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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

Exhibit 2-100a:
Salt River Project 2023 IRP

Delivering water and power®

2023 INTEGRATED SYSTEM PLAN

2023 INTEGRATED SYSTEM PLANNING CONTENTS

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SECTION 1

Executive Summary

Salt River Project (SRP) is a community-based, not-for-profit organization with a mission to provide reliable, affordable and sustainable water and energy to more than 2 million people in central Arizona. To ensure we can continue to carry out this mission as we have for over a century, we regularly perform long-term power and water planning to anticipate and meet future needs. Recently, we completed an Integrated System Plan (ISP), an industry-leading, multidisciplinary effort to identify strategies to help guide our power system planning through 2035.[1]

The world is changing in dramatic ways that will directly and indirectly impact the power system. Key forces of change that are reshaping our industry include:

- Growing electricity demand driven by migration to the region, increasing levels of large customers such as manufacturers and data centers, and the rapid adoption of electric vehicles (EVs), which is also exacerbated by the increasing and prolonged severity of extreme heat due to climate change and urban heat effects;
- Rising costs and extended development timelines for new infrastructure projects as a result of the lingering effects of inflation and supply chain disruptions that began during the COVID-19 pandemic;
- The anticipation that the Inflation Reduction Act will encourage deployment of clean energy resources and accelerate research and development of innovative technologies;

[1]The ISP focuses exclusively on power system planning. SRP plans the water system through separate processes.

- Increasing momentum behind decarbonization efforts, including customer demand for sustainable energy, retirement of coal plants and expansion of renewable and storage resources throughout the West, and electrification of transportation and buildings; and
- Growing tightness in regional electricity markets as significant quantities of aging baseload generators receive additional regulatory scrutiny and approach the end of their operating lifetimes.

The past several years provide a powerful reminder of how suddenly — and unexpectedly — change can occur. In such a dynamic environment, we must plan for a range of potential outcomes in order to develop effective strategies that can stand up to the pressure of unanticipated changes while allowing for flexibility and adaptation.

Simply put, SRP's customers expect the same quality of service from us despite the changing and increasingly complex landscape. Meeting customers' needs over the next decade will require a complete transformation of our power system, including:

- How, when and where we generate and store electricity
- How we deliver electricity over our transmission and distribution systems
- How we engage with our customers through rate design and customer programs

Successfully transforming our power system and achieving our 2035 Sustainability Goals depends on our ability to plan in an integrated fashion, allowing for close coordination and collaboration among groups to identify the best systemwide solutions for customers. By planning together, we can best meet customers' needs and ultimately ensure a more reliable, affordable and sustainable future despite the challenges and uncertainties ahead.

The primary outcome of our first ISP is a set of seven interdependent **System Strategies**. These strategies will guide the actions of our planning teams and help establish a common vision for how we plan the system of the future. They will also help our teams ensure that their specific near-term actions — including siting, engineering, permitting, procurement, development, construction, operations, workforce development, etc. — are consistent with the common strategic vision.

Based on the System Strategies, SRP has already identified some of these near-term actions — the **ISP Actions** — which are summarized later in this section. While the System Strategies provide direction for planning the system, they are also developed with flexibility in mind. Because the future is difficult to predict, SRP cannot lock in all decisions through 2035 today. However, we can adapt and respond to these changing conditions while using the System Strategies to guide us.

Significant changes to SRP's power system are already underway. By the mid 2020s, we will add more than 2,000 megawatts (MW) of solar projects and more than 1,000 MW of battery storage. By 2032, we will retire more than 1,300 MW of capacity at four coal plants, replacing this capacity with new lower-carbon-emitting resources. We are also actively exploring regional market initiatives and have already committed to joining the Western Resource Adequacy Program (WRAP), a regional program designed to ensure there is enough resource capacity to maintain system reliability.

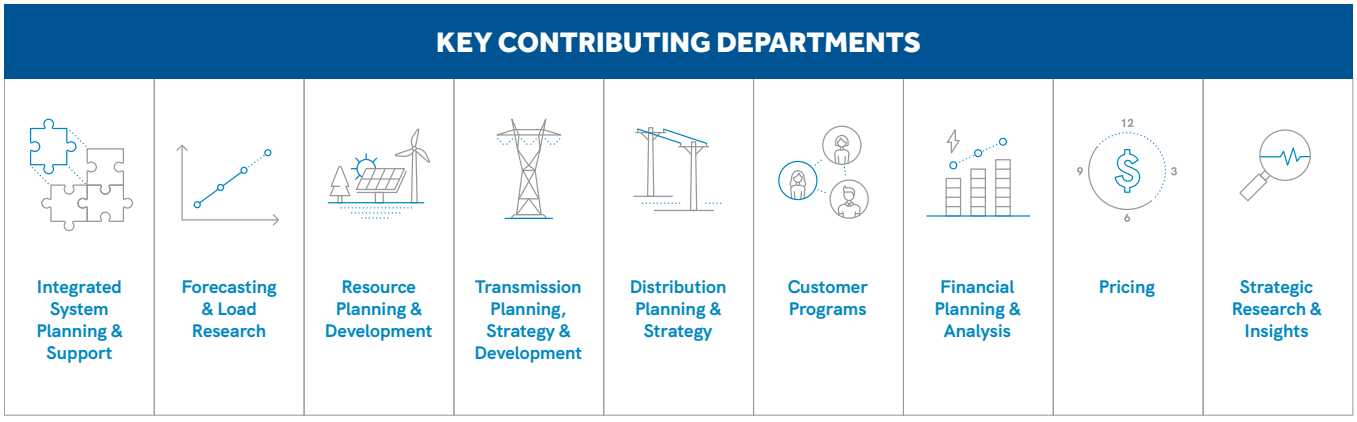
Need for Integrated System Planning

Historically, many of the planning functions that have existed within power utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan, has traditionally focused on future generation choices with limited insight into how those choices might impact all parts of the system.

Given the rapid pace of disruptive change in the power sector, planning decisions across the system must be coordinated from end to end to identify the best path forward for customers. For example:

- Adoption of EVs will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if SRP can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, this can limit the amount of new infrastructure investment needed.
- Many of the new large-scale generation resources that SRP will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of transmission and renewable resources.
- As the share of solar generation in SRP's portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative framework that includes all of SRP's key planning areas. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary and advanced engineering questions that will confront utilities in the coming decade. It will also help us ensure that the solutions we identify are robust given the many uncertainties for the future. A more in-depth overview of SRP's current system and the forces driving the need for an ISP is provided in Section 2.



Our Planning Objectives

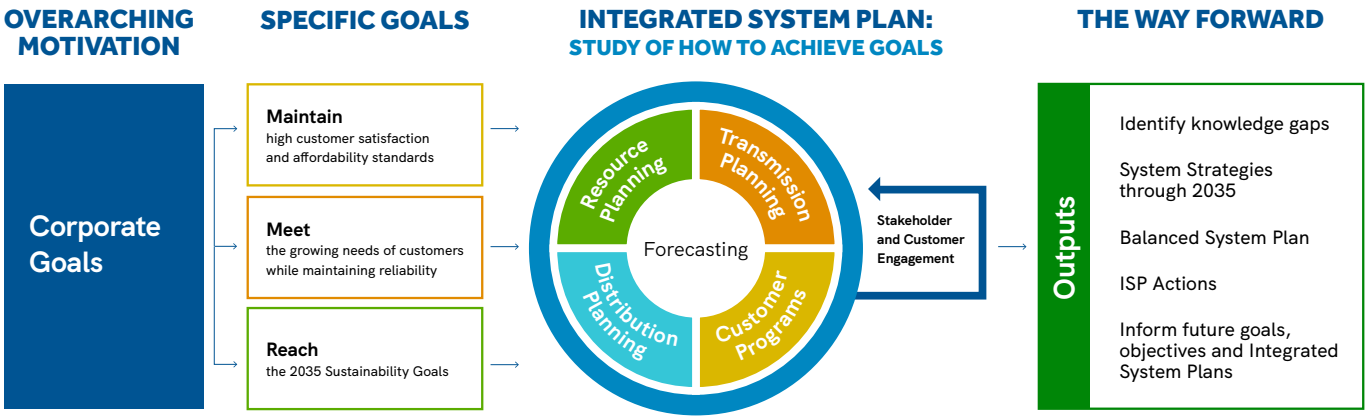
Reliability, affordability and sustainability are the cornerstones of SRP's 2035 goals, which in turn guide our planning efforts. Each of these is essential to upholding our mission and commitment to our customers.

Reliability: We are committed to maintaining electric reliability for our customers who depend on uninterrupted service, especially on the hottest days of the year.

Affordability: We recognize that electric bills represent a large cost to households and businesses. As many of our customers are facing mounting financial hardship and rising prices elsewhere in the economy, it is imperative that we strive to limit future increases to the cost of service.

Sustainability: We understand that our actions today will have far-reaching consequences for generations to come and recognize the importance of environmental stewardship to our community. These priorities are reflected in our comprehensive set of 2035 goals for minimizing our environmental footprint.

In the ISP, our teams performed rigorous systemwide modeling to identify viable pathways through 2035 to meet these goals. In addition to modeling, we engaged with customers and community stakeholders to inform and gather feedback on the ISP, while also building support for the ISP outcomes. The key deliverables of the ISP included the System Strategies approved by the Board, the Balanced System Plan and the ISP Actions. This first ISP also helped us identify opportunities to improve planning in future iterations. A more in-depth overview of the ISP process is provided in Section 3.



Stakeholder & Customer Engagement

A core component of the ISP effort included engaging our customers and stakeholders throughout the entire process, including study design, review of key findings, and development of strategies and actions. Since SRP delivers power to diverse communities, individuals and organizations, we took great care to ensure that we heard varying perspectives on how to design a first-of-its-kind ISP and how we should chart a path forward in planning the power system.

To engage our customers and stakeholders, we created an Advisory Group, which included 32 representatives from 23 different community organizations. This group met 18 times over the course of two years and provided feedback on all aspects of the ISP. We co-developed the ISP study design with the Advisory Group based on their feedback on how the future could unfold, how SRP could consider planning choices, and what aspects of planning the future power system were most important to capture. We also convened a Large Stakeholder Group, including over 140 organizations, eight times to inform a wider group of stakeholders and to receive feedback at key junctures throughout the process. In addition to engaging stakeholders, SRP convened groups of industry experts through four Technical Working Sessions to gather diverse industry perspectives on several key topics that are emerging in the industry. Through these three engagement tracks, customers, stakeholders and industry experts provided incredibly valuable feedback and played a key role in shaping the ISP study process and the final outcomes of the ISP. SRP greatly appreciates their participation and contributions throughout the entire process.

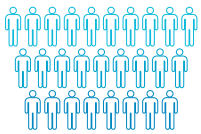
ISP PLANNING PROCESS **FAST FACTS**

NUMBER OF ADVISORY GROUP MEMBERS:

32
community representatives

from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



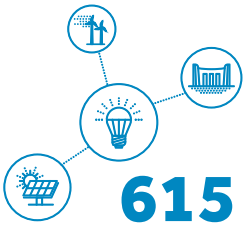
250
community representatives from
143
organizations

1,349
SLIDES PRESENTED

NUMBER OF MEETINGS:

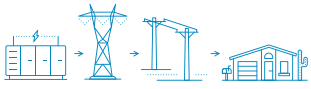
31 stakeholder meetings

totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED



42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED

4 **90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED**

STAKEHOLDER QUESTIONS ANSWERED:
588

In addition to convening stakeholders, SRP performed research in partnership with external research consultants to better understand the perspectives of residential customers. Residential customers have a diverse range of preferences, and it is challenging to capture these perspectives through a stakeholder meeting process given the time commitment required for those customers to meaningfully participate. To make sure that these diverse preferences were considered adequately within the ISP, we performed residential customer research. This customer research consisted of several focus groups and surveys of over 1,400 SRP customers, which SRP and its consultants ensured was a representative sample of residential customers based on demographics. Along with the stakeholder group meetings, this additional information provided us with a more complete picture of customers' desires and how the power system can help satisfy them.

Transparency was essential in the development of the ISP. To ensure visibility for interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the process. These can be found on our ISP webpage at srp.net/isp.

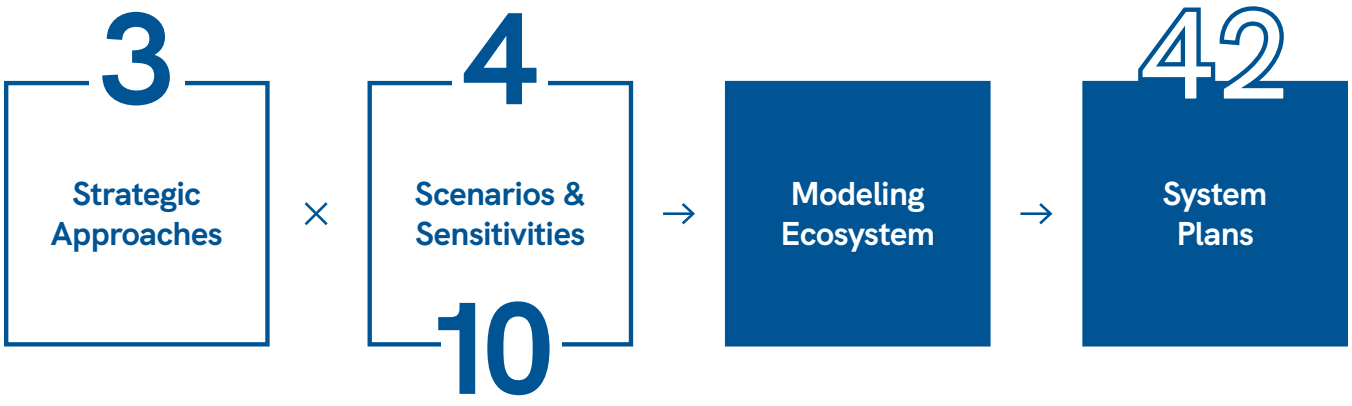
An Integrated Modeling Ecosystem

One of the principal challenges we encountered in implementing an ISP was designing an analytical framework with the appropriate level of detail to represent all parts of the system — from our biggest power plant to an individual customer's meter and every point in between. As the largest machine ever built by humans, the electric power system is incredibly complex. There is no single planning model with the capability to analyze the entirety of the electric power system as it undergoes transformative change over a long period of time. Instead, we sought to harmonize the models and tools currently used by each of our planning functions by utilizing common scenario definitions and consistent input assumptions. Additionally, we worked to improve the linkages between the models in such a way that information flowed fluidly between different analysis platforms. The result of these efforts is SRP's ISP modeling ecosystem that relies on common planning assumptions and connects tools used by each planning function with an unprecedented level of cohesion. This allows us to develop and analyze plans for the entire system.

Scenario-Based Analysis Framework

To identify solutions that benefit our customers across a wide range of uncertainties, we employed a scenario-based planning framework in the ISP. The planning framework included three key elements: scenarios, sensitivities and strategic approaches. A **scenario** represents a plausible future state of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions — generally, factors that are outside of SRP's control. A **sensitivity** modifies one assumption in a scenario to isolate the impact of that assumption. A **strategic approach** represents a decision or set of decisions that are within SRP's control as we develop the power system of the future. A detailed description of the scenarios, sensitivities and strategic approaches is provided in Section 4.

Studying each strategic approach under a range of scenarios and sensitivities provided a framework for understanding how different decisions stand up against the uncertainty of the future. The ISP analyzed three strategic approaches across four scenarios and 10 sensitivities, producing a total of 42 unique system plans. The methodology employed to develop these system plans is discussed in Section 5.



Each of the 42 system plans comprised specific plans for customer programs, distribution investments, transmission investments, and generation additions and retirements from 2025 to 2035. Additionally, for each system plan, SRP evaluated a variety of metrics that measured impacts to reliability, affordability, sustainability and customer value. Assessing strategic approaches across a variety of futures allowed us to identify strategies that work well across various scenarios and helps mitigate future risks. This also allows us to take advantage of potential opportunities, thereby creating a plan that is adaptive yet resilient to the forces of change.

Key Findings from Analysis

SRP gained new insights from performing systemwide analyses of the 42 system plans. This ISP showed how customer needs, infrastructure buildout and operations could evolve under a wide range of future scenarios and uncertainties. We also learned how our actions can influence reliability, affordability and sustainability while also helping to manage future risks and uncertainties. SRP distilled these insights into a list of key findings below. A detailed description of the analysis results is provided in Section 6 of the report.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how our customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers, while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity at an unprecedented pace in the next decade to serve customers while achieving reliability and sustainability goals.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230-kilovolt (kV) transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet infrastructure needs, supply chain and development solutions are essential to managing costs and to meeting the needed pace of transformation.

These key findings from the analysis underscore the tremendous transformation of SRP's power system over the next 10-plus years. Making this transformation a reality will be a significant undertaking requiring additional planning beyond the ISP to ensure there are detailed, sound engineering and operational plans in place for any additional infrastructure or changes to the system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc.

While the analysis provides insights into how to plan the future power system and tradeoffs for different approaches, SRP ultimately needs a plan that is specific enough for our planning groups,

communities and stakeholders to plan the power system. The plan also needs to be flexible, given uncertainties about the future and the potential for innovation. The plan should include strategies that are no-regrets across all futures, while also making tradeoffs between different objectives and identifying strategies that achieve an appropriate balance between reliability, affordability and sustainability. The next sections describe SRP's vision for how to plan the future power system, including System Strategies, an illustrative Balanced System Plan and ISP Actions.

System Strategies

SRP developed seven interdependent **System Strategies**, representing long-term strategies for planning and operating all parts of the power system, including customer programs, distribution, transmission, generating resources, pricing and system operations. The strategies were approved by SRP's Board on Oct. 2, 2023, and will guide planning through 2035 and beyond. Each strategy is anchored to key findings from the ISP and relies on the other strategies also being in place to ensure success and achievability. To develop these strategies, we synthesized a range of metrics and outputs across scenarios, sensitivities and strategic approaches. We also incorporated feedback from the ISP Advisory Group before finalizing and receiving Board approval.

Each strategy will require that we take action today. Some will take longer than others to implement, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 goals and beyond, manage costs for customers, achieve an adequate and reliable power system, and adapt toward a more sustainable future regardless of what that may be in 2035. The System Strategies are summarized below, and a full description is provided in Section 7.

Energy Investments
Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

Capacity Investments
Invest in firm generation, including natural gas, to support reliability and manage affordability, while also supporting advancement of emerging firm technologies.

Proactive Transmission
Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.

Distribution Innovation
Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.

Partnerships & Suppliers
Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.

Evolution of Customer Programs & Pricing
Evolve pricing and customer programs to improve economy-wide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.

Strategic Investment & Reinforcement of Existing Assets
Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.

Balanced System Plan

The System Strategies set the direction for SRP's planning efforts through 2035. To provide an illustration of how the system could look in 2035, following implementation of the System Strategies, SRP developed a **Balanced System Plan**. The Balanced System Plan provides an illustration of power generation, transmission, distribution and customer program plans, as well as reliability, affordability, sustainability and customer focus metrics, through 2035. To develop this plan, we drew upon the key findings from the analysis and residential customer research and built out a system plan consistent with the System Strategies.

The Balanced System Plan adds a significant quantity of resources, more than doubling SRP's total installed capacity by 2035 relative to today. This includes adding:[2]

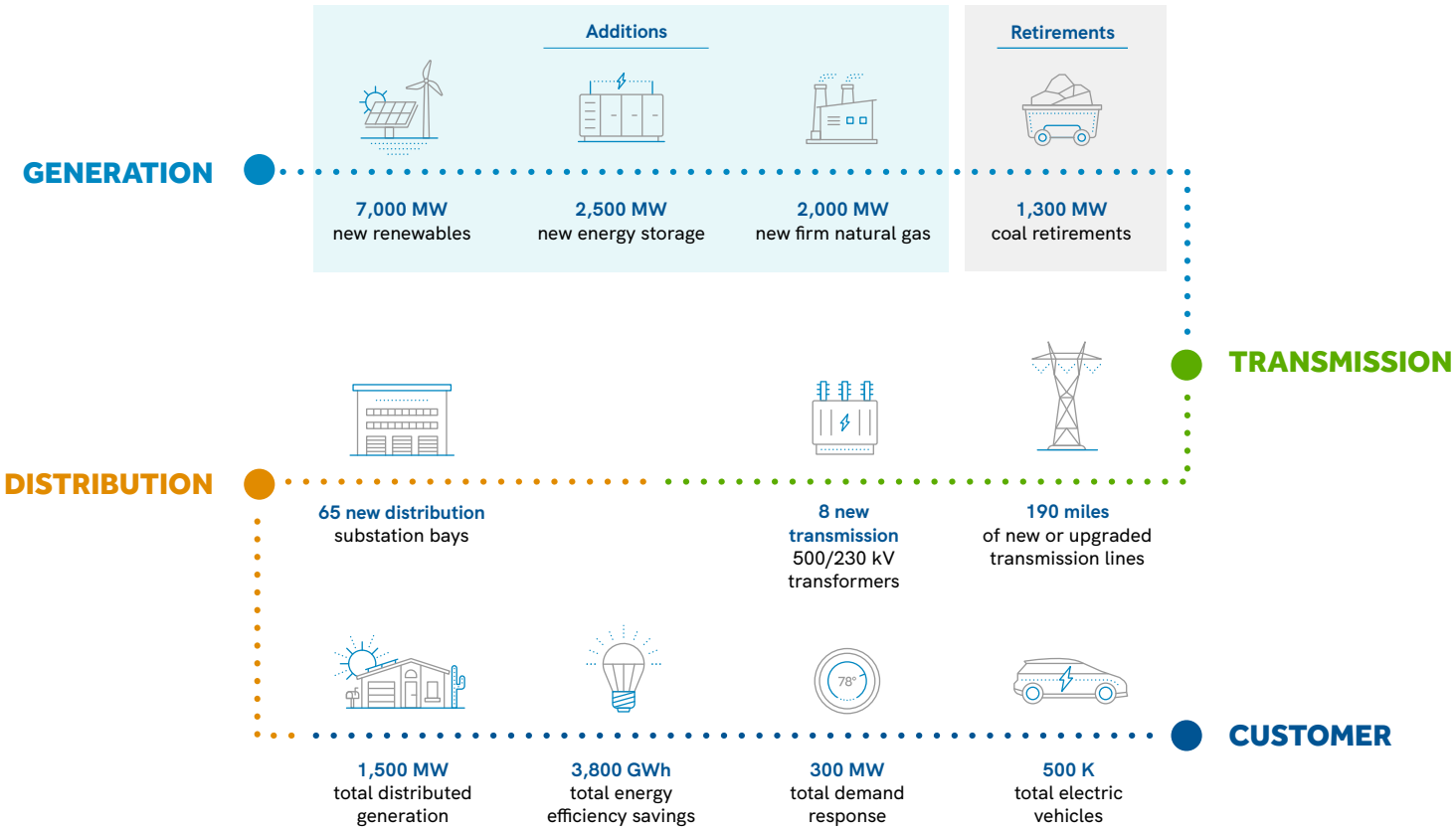
- 7,000 MW of new renewables
- 1,000 MW of new long-duration pumped hydro energy storage
- 1,500 MW of new battery storage
- 2,000 MW of new firm natural gas

This additional capacity, along with resources that are already contracted and planned to come online in the next few years, makes up for the loss of 1,300 MW of retired coal capacity and a retiring agreement with a natural gas plant. It also helps SRP keep pace with a greater than 40% growth in energy demand by 2035 and marks a significant increase of clean energy resources in the future power supply.

To deliver generation from these new resources and to accommodate the increase in energy demand, the plan includes more than 190 miles of new or upgraded high-voltage transmission lines, as well as eight 500/230 kV transformers. This infrastructure can take several years to site, engineer, permit, construct and energize, so it is crucial that SRP takes a proactive approach to ensure transmission is in place to enable future growth. The plan also includes more than 65 new distribution substation bays across existing and new distribution substations which is necessary to accommodate increasing energy demand.

Customers play a significant role in the transformation of the system in the Balanced System Plan. Customers' total energy demand is expected to increase significantly due to new large industrial customers, migration to the Valley and the growing popularity of EVs. However, this growth is mitigated to an extent due to customer adoption of distributed generation, like solar and batteries, and customer participation in SRP's energy efficiency and demand response programs. Moreover, as the power system evolves, we believe that customers can play a central role in achieving that transition through participation in future time-of-use price plans, electric vehicle managed charging programs and other offerings that have yet to be rolled out. The graphic on the next page shows the key elements of the Balanced System Plan, including power generation, transmission, distribution and customer program components.

[2] MW additions reflect the mix of resources determined to best balance reliability, affordability and sustainability needs. However, actual additions may change over time as external conditions change, such as load growth and technology costs.



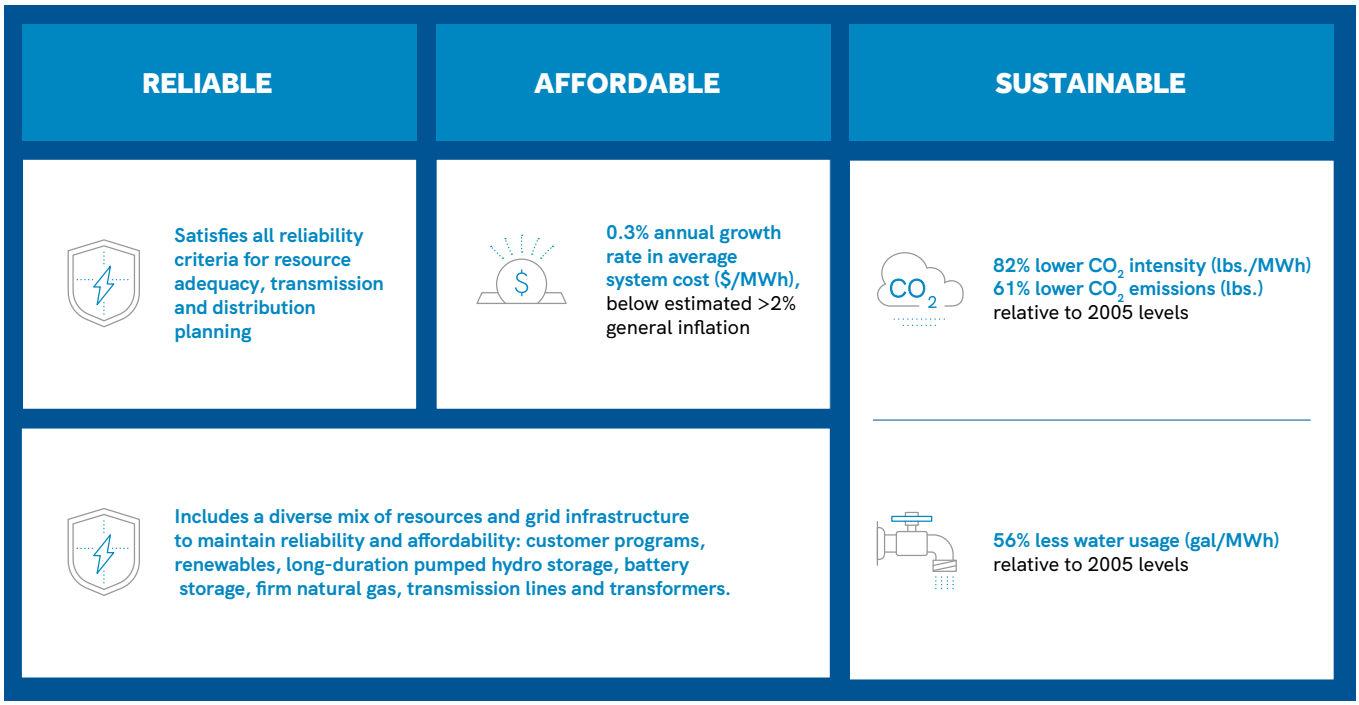
As mentioned earlier, the Balanced System Plan allows SRP to achieve important goals related to reliability, affordability and sustainability.

Reliability: By investing across the system — including new firm generation, long-duration and short-duration storage, renewables, transmission, distribution and customer programs — SRP will ensure strong reliability performance across the system.

Affordability: Due to the diverse mix of investments and programs, average system costs for this plan are projected to increase by less than 0.3% per year, well below projected general inflation. Ultimately, the driving force behind our plan is to meet customers' future energy needs at the best overall value. We believe this plan delivers on that goal.

