. PacifiCorp also explains that the IRP is informed by proxy resources where exact costs cannot be known until specific resources are known. We find, based on PacifiCorp's explanation and our review of Volume II, Appendix J, including the figures showing net differences in total system costs, that its analysis meets Guideline 4.g., and no additional analysis is necessary.

4. Miscellaneous Changes to the Presentation of Data

Alternative Portfolio Variants, Cluster Resources, and Scenarios. In response to Sierra Club's request for PacifiCorp to complete model runs of P01-JB3-4 GC, P04-Huntington RET28, and P17-Col3-4 RET25 variants under all of the different pricing

⁶⁰ *Id.*, at 22.

scenarios, PacifiCorp responds that because it is constrained from evaluating all studies under all possible conditions, it must prioritize which model variant to analyze. It bases its decisions on the likely investigative value. PacifiCorp states the P01, P04, and P17 results, for example, are so conclusive that further analysis under other, less likely, price scenarios doesn't add likely investigative value. PacifiCorp states that P17, for example, was examined only to determine the cost-effectiveness of an early retirement of both Colstrip units over the optimally selected approach of retiring one unit and continuing the other. PacifiCorp also explains the 2023 IRP evaluates portfolios under five price policy scenarios with attention to investigative value and resource availability. PacifiCorp states it cannot evaluate all studies under all possible conditions and therefore prioritizes cases. At the same time, PacifiCorp asserts, it has been responsive to stakeholder requests, conducting additional studies as time and resources allow.

PacifiCorp explains that the analysis of P18 and P19 likewise was conducted with the understanding that additional resources would likely result in a higher cost PVRR outcome and that the value of the studies was to assess the magnitude of that PVRR impact to determine possible least-regret paths to consider for the Preferred Portfolio. It further explains that the results of the studies supported the selection of the Preferred Portfolio without the additional marginal cluster resources in the East or West.

We find PacifiCorp's explanation that it cannot evaluate all studies under all possible conditions, and therefore prioritizes cases, is reasonable. We also find that PacifiCorp has been responsive to stakeholder requests for alternative and additional model runs, conducting additional studies as time and resources allow, and that running the proposed additional variants would produce more portfolios but would not change the final outcome and, therefore, be of limited value. Based on this, we find it is unnecessary for PacifiCorp to run the requested additional modeling.

Coal fuel costs for JB and pipeline capacity for conversions. We find PacifiCorp's response to the request that it use the base tier pricing from the 2023 JB long-term fuel plan for the JB plant, to be reasonable. PacifiCorp states that the fixed and variable cost structure assumed in the 2023 IRP captures the cost of continuing or ceasing coal-fired operation at JB units 3 and 4. It explains that opportunities to optimize coal supply for particular circumstances are ill-suited for modeling in the IRP and provide limited incremental benefit.

We also find PacifiCorp's response to Sierra Club's request that PacifiCorp provide an assessment of the availability and cost of firm interstate pipeline capacity necessary to supply its planned coal to gas conversions in the 2023 IRP Update, to be reasonable. PacifiCorp explains that due to confidentiality agreements between it and third-party entities, it is unable to disclose any terms on firm interstate pipeline capacity for planned conversions.

Carbon. Sierra Club recommends PacifiCorp increase the medium carbon price assumption to reflect recent federal regulations and incorporate the developments in the 2023 IRP Update. According to PacifiCorp, the request is based on a misunderstanding of the medium CO2 price assumption cost function. It explains that the medium CO2 price assumption is a proxy for future drivers. Its CO2 proxy cost forecast represents an established trend of decarbonization into the future and is based on a survey of (then) currently available forecasts. PacifiCorp explains that it is not the role of the proxy cost to drive decarbonization, rather its role is to represent drivers that can be reasonably forecast. It further explains its forecasting of the decarbonization trend will continue into the future. Regarding the request for elimination of “the medium gas price, zero CO2 price (‘MN’) price-policy scenario or zero CO2 (‘LN’) price-policy scenarios generally,”⁶¹ PacifiCorp states this would generally eliminate a source of information from the robustness of portfolios that indicates what may occur if the expected case CO2 proxy forecast is not realized. PacifiCorp asserts that while the medium gas price-policy scenario is the most likely, eliminating it or any alternative, as requested, is unnecessary. We find PacifiCorp’s response credible. On this basis, we find that it is unnecessary to run the requested analyses.