Sustainability: As SRP retires coal capacity and adds significant amounts of clean energy resources, CO_2 emissions intensity is projected to decline by 82% (relative to 2005) and water usage intensity is projected to decline by 56% (relative to 2005), in both cases surpassing SRP's 2035 Sustainability Goals.

We are excited by the performance of this plan. However, as mentioned earlier, this illustration supports a common vision of what the future may look like based on what is known today. As expectations change — such as economic development forecasts, technology cost projections, or the implementation of new laws and regulations — the system plan will need to adapt and evolve accordingly. The Balanced System Plan is described in more detail in Section 8.



ISP Actions

Our planning processes do not stop with the ISP. In many ways, the conclusion of the ISP represents new beginnings as our teams start to execute the System Strategies. As a first step, SRP has defined 10 **ISP Actions**, which we have already started to implement. The ISP Actions will also help enhance our planning capabilities, establish a roadmap to implement the System Strategies and further our progress toward meeting our 2035 goals. The ISP Actions are summarized below, and a full description is provided in Section 9.

ISP Action #1: Residential Time-of-Use Pilot: Execute a residential time-of-use price plan pilot and perform customer research to evaluate customer response to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform SRP's load forecast for long-term system planning and SRP's price process.

ISP Action #2: Time-of-Use Evolution: Engage commercial, small business, large industrial and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods. Develop a roadmap for implementing new time-of-use periods, including the following elements: undertake a pricing process informed by the ISP as to how time-of-use plans need to evolve and develop a communication plan for all customer types and segments to educate them about any new time-of-use price plans.

ISP Action #3: Customer Programs: Continuously refresh program plans and drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from SRP's initial 2035 Sustainability Goal for energy efficiency.

ISP Action #4: EV Management: Develop a roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing EV charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.

ISP Action #5: Electrification: Analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on SRP operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.

ISP Action #6: Distribution Enablement Roadmap: Continue implementing SRP's Distribution Enablement (DE) Roadmap, including the following elements: deploy the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024; continue implementing advanced locational planning tools; advance the interconnection process; execute the Distribution Enablement Research & Development plan; and share the Distribution Enablement Strategy with external stakeholders.

ISP Action #7: Resource Selection: Issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that SRP can agnostically select resource technologies that minimize total system costs while meeting SRP's reliability and 2035 Sustainability Goals.

ISP Action #8: Coal Transition Action Plan: Develop a coal repurposing action plan, including the following elements: coordinate with co-owners to develop a path forward for the Springerville Generating Station; prepare a plan or plans for repurposing the Coronado Generating Station site; develop solutions that preserve transmission following the retirement of coal plants; and test strategies for minimizing emissions from coal power plants.

ISP Action #9: Proactive Siting: Develop and initiate collaborative community engagement, land, resources and transmission siting research to proactively identify, prepare and preserve options for feasible future system infrastructure sites.

ISP Action #10: Regional Transmission: Pursue transmission projects that would enable SRP to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.

The completion of the ISP Actions will significantly advance SRP's planning and development of the future power system. The ISP Actions related to time-of-use price plans, customer programs, EV management, electrification and the Distribution Enablement Roadmap will ensure that SRP continues to provide customers with the best options for managing their energy costs, adopting clean energy technologies and helping SRP achieve the future transformation of the power system. The ISP Actions related to resource selection, the coal transition action plan, proactive siting and regional transmission will ensure that SRP takes a proactive approach to managing the transition of existing coal assets, maintaining a reliable power grid, accessing the best available resource options and driving improved sustainability. Like the System Strategies, these ISP Actions work together to help SRP achieve its reliability, affordability and sustainability goals. To keep SRP's Board, customers and stakeholders informed on progress made toward the ISP Actions, SRP will provide annual updates.

Beyond the First ISP

SRP is excited to have completed this first ISP. It was a first-of-its-kind effort that required creative thinking in how to plan the entire system in a coordinated manner and led to a comprehensive set of System Strategies and ISP Actions that will allow us to take concrete steps to transform our power system. Given that this effort was trailblazing in many regards, there were challenges in doing end-to-end modeling of the entire system across so many different futures. However, upon reflecting on this effort, we are more confident than ever that an integrated system planning framework is the best way to plan the future power system. By planning for the entire power system within one process, we can identify solutions across the entire system and how those solutions must work together to allow us to achieve reliability, affordability and sustainability goals at the best value to our customers.

The first ISP is just a starting point. SRP has learned a lot about how to perform systemwide planning through this effort and plans to continue to improve upon it in future iterations of the ISP. This will provide us with opportunities to update scenarios as new information becomes available and consider any adjustments to strategies, a balanced plan and actions based on updated systemwide analysis. In the meantime, we will use findings from the ISP to support other ongoing efforts at SRP, including annual planning activities, procurement of new resources through all-source requests for proposals (RFPs), and our 2035 Sustainability Goals update process.

SECTION 2

SRP Overview and Background

About SRP

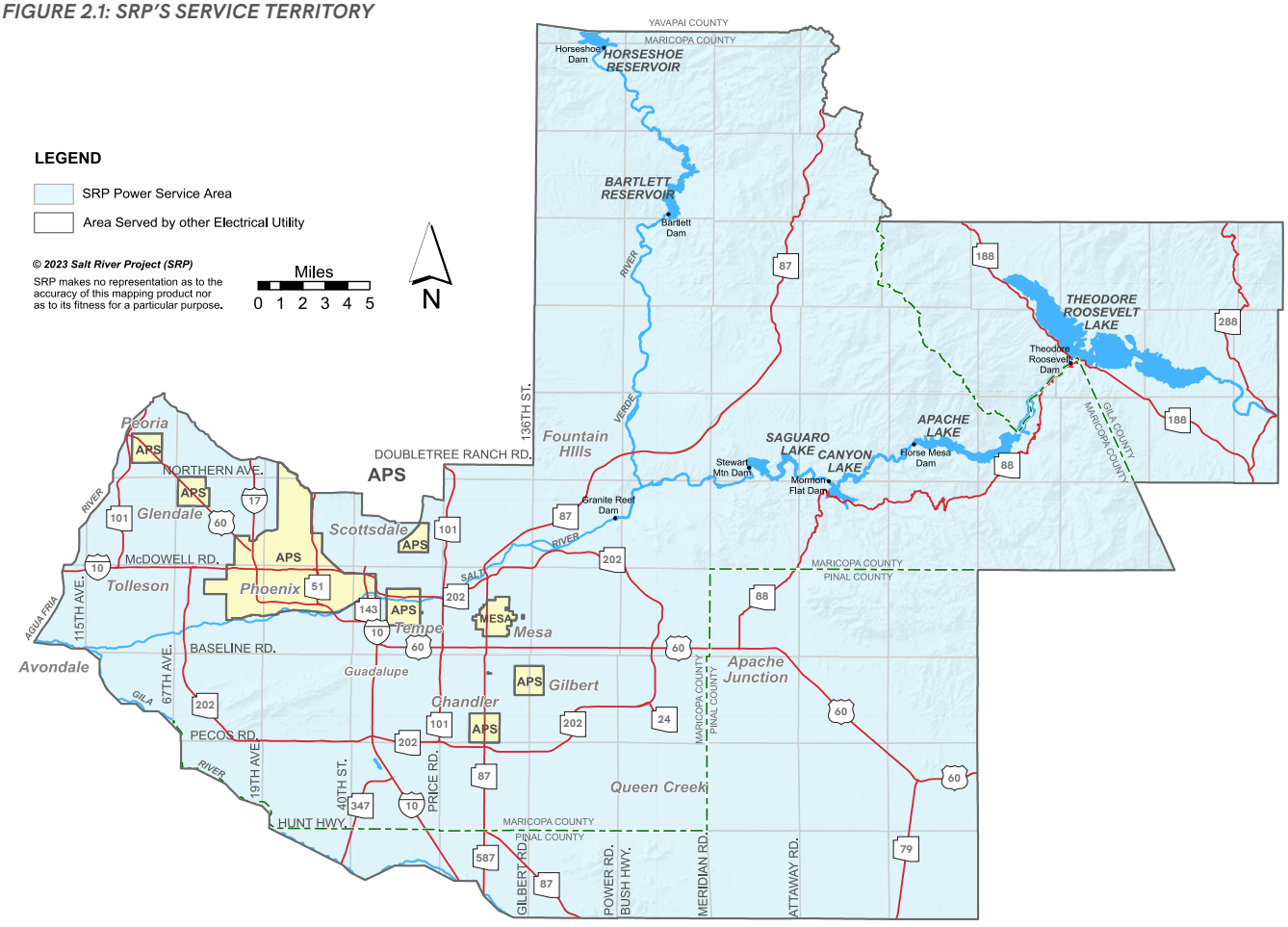
Salt River Project (SRP) is the oldest multipurpose federal reclamation project in the United States and one of the nation's largest public power utilities. As a community-based not-for-profit organization, SRP's mission is to serve our customers and communities by providing reliable, affordable and sustainable water and energy. Our long history, beginning in 1903, predates Arizona's statehood.

SRP comprises two separate organizations: the "Association," a private water corporation founded in 1903, and the "District," an electricity provider formed as an agricultural improvement district and a political subdivision of the State of Arizona in 1937.

SRP has helped and will continue to help the Phoenix metropolitan area develop and thrive by providing these essential water and power resources. Our guiding principles have remained the same since our founding: to act in the best interest of the people we serve and strive to help build a better future for Arizona.

For over a century, SRP has focused on building strategic partnerships and innovative solutions to meet the Phoenix metropolitan area's ever-changing needs. In the years ahead, we will continue to lead the way by applying a forward-thinking approach and new technologies to address energy supply challenges.

FIGURE 2.1: SRP'S SERVICE TERRITORY



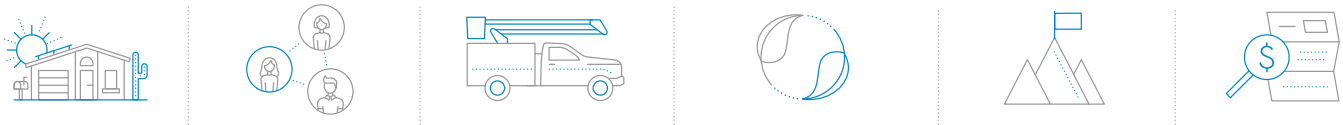
Electric Customers

SRP takes great pride in serving over 1 million electric residential, municipal, large commercial, industrial and small business customers. Residential customers are households that use electricity for their daily needs, such as lighting, heating and cooling. Municipal customers are local governments that use electricity to power public facilities, such as streetlights, traffic signals and water treatment plants. Small business customers are businesses that consume a relatively small amount of electricity, such as small shops and restaurants. Large commercial customers, such as shopping malls, hospitals and universities, consume a significant amount of electricity. Industrial customers are businesses that use electricity to power heavy machinery and equipment, such as factories and manufacturing plants.

J.D. Power recently ranked SRP highest in customer satisfaction in the western United States among large electric utilities for the 22nd time in the 23 years that J.D. Power has been surveying residential electric customers — and the 20th year in a row. Among large electric utilities (500,000-plus households), customers ranked SRP as the top-performing large electric provider in the West in all six customer satisfaction factors: power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service.

SRP's 2035 Goals

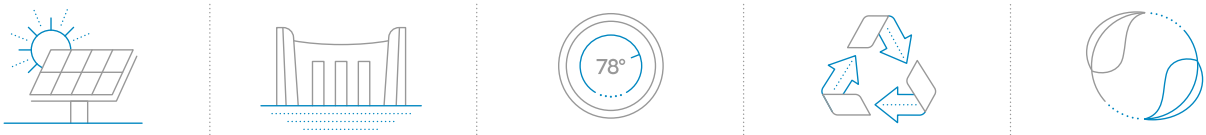
For over 120 years, SRP has fulfilled its mission to deliver reliable, affordable and sustainable water and energy. Our 2035 Corporate Goals define what we want to achieve over the long term in order to continue delivering on our mission. The categories for our corporate goals are shown below. These goals provide us with a purposeful structure for planning strategically as a company. They also allow us to anticipate and respond to the many ways in which our customers' expectations are changing, new technologies are emerging and advancing, and the energy sector is transforming.



CUSTOMERS | **COMMUNITY** | **WORKFORCE** | **SUSTAINABILITY** | **LEADERSHIP** | **FINANCES**

A subset of goals within the 2035 Corporate Goals are sustainability targets that impact SRP's future resource and customer program planning. They include Carbon Footprint and Water Resiliency Goals related to generating resources and Customer and Grid Enablement Goals related to customer programs.

SRP SUSTAINABILITY GOALS



Carbon Footprint | **Water Resiliency** | **Customer & Grid Enablement** | **Supply Chain & Waste Reduction** | **Customer, Community & Employee Engagement**

Carbon Footprint & Water Resiliency Goals:

- Reduce carbon emissions from generation intensity reaching 65% reduction by 2035 and 90% by 2050.
- Achieve a 20% reduction in generation-related water use intensity across all water types.
- Eliminate or offset power generation groundwater use in Active Management Areas (AMAs).

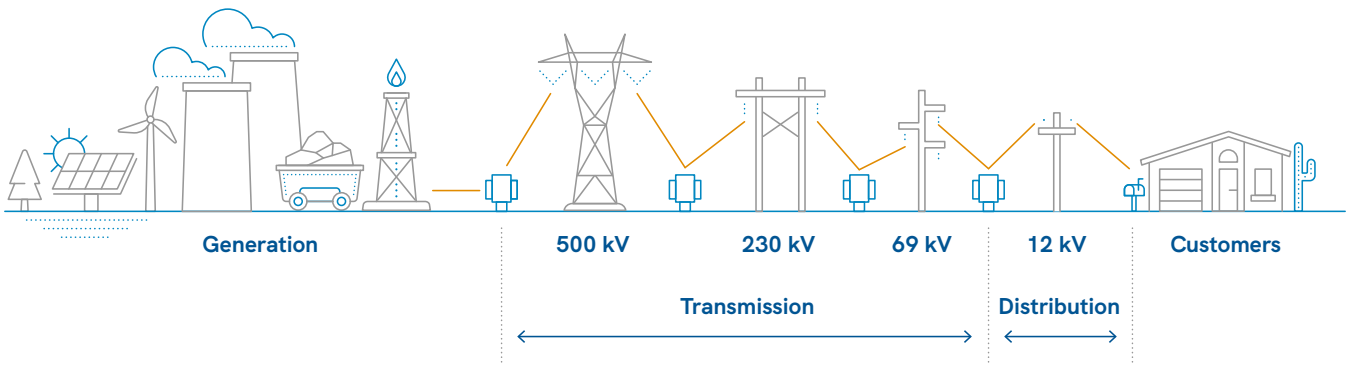
Customer & Grid Enablement Goals:

- **Energy Efficiency:** Deliver over 3 million megawatt-hours (MWh) of annual aggregate energy savings.
- **Demand Response:** Deliver at least 300 megawatts (MW) of dispatchable demand response and load management programs.
- **Electric Transportation:** Support the enablement of 500,000 electric vehicles (EVs) in SRP's service territory and manage 90% of EV charging through price plans, dispatchable load management, original equipment manufacturer integration, connected smart homes, behavioral and other emerging programs.
- **Electric Technologies:** Expand the electric technology (non-EVs) program portfolio to deliver 300,000 MWh of annual aggregate energy impact.
- **Grid Enablement:** Enable the interconnection of all customer-sided resources, including solar photovoltaic (PV) and battery storage, without technical constraints while ensuring current grid integrity and customer satisfaction.

The 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders. To learn more about SRP's 2035 Sustainability Goals, visit srp.net/2035.

Existing Power System

SRP is a vertically integrated utility that owns and plans for all-electric energy supply chain levels, including generation, transmission, distribution and customer programs. As a vertically integrated utility, SRP owns and controls the electricity supply chain's generation, transmission and distribution components. We are responsible for producing, transmitting and distributing electricity to our customers. We also design customer programs and pricing to ensure we meet customers' evolving needs and signal customers when to use electricity.



Being a vertically integrated utility, SRP has some advantages when planning, including greater flexibility in designing and implementing customer programs and pricing plans that meet the specific needs of our customers and our system. We can use our oversight of the entire electricity supply chain to ensure that our customer programs are integrated with our operations. This can help improve the reliability and efficiency of SRP's operations, ultimately benefiting customers by reducing costs and improving service quality.

Historically, many of the planning functions that have existed within vertically integrated utilities like SRP have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing.

Generation Overview

Resource planning at SRP determines what generation resources we need to add to our system to maintain reliability and achieve SRP's 2035 Sustainability Goals. SRP's generation resources can be viewed as capacity or energy sources. Capacity is the maximum output a generating resource can physically produce or export at a single point in time, measured in megawatts (MW). This output helps serve high peak demand hours and when the system has critical needs. Not all resources have the same capability to produce power at full capacity for all hours of the day and year. Demand resources, such as Demand Response and Energy Efficiency, are measured by their capacity to reduce demand, also in MW.

Energy is the amount of electricity a generator produces over a specific period of time, measured in MWh. Many generators do not operate at their full capacity all the time. A generator's output may vary according to conditions at the power plant, the availability of fuel, variability of wind and sun, or dispatch instructions from the utility due to changes in fuel costs or market prices. To maintain a balanced grid, SRP must constantly match demand with supply at any given instant.

Think of capacity like the lanes on a freeway and the maximum number of vehicles it can allow. Commuters need enough lanes to accommodate the number of vehicles during rush hour traffic. This means several of the lanes may be empty during lighter traffic times of the day, but the additional lanes are necessary for vehicles during a peak traffic time. Think of the energy as the flow and number of vehicles traveling on the freeway over a given period of time.

ANALOGY

Capacity: Maximum number of cars that can fit on an interstate during rush hour.

Energy: Number of cars per year traveling on that same interstate.

Previously, SRP used an Integrated Resource Plan (IRP) to determine the generation resources needed to meet our forecasted demand. Using this IRP process, SRP could understand how different resource choices and energy portfolios performed in various scenarios and future business environments. Our past IRPs aimed to analyze possible critical uncertainties and the generation of resources available to navigate them. This process involved evaluating current and future energy needs and developing a resource plan to meet those needs in a cost-effective, sustainable and reliable manner. The IRP process included a variety of analyses, such as load forecasting, resource planning and economic analysis. The IRP process aimed to ensure that the utility can provide reliable and affordable electricity to its customers while minimizing environmental impacts.

Once the IRP was completed, SRP would then develop specific plans linearly based on annual load forecasts, starting with a resource plan, then transmission, distribution, and customer programs and pricing. The resource plan was based on the resulting strategic directions from the IRP process, inclusive of annual load growth projections. Then, each subsequent plan was developed and designed to meet SRP sustainability and corporate goals. On an annual basis, between IRP cycles, we monitored and evaluated our operations and adjusted individual planning area plans to ensure that we met our goals and continued providing reliable, affordable and sustainable electricity to our customers.

The overall objective of the IRP was to incorporate a flexible resource plan that could embrace the challenges, uncertainties and growing energy requirements of tomorrow's world. The following are the concluding strategic directions from the 2017-2018 IRP.

Coal Generation: Reduce the amount of energy in SRP's portfolio produced by coal generation.

Natural Gas Generation: Develop flexible natural gas generation options to meet peak demand and integrate renewables.

Renewable Energy: Grow SRP's renewables portfolio to reduce CO_2 intensity and manage costs; expand opportunities for customer-dedicated projects.

Energy Storage: Add cost-effective energy storage to support additional renewable energy integration.

Nuclear Generation: Preserve option for new nuclear generation in the mid-to-late 2030s with a focus on small modular technology.

Customer Programs: Continue the promotion of energy efficiency programs and technologies that help customers save energy and money.

Market Resources: Implement Energy Imbalance Market participation as planned and seek opportunities to expand participation in other regional markets.

New Technologies: Pursue pilot projects and research and development efforts for innovative applications of new power generation, load management, energy storage and electrification.

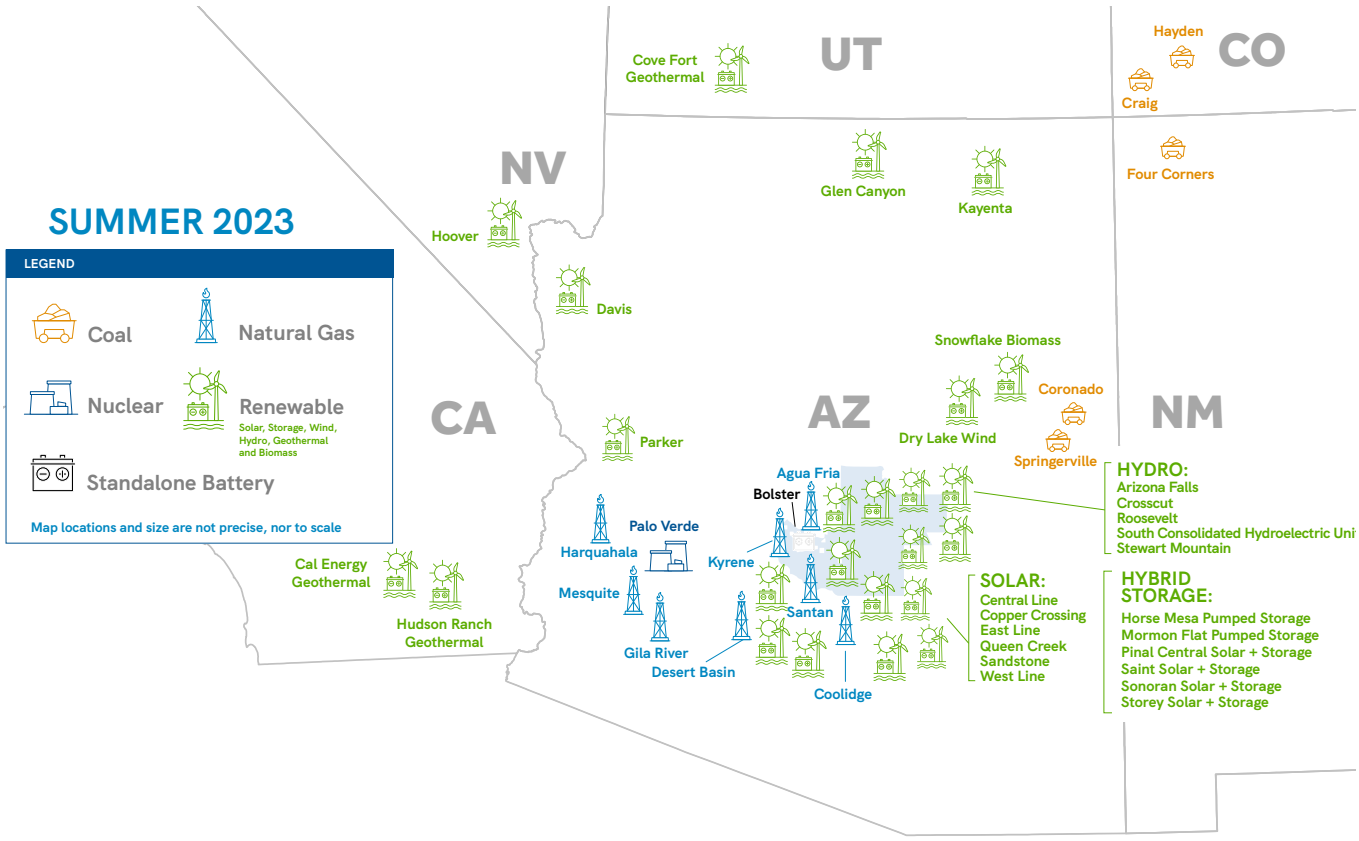
Featured in the next section are brief overviews of each planning area, where they are today and what we must consider when planning for the future.

SRP's Generation Sources Today

Over the past few years, SRP's service area has been experiencing significant and unprecedented growth in demand. In 2023, SRP served a multiday record peak for electricity demand. On several days, power demand reached over 8,000 MW, and SRP served its highest peak demand of 8,163 MW on July 18, 2023. The 2023 peak was 7% higher than last summer.

Where Does SRP Power Come From?

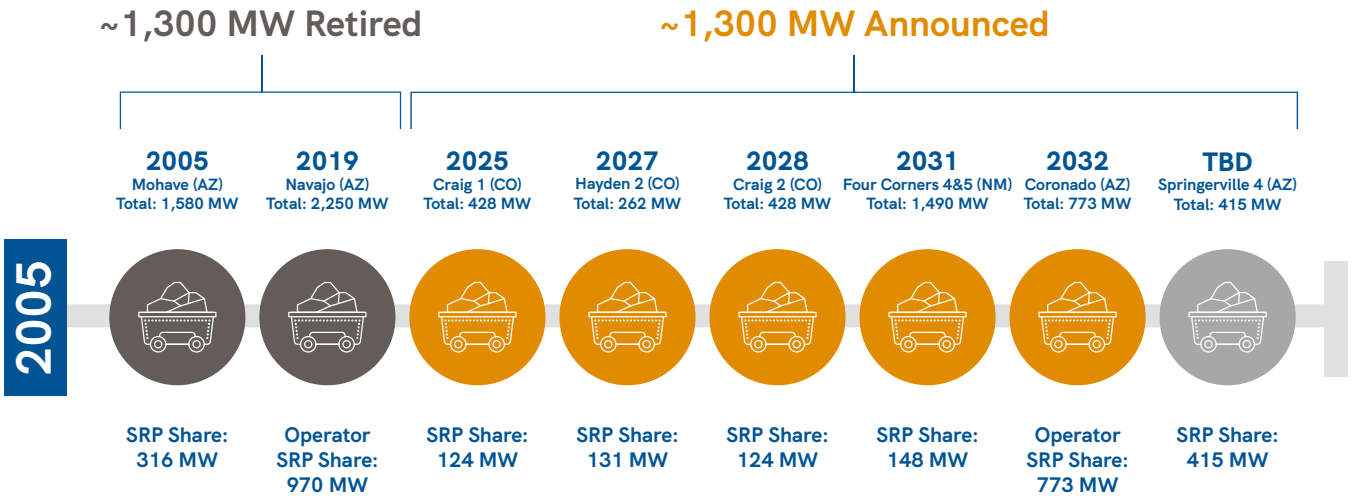
SRP generates electricity from renewable, traditional fossil fuel and carbon-free sources. The renewable sources include solar, geothermal, biomass, wind and hydropower. Traditional fossil fuel sources include coal and natural gas, and carbon-free sources include nuclear generation. Below is a graphic that displays what and where SRP generation sources are today.



To address growing demand and enable the achievement of our 2035 carbon reduction goals, SRP has been positioning its resource portfolio in alignment with the IRP strategic directions that would allow for a lower-carbon future by retiring coal plants, adding new renewable resources, integrating storage, adding flexible natural gas and acquiring existing zero-carbon nuclear resources.

Progress in Reducing Coal

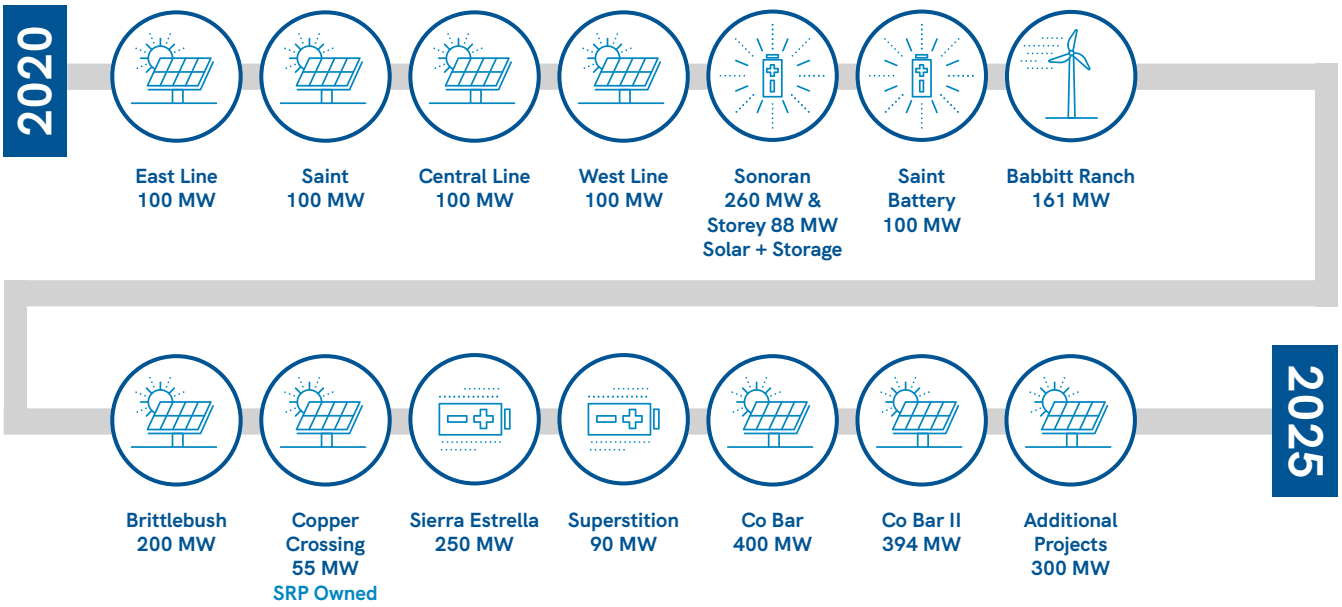
Since 2005, SRP has taken action to retire approximately 1,300 MW of coal generation. By 2032, SRP will retire an additional 1,300 MW from four coal plants already announced for retirement that will be replaced with new lower-carbon resources.



Increase carbon-free resources

In fiscal year 2023 (FY23), SRP added 104 MW of carbon-free generation from Palo Verde and has contracted an additional 10 MW in 2024 for a total of 114 MW. With this purchase, SRP increases the carbon-free energy delivered to our customers by up to 1,000,000 MWh annually, over 2.5% of our annual retail electricity.

SRP also prioritized additional renewable resources by adding 400 MW of new solar and has contracts in place for an additional 1,697 MW and continues to work with developers to implement 1,088 MW of storage and 161 MW of wind under contract.



Develop long-lead carbon-free resources

We have made great efforts to develop the capability to effectively integrate utility-scale storage technologies into our system to provide the optimal value to SRP and our customers, improve our ability to decarbonize with greater amounts of low-cost intermittent renewable resources, and potentially avoid or defer adding conventional generation or power delivery infrastructure while mitigating life-cycle environmental impacts. In addition to new lithium-ion storage technology, we have initiated early development of a Pumped Hydro Storage Project for up to 2,000 MW with a 10-hour duration. Pumped storage can provide utility-scale storage resource diversity and is a proven technology that SRP has had decades of experience owning and operating.

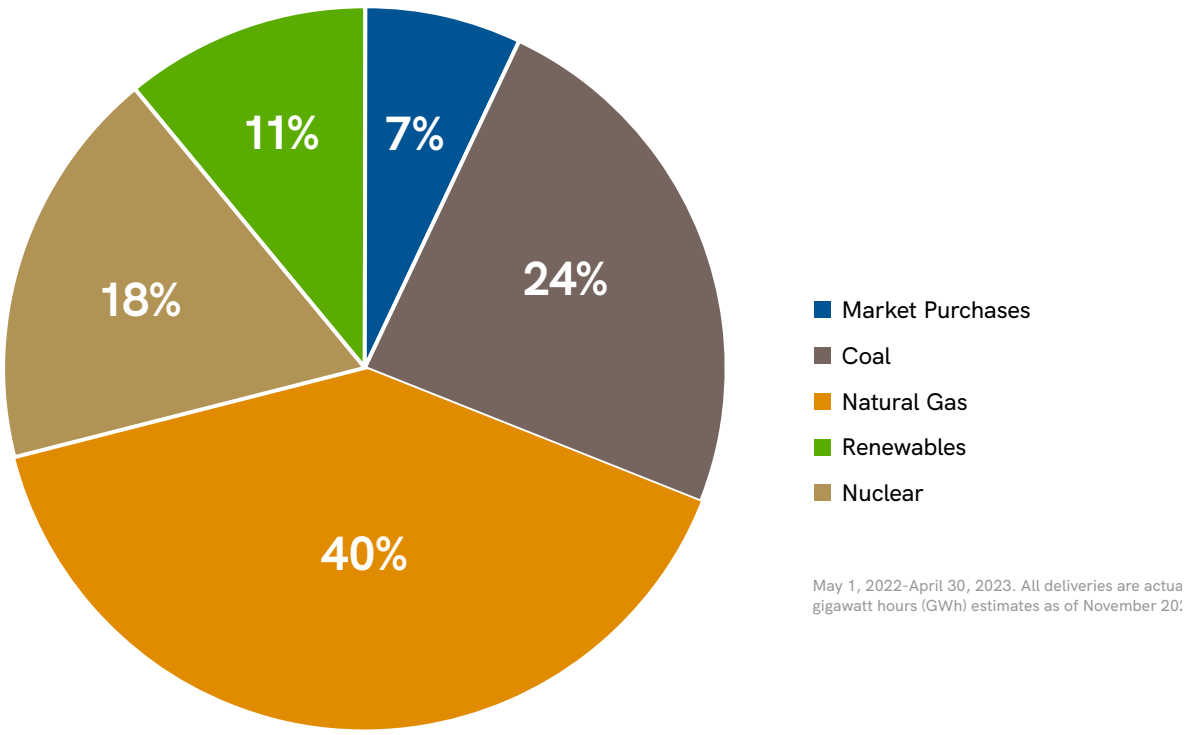
Adding flexible firm resources for future renewable integration and reliability

Without sufficient generation resources and power system stability, SRP customers may experience power shortages. Firm resources are sources of electricity (generation resources) that the utility can dispatch to meet system needs. Characteristics of a firm resource include reliable capacity in all seasons and over long durations. Natural gas is a firm resource that provides flexibility to balance ramps caused by intermittent resources (such as solar and wind) and fast response during emergencies. In 2023, we obtained an Amended Certificate of Environmental Compliance (CEC) authorizing SRP to build the natural gas peaking Coolidge Expansion Project to help integrate intermittent renewable resources.

SRP's Energy Mix

SRP's resource mix is constantly evolving to meet growing customer demands. The chart in Figure 2.2 summarizes SRP's latest energy mix delivered to customers from FY23.

FIGURE 2.2: ENERGY DELIVERED TO CUSTOMERS



May 1, 2022-April 30, 2023. All deliveries are actua
gigawatt hours (GWh) estimates as of November 20

Transmission System Overview

Transmission and distribution refer to the various stages of delivering electricity, from generating resources to a "load" such as a home or a business. The primary distinction between transmission and distribution is the voltage level at which electricity moves. At SRP, transmission refers to energized facilities at 69 kilovolts (kV) (69,000 volts) or higher.

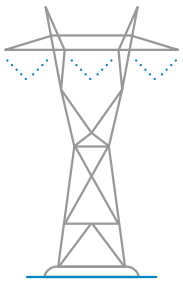
The transmission system is like the "interstate highway" of electricity delivery. It comprises three primary components: substations, switchyards and transmission lines. Both substations and switchyards are connection points where two or more transmission lines connect to form an "intersection."

The transmission lines are responsible for getting large quantities of electricity from the generation resources over long distances to the distribution system to deliver to customers. In some instances, larger energy customers connect directly to the transmission system.

SRP's transmission system is also part of a more extensive transmission network called the Western Interconnection, which ties SRP to other regional utilities and allows SRP to participate in wholesale power markets. The SRP transmission system is just a portion of this more extensive system with solely owned and co-owned lines with neighboring utilities. Being part of the Western Interconnection enables utilities to share generating resources to help balance the region's needs. Transmission Planning at SRP determines what new transmission infrastructure is needed to deliver energy reliably to SRP's service territory.

Transmission System Today

As of April 2023, SRP owns and/or operates and maintains about 3,333 circuit miles of three-phase power lines at 69 kV–525 kV voltages. Of these power lines, SRP owns approximately 955 miles of 69 kV, 263 miles of 115 kV, 493 miles of 230 kV and 361 miles of 525 kV. SRP jointly owns about 36 miles of 230 kV and 1,103 miles of 525 kV. These power lines and additional equipment, including over 1,200 circuit breakers and 72 transformers, make up the SRP transmission system today.



3,333 CIRCUIT MILES

Transmission Planning for the Future

As the demand for electricity in the Phoenix metropolitan area continues to grow, the need for new and upgraded transmission infrastructure also increases. Transmission infrastructure is planned to construct facilities and place them in service before they are needed. One of the significant challenges with planning the transmission system is the uncertainty around the location of the new electric demand and future generation resources. SRP proactively identifies and develops effective transmission solutions for current and future electric customers.

SRP is integrating low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts the transmission system. Some of the transmission-related challenges facing utilities are system voltage control, greater fluctuations in frequency, and increased risk of interruption due to forest fires. To best prepare for these transmission-related issues, we are shifting our planning practices to integrate consideration for all key planning areas. These new efforts will aid in developing plans to address grid needs across all of our planning areas holistically. This move also bolsters our efforts to achieve our 2035 Corporate Goals.

Distribution System Overview

The distribution electrical system includes the distribution substations and the infrastructure required to bring power safely and reliably to SRP customers. Distribution Planning is responsible for ensuring that we can serve the energy needs of current and future customers safely and reliably. This is accomplished by developing short- and long-term load growth plans and designing a highly configurable, robust looped system, allowing us to serve customers by multiple paths. If service from one path gets interrupted, we can still serve the customer from a secondary path. This configuration also allows us to reconfigure the system for optimal use of existing capacity.

This commitment to providing reliable power is why SRP has been ranked highest in customer satisfaction in the western United States among large electric utilities 22 times in the past 23 years that J.D. Power has been surveying residential electric customers.

Distribution System Today

As of 2023, SRP provides power to more than 1.1 million customers in a 2,900-square-mile service area. More than 1,198,000 advanced meters are serving SRP customers. Some of our customers are becoming increasingly involved with their energy future now more than ever by taking more of a prosumer role of consuming as well as producing electricity. In total, 51,287 customer-owned distributed energy resources (DERs) are interconnected with the SRP grid, including standalone solar generation, solar paired with battery storage, and standalone battery storage. Of those DERs, 50,468 are residential and 819 are commercial. These DERs provide a total generation capacity of 472 MW and a battery storage capacity of almost 16 MW.

Most of SRP's distribution system is looped, meaning there is more than one path that electricity can travel to serve a customer, but only one path at a time. SRP operates and maintains 21,736 circuit miles of lines that comprise the SRP distribution system, which entails 1,428 distribution circuits.

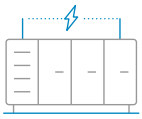
SRP operates and maintains 286 substations, including 191 distribution substations that transform power to the 12 kV voltage level to serve neighborhoods and other customers. A substation can accommodate one to four transformers, each serving 2,000–3,000 customers, depending on load requirements.

SRP is committed to providing reliable power, which is why we have ranked in the top 10 in the nation for our low System Average Interruption Duration Index (SAIDI) among all electric utilities with more than 500,000 customers every year for at least the past 10 years. This metric tracks the number of minutes customers are without power for more than five minutes averaged over all SRP retail customers. This includes any loss of customer load, planned or unplanned. SAIDI is an industry metric commonly used to assess overall power reliability.

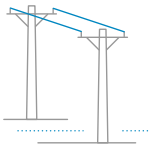
1.1 MILLION+ CUSTOMERS

2,900-SQUARE-MILE SERVICE AREA

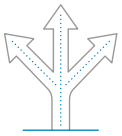
16 MW
DER BATTERY STORAGE CAPACITY



21,736
CIRCUIT MILES



286
SUBSTATIONS



Distribution Planning for the Future

The SRP distribution system is experiencing unprecedented growth due to a wide variety of new and expanding customers, including tech firms and advanced manufacturing. As more DERs, including solar generation and battery storage, are added to the distribution system, the possibility of voltage issues increases. The system is also experiencing an increase in electrification (EV adoption, smart appliances, etc.) that draws more of the load.

When we consider these factors, it becomes clear that we need to enhance our projection models of the distribution system and increase our ability to collect and analyze data. These efforts to plan for the changing grid will enable distribution planning to work collaboratively with other planning areas at SRP through an improved planning process.

Customer Programs Overview

Providing customers with reliable, affordable and sustainable service includes helping them understand and manage their energy usage through energy efficiency, demand response, electrification, EV and grid enablement programs. Customer programs enable us to effectively limit power plant emissions, lower costs, manage current demand and plan for future growth.

SRP has developed and fielded innovative customer programs and price plans to meet changing patterns in electricity use and customer needs. Demand Response (DR) programs such as smart thermostat and EV-focused programs and price plans encourage customers to shift energy usage to times energy is abundant and affordable. Looking to the future, we must evolve our programs to match the changing grid. Distributed energy programs enable the interconnection of thousands of customer-owned solar and battery systems each year. For customers unable to invest in their own renewable energy projects, SRP has invested heavily in system-scale solar and battery storage projects to offer unique solar energy programs that take advantage of economies of scale to help customers large and small achieve their individual sustainability goals. Customer programs will continue to meet evolving customer needs while spurring the transition to low-carbon energy for all customers.

Forecasting SRP customers' future energy demand (load) is one of the most important considerations for any long-term planning. We need to understand our customers' unique needs in order to plan for and maintain the reliability of SRP's transmission and distribution systems and have enough generating resources online to meet that load.

Customer Programs Today

For fiscal year 2023, SRP maintains a robust and comprehensive portfolio of customer programs; SRP's energy efficiency (EE) portfolio remains one of the largest and most cost-effective in the Southwest and across the country. For the 10th consecutive year, SRP was awarded the EPA's 2023 ENERGY STAR® Partner of the Year award with Sustained Excellence in recognition of outstanding delivery of Energy Efficiency programs.

Aside from EE and DR, SRP's growing Transportation Electrification programs are working to support the adoption of EVs and tackle the challenge of managing EV charging demands to avoid future on-peak hours. Electric Technology programs further support the electrification of fossil fuel-served loads today. In contrast, Distributed Energy programs support customer access to

utility-scale renewable energy projects and the interconnection of customer-owned solar and battery systems. SRP has also committed to developing programs like the Sustainable Energy Offering and others to partner with large customers with sustainability goals to reduce carbon emissions on a grand scale.

In fiscal year 2023, SRP's programs helped customers:

- Save 616,847 MWh — enough to power 37,000 homes annually — by:
    - Completing 70,000-plus residential efficiency upgrades and 1,200-plus commercial efficiency projects
    - Moving into 15,000-plus new, efficient homes and commercial spaces
    - Learning more about efficient, cost-saving behaviors (94,000 SRP Energy Scorecard™ and 148,000 SRP M-Power® participants)
    - Planting 5,300-plus drought-tolerant shade trees
- Develop 128 MW of dispatchable demand response capacity by:
    - Subscribing 87 MW of capacity through 76,143 smart thermostats in the residential SRP Bring Your Own Thermostat Program™
    - Enrolling more than 500 business customer facilities to deliver 41 MW of DR capacity
- Adopt 40,585 EVs within SRP's service territory and:
    - Install Level 2 or better charging for 3,300-plus EVs (581 business ports, 2,020 residential ports and 763 EV-ready homes)
- Electrify 15,897 MWh of business equipment load
- Achieve renewable energy goals by:
    - Commissioning 11,925 solar PV or PV+battery storage systems
    - Matching 100% of the electricity needs for 33 large commercial customers with 300 MW of dedicated solar energy through SRP's Sustainable Energy Offering (trimming carbon pollution in Arizona by 1.6 million tons)
    - Connecting 6,544 residential and small business customers to system-scale solar through the SRP Solar Choice™ program
- Avoid the consumption of 250 million-plus gallons of water through avoided generation and water efficiency embedded in the programs

Cutting carbon emissions by 1.6 million tons is equivalent to taking 300,000 cars off the road for a year!

SRP is committed to delivering programs and price plans that continually evolve to align with customer needs while maintaining a reliable, affordable and increasingly sustainable system. Despite recent achievements, there is a future need for even more energy efficiency to help maintain affordability by reducing customer energy consumption and pacing infrastructure investments. SRP has committed to accelerating its energy efficiency plans and goals while expanding demand response initiatives to help achieve established 2035 DR targets.

Customer Programs of the Future

As the population of SRP's service territory expands, we remain committed to meeting the growing needs of the communities we serve while staying focused on our 2035 Sustainability Goals. During our transition to a more sustainable future, the types and availability of low-cost resources will change with the increased adoption of renewables. As these changes occur, we will remain focused on striking the right balance of reliable, affordable and sustainable power for our customers. SRP continues to adapt its customer programs to meet changing patterns in electricity

use and needs by maintaining the acceleration of Energy Efficiency and Demand Response program plans to help address the significant load growth and capacity constraints SRP faces over the next several years.

As we plan further into the future, we must maintain affordability for our customers by continuing to leverage the existing infrastructure upgrades and expansion of customer program strategies to help reduce the need for costly new capital investments to meet near-term capacity needs. We must monitor how customers' energy usage and needs evolve and change as the digital economy drives how and when customers use power. Lastly, we must ensure customer programs will continue to help SRP cost-effectively meet growing customer needs while helping to address load growth and reliability challenges.

Uncertainties Facing SRP Today

While SRP's power system is transforming, other external factors also impact our planning efforts, including explosive load growth in SRP's service territory, evolving customer needs, supply chain volatility, regulatory policy uncertainties and resource adequacy uncertainty in the West. This section covers the significant drivers and trends we observed during our ISP planning efforts.

Explosive Load Growth & Evolving Customer Needs

The Phoenix metropolitan area continues to rank high in population growth nationally. For SRP, this growth means more customers, higher energy demand and increased peak demand. This demand is coming rapidly, putting pressure on us to develop solutions quickly. Demand has increased by 1.7% per year during the last decade, and these trends are expected to continue. While the SRP service area experienced extraordinary residential growth in the early mid-2000s, SRP is now experiencing unprecedented growth in the commercial and industrial sectors, including high-energy users such as semiconductor manufacturing, data centers and other high-tech industries.

Additionally, customers' energy usage and needs continue to evolve and change as the digital economy drives an evolution in how and when customers use power. These new customers not only need 24/7 power but also have specific power quality needs and an increased need for reliable power delivery. Large and small business customers are also driving renewable energy development needs for SRP, with an increased desire for partnership opportunities to help them achieve their sustainability goals.

Supply Chain Volatility

Volatility within the global supply chain impacts each group involved in SRP's integrated system planning process. COVID-19 exposed how quickly the interconnectedness of the global supply chain can lead to fewer suppliers, longer lead times, higher prices, material shortages and logistics challenges. Russia's war with Ukraine further exacerbated the disruptions to an already taxed supply chain and added to the uncertainty. Additionally, as inflation continues to rise, we can expect it to play a significant role in pricing in the future. Supply chain uncertainties are an essential factor in future planning and budgeting, as collectively or individually they can change the direction of our planning. Continuing to work jointly with our Supply Chain organization will enable us to find the flexible solutions needed to support our customers.

Regulatory Policy Uncertainty

Shifts in regulatory policies make it more difficult for SRP to make decisions because it is difficult to assign probabilities to possible future states confidently. Two policy developments that have a high potential impact on SRP's long-term planning efforts are the Inflation Reduction Act and the proposed EPA 111(b) and 111(d) rules.

Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) was passed by Congress and signed into law by President Biden. SRP has traditionally contracted for renewable and energy storage projects through power purchase agreements (PPAs) with developers who could take advantage of previous tax credits. The IRA now provides SRP and other public power entities with access to direct pay credits for the first time, which may create the opportunity for SRP to receive federal incentives for self-built renewable and energy storage resources. The IRA could provide several potential benefits to power utilities; however, there are uncertainties about how the domestic supply chain will ramp up to meet increasing demand and what specific requirements must be met to qualify for IRA credits, given implementation guidance has not yet been issued.

Proposed EPA 111(b) and 111(d) rules

In May 2023, the EPA released its proposed carbon pollution standards for new, modified, reconstructed and existing power plants under sections 111(b) and 111(d) of the Clean Air Act. The regulatory package proposed standards for new gas-fired combustion turbines, existing coal and gas-fired steam plants, and certain large and frequently used existing gas-fired combustion turbines. The proposed standards are based on control methods and technologies (e.g., limited capacity factor, combusting hydrogen and installing carbon capture) that can be applied directly at electric generating units. If finalized, the 111(b) and 111(d) rules could help decarbonize the energy sector. Still, uncertainty remains regarding the availability and timing of the control technologies that the EPA relies on to reduce emissions.

Resource Adequacy in the West and the Impacts of Climate Change

SRP must maintain the ability to meet customers' energy demands at all times of the day and across a variety of system conditions. This resource adequacy requirement is becoming more complex as the utility industry transitions from conventional generating technology to renewables and storage. Reliable electricity supply is also becoming increasingly important to society as recent extreme weather events triggered regional outages that impacted customers and communities across the electric system. SRP routinely monitors the current trends affecting the desert Southwest region to understand better how to plan our investments and resources amidst uncertainty.

Because SRP is connected to an extensive grid system that includes neighboring utilities, the entire regional grid is at risk when one area or utility is not resource-adequate. Extreme temperatures also put pressure on utilities to maintain reliability by driving up customers' demand for more energy and fueling natural disasters such as wildfires that can damage the transmission system and limit utilities' ability to move power where their customers need it. The climate change impacts experienced over the last few years are expected to continue.

In light of the dramatic transition in the utility industry and the importance of regional resource adequacy, the SRP Board in January 2023 approved SRP's participation in the Western Resource Adequacy Program (WRAP), which is the first regional program of its kind in the history of the West. WRAP will deliver a regionwide approach to assessing and addressing resource adequacy. It will help ensure that entities use consistent planning approaches as utilities become increasingly reliant on variable resources like solar, wind and battery storage.

Technology Advancements

To achieve continued decarbonization while maintaining a highly reliable grid, SRP is monitoring, developing and deploying advanced low- and zero-carbon firm technologies such as clean hydrogen, long-duration storage and small modular nuclear. Accelerating the deployment of firm low-carbon energy solutions is required to continue to provide reliable and sustainable energy for SRP customers. Significant progress is being made around new nuclear technologies and long-duration storage that could provide reliable, safe and carbon-free generation in the future. Unfortunately, the current development timeline for some of these resources is over a decade. While today's market is experiencing some obstacles, a combination of new technologies, efficiencies in permitting and lower financial risk during construction may provide a compelling option for these resources in the future. Therefore, it is important for SRP to continue to pursue activities that preserve varying resource options, such as potential site locating and early permitting.

Planning for the Future

The electric power industry has undergone a dramatic transformation in recent years, and that transformation is expected to accelerate, driven by a variety of factors mentioned above, including:

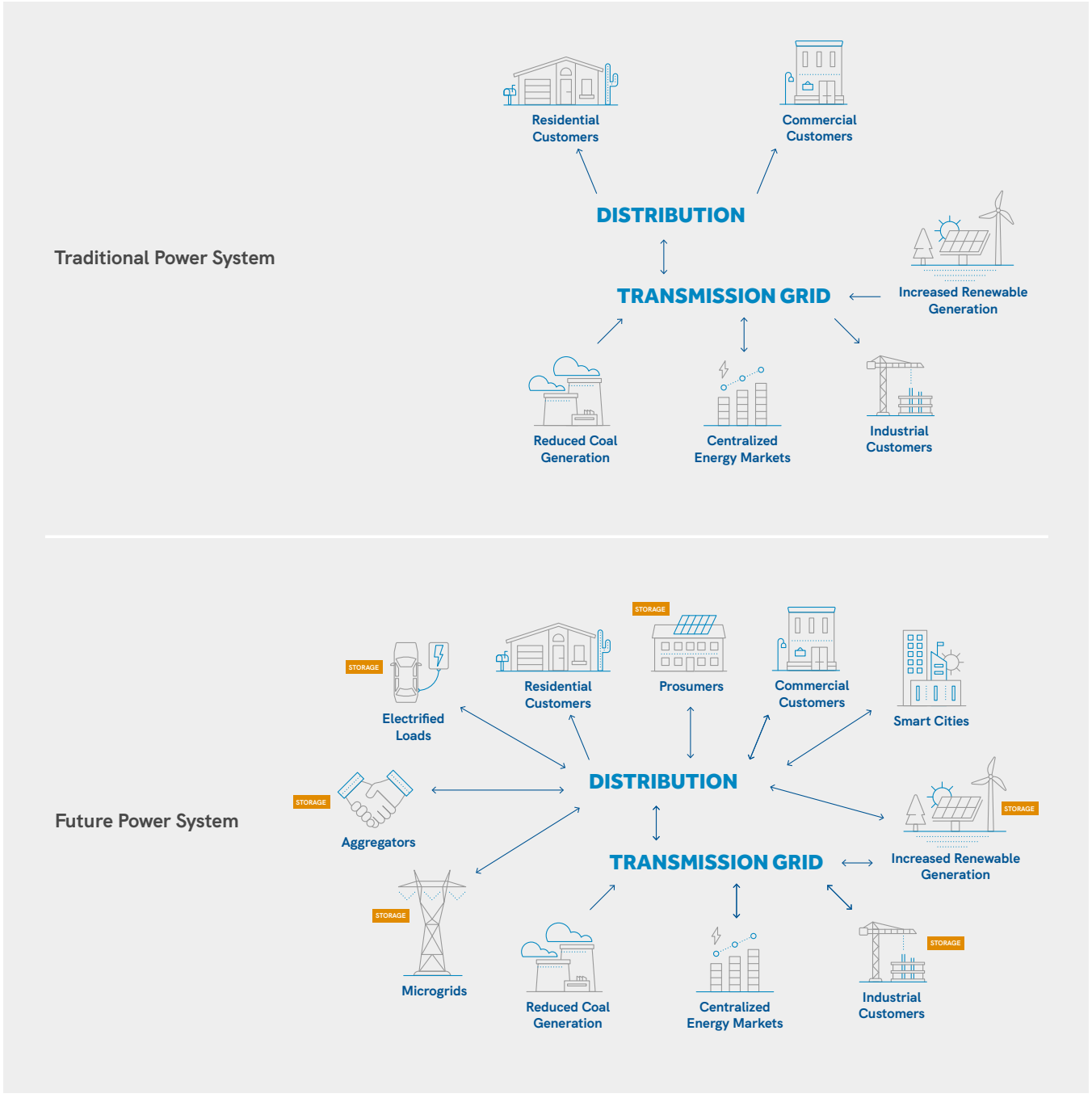
- Rapid deployment of large-scale variable energy resources (VERs) such as solar and wind
- The growth of distributed energy resources (DERs) like rooftop solar and residential battery storage
- Dramatic advances in digital energy and communications technologies
- Persistent low natural gas prices
- Increased reliance on just-in-time delivery of natural gas to support gas-fired generation
- Growing awareness of the electric sector's potential role in achieving environmental goals

While all of these external factors are changing, SRP is also evolving by integrating a significant number of low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts operations and the grid. Some of the transmission-related challenges facing utilities are system voltage control, more significant fluctuations in frequency, and increased risk of interruption due to forest fires. With these changes, traditional planning methods are increasingly insufficient to optimally develop a safe, reliable, affordable and environmentally responsible power system. Meeting our customers' needs over the next decade will require a complete transformation of the power system that touches all aspects of our business: how, when and where we generate and store electricity; how we deliver electricity over our transmission and distribution systems; and how we engage with our customers through rate design and customer programs. Our success

in this transformation depends on our ability to plan the system in an integrated fashion, allowing for close coordination and collaboration to identify the best solutions for our customers.

Integrated Resource Planning to Integrated System Planning

In the past, Integrated Resource Plans guided SRP's ability to plan long-term generation resource decisions by conducting structured analyses assessing risk and uncertainty. Given the many ongoing changes in the power sector, we must adapt these traditional planning methods to optimally develop a safe, reliable, affordable and environmentally responsible power system.



To best prepare for these impacts, SRP has transitioned from a conventional Integrated Resource Plan (IRP) solely focused on resource planning to a more holistic and comprehensive Integrated System Plan (ISP), including forecasting, resources, transmission, distribution and customer programs, to achieve our 2035 Corporate Goals.