⁶¹ *Id.*, at 26.

Collocated Resources. UAE recommends the PSC direct PacifiCorp to make its requested changes to Tables 9.31, 9.32, and 9.33, and Figures 9.60 and 9.62 in future IRP filings. UAE's main concern is that the tables lack detail on whether the generation and storage resources shown are collocated or standalone resources. PacifiCorp responds that collocation information is illustrated in Figure I.1 of the 2023 IRP. It lists the portfolio resources selected by location and year, including solar and wind resources that are collocated with storage. PacifiCorp also refers to the discussion on the expansion of collocation opportunities in section III.A.2 – *Process Improvements*, in the 2023 IRP indicating that collocation options are no longer constrained in the modeling. We find PacifiCorp's explanation is responsive to UAE's requests; therefore, we decline to order the requested changes in future IRP filings.

Surplus Interconnection. Sierra Club requests PacifiCorp allow storage to be paired with not only new renewable resources, but also existing fossil fuel resources. According to Sierra Club, this use of a thermal asset with a storage resource "would increase the flexibility of the asset and provide lower emission reliability services, such as spinning reserve" and likely "reduce operating costs as the storage asset could operate more responsively."⁶²

PacifiCorp responds that it has modeled surplus interconnection in the 2023 IRP, where storage resource options were available to be selected with potentially

⁶² Sierra Club Comments, at 55-56.

any technology or combination of technologies, allowing portfolio optimization to recognize the best location, size, and timing for storage concurrently with considerations of existing technology profiles, and also in tandem with thermal retirement options. PacifiCorp adds that storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed at any modeled location on the system. It explains that its strategy has exceeded the requests by allowing the model to make the best collocation determinations endogenously and refers Sierra Club to the IRP discussion of expanded collocation opportunities in section III.A.2 – *Process Improvements*. We find PacifiCorp’s response to be reasonable and find that PacifiCorp has already modeled the requested interconnection scenario, and no additional modeling is necessary.

C. PROCESS ISSUES

DPU contends the 2023 IRP was filed after the March 31 deadline for the third IRP cycle in a row, and the continual filing delay disadvantages stakeholders as it compresses their opportunity to review and evaluate the IRP. DPU explains it agreed to PacifiCorp’s extension request because it was the least objectionable alternative. OCS, UAE, and UCE also contend that PacifiCorp’s failure to provide the modeling results to stakeholders before it filed the preliminary IRP prevented them from having any opportunity to review, evaluate, and provide public input, which OCS and UAE claim violates Guideline 3. DPU and OCS note that even the media knew the modeling

results before stakeholders who invest significant time and resources into the IRP planning process. UCE agrees that PacifiCorp should provide the modeling results to stakeholders to allow for sufficient review before filing the IRP. WRA also joins DPU, OCS, UAE, and UCE in the overall concern that time constraints impact not only the ability to appropriately review, evaluate, and provide input, but also lessen the accuracy and quality of the IRP. WRA also asserts the current IRP process and timeline do not work and suggests the PSC make a structural change.

PacifiCorp responds the two-month extension to file the 2023 IRP by May 31, 2023 was necessary to allow PacifiCorp to incorporate recent federal and state law changes such as the OTR, the IRA interconnection rules, and other state regulatory requirements. PacifiCorp asserts that while several parties expressed concern over the requested extension, no one recommended the PSC deny it and notes that stakeholders requested PacifiCorp provide a draft IRP in comments related to the 2021 IRP. PacifiCorp further asserts the extended stakeholder engagement process enhanced the accuracy and comprehensiveness of the IRP that led to a significantly improved analysis in the final 2023 IRP. In sum, PacifiCorp notes that the public input process affords many opportunities for comment and quotes the PSC stating, “[t]he purpose[] of the process is *not* to allow stakeholder[s] an early preview of what

PacifiCorp has [ultimately] elected to do. The purpose is to allow them an opportunity to provide meaningful feedback at each stage of a collaborative process.”⁶³

Our direction on the interpretation of Guideline 3 has been clear. The opportunity for stakeholders to examine and provide information during the IRP development, rather than after the fact, is an important aspect of the process.⁶⁴ The IRP is to be developed in consultation with stakeholders who must have ample opportunity for meaningful feedback and information exchange during the development of the plan and at each stage of the process.⁶⁵ In this docket, PacifiCorp did not share its modeling results and the Preferred Portfolio, two of the most critical aspects of the IRP, with stakeholders until after it filed its preliminary IRP on April 3, 2023. This is the first time that PacifiCorp has not provided modeling results and Preferred Portfolio selections before making its IRP public. However, this is also the first time that we have added an extended filing period that included the filing of a preliminary IRP and a comment deadline. In light of the uncertainties created by this new procedure, we do not find PacifiCorp violated Guideline 3. Nevertheless, we

⁶³ PacifiCorp Reply Comments, at 11. In quoting the PSC’s order about the purpose of the process, PacifiCorp unfortunately misinterpreted our language and quoted it out of context. The PSC was reacting to PacifiCorp’s pattern of untimeliness, of presenting meeting materials at the last minute, and of making key modeling decisions without giving stakeholders time to review and provide meaningful input. A major purpose of the IRP Guidelines is to assure PacifiCorp collaborates and shares information with stakeholders before decisions, in particular crucial ones like the selection of the Preferred Portfolio, are made.

⁶⁴ PacifiCorp’s 2017 Integrated Resource Plan, Docket No. 17-035-16, Report and Order issued March 2, 2018, at 7-8.

⁶⁵ *Id.*, at 7.

remain troubled by the evident lack of collaboration, in particular with respect to key decision points in the IRP planning process. Here, parties did not collaborate on the most consequential aspects of the IRP — modeling results and the Preferred Portfolios — before the preliminary IRP became public. Therefore, in this order we provide notice that in all future IRP dockets, Guideline 3 will apply to preliminary IRP disclosures and filings. As we have said before, PacifiCorp must provide parties ample opportunity to review, analyze, and provide meaningful input at all stages of the IRP process. Moreover, this must be done with adequate time for PacifiCorp to evaluate and, as appropriate, apply that input before filing any IRP, whether preliminary or final.

D. MISCELLANEOUS REQUESTS RELATED TO THE 2025 IRP

Modeling extreme weather events.

The OCS and DPU recommend PacifiCorp include in its modeling the effects of long-lasting extreme weather events. OCS specifically cites the September 2022 heatwave and the February 2021 Texas extreme cold event as examples of the types of weather events that should be modeled in order to identify potential system reliability issues. PacifiCorp responds that it already models several weather scenarios, and will continue to model them in upcoming IRP cycles. It explains that it not only considers climate change within its baseline forecast, but within multiple load forecast scenarios. As an example, PacifiCorp states that the 1-in-20-year extreme weather scenario evaluates peak weather impacts using the most extreme peak

observed over the past 20 years. PacifiCorp also states the 20-year normal weather scenario evaluates the weather impacts on load assuming weather is consistent with the average temperatures observed over the prior 20 years.

We find PacifiCorp's modeling of weather scenarios amply addresses OCS's concerns. To the extent other methodologies for modeling extreme weather events arise, we encourage PacifiCorp to study and discuss them with stakeholders during the IRP planning process.

Modeling GET.

OCS asserts the IRP model does not, but should, contain a process to evaluate GET or other advancements to maximize the efficiency of the grid. OCS explains that by avoiding construction of very costly transmission lines or transmission interconnection activities, GET could enable the development of lower cost Preferred Portfolios. Likewise, Interwest recommends that PacifiCorp include GET in future IRPs.

PacifiCorp responds that Chapter 4 and Appendix E of the 2023 IRP review the potential for reconductoring with advanced conductors as well as using other GET. It states it considers and identifies network upgrades using advanced conductors and GET wherever feasible, and this approach provides adequate analysis for the long-term. We find the 2023 IRP sufficiently evaluates GET as evidenced in Chapter 4 and Appendix E. We therefore decline to direct PacifiCorp to perform additional analysis in this area.

Modeling Enhanced Geothermal Systems (“EGS”).

UCE recommends PacifiCorp consider evaluating EGS technologies in the 2025 IRP cycle. UCE explains that Utah is home to the Utah Frontier Observatory for Research in Geothermal Energy (“FORGE”) project⁶⁶ which is sponsored by the Department of Energy for developing, testing, and accelerating breakthroughs in EGS. UCE states that Fervo Energy is developing the 400 MW Cape Station project in Beaver County, Utah that is expected to go online in 2028. UCE concludes that EGS should be added to other emerging technologies like Sodium and non-emitting (hydrogen) resources that PacifiCorp evaluates.⁶⁷

PacifiCorp responds that it studied and updated geothermal technologies as an option in the 2023 IRP, but they were not selected in the Preferred Portfolio. PacifiCorp states it intends to continue to include geothermal options and update its costs and technical assumptions in future IRPs and remains open to considering geothermal competitive bids in its RFP processes.⁶⁸ We find, based on PacifiCorp’s explanation, that it has considered, and intends to continue to consider, EGS as another emerging technology for evaluation in future IRPs.