An integrated system planning approach is necessary to meet changing customer needs, such as enabling two-way power flow for rooftop solar additions, managing charging of EVs, and anticipating the power system transition to a lower-carbon, increasingly complex grid. Given the effort needed to implement a holistic ISP, we focused on the period from 2025–2035 for our first-ever ISP, which will be covered in more detail in the next section.

SECTION 3

ISP Overview and Process

Why Integrated System Planning?

Historically, many of the planning functions that have existed within utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan (IRP), has traditionally focused exclusively or primarily on future generation choices with limited insight into the implications of those choices for other aspects of the utility's systems.

Given the rapid pace of change in the power sector, we identified a need to integrate planning within a single process — the Integrated System Plan (ISP) — to optimally develop a safe, reliable, affordable and sustainable power system. Planning decisions across the system must be coordinated to identify the best path forward for customers. For example:

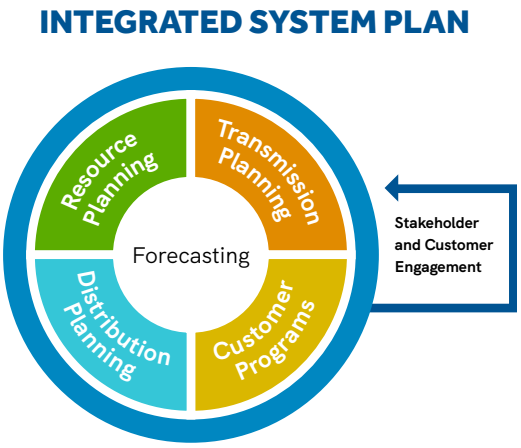
- Adoption of electric vehicles (EVs) will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if we can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, we can limit the amount of new infrastructure investment needed. The most advantageous periods for charging will depend on future resource, transmission and distribution needs.
- Many of the new large-scale generation resources that we will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of renewable resources to take advantage of transmission opportunities.
- As the share of solar generation in our portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative planning framework that includes all key planning areas at SRP. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary questions that will confront utilities in the coming years.

What is the Integrated System Plan?

SRP's ISP is a holistic power system roadmap that considers evolving customer needs for reliability, affordability and sustainability while achieving our 2035 Corporate Goals. The ISP includes all elements of meeting future customer demand: forecasting, power generation, transmission, distribution and customer programs. The ISP will help SRP plan for a future power system while maintaining a high standard of customer service from 2025 to 2035.

Before initiating the objective setting phase of the ISP, SRP retained Energy and Environmental Economics (E3), an energy consulting firm that works with utilities, regulators, policymakers, developers and investors to tackle the most pressing, difficult questions facing the electric industry. In our ISP — one of the first comprehensive efforts in the industry to initiate a systemwide planning process — E3's combination of broad experience, technical expertise and creative problem-solving made their support invaluable to our success. Further, having worked with each of Arizona's three largest utilities in support of integrated resource planning processes, E3 brought an understanding of our state's unique utility planning landscape that made their advice throughout the process germane and direct. At every step of the process, E3 was a vital partner for SRP, providing full-service support in the following areas: scoping the planning process; designing the analytical and stakeholder engagement frameworks; overseeing analysis and validation; and providing modeling support for the ISP process.



Objectives for the ISP

In April 2021, the SRP ISP project team and E3 concluded the objectives phase of the ISP after conducting many interviews and holding alignment workshops with SRP leadership. Through this process, the ISP project team received direction from senior leaders on the vision and objectives of the first ISP and received approval to develop a more detailed study plan.

ISP Vision Statement and Objectives

This vision, the goals and SRP's 2035 Corporate Goals guided the development of the ISP vision statement and objectives below.

"An ISP is a data-driven, collaboratively developed plan for generation, transmission, distribution and customer-sided resources to meet SRP's 2035 Corporate Goals and prepare for SRP's 2050 ambitions and system needs."

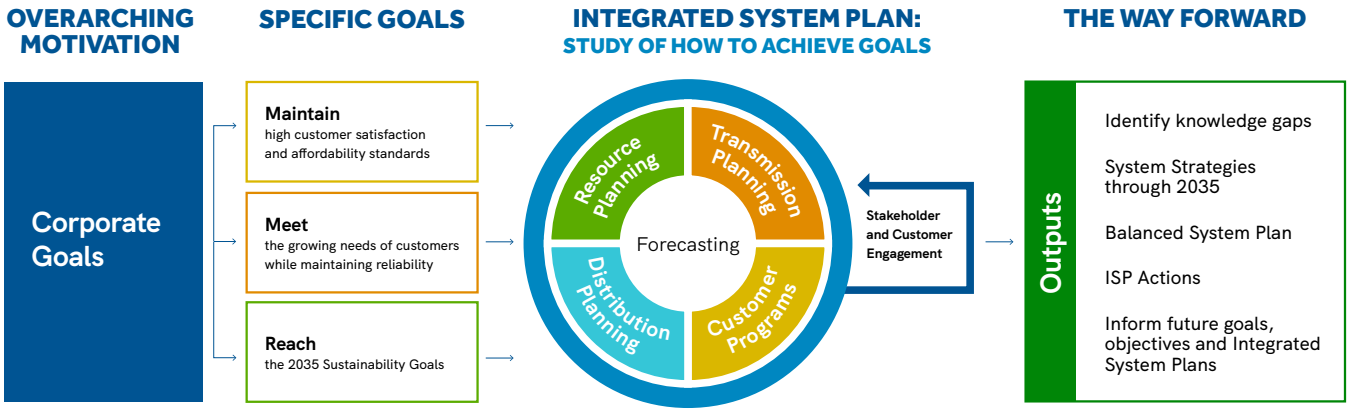
ISP objectives are to identify:

- Viable pathways for achieving SRP's 2035 Corporate Goals
- Costs, risks and trade-offs of these different pathways
- System solutions that are valuable across different pathways
- New capabilities or tools required to plan and operate as the system evolves effectively
- Activities SRP should undertake in the next six years to plan for these system solutions

SRP's 2035 Corporate Goals have been updated. The ISP leveraged goals established in 2019 and was completed prior to the 2024 updates.

Process for the ISP Development

The ISP process begins with SRP's Corporate Goals which establish the specific performance objectives of SRP and the motivation for the ISP. The ISP objectives relate to reliability, affordability and sustainability ("the what"), and the ISP determines how best to meet those objectives ("the how"). The ISP analytical process then combines the power system planning functions into an integrated planning framework to ensure that investments across the functional areas contribute together to support the corporate goals and objectives. In addition to the analysis, the ISP process included a comprehensive engagement process with customers and stakeholders to inform and gather input on the ISP and build support for the ISP outcomes. Key outputs of the ISP include a set of ISP Actions and longer-term System Strategies that help guide the development of SRP's power system through 2035.



The ISP analytical process, or "framework," was developed as part of the ISP objective setting process and involves conducting scenario analysis across the system functions to evaluate the cost and performance trade-offs and risks in achieving SRP's Corporate Goals. The process steps included:

1. Establishing an appropriate set of scenarios that evaluate key drivers of uncertainty outside of SRP's control.
2. Evaluating system needs for each scenario, subject to minimum reliability planning criteria.
3. Developing alternative solutions to meet the system needs for each scenario that consider key SRP decisions.
4. Synthesizing the scenario analysis to develop an illustrative Balanced System Plan that depicts the execution of ISP outputs, including System Strategies and ISP Actions, considering costs, performance and risk trade-offs metrics.

The objective development phase also included a stakeholder and customer engagement approach. SRP obtained the services of Kearns & West, a collaboration and strategic communications firm with experience in similar projects for other power utilities and an impartial approach to outcomes. Kearns & West offered input on establishing stakeholder groups and engagement methods, facilitated and documented meetings with stakeholders, and provided feedback on other aspects of stakeholder engagement. SRP, E3 and Kearns & West established a communications team, closely collaborating to create this approach. The communications team designed and executed all ISP stakeholder engagements, including scheduling, material

preparation and coordinating discussions with stakeholders internally and externally. The process included a review of best practices and lessons learned at SRP and other utilities. The effort also reviewed how other utilities capture residential and small commercial viewpoints in planning activities and consulted with SRP's Community, Communications and Marketing (CCM) organization to identify existing research resources and explore future approaches for gaining residential and small commercial customer input. Finally, the team consulted the CCM organization on best practices and options for stakeholder information sharing and regularly consulted SRP's 2017 IRP and Sustainability 2035 leads.

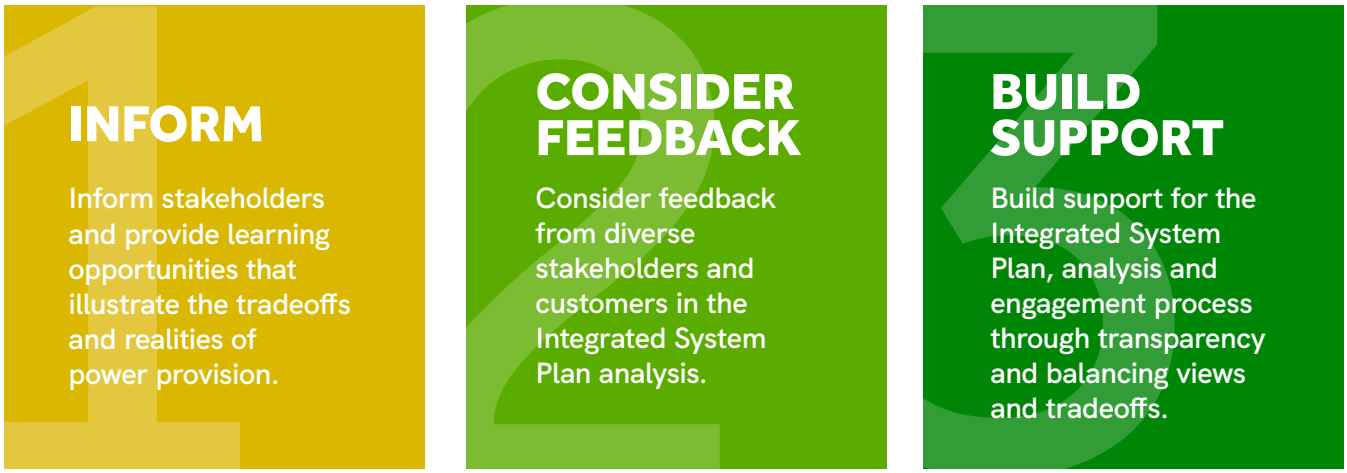
The stakeholder groups and customer engagement approaches are depicted below. SRP, E3 and Kearns & West also worked together to develop the details of the engagement approaches, including stakeholder group membership, roles, meeting topics and information sharing.

Stakeholder Group	Engagement Method
Advisory Group	• Focused engagement from a smaller diverse group • Regular meetings • ~20 representatives from diverse organizations • Role(s): Inform, Consult and Involve
Large Stakeholder Group	• Large-scale public platform • Eight meetings • Over 140 organizations • Role(s): Inform and Consult
Technical Working Sessions	• Small groups convened on specific topics with topical experts • Single sessions scheduled as needed around topics of interest • Role(s): Consult
Customer Research	• Multipronged approach to include the customer's voice • Surveys, customer preference elicitation, focus groups • Role(s): Consult

Role of the ISP Stakeholder Groups

A vital aspect of the ISP is developing and implementing a robust plan to actively engage customers and external stakeholders. SRP delivers power to diverse communities, individuals and organizations, and these stakeholders may hold varying views of the future and preferences for SRP's path forward. Providing information to stakeholders about the challenges SRP faces and collecting feedback on these challenges helped us roadmap a viable path forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped build support for the ISP process underlying SRP's strategic decisions. Much of the stakeholder and customer engagement efforts were planned to interact with the development of the ISP at specific touchpoints. These engagement efforts had the following three Global Goals:

FIGURE 3.1: ISP ENGAGEMENT GLOBAL GOALS



Transparency was essential in the development of the ISP. We designed the process to engage customers and other stakeholders and be responsive to their questions and input. In our best effort to keep transparency with all interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the entirety of the project. These can be found on our ISP webpage at srp.net/isp.

Where We Needed Stakeholder Input for the ISP Process

Through the engagement tools described in the section below, SRP obtained input from stakeholders, including residential customers, regarding the questions proposed below. Their input helped shape all elements in the ISP study plan and informed the design on the final ISP outputs.

- Looking to 2035, what are Arizona's major sources of uncertainty relative to electricity generation, delivery, consumption and affordability?
- What system options should SRP include in its planning analyses for the future power system through 2035?
- What does success look like from your perspective when evaluating reliability, affordability and sustainability?

- What is the scope of the first ISP and which topics of interest should be considered for further research and future ISPs?
- What are the methods for balancing the trade-offs between reliability, affordability and sustainability?
- How might SRP improve our approach to stakeholder engagement for future ISP processes?

Stakeholder and Customer Engagement Tools

The ISP included customer research, technical working groups, large stakeholder group meetings, one-on-one discussions with interested stakeholders and the formation of an Advisory Group. This portfolio of engagement tools helped to achieve all three Global Goals described in Figure 3.1 on the previous page. Some groups focused more on bilateral dialogue, considering feedback and building support, whereas others focused on providing information to stakeholders and the public. The objectives and a brief description of each tool are given below.

The **Advisory Group** is made up of over 20 diverse community organizations and over 30 customer interest representatives. The group contributed wide-ranging expertise and perspectives to the ISP, which helped SRP produce a plan that reflects the diverse interests and values of the customers and communities we serve. Below are the mission and objectives of the ISP Advisory Group. For more information, please reference SRP's ISP Advisory Group Charter.

Mission Statement

The charge of the Advisory Group is to contribute wide-ranging expertise and perspectives to the ISP, resulting in an end product that integrates the diverse interests and values of the customers and communities SRP serves.

Objectives

- Create a dialogue around the ISP.
- Include diverse perspectives as input, guidance and review for the ISP.
- Provide a forum for deep and technical discussion of the trade-offs in energy system planning and the various perspectives to build support around the strategic directions and resource, transmission, distribution and customer program action plans.
- Focus communication for the Large Stakeholder Group.

Choosing a balanced and diverse group of stakeholders for the Advisory Group was critical to ensure that all perspectives were represented and that a single viewpoint was not dominant. To maintain balance, SRP chose members that were representative of one or more of the following stakeholder categories:

Local or special interest groups

- Community Advocates
- Equity Representatives
- Native American Interests
- Environmental Advocates
- SRP Resource Communities
- Public Interest Groups

Customer groups

- Commercial Customers
- Residential Customers
- Small Business Customers

Industry groups

- Energy Efficiency Industry Representatives
- Electric Vehicle Industry Representatives
- Renewable Energy Industry Representatives

Advisory Group Modeling Subgroups – Modeling subgroups were arranged as needed during the ISP process. Advisory Group members who were intensely interested in diving deeper into the ISP analysis self-selected into these subgroups. Efforts were made to include Advisory Group members who span stakeholder interests. Subgroup meeting discussions were reported in subsequent Advisory Group meetings. The Advisory Group's input, questions, ideas and concerns guided and initiated modeling subgroup meetings. If more than 50% of Advisory Group members were interested in participating in a specific subgroup, SRP would consider integrating the subgroup discussion content into the regular Advisory Group meeting series.

Large Stakeholder Group – This group of over 140 organizations was invited to eight meetings throughout the process. The meetings addressed informing stakeholders and considering feedback.

Mission Statement

To provide transparent communication to stakeholders regarding SRP's planning initiatives and allow for stakeholders to ask questions and provide feedback.

Objectives

- Keep stakeholders informed of SRP's planning initiatives in a transparent and proactive way.
- Build understanding of the trade-offs SRP faces and emerging trends in energy markets, regulations and technology.
- Provide opportunities for stakeholders to ask questions and receive answers from SRP experts.
- Provide feedback opportunities for stakeholders and consider their perspectives when balancing trade-offs while developing the ISP.

The Large Stakeholder Group was made up of over 140 organizations and 200 individuals, including representatives from SRP's customers and communities; 120 organizations were initially invited based on their existing relationships with SRP, standing within the Arizona community and diversity of perspectives. Types of organizations also included local and special interest groups, customer groups and industry groups. Throughout the process, SRP received many requests from individuals and entities to join the ISP Large Stakeholder Group outside of the initial organizations invited. They were all accepted and integrated into the process, resulting in a total of over 140 organizations at the end of the process. SRP strove to maintain inclusivity and representativeness within the Large Stakeholder Group so that the group reflected the diverse interests and values of the customers and communities SRP serves.

Technical Working Sessions – These sessions addressed specific technical topics of interest that arose throughout the ISP process and were attended by both external and internal SRP experts. The sessions leveraged external technical expertise for advice on the analytical methods used in

the ISP. The objectives of the Technical Working Sessions addressed considering feedback and building support and were to:

- Create a structured forum for external experts to give deep technical input to the most complex challenges in future planning.
- Build support around the ISP methodologies by leveraging external best practices.

Customer Research – This was a multipronged research approach that focused on understanding the preferences and perspectives of residential customers with the overarching goal of reflecting diverse customer voices and perspectives in the ISP. Customer focus groups and surveys were conducted to collect the preferences of SRP customers on balancing reliability, affordability and sustainability in potential energy futures. This data allowed SRP to consider the customer's perspective when choosing the best path forward. Customer research addressed bilateral dialogue, considering feedback and building support from our residential customers through the achievement of the specific following objectives:

- Co-create learning opportunities about the ISP and SRP's strategies, decisions and initiatives with customer input.
- Understand the energy/utility programs customers participate in and why.
- Understand customers' concerns about the future of Arizona, the economy and the United States.
- Align how customers plan for their futures and how secure they feel in their lot with the process and messaging of the ISP.
- Understand customer perspectives on power, reliability and potential trade-offs with sustainability.
- Understand the diverse perspectives and opinions on SRP's route to sustainability and how these opinions evolve.
- Include customer input into the ISP analysis and the balancing of trade-offs.

Guiding ISP Principles

These principles were developed in collaboration with ISP team and ISP Advisory Group members. The purpose of the Guiding ISP Principles was to balance all important considerations in developing an ISP. SRP strove to understand the inherent trade-offs between reliability, affordability and sustainability for the principles and sought to establish an ISP in accordance with these Guiding ISP Principles.

Integrated Long-Term View

Develop a holistic view, including resources, transmission, distribution and customer program perspectives, for meeting evolving customer needs and achieving our Corporate Goals for 2035 and beyond. The long-term view ensures that SRP is making the right decisions today to support its customers and stakeholders in the future.

Transparency

Engage customers and other stakeholders in a system planning process that is responsive to questions and input.

Measure Success Through the Eyes of Our Customers

Maintain industry-leading customer satisfaction by responding to evolving customer needs by providing safe, reliable, affordable and sustainable power while equitably recognizing the different needs, challenges and perspectives of our customers.

Manage Costs

Deliver exceptional system and energy value by minimizing impacts from additional grid needs and future uncertainties to average retail prices while maximizing customer value through diligent long-term-oriented cost management.

Build an Adequate and Reliable Power System

Meet (and in some cases exceed) industry standards to provide a dependable supply of electricity to all SRP customers. Provide a reliable grid that is able to prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability.

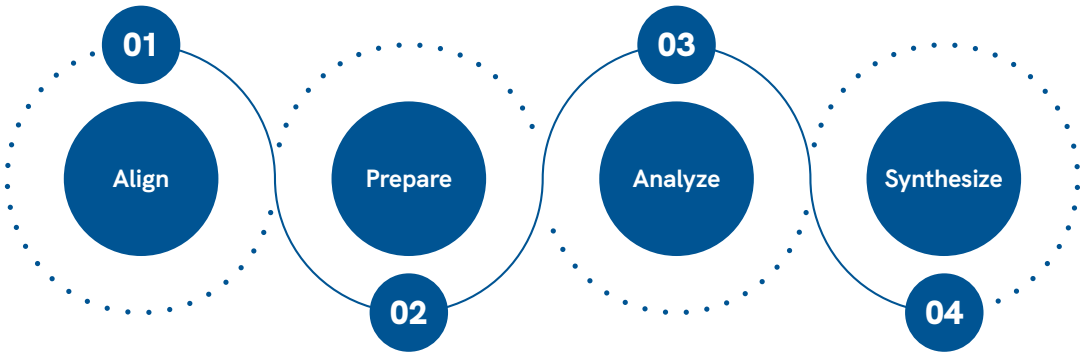
Adapt Toward a More Sustainable Future[1]

Meaningfully reduce carbon emissions and generation water usage to achieve SRP's 2035 Sustainability Goals to help address climate change and create less waste.

ISP Stakeholder Engagement Overview

Below is a summary of the stakeholder engagement process in the ISP and how we gathered and used internal and external stakeholder input to inform this first-of-its-kind planning effort in accordance with the above Guiding ISP Principles.

FIGURE 3.2: SRP ISP ROADMAP - STAKEHOLDER ENGAGEMENT



SRP ISP ROADMAP

Stakeholder Engagement

Align on Objectives of the first ISP

Collaboratively develop Study Plan:

Scenarios & Sensitivities Strategic Approaches Metrics

Gather input data

Perform system analysis

Validate and share results

Recommend new SRP system strategies

Recommend near-term actions

[1]The 2035 Sustainability Goals are being revised in 2024 in collaboration with community stakeholders. The next iteration of the ISP will focus on achieving and exceeding those revised goals.

Advisory and Large Stakeholder Group Engagements

For the initial Align Phase of the ISP depicted in Figure 3.2 on the previous page, SRP hosted four Large Stakeholder Group meetings over the summer of 2021. The SRP Summer Stakeholder Series was an opportunity to update, educate and engage with valued community stakeholders regarding SRP's efforts to transition from a traditional generation resource-focused Integrated Resource Plan (IRP) to a more holistic, comprehensive ISP inclusive of forecasting, customer programs, resource, transmission and distribution planning.

As shown in Figure 3.2, the Prepare Phase of the ISP stakeholder engagement strategy focused on creating a bilateral dialogue with stakeholders where they could comment, provide feedback and contribute their perspectives to the ISP analysis. This phase included customer research, one-on-one discussions with interested stakeholders, technical working groups, Large Stakeholder Group meetings and forming an Advisory Group. Together with community stakeholders, SRP set up a study plan that incorporated principles of scenario planning. This looked at how the future might unfold by analyzing key drivers, as well as the policy choices SRP could make and how those might perform in the future. We presented the co-created study plan for SRP's first-ever ISP to the Large Stakeholder Group on April 29, 2022.

Following along with the Figure 3.2 ISP Roadmap, at the end of April 2022, SRP kicked off the Analyze Phase of the ISP and conducted modeling through 2023. During this phase, SRP provided regular updates on ISP analysis to the Advisory Group as well as a final key findings presentation on April 21, 2023. Final key findings were presented to the Large Stakeholder Group on May 12, 2023.

As indicated in Figure 3.2, the final phase of the ISP was the Synthesize Phase, where SRP discussed with stakeholders and answered questions on viable pathways for meeting growing customer needs and achieving our 2035 Corporate Goals. SRP provided information to stakeholders about the trade-offs SRP faces, and collecting feedback helped SRP design a pathway moving forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped to build support for the first-ever ISP that will help guide major SRP strategy decisions.

Technical Working Sessions

In response to stakeholder feedback received throughout the objectives setting phase of the project, SRP developed Technical Working Sessions around topics of interest that stakeholders wanted to explore further. Starting in January 2021, SRP hosted four Technical Working Session webinars where experts from SRP and from around the country explored special topics. During 2022, SRP surveyed stakeholders to gauge their interest in different technical topics to help inform the topics for these sessions. The four sessions included the Inflation Reduction Act, inverter-based resources, regional market developments, and evolving time-of-day use programs.

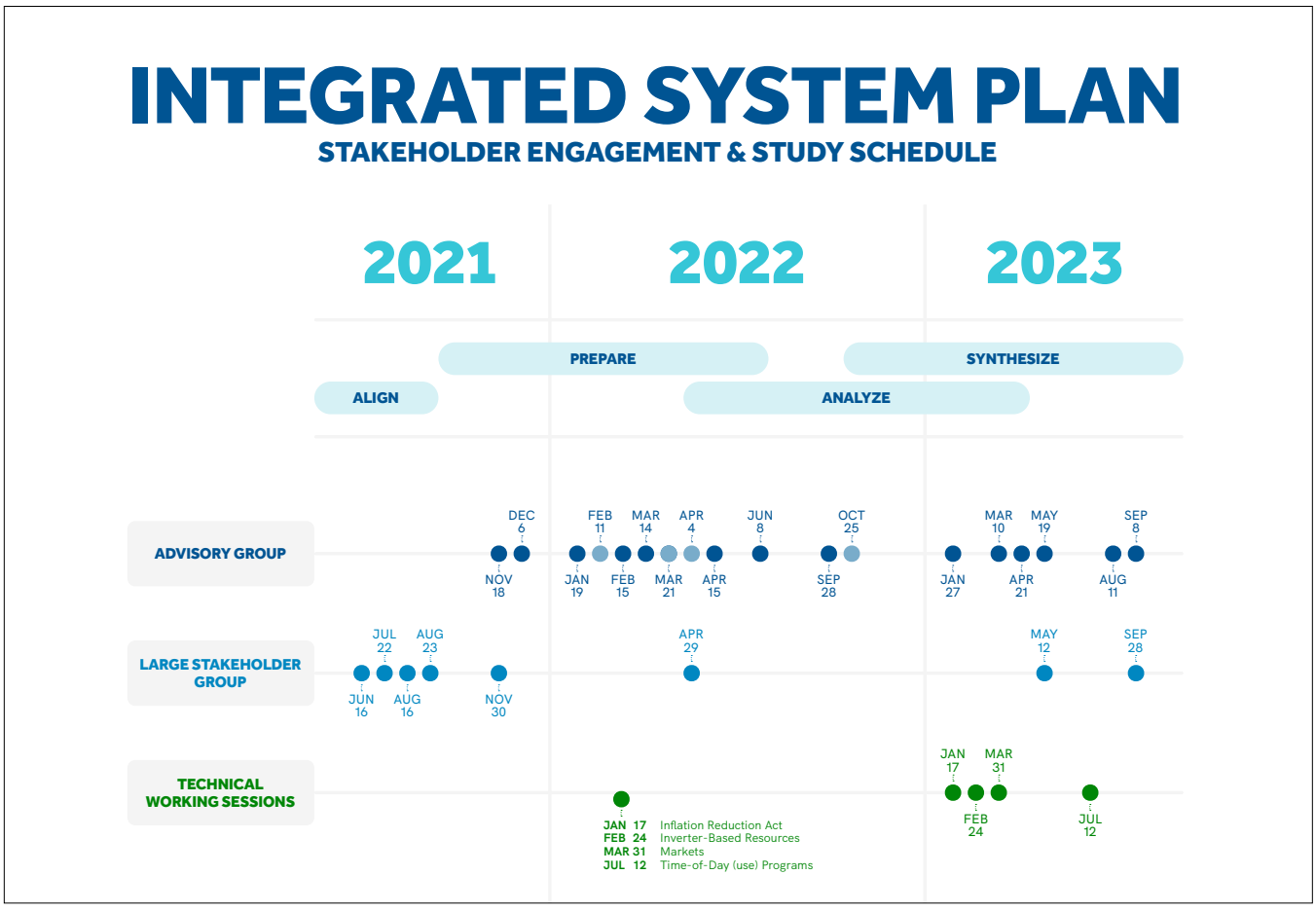
During these sessions, SRP shared work that has been done to date by our team in relevant areas. Each Technical Working Session featured a moderated panel discussion where external experts in relevant areas from around the country were invited to share leading industry experience and discuss potential enhancements SRP could undertake in future planning activities. Through these webinars, we had the opportunity to learn alongside stakeholders, gather input from these stakeholders, collect expert opinions in relevant topical areas and discuss potential enhancements applicable to SRP's system.

Customer Research

Throughout the process, SRP partnered with research consultant Bellomy Market Intelligence to execute the effort to bring the voice of SRP's residential customers into planning the future power system. Bellomy is a full-service market research firm that partners with healthcare, retail, financial, energy and consumer product companies to identify insights and strategic business implications derived from those insights. Having been immersed in the industry for over 25 years, Bellomy understands utility and energy clients' unique needs in regulated and deregulated landscapes. The customer research was a three-phased approach that started with phase 1, virtual focus groups (December 2021), followed by phase 2, quantitative confirmation survey (March 2022). The first two phases of research results were provided to Advisory Group members for consideration in designing the ISP study plan elements. Finally, for phase 3, a choice exercise was executed (May 2023). This research was designed to understand how customers think about reliability, affordability and sustainability related to power provision and gauge their reactions to a potential energy plan. All customers included in the research were SRP residential customers who were considered to be energy decision-makers and who did not work for a competing industry and were over 18 years old.