⁶⁶ UCE Comments, at 7.

⁶⁷ *Id.*, at 8.

⁶⁸ PacifiCorp Reply Comments, at 31-32.

Federal and state incentives.

Sierra Club recommends PacifiCorp apply tax bonus credits for “energy communities” to all qualifying communities and correct inaccuracies and update its supply side resource workpapers to include the investment tax credits and production tax credits granted under the IRA for storage resources.⁶⁹ PacifiCorp responds it will continue to pursue opportunities to share government funding updates with stakeholders.⁷⁰ PacifiCorp also states that not all resources planned in the 2023 IRP over the 10-year period qualify for EIR, as Sierra Club appears to imply.

For example, PacifiCorp explains that only company-owned resources would be expected to qualify, and this would exclude non-owned purchase power agreements selected by the RFP process.⁷¹ PacifiCorp reiterates that the long-term IRP is based on proxy resource selection. PacifiCorp asserts that cost-saving opportunities, such as those provided by federal incentives, are addressed during the acquisition process and will manifest through an all-source RFP. PacifiCorp encourages stakeholders to actively monitor PacifiCorp press releases to look for new funding developments.

We find PacifiCorp’s response is reasonable. No additional analysis on federal and state funding opportunities is necessary in the IRP. We find that incentive-based

⁶⁹ Sierra Club Comments, at 3.

⁷⁰ PacifiCorp Reply Comments, at 29.

⁷¹ *Id.*

savings opportunities associated with specific resources are more appropriately considered in the acquisition approval regulatory process.

Participation in Regional Transmission Planning.

Interwest contends that solar-rich regions of PacifiCorp's service territory could provide valued capacity and energy diversity and recommends PacifiCorp include in the next IRP detailed participation updates regarding coordination between NorthernGrid and WestConnect regional planning authorities.⁷² Additionally, Interwest suggests the PSC direct PacifiCorp to participate in and report on other transmission planning efforts such as the Western Transmission Expansion Coalition. Interwest further recommends that PacifiCorp include an analysis of potential interconnection points to other utilities.⁷³

PacifiCorp responds that participation in regional planning authorities is important and that it is an active member of NorthernGrid and coordinates with WestConnect through NorthernGrid via Interregional Coordination meetings.⁷⁴ PacifiCorp points to Volume I, Chapter 3 - Planning Environment, of the 2023 IRP for information on the Western Energy Imbalance Market, Extended Day-Ahead Market, the WRAP, "Markets+" a Southwest Power Pool day-ahead market offering, and other developments to demonstrate it takes an active role in regional planning. It also states

⁷² Interwest Comments, at 25.

⁷³ *Id.*

⁷⁴ PacifiCorp Reply Comments, at 43.

that collaborating with other utilities is a common practice in transmission planning, and where feasible, collaborations with other utilities can be used to inform the IRP.⁷⁵

The PSC finds the IRP sufficiently discusses and analyzes PacifiCorp's participation in regional planning and provides adequate information on PacifiCorp's regional market participation and the significant benefits that current energy imbalance market participation brings to customers. The PSC finds it is not necessary to require the requested additional analysis.

Integration costs reporting.

Interwest urges PacifiCorp to study and report in the 2025 IRP the costs of inflexible thermal resources in assigning integration costs.⁷⁶ PacifiCorp explains that integration costs represent the incremental cost of holding reserves for additional renewable resources. It states that the number of reserves required is reduced because wind and solar resources are added to a pool of reserve requirements that includes load, wind, solar, and non-dispatchable thermal and hydro resources.⁷⁷

PacifiCorp explains that using a pool of reserves to cover variations reduces the reserve requirement. For example, higher than expected wind output may offset lower than expected solar output, load may drop at the same time as wind output, and both circumstances can result in a reduced need for reserves to be deployed.⁷⁸

⁷⁵ *Id.*

⁷⁶ Interwest Comments, at 30.

⁷⁷ PacifiCorp Reply Comments, at 44.