By using these engagement tools, SRP effectively collaborated with stakeholders and customers to build support for a shared vision for the future of the power system with 31 stakeholder meeting engagements executed and a multipronged residential customer research effort throughout the process, depicted in the timeline below.

FIGURE 3.3: ISP ENGAGEMENT TIMELINE



Transparent and Engaging ISP Process

SRP considered customers and community stakeholders essential partners in building a reliable, affordable and sustainable future power system. The holistic study plan was developed with input from SRP subject matter expert, customer and stakeholder feedback. The SRP project team, consisting of representatives from Forecasting, Resource Planning, Transmission Planning, Distribution Planning, and Customer Programs, performed a first-of-its-kind systemwide scenario analysis that allowed SRP to test strategies for building the future power system across a wide range of futures. Based on learnings from that analysis, the project team developed and shared with stakeholders the ISP key findings that identified costs, risks and trade-offs to consider when planning the future power system.

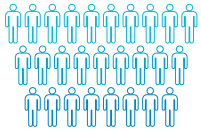
ISP PLANNING PROCESS FAST FACTS

NUMBER OF ADVISORY GROUP MEMBERS:

32
community representatives

from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



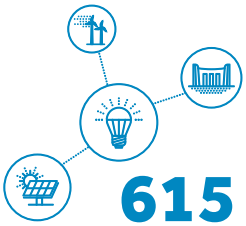
250
community representatives from
143
organizations

SLIDES PRESENTED

NUMBER OF MEETINGS:

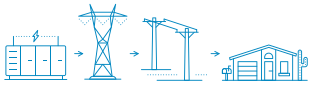
31 stakeholder meetings

totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

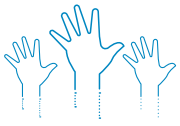
1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED



42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED

4
90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED

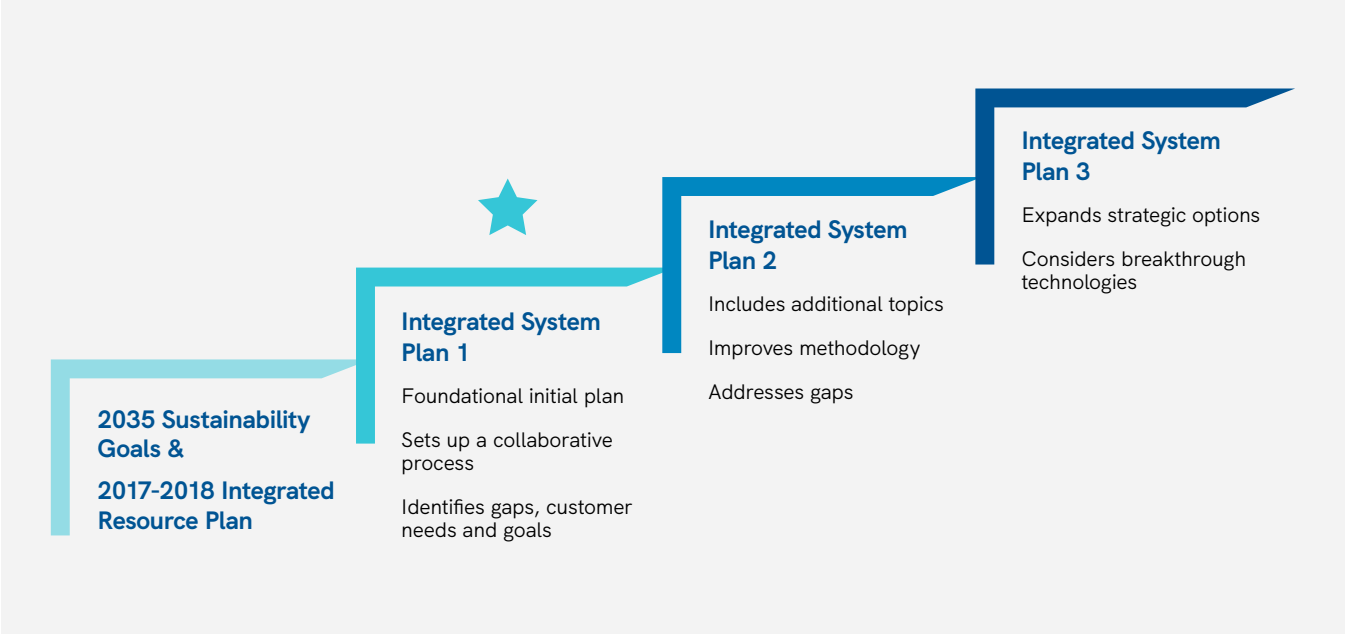
STAKEHOLDER QUESTIONS ANSWERED:
588



ISP Evolution

The scope of the ISP will evolve as SRP's planning groups gain experience and develop new capabilities. Participants in the objective development phase explored and discussed both the long-term vision and initial scope of ISP. Planning groups aligned on the importance of tackling a reasonable scope for the first ISP and building toward a long-term vision over time. One vision for what that evolution could look like is depicted below in Figure 3.4.

FIGURE 3.4: ISP LONG-TERM VISION



The initial ISP, or ISP 1, includes three key enhancements to current planning practices agreed to by the ISP team. The enhancements include consistent scenario and sensitivity analysis across the planning areas, incorporating transmission capacity headroom and expansion costs with supply-side resource planning, and expanding and enhancing the avoided cost framework to better evaluate customer programs. The process could evolve in future ISPs as new capabilities and tools are developed to be more cyclical. The pace and scale of ISP evolution will largely be determined by the experiences and lessons learned with ISP 1 and continued SRP exploration. The ISP enhancements for ISP 2 and ISP 3 in Figure 3.4 are illustrative and reflect stepwise progress of the potential elements identified in the long-term ISP vision.

Lastly, as part of the objective development engagement, the ISP team began a preliminary exploration of how the existing planning and sustainability processes might integrate with the ISP process in the future and the related issue of the cadence or frequency of the ISP. Consistent with the measured approach to the scope of ISP 1, the group generally agreed that gaining experience through ISP 1 would be helpful to inform future discussion on these topics.

The remainder of the report will describe the ISP 1 methodology, analytical framework, modeling results and critical findings that helped shape the concluding ISP deliverables, including System Strategies, ISP Actions and an illustrative Balanced System Plan.

SECTION 4

Scenarios, Sensitivities and Strategic Approaches

Scenario Framework

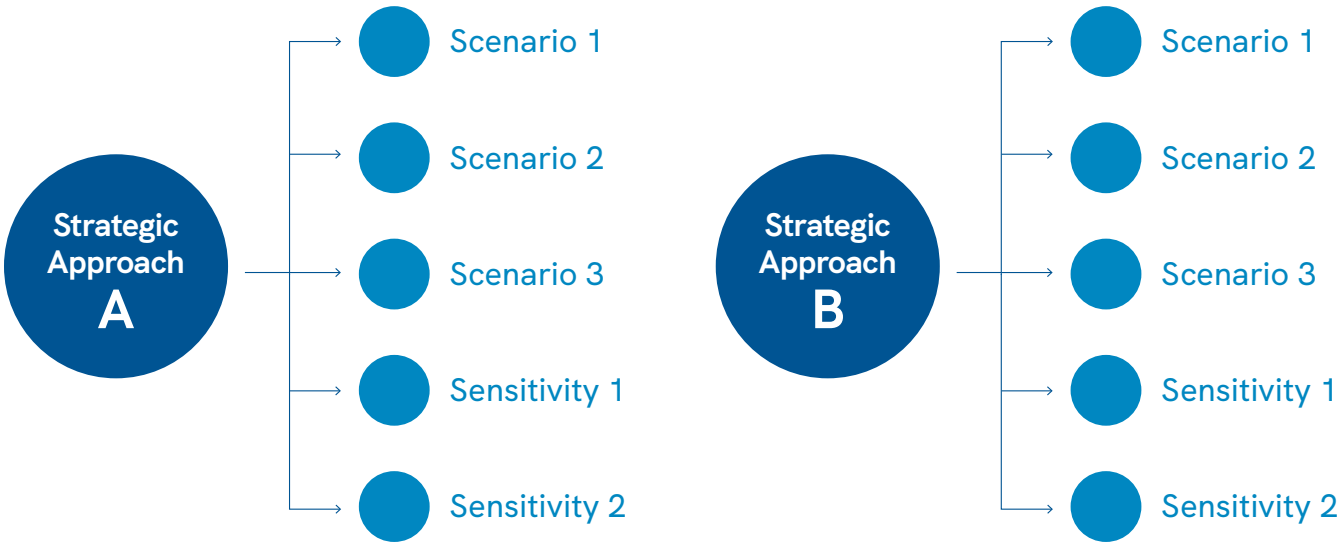
The decisions SRP makes today must withstand the risks and uncertainties of any future. Therefore, we utilized a scenario planning framework to test how different strategic decisions perform in an uncertain future.

The scenario planning framework used for the Integrated System Plan included three key elements: scenarios, sensitivities and strategic approaches. Scenarios defined plausible future states of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions. These factors are outside of our control and reflect the unpredictable nature of the future that needs to be accounted for in SRP's planning activities. Sensitivities, like scenarios, capture future states of the world around us but vary a single planning assumption. Finally, strategic approaches represented possible decisions that we could make in planning the future power system. These decisions are fully within our direct control.

FIGURE 4.1: SCENARIO DESIGN FRAMEWORK

In the Integrated System Plan, each strategic approach was tested against each of the future scenarios and sensitivities. This allowed us to examine the performance of each strategic approach under different futures and identify the components that best achieved SRP's goals, supporting the development of a robust system plan that positions SRP to take advantage of opportunities and react quickly as changes occur.

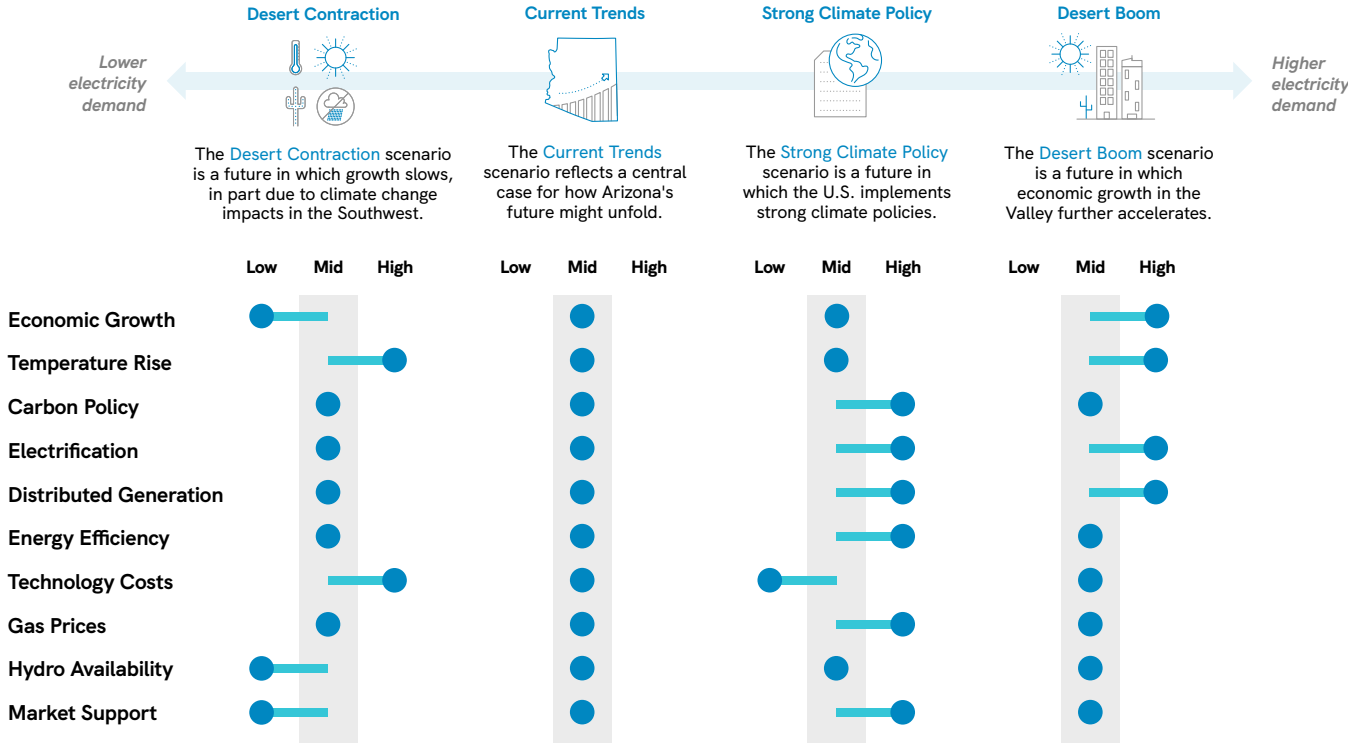
FIGURE 4.2: SCENARIO ANALYSIS



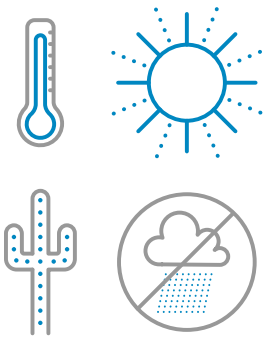
Scenarios

In collaboration with community stakeholders and based on results from customer research efforts, we developed four scenarios to analyze in the first Integrated System Plan: Desert Contraction, Current Trends, Strong Climate Policy and Desert Boom. The four scenarios considered many of the different external factors that can affect SRP's business environment and were designed to reflect a range of diverse yet plausible futures. Figure 4.3 below shows the four scenarios including how each external driver changed across the scenarios.

FIGURE 4.3: SCENARIOS



The following subsections describe each scenario in more detail and the key drivers associated with each scenario.

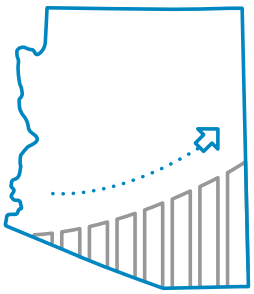


Scenario: Desert Contraction

The Desert Contraction scenario envisions a future where Arizona becomes a less desirable place for people and businesses due to a slowing economy and worsening climate conditions, which negatively impact residential and commercial growth. Additionally, global competition and consolidation initiates an exodus of large industry from the Valley, creating a cascading effect for the state's population. As a result, electricity demand in SRP's service area falls well short of current projections. Climate change also affects the region's watersheds, as declining rainfall throughout the West leads to lower reservoir levels along the Colorado River.[1] The corresponding reductions in generating capacity at large hydroelectric power plants significantly stress power markets, especially during peak demand periods.

[1]The Salt and Verde watersheds are more resilient to climate change and are unaffected in this scenario.

Key Drivers	Descriptions
Economic Growth	Higher summer temperatures and water supply issues stifle growth in the Southwest, limiting new migration and reversing expected growth trends. Large commercial and industrial customers emigrate out of Arizona and population growth levels off over time.
Climate Change	The Southwest experiences accelerated temperature rise consistent with the Intergovernmental Panel on Climate Change's (IPCC's) pessimistic Representative Concentration Pathway (RCP) 8.5 scenario, resulting in warming to the region that is more severe (0.91°F increase per decade). These conditions exacerbate current regional drought conditions, resulting in Lake Powell dropping below minimum power production levels for hydrogeneration from Glen Canyon Dam starting in 2025.
Policy	A worsening climate and intense global competition increase economic pressure on governments, resulting in a failure around the globe to adopt more consistent and aggressive carbon emission reduction regulations. While SRP remains committed to its 2035 Sustainability Goals, no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Spurred by the worsening impacts of climate change and the lack of cohesive federal climate action, more and more Arizonans prioritize sustainability. Therefore, adoption rates for electric vehicles (EVs), heat pumps, and distributed solar and batteries increase. Growing adoption rates for these customer-sided technologies are tempered by lower overall population growth.
Technology	Increased global market competition, prolonged supply chain issues and stagnant economic growth in the Southwest raise material and labor costs, slowing the decline of renewable and storage costs. Tax credits provided through the Inflation Reduction Act help to reduce costs, although a stretched labor market makes qualifying for such credits expensive.
Market Dynamics	Extreme heat waves, wildfires and the loss of power capacity at Glen Canyon Dam as well as other hydrogeneration in the West lead to constrained regional markets that cannot be relied upon during peak periods.

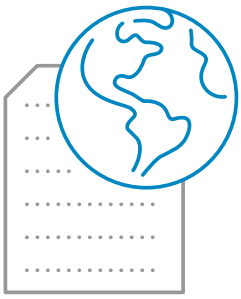


Scenario: Current Trends

The Current Trends scenario presumes that the large-scale changes currently underway in society, the region and the utility sector continue, resulting in substantial changes for SRP and Arizonans by 2035. Population in the Valley grows at a steady pace as the affordable cost of living and pleasant weather most of the year in the Phoenix area continue to attract new residents from California and surrounding states. With land availability, a competitive workforce, a geographical location in the middle of large markets (including California, Texas and Mexico), and with local and federal support of industries such as domestic semiconductor manufacturing, Phoenix becomes increasingly attractive to large commercial and industrial businesses. Data centers and manufacturing companies continue to move into the Valley, creating more jobs and bringing even more growth for Arizona. Some of these companies have significant load requirements measured in the hundreds of megawatts, much larger than those seen in the past. EVs gain popularity due to the broadening availability of vehicle models and improving charging infrastructure across the nation.

Key Drivers	Descriptions
Economic Growth	Continued growth is sustained in the greater Phoenix area, driven by continued migration and expansion in commercial and industrial business activities.
Climate Change	Climate change impacts are consistent with the projected RCP 4.5 scenario modeled by the IPCC, which envisions global emissions dropping below 2005 levels by 2100. Temperatures increase moderately (0.67°F per decade), while current drought conditions in the West persist but do not worsen throughout the study period.
Policy	While the Inflation Reduction Act provides a strong, sustained economic stimulus to support clean energy development, further federal action on climate policy is limited: Partisan politics continue to create a gridlock that prevents adoption of any comprehensive federal climate policy. In the absence of federal policy, state governments, utilities and corporations continue to drive advancements toward clean energy and sustainability goals. Like many other utilities in the region, SRP continues its independent efforts to meet voluntary sustainability goals.

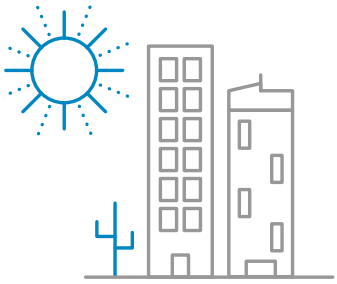
Customer Participation (EE, DG, electrification)	SRP continues to be a regional leader in offering energy efficiency and demand response programs to customers. The number of light-duty EVs increases significantly by 2035, benefiting from strong federal policy support provided in the Infrastructure Investment and Jobs Act, and consistent with SRP's current 2035 Sustainability Goals. Cost declines of distributed solar and batteries drive increased adoption by residential and commercial customers.
Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits provided through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting increased demand.



Scenario: Strong Climate Policy

The Strong Climate Policy scenario reflects a future where political consensus is reached on the need for swift and decisive action to combat climate change, resulting in several new policies and measures at the U.S. federal level. These policies are guided by an economywide net-zero emissions target by the year 2050, resulting in mass-based emissions reductions targets for electric utilities throughout the country by 2035. Decarbonization policies also impact demand: The pace of electrification in the building and transportation sectors accelerates, causing demand for electricity to increase, and government support for energy efficiency measures results in improvements in efficacy, reduction in cost and more widespread adoption. These two effects are offsetting but change the patterns and timing of electricity consumption. Extensive research and development support of clean energy resources advances power companies' operational learning curves and accelerates cost declines. Such cost declines also impact distributed generation on the customer side and create favorable conditions for the adoption of solar and storage systems. A Regional Transmission Organization (RTO) or a regional resource adequacy program would be established in the Southwest, allowing power companies to better take advantage of load and resource diversity in the region.

Key Drivers	Descriptions
Economic Growth	Growth is sustained as large commercial and industrial customers continue to migrate to the Valley. Furthermore, electricity demand is accelerated by rapid electrification of the building and transportation sectors.
Climate Change	Through 2035, temperatures in the Southwest remain consistent with the IPCC's RCP 4.5 scenario. Temperature increases moderately (0.67°F per decade), while current drought conditions in the West continue throughout the study period.
Policy	The U.S. federal government implements a suite of comprehensive policies to address climate change. These policies are designed around an economywide net-zero emissions target by 2050.
Customer Participation (EE, DG, electrification)	Stronger federal codes, standards and incentives lead to high energy efficiency growth. Technology improvements and rapid cost declines drive accelerated distributed solar and battery adoption among SRP's residential and commercial customers. The number of light-duty, medium-duty and heavy-duty EVs as well as heat pumps increases significantly, with federal support for these technologies.
Technology	Additional federal tax incentives, research and development investments, and increased deployment of clean energy resources advance learning curves, driving significant cost declines for renewables and storage and accelerating the commercialization of emerging technologies. Domestic manufacturing is able to keep up with demand, and no price increases from supply chain constraints are expected.
Market Dynamics	Federal policy support, incentives and subsidies drive increased transmission buildout across the nation. An RTO or a regional resource adequacy program would be established in the Southwest region, and system planning is conducted at a regional level. The regional planning paradigm and operational coordination allow the Balancing Authority Areas in the region to better take advantage of regional load and resource diversity, lowering the planning reserve margin SRP requires. More aggressive policies related to the natural gas supply chain increase natural gas prices.



Scenario: Desert Boom

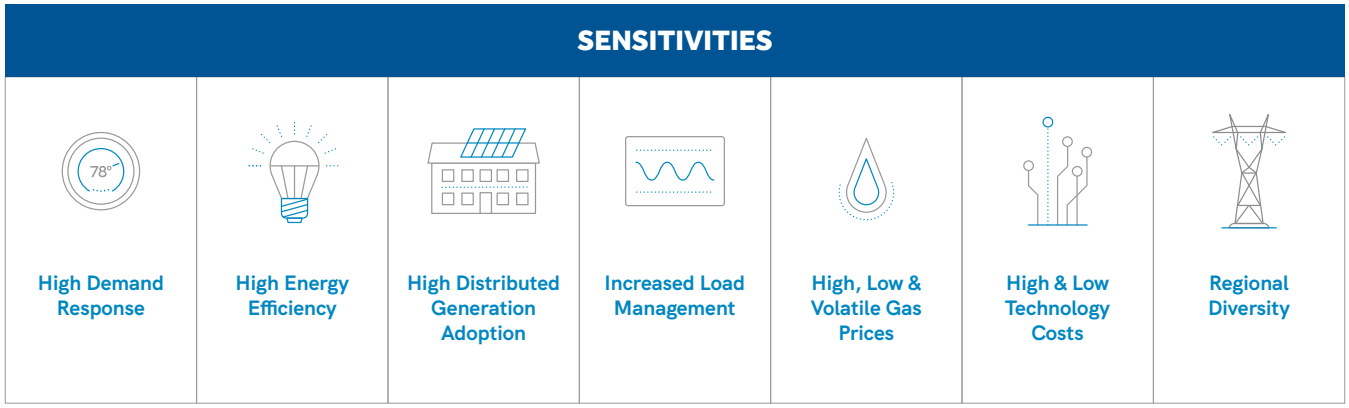
The Desert Boom scenario is characterized by explosive growth in SRP's service territory. Arizona becomes a regional energy, technology and manufacturing hub, creating a second "Silicon Valley" in the Phoenix metropolitan area. Economic growth in the Phoenix metropolitan area accelerates far beyond current projections and is led by a strong global technology industry and a supportive environment in Arizona. Electricity demand increases significantly with accelerated economic activity, growth in energy-intensive businesses and increased energy exports. Arizona's central location, affordable cost of living and skilled workforce attract an influx of people and businesses to the area. Strong economic growth supports accelerated EV and heat pump adoption, adding more electrification loads to the grid. Increased availability of distributed solar and battery technology helps mitigate system demand but not at the scale needed to provide full grid backup.

Key Drivers	Descriptions
Economic Growth	Growth accelerates significantly as Arizona becomes a regional energy, technology and manufacturing hub.
Climate Change	Climate change accelerates around the globe due to both climate policy inaction and strong global economic activity. Greater temperature rise occurs (0.91°F per decade) consistent with the Intergovernmental Panel on Climate Change (IPCC)'s pessimistic Representative Concentration Pathway (RCP) 8.5 scenario while current drought conditions in the West continue throughout the study period.
Policy	Governments around the globe prioritize economic growth over carbon emission reductions in the midst of an economic boom. SRP is committed to its 2035 Sustainability Goals, and no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Population growth and higher incomes accelerate adoption of light-duty EVs, heat pumps, and distributed solar and batteries.

Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture, and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting continued demand growth and declining supply.

Sensitivities

In addition to the scenarios, SRP also analyzed 10 sensitivities under the Current Trends scenario. A **sensitivity** varied a single assumption in the Current Trends scenario, allowing SRP to understand the impact of the assumption on the overall system plan. Sensitivities were analyzed under the Current Trends scenario to assess the impact of varying individual assumptions on the system plan at a central case of potential future load growth. Details on the assumptions used for each sensitivity are included in Section 5: Methodology.



In the graphic above, the "High, Low & Volatile Gas Prices" icon encompasses three sensitivities, including High Gas Prices, Low Gas Prices and Volatile Gas Prices. The "High & Low Technology Costs" icon encompasses two sensitivities, including High Technology Costs and Low Technology Costs.

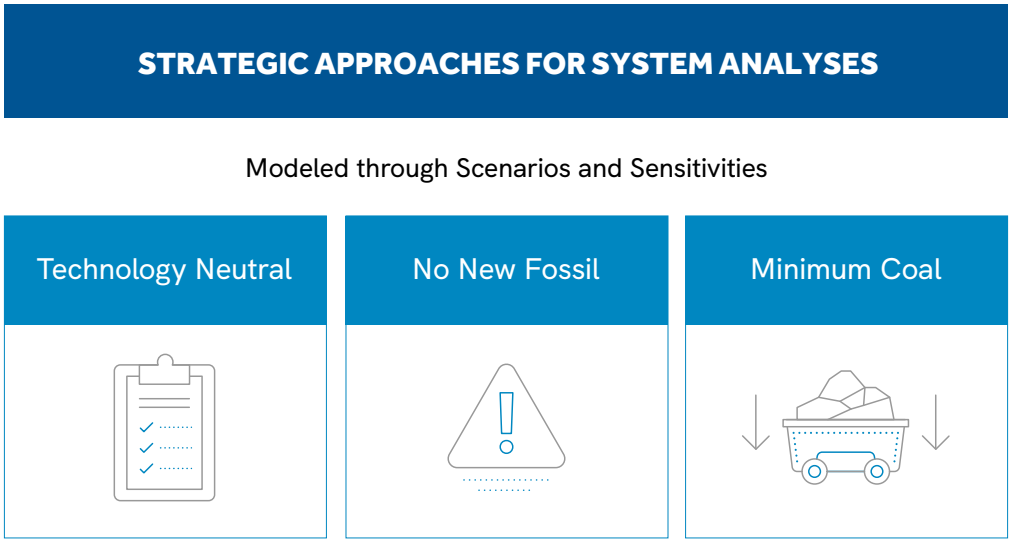
Strategic Approaches

SRP developed three strategic approaches to analyze in the Integrated System Plan. The three strategic approaches were analyzed across each of the scenarios and sensitivities described above.

The **Technology Neutral** strategic approach aims to develop future system plans on a least-cost basis to meet reliability and sustainability goals without any preferences for or restrictions upon the specific technologies included in the portfolio.

The **No New Fossil** strategic approach seeks to meet future system needs with exclusively carbon-free resources, excluding investment in new natural gas resources from consideration. Existing natural gas units remain in service and are still used to meet customer needs. Further, no changes to planned coal retirement dates are included in this strategic approach.

The **Minimum Coal** strategic approach aims to reduce power generation from coal in SRP's system by testing operational changes to SRP's coal resources, including seasonal operations and the full retirement of coal by 2035. This strategic approach builds upon the No New Fossil approach described above, meaning that all new generation resources must not rely on fossil fuel technologies.

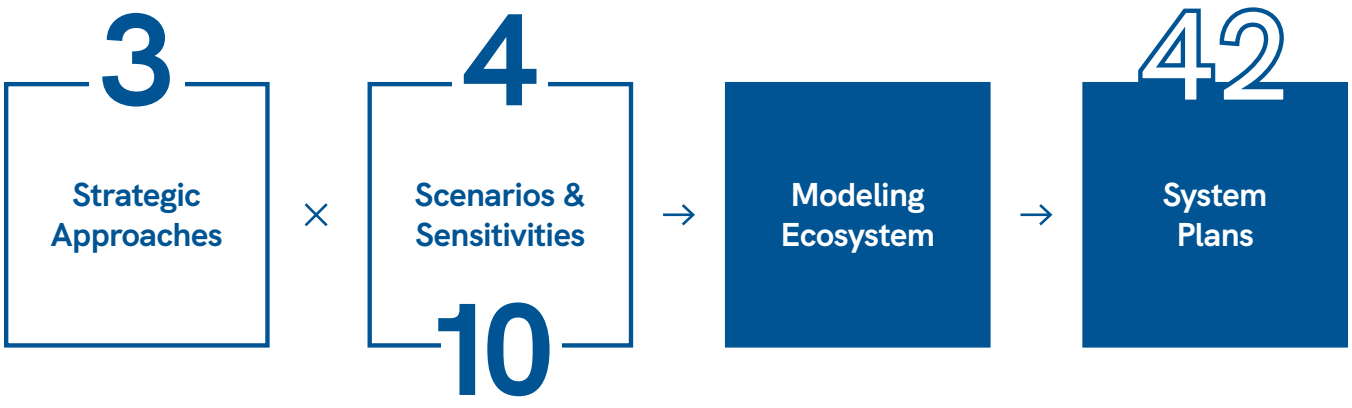


SECTION 5

Methodology

Methodology Overview

As discussed in Section 4, the ISP tested three strategic approaches across four scenarios and 10 sensitivities to evaluate 42 different planning cases. For each of these planning cases, SRP developed a system plan for the years 2025–2035 which included customer programs, distribution investments, transmission investments and resource additions.

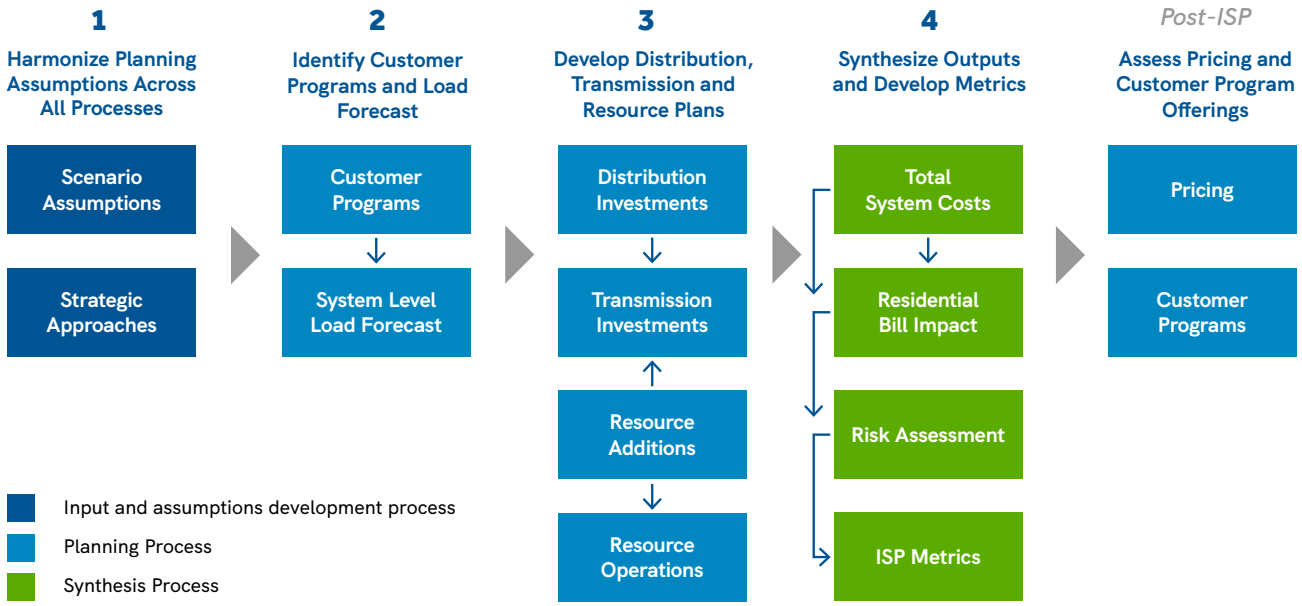


Our team evaluated and compared these plans by developing metrics to understand how each strategic approach performs across different futures and to identify the system components that could help SRP deliver a reliable, affordable and sustainable future power system. While we cannot know what the future will hold, assessing system plans across a variety of potential futures allowed us to identify strategies to mitigate future risks and take advantage of potential opportunities. This section describes the modeling ecosystem, key modeling inputs and metrics that we utilized to develop and evaluate each of the system plans.

Modeling Ecosystem

This first-of-its-kind ISP required a new approach to perform comprehensive system planning. Because there was no single planning model available that we could use to analyze all parts of the system simultaneously, we needed to develop an analytical ecosystem that included multiple planning processes, each with its own model(s). Each planning process utilizes the same planning assumptions, and then results from one planning process feed into other planning processes to help us create integrated system plans. An overview of this modeling ecosystem is shown in Figure 5.1.

FIGURE 5.1: MODELING ECOSYSTEM OVERVIEW



For a given planning case, we utilized the same scenario and strategic approaches across all planning processes (Step 1). We then forecasted energy demand during all times of the year, including the adoption of customer programs and customer-sited generation (Step 2). We next identified distribution investments, transmission investments and resource additions to meet future needs through 2035 (Step 3). The Distribution Investments planning process identified where the load would grow on the distribution system and the distribution infrastructure required, while the Resource Additions planning process identified which resources would be added. These results fed into the Transmission Investments planning process, which determined what transmission investments would be needed on SRP's system to connect large-scale resources to serve customers' energy demand. In addition, the Resource Operations process simulated how the future system could operate. We then leveraged all of these outputs to develop reliability, affordability, sustainability and customer-focused metrics (Step 4).

We will use this information to inform the design of customer programs and pricing plan offerings following the first ISP. These planning processes and metrics are described further in the following sections.

Due to time constraints, we could not perform every modeling process for all 42 planning cases. For the Transmission Investments, Residential Bill Impact and Risk Assessment processes, we performed modeling for a subset of the 42 planning cases, as detailed further below. We quantified all metrics for the 12 "core system plans" (three strategic approaches evaluated against four scenarios) and assessed all 42 system plans when developing key findings, as discussed in Section 6.

Customer Programs and End-Use Technologies

We developed customer program and end-use technology forecasts for energy efficiency, demand response, electrification (transportation and other technologies) and distributed

generation — including distributed solar and distributed batteries — for scenarios and sensitivities. These forecasts served as inputs into the load forecasts, which subsequently served as key inputs for each of the planning processes. The demand response forecast served as a direct input for the Resource Additions process.

Methodology Overview

To meet customers' diverse needs and the overall system needs, we developed a cost-effective portfolio of programs that achieve SRP's 2035 Sustainability Goals for energy efficiency, demand response, transportation electrification and electric technologies. In addition, we developed forecasts for customer adoption of other end-use technologies, including distributed generation in alignment with SRP's 2035 Sustainability Goal for grid enablement.

We developed customer program and end-use technology forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Demand Response (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Across these scenarios and sensitivities, we assumed that external factors drive customer adoption differences relative to the Current Trends scenario. For example, in the Strong Climate Policy scenario, we assumed that increased federal support for decarbonization efforts drives an expansion in energy efficiency, electric vehicles, building electrification and distributed generation.

Key Inputs

Key inputs for the customer programs and end-use technologies planning process included SRP's 2035 Sustainability Goals, assumptions for specific measures and programs, and market drivers.

2035 Sustainability Goals

SRP has established 2035 Sustainability Goals for various customer program offerings. In all ISP cases, we included customer program projections that met or exceeded these levels by 2035. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

- Energy efficiency: 3 million MWh
- Demand response: 300 MW
- Transportation electrification: 500,000 EVs
- Electric technologies: 300,000 MWh
- Grid enablement: Enable all distributed energy resources that customers choose to install

SRP Customer Program Planning Assumptions

SRP offers customer programs for energy efficiency, demand response, transportation electrification and electric technologies. The assumptions for these programs reflect the suite of customer program opportunities available to SRP, as well as their performance and costs.

SRP has implemented a continuous improvement process over many years to refine planning assumptions for specific measures for energy efficiency, demand response and electric technology programs. SRP's Measurement & Evaluation team and third-party consultant Guidehouse formally evaluate a subset of programs each year to continually refine assumptions for the measures included in each program. Based on this process, we have defined planning assumptions for each of the following measures:

- Reduction in energy demand during peak hours (kW)
- Reduction in energy demand during the entire year (kWh)
- Timing of energy demand reduction on an hourly basis
- Useful life over which SRP can expect energy savings
- Incremental cost, which serves as the basis for rebate design

Market Research

SRP regularly performs market research to understand the market activity and customer willingness to participate in different programs and to adopt various end-use technologies. In addition to speaking with customers, SRP gathers information from implementation partners, trade allies and third-party research. To develop the distributed generation forecast, we relied on historic and recent trends for distributed generation installations within SRP's power system area as well as advanced metering infrastructure data for the historic and recent generation of the systems already installed. To develop the electric vehicle forecast, we relied on information from the Electric Power Research Institute (EPRI) related to feasible EV adoption rates and supplemented this with internal research on EV load impacts within SRP's service area. We then leveraged this market research information, along with historical trends, to inform the forecast of future customer participation in SRP programs and adoption of end-use technologies.

Key Outputs

Below are the key outputs from this planning process.

Output	Description	Output Units
Energy Efficiency and Electrification Impacts on Annual Load	Forecast of energy efficiency and electrification (transportation and other technologies)	MWh

Demand Response Capacity	Forecast of the amount of capacity on the system that is available to provide demand response services	MW
Distributed Generation Adoption	Forecast of customer-sited solar and batteries	MW
Customer Program Costs	Forecast of program costs for SRP customer programs	$

Load Forecast

In the load forecasting process, we forecasted customer energy demand on an hourly basis through 2035. The forecast reflects typical patterns in energy demand throughout the year and across the hours within a given day, including during peak energy demand periods. This information served as a key input for determining future system needs in the ISP.

Methodology Overview

First, our team created a baseline forecast for the Current Trends scenario. We then employed the Statistically Adjusted End-Use (SAE) model (developed by Itron) to forecast electricity demand from customer end uses. We updated this model to align with inputs related to economic growth, end-use saturation and efficiency trends, adoption of customer programs, adoption of distributed generation, adoption of electric vehicles, and temperature trends. Finally, we used the outputs of this model to determine the hourly energy demand through 2035.

To develop additional forecasts for each of the four planning scenarios and two of the sensitivity cases, we modified one or more key assumptions. We developed load forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Key Inputs

The following sections describe the key inputs for the Load Forecast process, including economic growth and temperature increase. In addition to these inputs, we factored in changes in customer energy usage from energy efficiency, electrification and adoption of distributed generation. These inputs are the results of the Customer Programs and End-Use Technologies process and are discussed in Section 6.

Economic Growth

We developed economic growth projections for all four scenarios to determine key inputs, such as change in population and growth in energy demand from large customers. To do so, we developed an economic outlook for the Phoenix metro area by creating a composite forecast from a variety of external economic forecast providers, including University of Arizona, Arizona State University, Moody's, Woods & Poole Economics, and R.L. Brown Construction. We also developed an outlook for large customer growth by leveraging information from a variety of sources, including SRP's Strategic Energy Managers, SRP Economic Development, the Greater Phoenix Economic Council, state and local commerce authorities, and observed historical trends.

Figures 5.2 and 5.3 show the population and incremental large customer load growth forecasts for the four scenarios. In the Current Trends and Strong Climate Policy scenarios, the population and new industrial loads increase markedly, consistent with recent trends in migration and expansion of business activity. In the Desert Boom scenario, there is even greater growth as Arizona develops further as a regional energy, technology and manufacturing hub. In the Desert Contraction scenario, there is limited new migration and a significant slowing of large customer growth trends.

FIGURE 5.2: PHOENIX METRO POPULATION

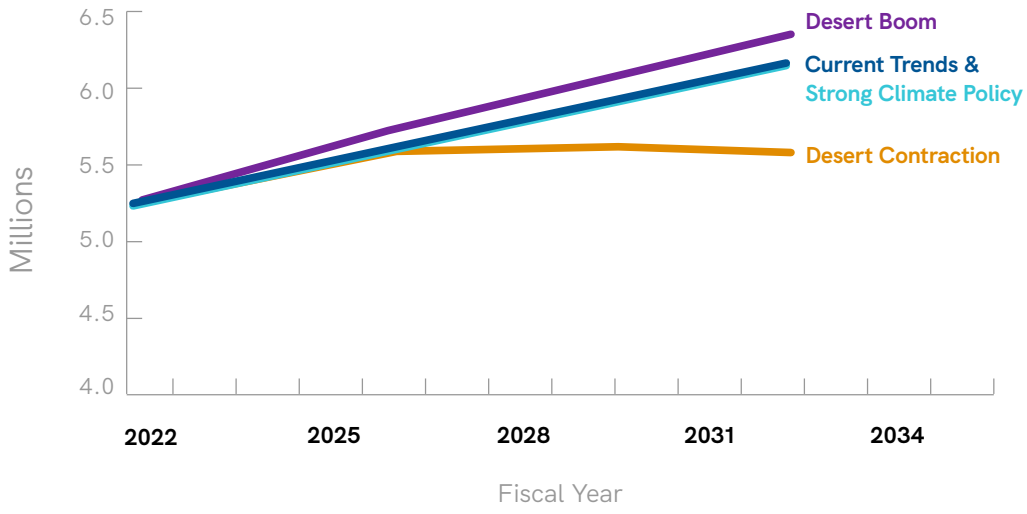
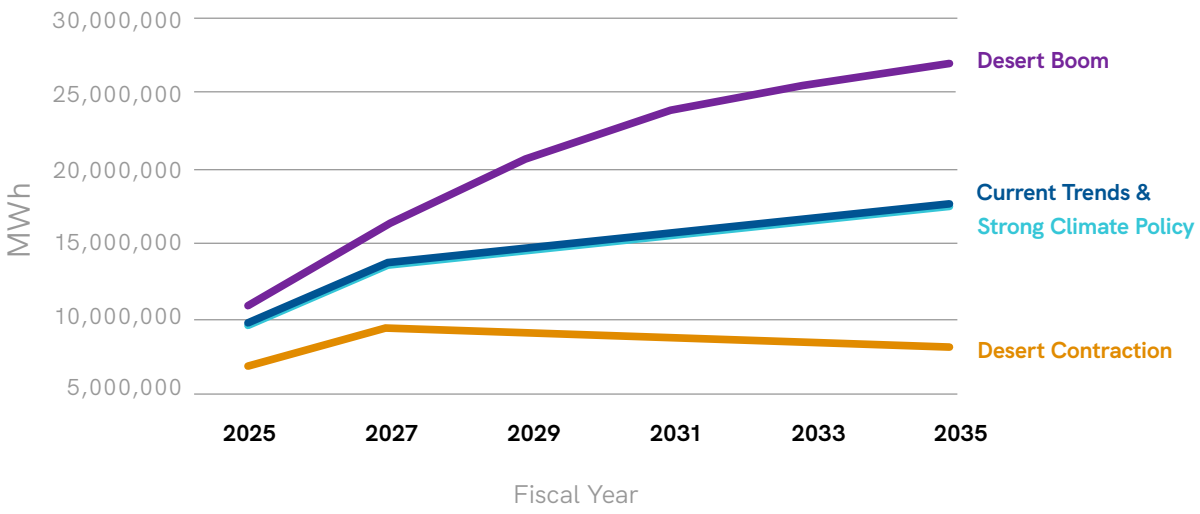


FIGURE 5.3 INCREMENTAL LARGE CUSTOMER LOAD GROWTH



Temperature Increases

In all scenarios, we considered the impacts of global warming. To characterize the future temperature increases, we relied on data from the Intergovernmental Panel on Climate Change (IPCC). For the Current Trends and Strong Climate Policy scenarios, we used the Representative Concentration Pathway (RCP) 4.5 trajectory, which corresponds to a temperature increase of 0.67°F per decade. For the Desert Boom and Desert Contraction scenarios, we used the RCP 8.5 trajectory, which corresponds to an even greater temperature increase of 0.91°F per decade. We then translated these changes in temperature into changes in cooling degree hours and heating degree hours (see figures 5.4 and 5.5), which are metrics that are correlated with energy demand from cooling and heating buildings.

FIGURE 5.4: COOLING AND HEATING DEGREE HOURS

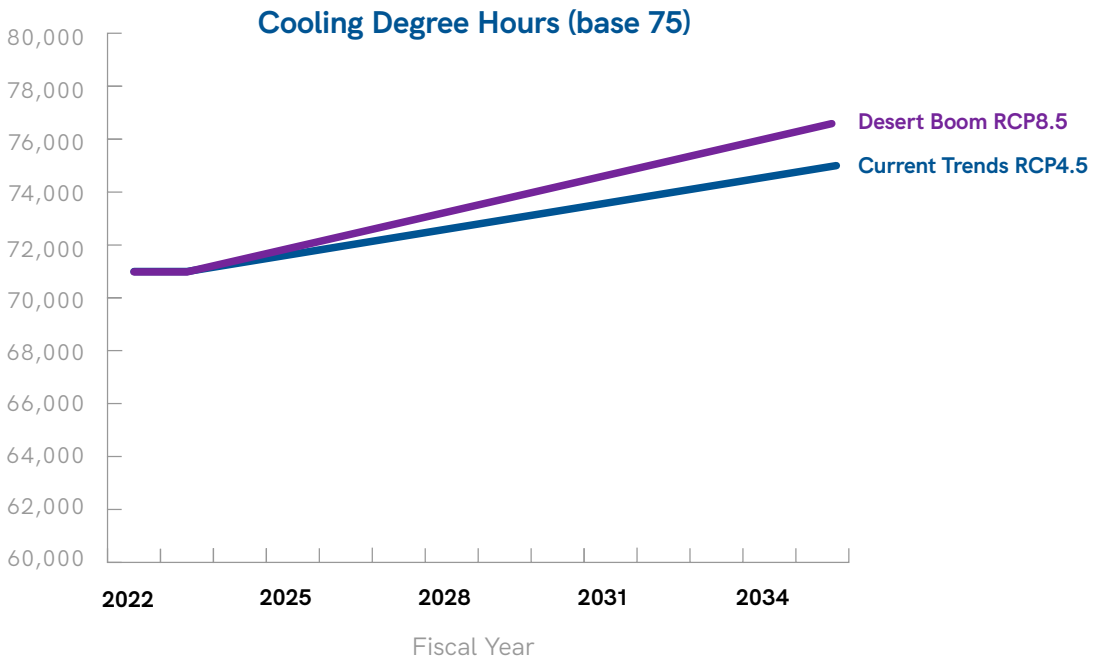
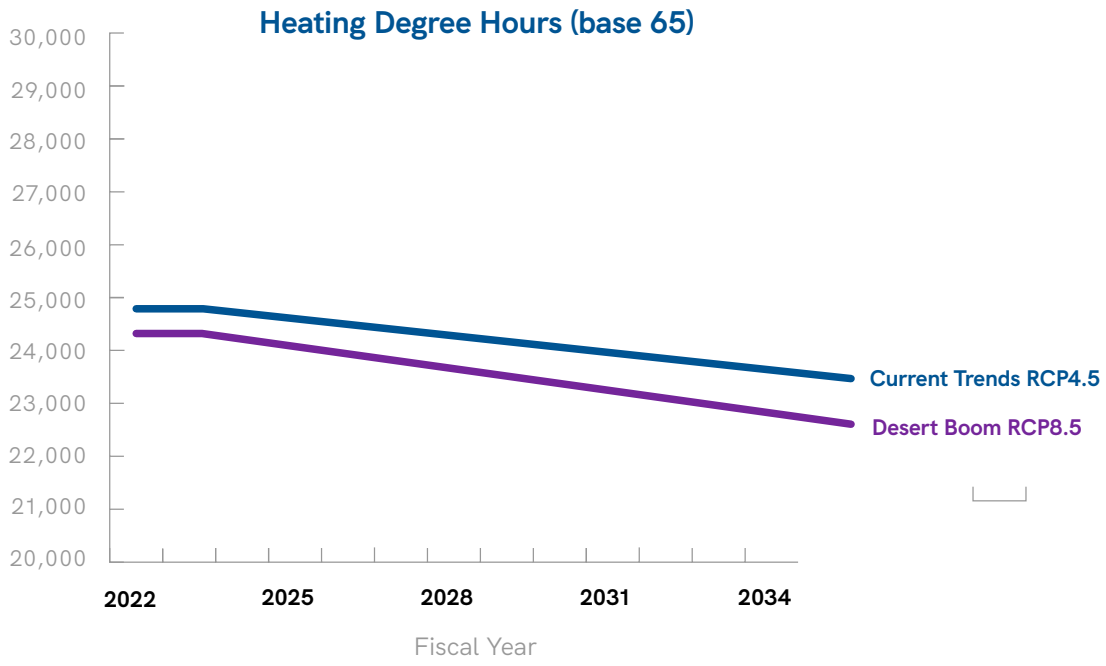


FIGURE 5.5: COOLING AND HEATING DEGREE HOURS



Key Outputs

SRP developed the following outputs, which served as inputs for other planning processes.

Output	Description	Output Units
System Load Forecast	System peak load and hourly energy demand forecast	MW
Transmission-Level Forecast	Peak load forecast for customers that connect directly to the high-voltage transmission system	MW
Distribution-Level Forecast	Peak load forecast for customers that connect to the lower-voltage distribution system	MW

Distribution Investments

In the Distribution Investments planning process, we determined which investments are needed on the distribution system to accommodate growth in customer energy demand, including the impacts from adoption of electric vehicles and customer-sited generation, while ensuring reliability.

Methodology Overview

First, we allocated the system-level load forecast (described in the Load Forecast section) to granular localized levels of the distribution system. We utilized LoadSEER (developed by Integral Analytics), which is a distribution forecasting and planning tool that allocates the system-level load to individual substations based on geographic, economic and historical customer usage data. This resulted in a peak load forecast for each substation, allowing us to understand where customer demand is changing and how the system may need to adapt.

After we allocated the system-level load forecast to the localized levels of the distribution system, SRP analyzed capacity-constrained locations and evaluated applicable infrastructure solutions to alleviate these constraints. Due to modeling limitations and time constraints, we focused on substation equipment and did not evaluate individual distribution lines that connect to the substations. We utilized the following reliability planning criteria, consistent with SRP's distribution planning practices:

- A distribution substation bay may not exceed 85% of its emergency rating.
- The total distribution system load should not exceed 70% of the total distribution system capacity.

One way we addressed an overloaded substation was by shifting loads to adjacent substations, which was possible if the neighboring substation had available capacity. This ensured the existing distribution infrastructure was used efficiently. In areas that were significantly capacity-constrained and existing distribution infrastructure could not be utilized, SRP strategically placed new substations, adding capacity to an area to address as many overloads as possible.

We performed this analysis for the following scenarios and sensitivities, which covered all planning futures in which load and customer programs change and could impact distribution investment needs:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

For the two sensitivity analyses, the team estimated the required number of substation bay additions through interpolation by calculating the relationship between forecasted load and

resultant substations required in the four major scenarios. This relationship was then applied to the forecasted load for the two sensitivity cases. This process resulted in a high-level estimate of substation bay addition requirements for each sensitivity case, and it assumes that these technologies are adopted evenly throughout the service territory.

Key Outputs

The modeling process resulted in a plan detailing the location of each substation addition for each year as well as the load for each substation in each year.

Output	Description	Output Units
Substation Load Forecast	Projects addition of new substations and allocation of load between substations.	MW
Distribution Investments	Specification of substation additions or upgrades to meet system requirements, as well as associated costs.	$

Resource Additions

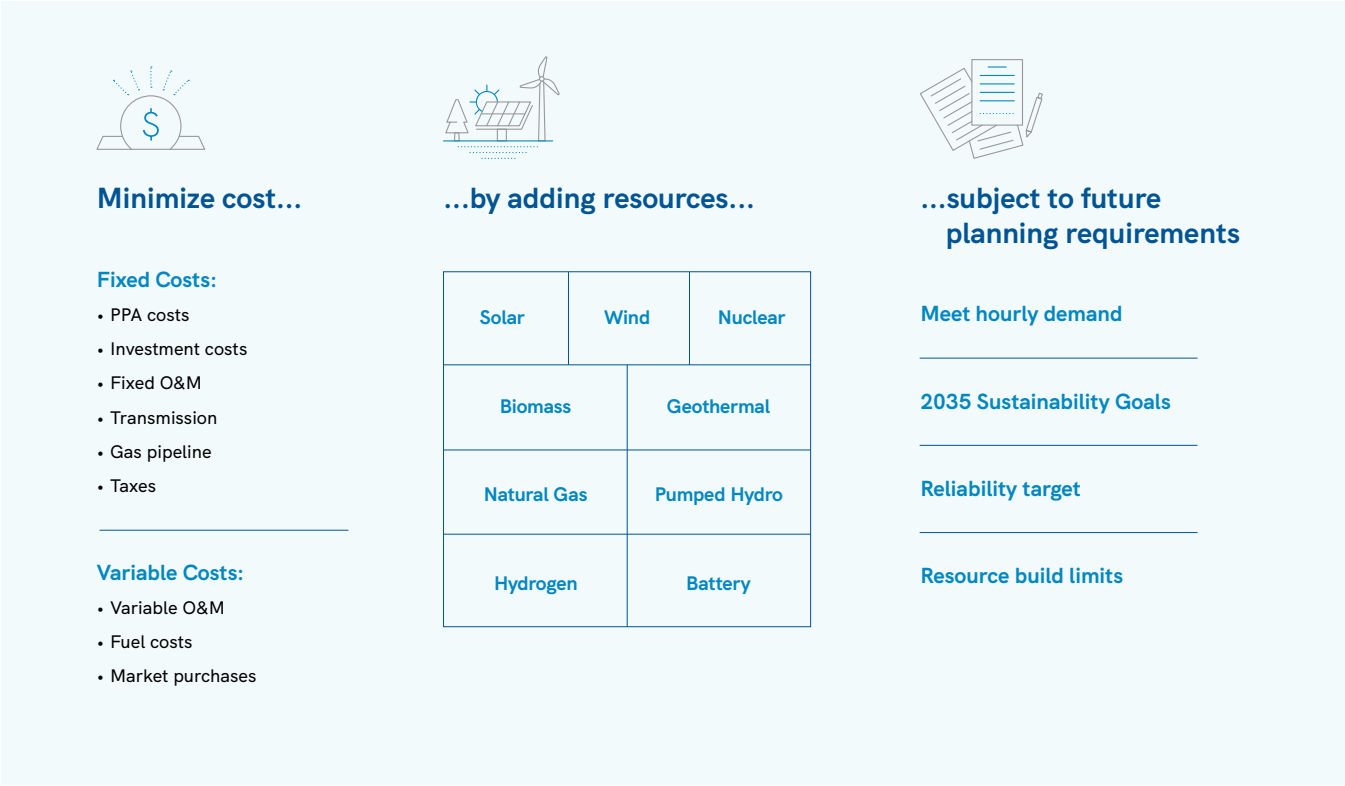
In the Resource Additions planning process, we determined the least-cost resource additions needed to meet future energy demand while ensuring reliability and meeting SRP's 2035 Sustainability Goals related to carbon dioxide emissions and water usage.