⁷⁸ *Id.*

PacifiCorp states that as part of the 2025 IRP, it intends to develop updated reserve requirements for load, wind, solar, and non-dispatchable resources, and will present the analysis and results as part of the public input process for stakeholder feedback. PacifiCorp adds that as part of model optimization, PLEXOS ensures these reserve requirements are met by dispatchable resources specific to a given portfolio, where portfolios with more dispatchable resources can fulfill those requirements at lower cost.⁷⁹ As a result, integration costs are embedded within the reported cost results. PacifiCorp states that portfolio results do not have a dollar per megawatt-hour integration cost added for wind and solar generation, as these costs are part of the core optimization calculation and in any case differ widely across portfolios and future conditions.

The PSC finds PacifiCorp's explanation that integration costs are embedded within the reported cost results satisfies Interwest's request. Other than PacifiCorp's plan to develop updated reserve requirements and the presentation of its analysis as part of the 2025 IRP public input process, we find that no other analysis at this time is necessary.

⁷⁹ *Id.*, at 44-45.

E. PROPOSED STRUCTURAL CHANGES TO THE IRP PROCESS

We recognize this is the third cycle in a row that PacifiCorp has requested and received additional time to finalize its IRP. WRA provides evidence that since 1992, almost half of the IRPs were filed after significant delay and only three were unequivocally timely filed.⁸⁰ In this instance, the 2023 IRP, its Action Plan, and Preferred Portfolios were developed in the context of rapidly changing laws and energy policies. This necessitated an extension of the schedule to provide some opportunity for stakeholders to review the modeling results and the Preferred Portfolios. The two-month extension turned out to be too short. Both DPU and WRA note that non-confidential supporting information was not made available to stakeholders until April 17, 2023, confidential information supporting the filing was made available on May 1, 2023 after the April 30, 2023 comment deadline, and final confidential supporting information was filed on June 16 and June 20, 2023. The last of the finalized information was filed more than 11 weeks after the 2023 IRP original due date.

It is evident once again in this IRP cycle that the current IRP planning process, even with the authorized extensions, does not provide sufficient time 1) for PacifiCorp to develop an effective IRP, and 2) for stakeholders to review, evaluate, and provide

⁸⁰ WRA states, “[o]f the fifteen planning cycles [since] 1992, three were unequivocally timely; one provided a partial filing on the required date but added an addendum three months later; three were late by days rather than months; but six, close to half, were more significantly delayed ... rang[ing] from one month to two-and-a-half years with a median delay of five months.” WRA Comments, at 6.

meaningful input at all phases of IRP development. Consequently, we direct DPU, and invite OCS and other IRP participants, to file in this docket by May 30, 2024 recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the public collaboration and participation objectives of the Guidelines and described in this and prior IRP orders. We will issue an order outlining the next steps in our consideration of changes to the IRP schedule after reviewing parties' recommendations.

F. THE P-MM PREFERRED PORTFOLIO AND THE LEAST-COST, LEAST-RISK RESOURCE

The fundamental objective of the IRP planning process is to arrive at the least-cost, least-risk resources otherwise known as the Preferred Portfolio. As discussed in detail above,⁸¹ the disparate and inconsistent treatment of Natrium, non-emitting resources, new natural gas plants, and CCUS technologies, resulted in a Preferred Portfolio that fails to withstand scrutiny. Most parties recommended we not acknowledge the 2023 IRP, in part, due to the lack of analytical consistency. DPU put it best that "... small assumptions or changes in inputs can have a large impact on the resource mix ten years down the road ...".⁸² The impact of consequential decisions like a dramatic change in the cost recovery period for new proxy gas plants is even greater and should not be made arbitrarily and unilaterally. For these reasons, we

⁸¹ See Section IV.B.1. of our Order.

⁸² DPU Comments, at 29.

find and conclude the portfolio selection process, and the P-MM Preferred Portfolio, lack credibility and do not acknowledge them.

G. THE ACTION PLAN

The 2023 Action Plan identifies specific actions PacifiCorp intends to take over the next two- to four-year period to deliver resources included in the Preferred Portfolio. PacifiCorp requests that we acknowledge and express support for this Action Plan. Utah Admin. Code R746-430-1 defines “Action Plan” and outlines the contents and supporting information and analysis required. It also states: “Nothing in these rules requires any acknowledgment, acceptance[,] or order pertaining to the Action Plan submitted.” Despite that provision, for clarity we state explicitly that we decline to acknowledge or approve the Action Plan submitted with the 2023 IRP. We agree with parties who assert the suspension of the 2022 AS RFP must certainly and substantially impact the Action Plan, yet, on this record we have no way to know exactly how or to what precise degree. Additionally, as with the Preferred Portfolio, the unjustified inconsistencies in the modeling of various resource types cast serious doubts as to the trustworthiness of the resulting Action Plan. In particular, we find the decision to model a 10-year technical life for a proxy new natural gas plant impacts near-term decisions that could prevent customers from potentially attaining significant savings starting in the 2028-2030 period.⁸³ This finding is corroborated by

⁸³ See Figure 9.45, 2023 IRP Volume I, page 306.

DPU, OCS, and several other parties that urge us to refrain from acknowledging the Action Plan.⁸⁴

V. SUMMARY AND CONCLUSIONS

We recognize the substantial body of quality work completed by PacifiCorp in preparing the 2023 IRP. PacifiCorp filed extensive documentation and workpapers with the 2023 IRP. The level of detail is useful, and the information provided is well organized. We encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.

We also appreciate the diligent efforts and thoughtful comments provided by all parties. We recognize the frustration expressed by many participants with the limitations on their opportunities to provide timely feedback at each stage of the planning process.

After fully considering the 2023 IRP and the parties' comments and reply comments, we acknowledge that, with the exceptions noted, PacifiCorp substantially adhered to the Guidelines in developing its 2023 IRP. Nevertheless, the identified exceptions are of such significance they undermine our confidence in the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan. Accordingly, we do not acknowledge these aspects of the IRP.

⁸⁴ See e.g., Section IV.A. and IV.B.1. of our Order.

VI. ORDER

We direct DPU, and invite OCS and other IRP participants, to file in this docket by **Thursday, May 30, 2024**, recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the Guidelines' public collaboration and participation objectives, including those described in this and prior IRP orders.

DATED at Salt Lake City, Utah, April 17, 2024.

/s/ David R. Clark, Commissioner

/s/ John S. Harvey, Ph.D. Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#333432

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 30 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on April 17, 2024, a true and correct copy of the foregoing was served upon the following as indicated below:

By Email:

Data Request Response Center (datareq@pacificorp.com, utahdockets@pacificorp.com)
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Administrative Assistant

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-130:
Idaho PUC on Pac 2023 IRP

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP'S	)	CASE NO. PAC-E-23-10
APPLICATION FOR	)	
ACKNOWLEDGEMENT OF THE 2023	)	ORDER NO. 35977
INTEGRATED RESOURCE PLAN	)	
	)	

On March 31, 2023, Rocky Mountain Power, a division of PacifiCorp (“Company”), filed an application (“Application”) with the Idaho Public Utilities Commission (“Commission”) requesting acknowledgment of the Company’s 2023 Integrated Resource Plan (“IRP”). On May 31, 2023, the Company submitted an amended 2023 IRP (“2023 IRP”).

The Company represented that it submitted the 2023 IRP filing in compliance with Order No. 22299, Case No. U-1500-165, dated January 1989; whereby the Commission ordered biennial filings of the electric integrated resource plan. The Company stated that its plan was also submitted to the Commission as the Resource Management Report on the Company’s resource planning status.

The Company represented that the 2023 IRP contains information outlining how the Company has addressed the Commission’s integrated resource planning requirements, and the Company requested that the Commission acknowledge the 2023 IRP in accordance with the Commission’s rules, and fully support the 2023 IRP conclusions, including the proposed action plan.

The Company files an IRP on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. The Company represented that the 2023 IRP fulfills the Company’s commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. 2023 IRP Vol. 1 at 35.

The Company represented that the 2023 IRP was developed through a collaborative public input process with involvement from regulatory staff, advocacy groups, and other interested parties, and that the Company’s selection of the 2023 IRP preferred portfolio was supported by comprehensive data analysis and an extensive public-input process, and includes substantial new renewables, facilitated by incremental transmission investments, demand-side management (“DSM”) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources. *Id.*

The Company represented that the 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (“RFP”) including 1,792 megawatts (“MW”) of wind and 495 MW of solar additions with 200 MW of battery storage capacity. *Id.* The Company stated that these resources will come online in the 2024-to-2025 timeframe, and that the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. *Id.* The Company also represented that through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 All-Source RFP is currently soliciting and evaluating resources to fulfill. *Id.*