Methodology Overview

During this process, our team assessed future resource additions through a resource portfolio optimization analysis that identified the least-cost long-term combination of generation investments subject to reliability, policy and technical constraints.

To perform the analysis, we engaged Energy and Environmental Economics Inc. (E3) to deploy a long-term capacity expansion model, PLEXOS (developed by Energy Exemplar), which we had not leveraged in prior resource planning efforts. PLEXOS considers investment costs, fixed costs and production costs to simultaneously select new resources and simulate system operations over a long planning horizon (see Figure 5.6).

FIGURE 5.6: OVERVIEW OF THE RESOURCE ADDITIONS MODELING FRAMEWORK



E3 produced optimized resource portfolios for all cases presented in the ISP, except for the volatile gas price sensitivities[1], totaling 39 cases. Each portfolio identified resource additions through 2035.

Key Inputs

The key inputs for this analysis included the system load forecast (see Load Forecast section), resource options, resource and transmission costs, reserve margin requirements, fuel prices, reliability requirements and sustainability requirements.

Resource Options

The ISP considered a wide range of resource options to meet future needs, including renewable, storage and thermal resources.

Renewable Resource Options

The ISP considered several renewable resource options, including biomass, geothermal, solar and various wind options that vary by location and transmission path.

[1]The volatile gas price sensitivities are intended to evaluate the impact of gas prices unexpectedly changing over short time periods without SRP being able to change decisions around resource additions. Therefore, SRP evaluated the volatile gas price sensitivities in the Resource Operations analysis, using the same resource additions as in the Current Trends scenario.

FIGURE 5.7: RENEWABLE RESOURCE OPTIONS

Resource	State	First Available Year	Capacity Factor[2]
Biomass	Arizona	2025	Varies
Bioenergy with Carbon Capture and Storage	Arizona	2035	Varies
Geothermal	California	2031	90%
Solar	Arizona	2025	32.2%
Wind – Existing SRP Transmission	Arizona	2033	31.3%
Wind – Existing non-SRP Transmission	Arizona	2025	31.3%
Wind – New Transmission	Arizona	2031	31.3%
Wind – New Transmission	New Mexico	2026	45.5%
Wind – New Transmission	Wyoming	2029	55.4%
Wind – Existing Transmission	Wyoming	2029	55.4%

To ensure that the resource additions identified reflect realistic plans that SRP can execute, the ISP included build limits for the renewable resource options to reflect development limitations in being able to bring such new resources online. Below are the total build limits by 2035 for each resource:

- **Biomass –** SRP assumed up to 150 MW of new additions, based on the amount of fuel that SRP assumed could be made available from forest-thinning projects such as those in the SRP Healthy Forest Initiative™.
- **Bioenergy with Carbon Capture and Storage (BECCS) –** SRP assumed up to 100 MW of new additions, given that the CCS component of this resource is not widely commercialized today and has a certain degree of uncertainty in terms of availability and cost.

[2]Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.

- **Geothermal –** SRP assumed up to 1,000 MW of new additions. Based on SRP's assessment of regional transmission, SRP expects that access to new geothermal resources in the Salton Sea area in California — which has high-quality geothermal energy — would require development of new long-distance transmission between the Salton Sea area and the Phoenix metropolitan area. SRP assumed that new transmission could be put in service as early as 2031 and that this would allow SRP to access up to 1,000 MW of geothermal resources. For details on the cost of this transmission, see the Transmission Costs section. In the Strong Climate Policy scenario, SRP assumed that increased federal support for regional transmission could accelerate the availability of this resource from 2029 to 2031.
- **Solar –** SRP effectively did not limit solar additions. In total, the model could add up to 20,000 MW of solar by 2035, but that threshold was never constraining.
- **Wind –** For wind, assumptions varied according to current and potential transmission availability. For more details on the cost of transmission, see the Transmission Costs section.

    - **Wind (AZ), Existing SRP Transmission —** SRP estimated that 800 MW of transmission would become available in 2033 following the retirement of the Coronado Generating Station and an additional 450 MW in 2034 in the Minimum Coal strategic approach following the retirement of the Springerville Generating Station.
    - **Wind (AZ), Existing Non-SRP Transmission —** SRP estimated that 50 MW of non-SRP transmission is currently available for new wind generation in Arizona.
    - **Wind (AZ), New Transmission —** SRP assumed a new transmission line could be added from eastern Arizona by 2035, which would provide access to approximately 500 MW of wind generation.
    - **Wind (NM), New Transmission —** SRP assumed new transmission could be added between a region in New Mexico with high-quality wind and the Valley by 2035. SRP assumed this transmission would enable SRP to access up to 1,500 MW of wind generation.
    - **Wind (WY), Existing Transmission —** SRP estimated that 100 MW of transmission could become available in 2029 following the retirement of the Craig and Hayden coal plants in Colorado.
    - **Wind (WY), New Transmission —** SRP assumed one or more new transmission lines could be added between Wyoming and southern Nevada by 2025, and that SRP could then utilize approximately 300 MW of existing transmission to deliver wind in Wyoming to the Phoenix metropolitan area.

For solar and wind resources, we developed hourly generation profiles by using the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL). The solar profile reflects a project with single-axis tracking in Arizona, while the wind profiles reflect differences in generation profiles across the different states.

Storage Resource Options

The ISP also considered energy storage resources, including lithium-ion batteries and pumped hydro storage, which can help integrate renewable resources on the system. For battery storage, the ISP considered both stand-alone storage and hybrid storage that is co-located with solar.

FIGURE 5.8: STORAGE RESOURCE OPTIONS

Resource	First Available Year	Duration (hours)	Round-Trip Efficiency
Battery	2025	4	85%
Pumped Hydro	2033	10	80%

As was done for renewable resources, SRP included build limits for storage resources to reflect development limitations in being able to bring new resources online. Below are the total build limits by 2035 for each resource:

- **Battery –** SRP assumed up to 8,500 MW of new additions, above and beyond the battery storage resources that are already contracted.
- **Pumped Hydro –** SRP assumed up to 1,150 MW of new additions, which corresponds to one large new project.

Thermal Resource Options

In addition to renewable and storage resources, the ISP considered several thermal resource technologies. We modeled conventional natural gas technologies, including combined cycle, combustion turbine (both frame and aeroderivative) and reciprocating engine technologies. We also modeled a few emerging technologies, including combined cycle with carbon capture and storage (CCS), combustion turbine that burns 100% green hydrogen (Hydrogen 100),[3] combustion turbine that burns a blend of natural gas and an increasing share of hydrogen (Hydrogen Transition), and nuclear small modular reactors (SMR). The ISP also considered biomass and geothermal as thermal resource options. Those resources are discussed in the Renewable Resource Options section above.

FIGURE 5.9: THERMAL RESOURCE OPTIONS

Resource	First Available Year	Fuel
Combined Cycle (1x1)	2028	Natural Gas
Combined Cycle (2x1)	2028	Natural Gas
Combustion Turbine (Frame)	2027	Natural Gas
Combustion Turbine (Aero)	2025	Natural Gas

[3] Green hydrogen is produced from 100% renewable energy.

Reciprocating Engine	2025	Natural Gas
Hydrogen Transition	2030	Blend (Green Hydrogen and Natural Gas)
Combined Cycle with CCS	2030 or 2035 depending on scenario	Natural Gas
Hydrogen 100	2034 or post-2035 depending on scenario	Green Hydrogen
Nuclear SMR	2034 or post-2035 depending on scenario	Uranium

The resource availability assumptions reflect the time required to site, permit and construct resources. For emerging technologies, including combined cycle with CCS, hydrogen and nuclear SMR resources, we considered the uncertainty of when these resources would become available, given that they have not yet reached widespread commercialization. See Figure 5.10 for the availability assumptions for emerging technologies. We excluded these resources from consideration within the planning horizon under most scenarios. However, to test an alternative scenario in which these technologies progress more rapidly following government support, we accelerated SRP's availability in the Strong Climate Policy scenario.

FIGURE 5.10: FIRST YEAR AVAILABLE FOR EMERGING TECHNOLOGIES

Resource	Strong Climate Policy Scenario	Other Scenarios
Combined Cycle w/ CCS	2030	2035
Hydrogen 100	2034	Post-2035
Nuclear SMR	2034	Post-2035

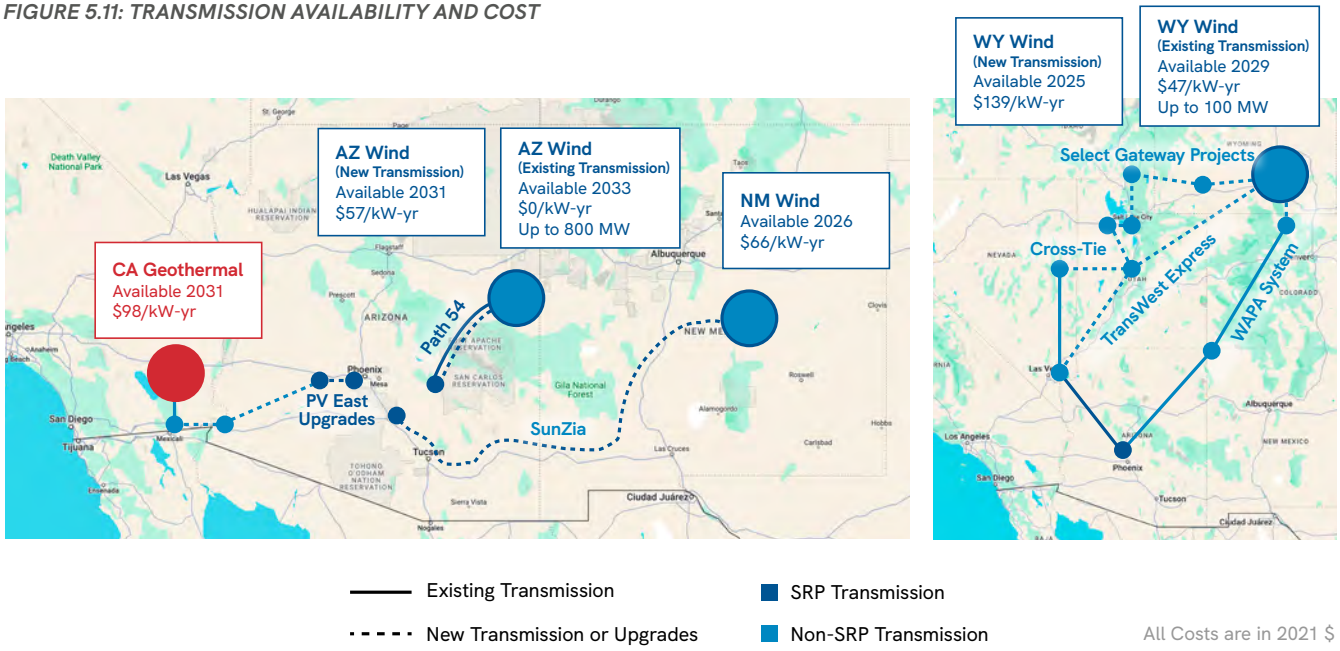
Transmission Costs

Several wind resource options, as well as the geothermal resource option, required consideration of transmission availability and costs of potential transmission expansion or upgrades. The Resource Additions planning process considered this availability and cost information when determining which resources to add.

See Figure 5.11 for the transmission availability and transmission cost adder for each resource option. For transmission paths that would require new or upgrades to transmission, we estimated the cost of this transmission and levelized the cost over the life of the transmission to determine

the transmission cost adder for those wind and geothermal resources. For existing transmission, we estimated how much transmission capacity would be available without further upgrades.

FIGURE 5.11: TRANSMISSION AVAILABILITY AND COST



Resource Costs

Our team forecasted future resource costs under different scenarios by relying on public data. We leveraged the 2022 NREL Annual Technology Baseline (ATB) for renewable and storage resource costs and the Energy Information Administration (EIA) 2022 Annual Energy Outlook (AEO) for thermal resource costs.

The fixed costs for resources included the following components: upfront capital, interconnection, property taxes, transmission (for remote resources, described in previous section), gas transportation (for gas resources), and fixed operations and maintenance costs. For upfront costs, we levelized these costs over the useful lifetime of each resource.[4] The variable costs for resources included fuel expense and variable operations and maintenance costs. This subsection focuses on the fixed costs, which don't vary with operations, while the Fuel Prices section below discusses fuel prices.

In August 2022, as our team was partway through the ISP analysis, Congress passed the Inflation Reduction Act (IRA), which provided an unprecedented federal investment in clean energy and created new federal tax credits for clean energy resources. Because of the significant nature of the IRA, we revised the cost of new resources to reflect these tax credits in all ISP scenarios and used these updated assumptions for the final ISP modeling. These revised costs were in part informed by the Technical Working Session SRP held with a group of industry experts on Jan. 17, 2023, to better understand the IRA.

[4]SRP utilized a lifetime of 15 years for battery storage resources, which was different from the NREL 2022 ATB but is consistent with the NREL 2023 ATB. SRP established this assumption based on experience with contracting for storage resources and after having conversations with members of the NREL ATB team to understand the underlying assumptions for battery lifetimes.

TECHNICAL WORKING SESSION ON THE INFLATION REDUCTION ACT

On 1/17/23, SRP held a Technical Working Session to better understand the impacts and uncertainties of the Inflation Reduction Act (IRA) and how to incorporate this into SRP's planning. Given the significant complexity of the IRA, SRP convened a group of experts with a wide range of viewpoints:

- Christine Turner, Solar Energy Manufacturers for America Coalition
- Mitch Rapaport, Nixon Peabody LLP
- Michael Mace, Public Financial Management (PFM)
- Hanson Wood, EDF Renewables North America

The experts highlighted a few ways in which the IRA could spur significant new clean energy investment:

- Provides significant incentives to grow domestic manufacturing, which could mitigate impacts from supply chain challenges experienced in recent years.
- Provides longer certainty for clean energy credits, through at least 2032 and likely longer.
- Expands eligibility of tax credits to a wider range of technologies, including standalone storage, nuclear, carbon capture and storage, and hydrogen.
- Creates an option for tax credit bonuses for domestic content and location within an Energy Community.
- Allows public power utilities like SRP to take advantage of tax credits via direct pay provisions, increasing feasibility of public power project ownership.

The experts also highlighted a few sources of risk and uncertainty:

- Greater guidance and certainty are needed from the Internal Revenue Service (IRS) for many of the IRA provisions to mitigate risks.
- Public power utilities like SRP must meet domestic content provisions to qualify for a direct pay credit.
- It is too early to tell whether projects will qualify for bonus tax credits, how much it will cost to monetize tax credits, and how tax credit savings will be split between developers and offtakers.
- Increased demand for clean energy demand could put increased pressure on supply chains in the near-term.
- Lack of support for new transmission in the IRA may lead to increased congestion, curtailment, and limitations in renewable resource growth.

Figure 5.12 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for renewable and nuclear resources in terms of levelized cost of energy (LCOE).[5] The LCOE metric expresses the levelized annual cost of a resource relative to its expected annual generation. One caveat in interpreting this metric is that it only reflects the cost of a resource and does not reflect the value that a resource provides to the system, nor does it reflect any renewable curtailment, which would increase the LCOE.

[5]Resource cost assumptions for the other scenarios and sensitivities are provided in Appendix A: [ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES].

FIGURE 5.12: RENEWABLE RESOURCE COSTS (2023 $/MWH)

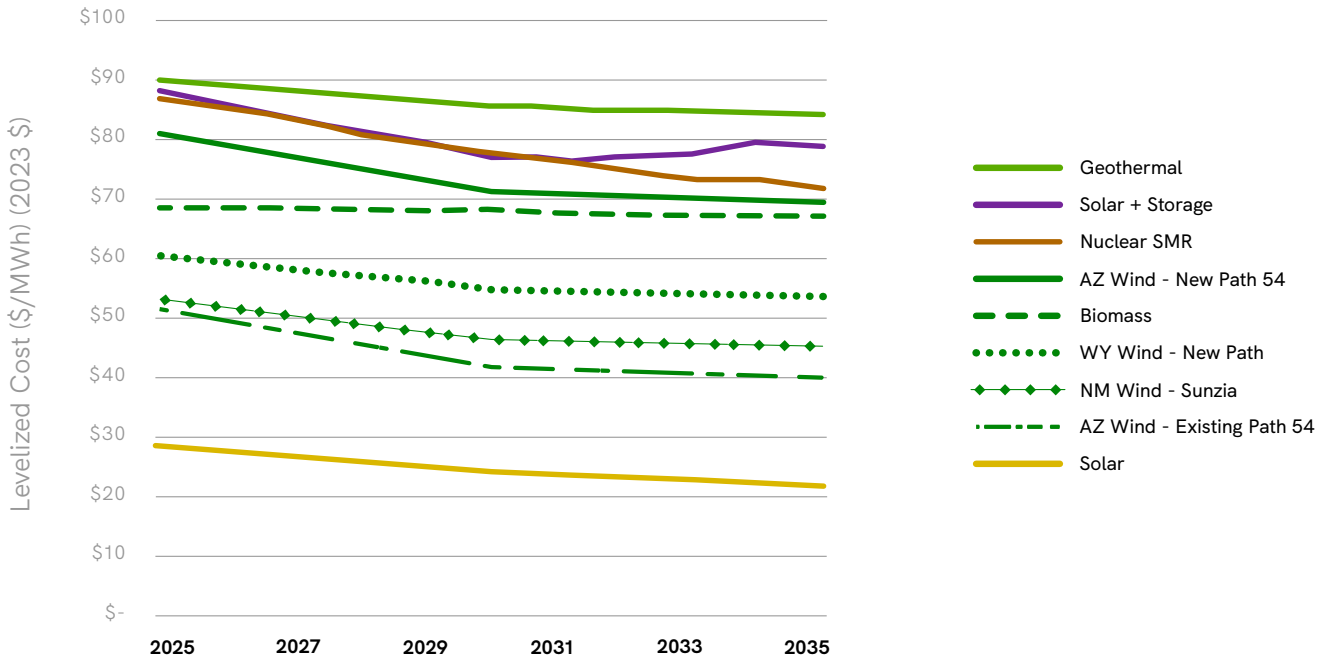
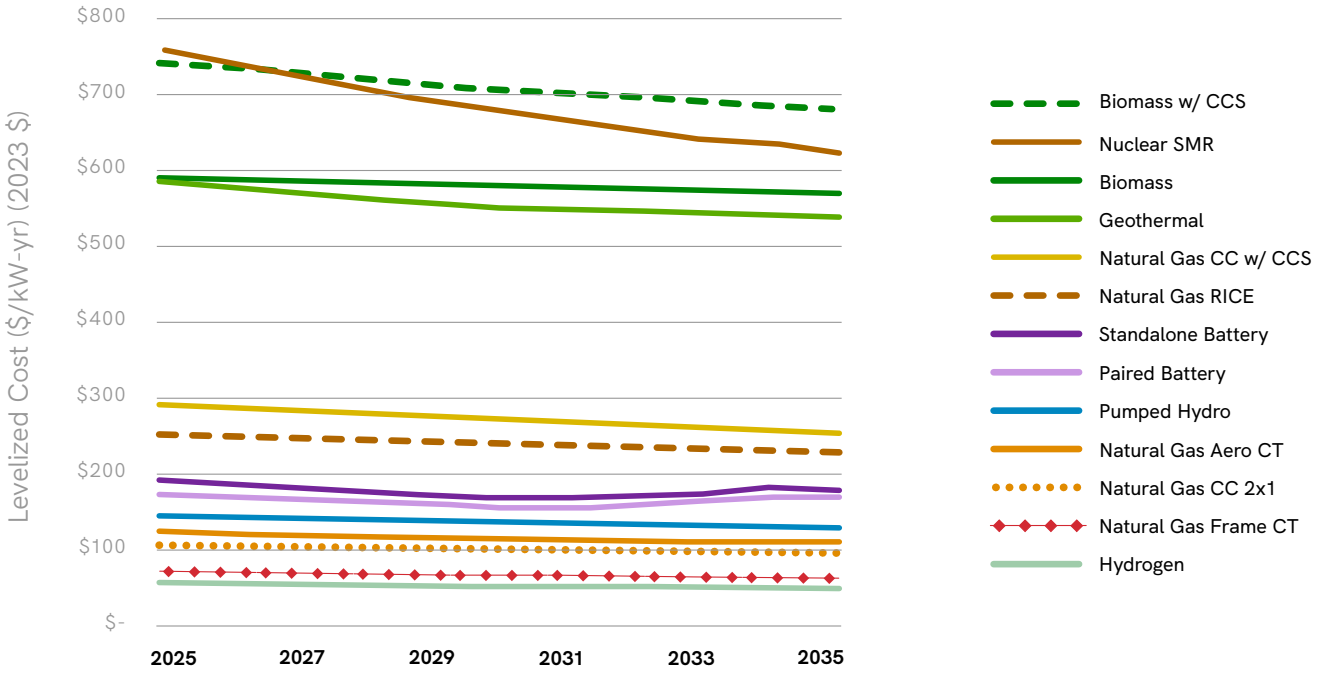


Figure 5.13 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for thermal and storage resources in terms of levelized fixed cost. Note that the LCOE metric used above is not commonly used for thermal and storage resources because the annual utilization of these resources can vary widely from one scenario to another or even year to year, while the LCOE metric assumes a fixed annual utilization.

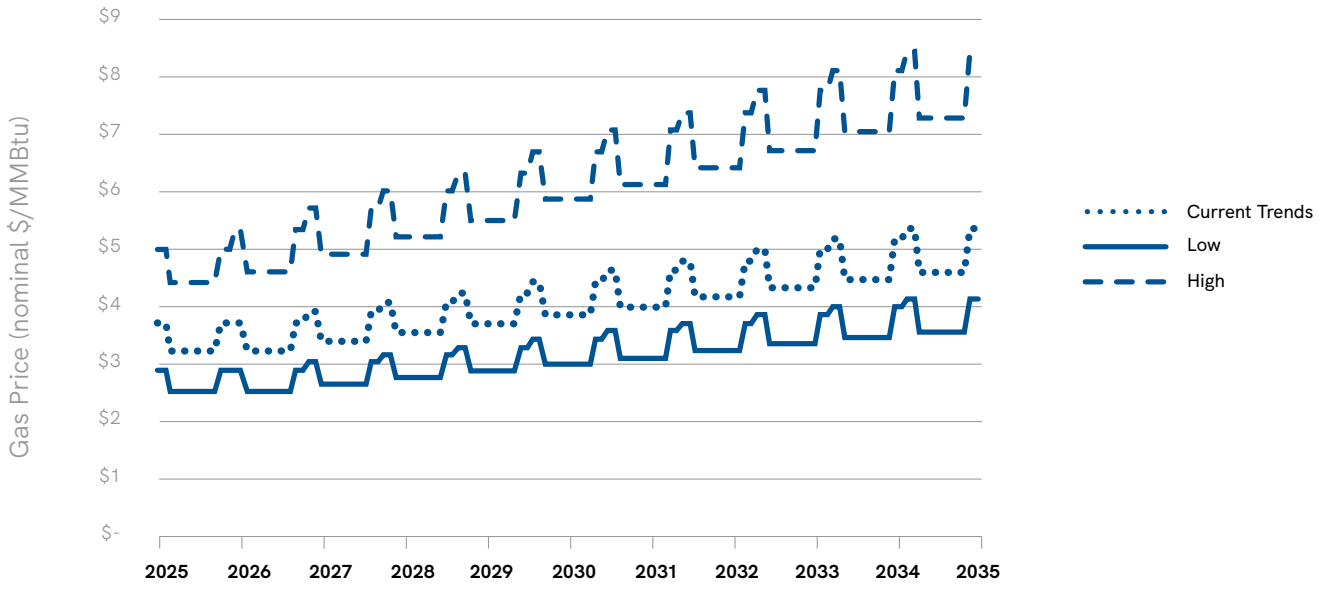
FIGURE 5.13: DISPATCHABLE RESOURCE COSTS



Fuel Prices

Fuel prices for the ISP were derived from several data sources. Natural gas forecasts were derived from the EIA 2022 AEO, with certain scenario trajectories regionalized based on SRP's gas supply. The gas price forecast varies by scenario and across the gas price sensitivities, reflecting low, mid, high and volatile trajectories. The low case reflects AEO's High Oil & Gas Supply Case; the mid case reflects AEO's Reference Case; the high case reflects AEO's Low Oil & Gas Supply Case; and the volatile gas case reflects observed volatility from 2000–2010 for the 2025–2035 analysis period. Figure 5.14 shows the Low, Current Trends (Mid) and High monthly forecasts through the 2025–2035 period.

FIGURE 5.14: GAS PRICE FORECASTS



Green hydrogen price forecasts were developed by E3, assuming electrolysis of hydrogen using an alkaline electrolyzer that is powered by solar energy (with solar resource costs as defined in this report). Hydrogen electrolyzer costs are derived from the California Energy Commission (CEC) publication on hydrogen production costs.[6] Hydrogen storage costs are derived from Department of Energy (DOE) project ST-001 costs.[7] Hydrogen transport costs are derived using Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM).[8] A $3/kg Production Tax Credit (PTC) is applied to all hydrogen produced through 2032. Market resource costs are derived and provided by internal SRP forecasts.

Reliability

To ensure system reliability, SRP must procure sufficient capacity to exceed annual peak demand over the entire planning horizon. In addition to serving the peak, a planning reserve margin (PRM) must be added to the amount of firm capacity on the system to ensure resource adequacy and avoid loss-of-load events while accounting for the potential for exceptional extreme loads, resource forced outages, uncertainties in load forecasting, and the operator's need to maintain a margin of operating reserves.

[6] https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf
[7] https://www.hydrogen.energy.gov/pdfs/review22/st001_ahluwalia_2022_p.pdf
[8] https://hdsam.es.anl.gov/index.php?content=hdsam

In most ISP cases, SRP applies a PRM of 16%, meaning that in each year of the planning horizon, SRP must have reliable capacity in an amount equal to or greater than 116% of forecast peak demand. In the Strong Climate Policy scenario and Regional Diversity sensitivity, the PRM is reduced to 13% as a proxy to represent the assumption that expanded transmission and regional coordination allows for increased resource and load diversity.

Due to high cooling loads, SRP has a summer-peaking system. Thermal generators are assumed to provide a PRM contribution (firm capacity value) equal to their summer monthly rating. Wind and pumped hydro storage resources contribute a fixed percentage of capacity (18% and 80%, respectively) to the PRM. Battery resource contributions to PRM decline with increasing battery penetration. New stand-alone solar resources are assumed to provide no firm capacity to SRP's system, but solar storage resources do contribute to the PRM due to the storage component.

CO_2 Emissions Target

SRP has established a goal of reducing carbon emissions intensity (lbs./MWh) by 65% by 2035 and by 90% by 2050, relative to 2005 levels. The carbon emissions intensity is the amount of carbon dioxide emissions (in pounds) from emitting power plants expressed relative to the amount of total generation (in megawatt-hours) across all power plants. In 2005, SRP's emissions rate was 1,576 lbs./MWh. In 2035, the CO_2 emissions target is 550 lbs./MWh. The ISP analysis capped CO_2 emissions to ensure that the future resource additions and operations are consistent with SRP satisfying its 2035 Sustainability Goals. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

Key Outputs

The following table reports the key outputs of the Resource Additions analysis:

Output	Description	Output Units
Resource Installed Capacity	Installed capacity of the generator, including new investments.	MW
Resource Contribution to Reliability	Firm capacity of the generator. For renewable resources options, this will equal the effective load carrying capability (ELCC) times the installed capacity.	MW
Resource Fixed Costs	Total fixed costs, including annualized build costs, fixed O&M and fixed charge (pipeline and/or fuel deliverability) costs.	$
Reliance on Emerging Technologies	Installed capacity and firm capacity for emerging technologies.	MW

Resource Operations

In the Resource Operations planning process, we simulated generating resource operations. For each future year, we simulated resource operations in each hour to understand how resources operate to meet total system demand and to understand the implications for cost, emissions, water usage and interactions with the regional power market. This information helped us evaluate the trade-offs between different system plans. This modeling process is sometimes referred to as production cost simulation in the industry.