The Company represented that the 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium demonstration project, anticipated to achieve online status by summer 2030, 1,000 MW of additional advanced nuclear resources through 2033, and 1,240 MW of non-emitting peaking resources through 2037. *Id.* Additionally, the Company stated that over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar. *Id.*

The Company represented that the preferred portfolio includes the construction of a 416-mile 500-kilovolt (“kV”) transmission line known as Gateway South connecting southeastern Wyoming and northern Utah, the 59-mile 230 kV transmission line in eastern Wyoming known as Gateway West Segment D.1, and the 500 kV, 290-mile transmission line across eastern Oregon and southwestern Idaho known as Boardman to Hemingway (B2H). *Id.*

STAFF COMMENTS

Based on Staff’s review of the Company’s 2023 IRP and Staff’s participation in the series of 2023 IRP Stakeholder Meetings, Staff believed that the 2023 IRP addresses the requirements outlined in Commission Order No. 22299. Staff recommended that the Commission acknowledge the 2023 IRP.

However, Staff is concerned that recent change in federal policy exposes the Company’s customers to higher costs and risks as the Company accelerates its transition away from dispatchable coal-fired generation toward other dispatchable resources. Staff is also concerned that technological and permitting challenges for implementing the new Natrium Nuclear plants add potential risk and higher cost if these plants are not completed as forecast; and that highly variable natural gas prices relative to more stable priced coal exposes customers to higher energy costs in both the near-term and long-term as the Company relies on more natural gas to maintain

dispatchable capacity for its system as it transitions away from coal as part of its coal unit conversions and exits.

Based on its review of the 2023 IRP, Staff recommended that:

1. The Company review its practices for hedging natural gas fuel supply to mitigate fuel-supply risk as it continues to step away from coal and into increased use of natural gas for dispatchable generation;
2. The Company keep the Commission informed with regular updates on the Company's progress toward implementation of the Natrium Nuclear plants;
3. The Company consider strategies to address potential delays in the capacity provided by the B2H transmission line; and
4. The Company begin forecasting the benefits of WRAP when it is projected to become a binding participant in the next IRP.

COMPANY REPLY COMMENTS

The Company noted that its risk management policy, which includes the power and gas limits program, is reviewed/revised at least once per year. The Company also stated that it is open to providing the Commission with updates to the status of the Natrium demonstration project as needed. Additionally, the Company represented that the 2023 IRP process includes ongoing evaluation of the Boardman-to-Hemmingway project, and that the Company remains open to suggestions for future analysis. Finally, the Company explained that it expects that its 2025 IRP will include discussion of the impacts of WRAP compliance and will include appropriate modeling of planning reserve margin and resource requirements.

PUBLIC COMMENTS

The Commission received seventeen (17) public comments, all of which reflect the same basic concern that the Company is not doing enough to commit to reducing greenhouse gas emissions.

COMMISSION FINDINGS AND DECISION

The Company is a public utility as defined in *Idaho Code* §§ 61-119 and -129, and the Commission has jurisdiction over it and the issues in this case under Title 61 of the Idaho Code, including Idaho Code § 61-501. Having reviewed the record, the Commission finds that the Company's 2023 IRP satisfies the requirements in the Commission's prior orders, and the Commission acknowledges the 2023 IRP.

In doing so, the Commission once again reiterates that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. An IRP is a plan, not a

blueprint, and by issuing this Order we merely acknowledge the Company's ongoing planning process, not the conclusions or results reached through that process.

The Commission does not approve the 2023 IRP, or any resource acquisitions referenced in it, endorse any particular element in it, opine on the Company's prudence in selecting the 2023 IRP's preferred resource portfolio, nor allow or approve any form of cost recovery. The appropriate place to determine the prudence of the Company's decisions to follow or not follow the 2023 IRP, and the validation of predicted performance under the 2023 IRP, is a general rate case or other proceeding where the issue is noticed.

ORDER

IT IS HEREBY ORDERED that the Company's 2023 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date upon this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code §§ 61-626 and 62-619.*

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 31st day of October 2023.



ERIC ANDERSON, PRESIDENT

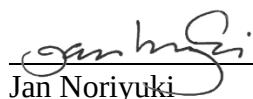


JOHN R. HAMMOND JR., COMMISSIONER



EDWARD LODGE, COMMISSIONER

ATTEST:



Jan Noriyuki
Commission Secretary