Methodology Overview

Although the Resource Additions planning process considered resource operations when determining which resources to add in the future, that planning process did not have the same level of granularity as the Resource Operations planning process. In this planning process, SRP modeled every hour of the year (rather than a representative sample) and factored in more detailed operating characteristics for generators, which can influence operations. This refinement allowed SRP to say with more confidence how resource operations could evolve over time and what that would mean for affordability and sustainability metrics.

During this process, our team performed modeling for all 42 system plans. We used the Aurora model (developed by Energy Exemplar) to simulate future system operations, including existing resources and any new resources selected through the Resource Additions planning process. For the Volatile Gas Prices sensitivity cases, which did not vary the resource additions relative to the corresponding Current Trends cases, we only modified the gas prices and market prices over time to understand the impact of a volatile fuel price environment on system operations, affordability metrics and sustainability metrics.

Key Inputs

For this modeling process, we leveraged most of the same inputs utilized in the Resource Additions modeling process. Whereas the Resource Additions modeling process determined which resources to add to the system, the Resource Operations modeling process took the resource additions as fixed and then simulated future system operations. Therefore, this modeling process did not utilize the inputs related to resource additions or reliability given the system already had sufficient resources to meet future reliability needs. The Resource Operations process utilized the resource addition results as inputs and then leveraged the same data for these inputs:

- Load forecast
- Renewable generation profiles
- Variable operations and maintenance costs
- Fuel price forecast
- Market price forecast
- CO_2 emissions target

Because the Resource Operations modeling process simulated future system operations in a more granular manner, it also incorporated additional key inputs:

- Detailed operating characteristics for thermal generators
    - Minimum stable operating level
    - Startup time
    - Ramp rate
    - Minimum runtime
    - Minimum downtime
- Startup and shutdown costs for thermal generators
- Operating reserve requirements

Key Outputs

This planning process generated detailed system operations data for all 42 system plans. The table below summarizes the key outputs:

Output	Description	Output Units
Fuel, Operations and Maintenance Costs	Hourly fuel use, operations and maintenance costs	$
Market Purchase Costs	Costs of procuring external electricity generation outside of SRP	$
SRP Carbon Emissions (Mass)	Carbon emissions from generating resources during the planning period	Tons CO_2
SRP Carbon Emissions (Intensity)	Carbon emissions per MWh generation emitted during the planning period	Lbs. CO_2 per MWh
Carbon-Free Generation (%)	Percentage of total generation that was carbon-free	%
Water Use	Total water use during resource operation	Gallons
Criteria Pollutants (NO_x, SO_2, PM, VOC)	Criteria pollutant emissions from generation during the planning period	Tons
Thermal Plant Capacity Factor	Capacity factors for thermal plants during resource operation	%

Transmission Investments

In the Transmission Investments planning process, we studied the forecasted load and resource additions, determined future transmission needs and identified transmission investments to meet those needs. For the year 2035, we simulated transmission operations under different load and resource assumptions to understand which transmission investments were needed and at what cost.

Methodology Overview

For the ISP, we analyzed the portion of the transmission system rated 115 kV and above. We focused on this part of the transmission system for two reasons. First, transmission investments at these higher voltages require longer lead times for siting, engineering, permitting and construction, so there is more value in identifying investment needs for these assets through 2035. Second, analyzing the 69 kV system was not feasible due to limited resources over this study period. While we did not analyze the 69 kV system, we did estimate investment costs for the 69 kV system based on the number of new distribution substations.

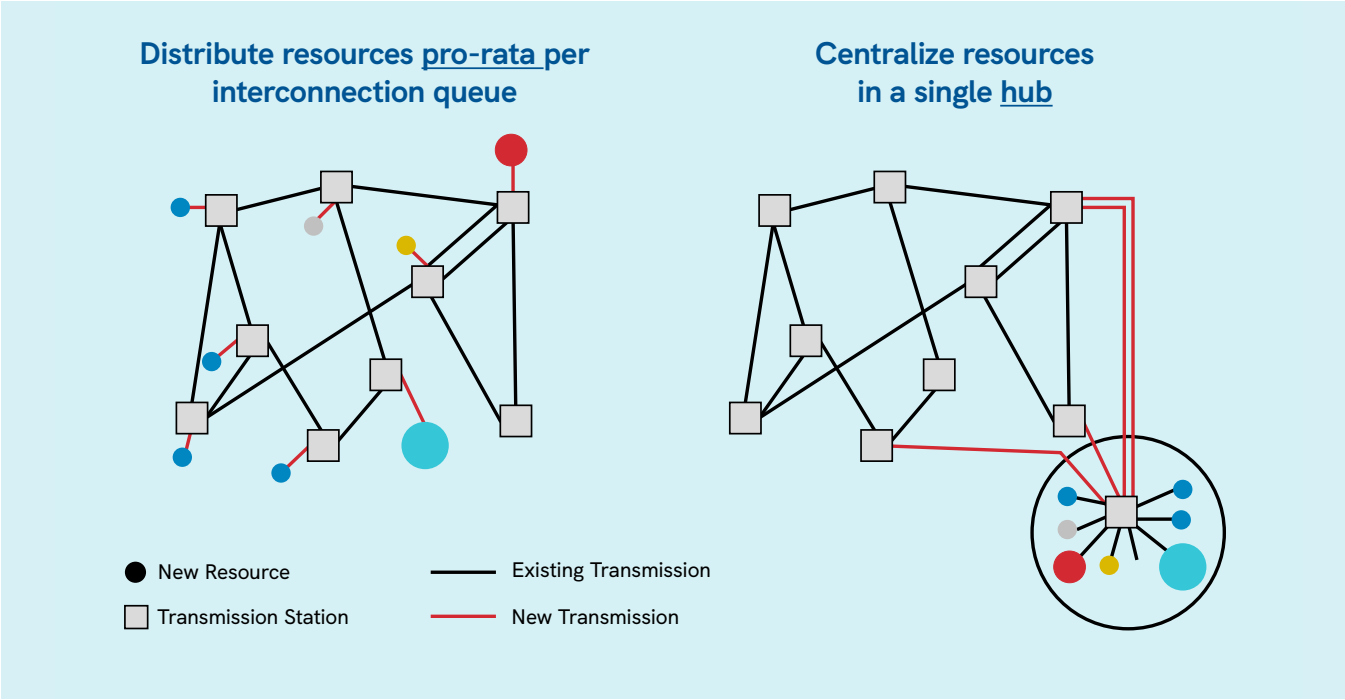
During this process, our team performed power flow analysis for the year 2035 to understand how power would flow across the transmission system and how the voltage would respond under certain conditions. We evaluated whether any element of the transmission system would be overloaded or be outside its acceptable voltage range. We also evaluated whether any element of the transmission system would be overloaded or fall outside its acceptable voltage range if other transmission elements were unavailable. We then identified transmission investments to mitigate the identified issues until none remained.

We studied two different operation hours for each case analyzed: the summer peak load hour, during which energy demand is greatest, and a summer peak renewables hour in which generation from solar, wind and other renewable resources are at maximum output. By studying these two conditions, we confirmed that the transmission system could meet the peak energy demand and accommodate renewable generation during peak production periods. For each case analyzed, we identified transmission investments that mitigated all issues across both operating conditions.

One of the key uncertainties in transmission planning is the location of future resources. Currently, developers decide where to site projects, submit interconnection requests and bid to provide energy to SRP or other utilities. As a result, we do not know where future resources will interconnect. The location of these resources can have a significant impact on the need for new transmission projects.

In the ISP, we chose to evaluate two resource location options: Pro-Rata and Hub (see Figure 5.15). The Pro-Rata option envisions new solar and battery resources being added across the system in proportion to the resources currently in SRP's interconnection queue. The interconnection queue served as a proxy for where developers would site future projects. With the Hub option, SRP would develop a new 500 kV switchyard southeast of the Valley and would encourage development of new gas, solar and battery storage resources at the hub. The Pro-Rata option represents a continuation of current practices in which developers locate throughout SRP's system, while the Hub option represents a potential alternative in which SRP concentrates development of resources in one location and connects that location to the rest of the system.

FIGURE 5.15: RESOURCE LOCATION OPTIONS



Our team identified transmission investments for the following cases under both the Pro-Rata and SRP Hub options. Due to time constraints through the ISP analysis, we could not perform detailed transmission analysis on all cases. Instead, we chose to analyze the following cases because they represent a wide range in both load growth and resource additions.

- Technology Neutral, Current Trends
- Technology Neutral, Desert Boom
- Minimum Coal, Current Trends

Key Inputs

For this modeling process, our team leveraged outputs from different planning processes, including Load Forecasting, Distribution Investments, Resource Additions and Resource Operations. As the transmission system acts as the link between utility-scale resources and customers, inputs related to loads and resources from these other planning processes were key inputs in determining transmission investment needs.

Because SRP's system is connected to other power systems in the Western Interconnection, we utilized models that represent the entire Western Interconnection. On an annual basis, SRP coordinates with neighboring utilities to develop "heavy summer" transmission models for up to 10 years into the future. For the ISP, we adapted the "2032 heavy summer" model to perform analysis for the different transmission cases through 2035.

Energy Demand

The projected energy demand at different locations on the transmission system came from two sources. First, the Load Forecasting modeling process identified the future energy demand for customers that connect directly to the transmission system. Second, the Distribution Investments modeling process identified the energy demand at each existing and new distribution substation to represent those customers connected to the distribution system. These inputs allowed SRP to identify the energy demand for each location on the transmission system.

Resource Locations

Figure 5.16 shows the location assumption for each new resource in the Pro-Rata and Hub options. For natural gas resources under the Pro-Rata option, we identified five potential locations based on preliminary gas siting screening efforts that were recently performed. For solar and battery storage resources under the Pro-Rata option, we allocated them to different substations in proportion to the interconnection queue. For the Hub option, we located new natural gas, solar and battery storage resources at the hub. The locations for other resources did not vary between the Pro-Rata and Hub options because the locations were already determined by the location of the underlying resource. The locations for wind and geothermal resources are discussed above in the Resource Additions section.

FIGURE 5:16: NEW RESOURCE LOCATIONS IN THE PRO-RATA AND HUB OPTIONS

New Resource	Pro-Rata	Hub
Natural Gas	Split across five locations	Placed at hub
Solar	Pro-rata allocation	Placed at hub
Battery Storage	Pro-rata allocation	Placed at hub
Pumped Hydro	Northeast of SRP service territory	
Wind	Varies by resource	
Geothermal	California, wheeled to Arizona, and injected at Hassayampa	
Biomass	Coronado	

Resource Operations

For the resource operations, our team identified the expected generation from all existing and planned resources for the peak load hour, so the transmission peak hour models reflected the planned resource outputs. This also included an economic dispatch order that was used to develop the peak renewable output hour scenarios.

Key Outputs

This planning process determined transmission investments. The table below summarizes the key outputs:

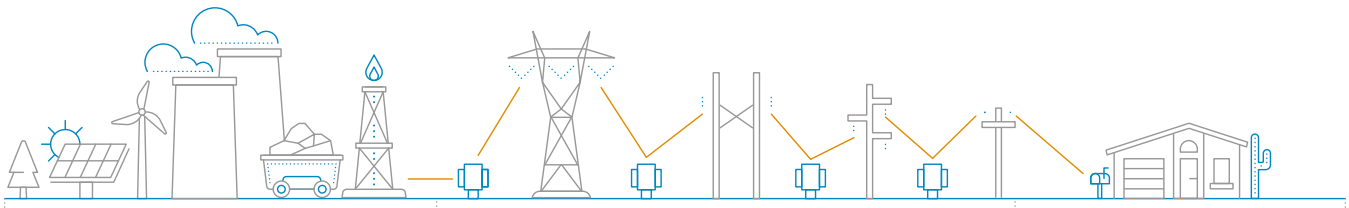
Output	Description	Output Units
Transmission Investments	Transmission projects to meet system requirements and associated upfront investment costs	$

Total System Cost

In this process, we performed simplified financial modeling to develop an annual total system cost metric for every case analyzed in the ISP. The purpose of this analysis was to provide indicative affordability metrics to compare system plans to one another and understand trade-offs between different system strategies. While the total system cost metric is helpful for these comparisons, it is not intended to provide a forecast of future rates for SRP customers or reflect SRP's financial outlook.

See Figure 5.17 below. We developed the total system cost by estimating system costs for generation, transmission, distribution, customer programs and other costs. These costs included costs of existing investments, new investments, operations and an estimate of system costs not modeled explicitly in the ISP. Many of these costs were outputs from the other modeling processes in the ISP.

FIGURE 5.17: COSTS INCLUDED IN TOTAL SYSTEM COST



Generation

Fuel

Market purchases and sales

Power purchase agreements

Existing and new investments

Operations and maintenance

Non-SRP transmission cost

Transmission & Distribution

Existing and new investments

Operations and maintenance

Customer Programs

Program and market enablement costs

Other

General & Administrative

Customer systems (metering, billing, customer service, etc.)

Telecom

Taxes

Assumed constant across all cases

Methodology Overview

For this methodology, our team first established a set of "base" costs that do not change across system plans. We forecasted the costs associated with existing generation, transmission and distribution assets, including the recovery of investment and maintenance costs. In addition, we forecasted other costs that do not relate to generation, transmission, distribution and customer programs, such as general and administrative costs. We held all of these "base" costs constant across cases.

We then determined the costs for investments that differed across the system plans and leveraged the outputs from the different planning processes to determine any incremental investments. To determine the annual costs for these investments, we applied straight-line depreciation and assumed a cost of capital consistent with SRP's weighted average cost of capital. SRP also estimated property taxes for these investments based on previously observed tax rates. Lastly, we leveraged the outputs from the planning processes to forecast operating expenses.

Generation

The Resource Additions process identified incremental generation investments, operation and maintenance fixed costs, and power purchase agreement costs. The Resource Operations process identified all variable operating costs associated with generation, including fuel expense, net market purchase costs, and variable operations and maintenance costs.

Transmission

The Transmission Investments process identified any incremental transmission system investments for the three cases analyzed. SRP further differentiated these costs by investments that are generation-driven versus load-driven to estimate costs in other cases. Using the three transmission cases analyzed, we calculated a linear relationship between (1) generation-driven costs and interconnected capacity additions, and (2) load-driven costs and peak load growth. We then applied those relationships to interconnected capacity additions and peak load growth observed in each of the remaining cases.

Distribution

The Distribution Investments process identified incremental distribution system investments, including transformers to serve new customers, new substations and substation upgrades. SRP identified these investments for each scenario as well as the high distributed generation and high energy efficiency sensitivities. The investment types and estimated costs remained consistent across the three strategic approaches.

Customer Programs

The Customer Programs process identified the incremental customer program operating costs. These costs reflected the cost of Energy Efficiency and Demand Response programs.

Key Outputs

The Total System Cost process generated annual cost estimates for all 42 system plans. The table below summarizes the key outputs. These outputs served as key inputs in calculating residential bill impacts across cases (see the Residential Bill Impact section below).

Output	Description	Output Units
Total System Cost	Total system costs across generation, transmission, distribution and other	$
Average System Cost	Total system cost divided by retail sales	$/MWh

Residential Bill Impact

In this process, we applied a simplified method to estimate the bill impacts over time for residential customers. While the Total System Cost process estimated how total costs could evolve over time, this process estimated how these changes could impact residential customers specifically and developed a residential bill impact metric.

This bill impact analysis does not necessarily reflect how future costs may be allocated and recovered from customers and therefore should not be considered as a projection of customer rates. SRP will carry out pricing processes in the future to determine future cost allocation and rates. Nevertheless, this metric provides a means for comparing cases to understand relative differences.

Methodology Overview

We leveraged information from our most recent Cost Allocation Study (CAS) to allocate costs in the ISP to residential customers. The CAS determined how the energy usage of residential customers differed from other customer classes (e.g., commercial and industrial) and developed cost allocators for different system cost components (e.g., generation and fuel). Because different system cost components are driven by different factors (e.g., total annual energy use, peak hour energy usage), the cost allocators differ by system cost component. This ensures that each customer class pays its fair share of system costs, based on the cost of serving those customers.

Below is the methodology we used in the ISP to allocate costs for different system components to residential customers:

- **Generation –** Generation-related costs, including operations and maintenance (O&M) costs, power purchase agreement (PPA) costs and recovery of investment costs, are allocated based on a blend of two factors: the share of annual delivered energy (in kWh) and the share of energy demand (in MW) during overall system peak periods.

- **Fuel –** Fuel costs, including natural gas, coal and (in some ISP cases) hydrogen fuel costs, are allocated based on the share of total annual energy demand (in kWh), calculated as the total annual delivered energy less any energy exported to the grid.
- **Transmission –** Transmission costs, including O&M costs and recovery of investment costs, are allocated based on the share of energy demand (in MW) during overall system peak periods.
- **Distribution –** Distribution costs, including O&M costs and recovery of investment costs, are allocated based on the peak hourly energy demand of the customer class (in MW) — not necessarily during the overall system peak period — relative to the peak hourly energy demands of other customer classes.
- **Customer Service, Billing and Metering –** Customer service, billing and metering costs are allocated based on the share of the total number of customers served by SRP.
- **Other Costs –** Other costs, including net market purchase expenses and any other costs not described above, are allocated according to the share of total generation, transmission and distribution costs.

To determine the average residential customer cost (in ¢/kWh), SRP divided the total costs allocated to residential customers by the total annual energy demand (in kWh). SRP then compared these average residential costs to the actual costs for residential customers in November 2022 to show the change through 2035.

Key Outputs

The key output of this process is the average residential bill impact:

Output	Description	Output Units
Average Residential Customer Cost	Average residential customer cost for each ISP case.	¢/kWh

Development and Operational Risk Assessments

Our team evaluated the development and operational risk factors for different system plans. While the various planning processes identified future infrastructure additions based on least-cost optimization analysis, as well as future operations based on simulations, there are many real-world risks to consider that could impact SRP's ability to develop and operate these system plans.

There are risks and challenges in developing new infrastructure, including risks related to permitting, siting, constructing and acquiring new infrastructure. As we have observed over the last few years, third-party projects can be delayed or even cancelled due to supply chain challenges. Supply chain issues have also led to increased timelines for acquiring new transmission and distribution infrastructure. There are also risks in developing large new infrastructure projects, which may depend on multiple regulatory approvals and therefore come with uncertainty. Because each of the ISP system plans requires significant development

of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems.

There are also risks and challenges in operating the power system in new ways. While the production cost model simulated future operations based on hourly optimization analysis, many real-world risks cannot be captured fully in that analysis and could potentially impact SRP's operations. There are risks related to more variable system operations, fuel availability, wear and tear on generating resources, etc. Because each of the ISP system plans requires a meaningful shift in the future operations of the system, we performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems.

Methodology Overview

Our team developed qualitative development and operational risk ratings for each system plan to understand the relative risks between different system plans. This approach is used to assess uncertainty in factors where it is not easily quantified and is known as the expert opinion method.

First, because the ISP assessed many planning cases, and some of the resulting system plans were relatively similar across cases, we clustered some plans together when performing the risk assessment.[9] The clustered system plans were representative of the 12 core system plans (three strategic approaches evaluated against four scenarios). We then convened an internal group of subject matter experts from various departments to assess the development and operational risks for each of the system plans. After the group assessed the different system plans independently, SRP held a joint workshop during which the group discussed findings, identified risks, discussed mitigation factors and developed risk ratings.

To develop a quantitative risk rating, each participant rated each cluster of system plans on a scale from 1 to 5, with 1 being lowest risk and 5 being highest risk. We identified a reference plan (Tech Neutral, Current Trends) to correspond to a risk rating of 3 to calibrate a point of reference. The participants rated each cluster of system plans based on how the risk factors for that plan compared to the risk factors identified for the reference plan, and SRP averaged these ratings to develop a final risk rating for each system plan.

Development Risk Assessment

To evaluate the development risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Resource Planning, Acquisition and Development**, consisting of engineers and analysts responsible for acquiring and developing power generation resources (renewable and thermal) to meet system needs
- **Distribution Planning**, consisting of engineers who plan distribution infrastructure
- **Innovation & Development**, consisting of engineers who support research into emerging generation technologies (e.g., hydrogen, nuclear small modular reactors, and carbon capture and storage)

[9] For the development risk assessment, SRP clustered system plans based on resource additions across different technologies. For the operational risk assessment, SRP clustered system plans based on multi-hour ramping needs, natural gas fuel consumption, market purchases, solar additions, wind additions, battery storage additions, and curtailment.

- **Power Delivery**, consisting of engineers and planners who support generation interconnection and plan, site and build necessary transmission infrastructure
- **Land**, consisting of analysts responsible for acquiring necessary land for new projects
- **Supply Chain Management**, consisting of analysts managing procurement of long-lead-time equipment
- **Supply and Trading & Fuels**, consisting of power and natural gas traders and analysts focused on market operations
- **Customer Programs**, consisting of analysts who develop and manage customer programs (e.g., energy efficiency, electrification)
- **Environmental Services**, consisting of engineers and scientists who support site permitting and ensure compliance with environmental regulations
- **Community Partnerships**, consisting of community strategists who work with and support the communities that SRP operates within

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following development risk factors:

- Permitting, siting and land acquisition
- Supply chain challenges
- Long lead times to develop infrastructure
- Interconnection of new resources
- Natural gas pipeline development
- Reliance on emerging technologies
- Reliance on customer adoption of end-use programs (such as energy efficiency and distributed generation)

Operational Risk Assessment

For the operational risk assessment, we followed a process similar to that used for the development risk assessment. To evaluate the operational risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Supply and Trading & Fuels**, consisting of electricity and natural gas traders and analysts focused on markets and operations
- **Operations Planning**, consisting of analysts focused on modeling the market, optimal dispatch and maintenance planning
- **Transmission & Generation Operations**, consisting of real-time power dispatchers
- **Operational Readiness**, consisting of engineers leading the processes for enabling additional solar and batteries onto SRP's system
- **Generation Engineering**, consisting of engineers analyzing the maintenance needs of generation plants

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following operational risk factors:

- System ramping needs and capabilities
- Renewable curtailment
- Thermal unit operations (capacity factor, starts and hours of operation)
- Reliance on market purchases for electricity
- Natural gas hourly and daily consumption

Key Outputs

Output	Description	Output Units
Development Risk Rating	Risk rating summarizing the degree of development risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)
Operational Risk Rating	Risk rating summarizing the degree of operational risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)

Metrics

We developed metrics for ISP cases to evaluate the performance of each strategic approach across scenarios and sensitivities, provide information to customers and other stakeholders, and to inform the ISP residential customer research. Figure 5.18 lists the metrics we developed to evaluate the performance of different system plans, which include reliability, affordability, sustainability and customer focus metrics.

FIGURE 5.18: ISP METRICS

Reliability

Resource Contribution to Reliability

Reliance on Emerging Technologies

Qualitative Risk Ratings (Development Risk and Operational Risk)

Planning Reserve Margin

Affordability

Total System Costs

Average System Costs

Average Residential Price Impact

Sustainability

CO_2 Reductions

Water Use

Carbon-Free Generation

Capacity Factor for Gas Fleet

Direct Air Emissions (NOx, SO_2, PM, VOC)

Customer Focus

Customer Preference Rating

CO_2 reductions from energy efficiency, distributed generation and electrification

We developed most of these metrics through the modeling processes described above. The Total System Cost and Residential Price Impact processes produced the affordability metrics. The Resource Operations process produced the sustainability metrics. And lastly, the Resource Additions, Development Risk Assessment and Operational Risk Assessment processes produced the reliability metrics.

For the Customer Focus metrics, we completed additional analysis separate from the modeling processes described above. To develop the Customer Preference Rating, SRP engaged Bellomy Market Intelligence to complete the ISP residential customer research. The goal of Bellomy's research was to bring the voice of SRP's residential customers into the planning of the future power system. More specifically, this research was designed to gain an understanding of how customers view and value sustainability, affordability and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems being analyzed in the ISP. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the ISP and ultimately develop the Customer Preference Rating. More details on the specific methodology are included in appendices B and C, which contain reports from all phases of the ISP residential customer research effort.

To develop the CO_2 Reductions metric for various customer programs (including energy efficiency, distributed generation, demand response and electrification), we estimated the amount by which additional amounts of these programs could decrease economywide greenhouse gas emissions. For energy efficiency and distributed generation, we evaluated how much annual emissions would decrease in each planning case if customer adoption increased slightly. For electrification measures (including electric vehicles and heat pumps), we estimated how much annual emissions from electricity generation would increase from customers adopting these measures and increasing energy demand. In addition, we estimated how much emissions would decrease from displaced fossil fuel consumption (in vehicles or home heating systems) to arrive at an estimate for net decrease in economywide emissions for adoption of electrification measures.

Ultimately, planning a future energy system involves trade-offs between different planning goals for the system. No single system plan performed the best in every metric that we quantified. We utilized this suite of metrics to evaluate trade-offs between different strategic approaches and to understand how planning would need to adapt under future planning uncertainties.

SECTION 6

Results

This section presents the modeling results and key findings from the ISP analysis. The analytical results are presented for each planning process described in Section 5, including Customer Programs and End-Use Technologies, Load Forecast, Distribution Investments, Resource Additions, Resource Operations, Transmission Investments, Total System Cost, Residential Bill Impact, Development and Operational Risk Assessment, and Residential Customer Research. Several ISP key findings are highlighted in callout boxes throughout and then summarized at the end of this section.

Results

Customer Programs and End-Use Technologies

Customer programs play an important role in managing SRP's load and are a key input to the load forecast used in the ISP. Also, customer adoption of end-use technologies, such as electric vehicles and distributed generation, have an increasing impact on the load forecast over time. This section presents the forecasts through 2035 for annual energy efficiency savings, demand response capacity, additional electrification load, and customer adoption of distributed generation across each scenario.

Figure 6.1 shows the incremental new energy efficiency savings. Under Current Trends, Desert Boom and Desert Contraction, there is continued expansion in energy efficiency over time, reaching 3,236 GWh of new energy efficiency savings by 2035. Under Strong Climate Policy, expansions to federal codes, standards and incentives lead to even higher energy efficiency growth, reaching 3,896 GWh of total energy efficiency savings by 2035.

Figure 6.2 shows the cumulative demand response capacity through 2035. Under all scenarios, SRP doubles demand response capacity, reaching 300 MW of total demand response by 2035.

FIGURE 6.1: ANNUAL NEW ENERGY EFFICIENCY ASSUMPTIONS

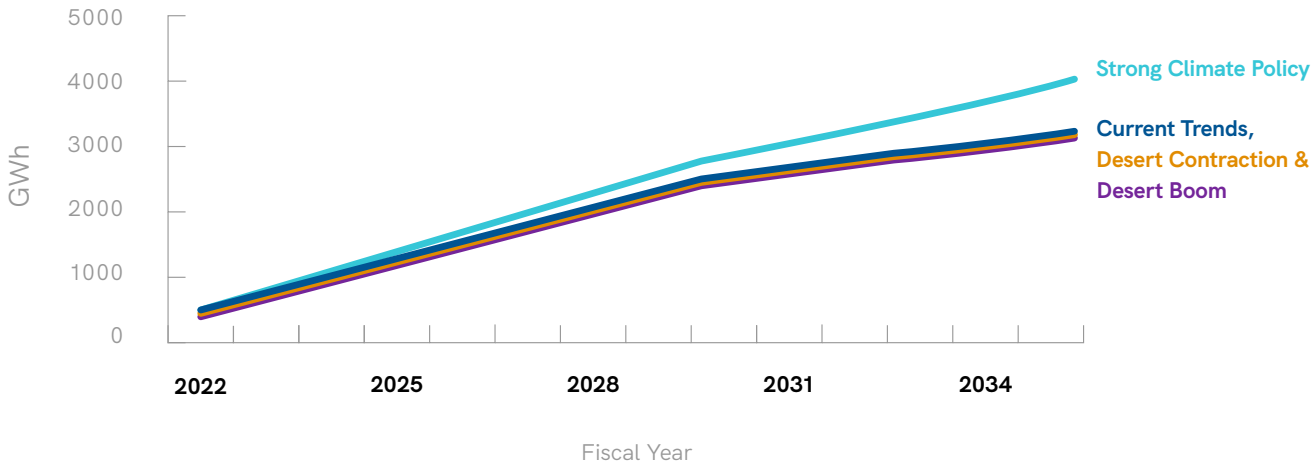
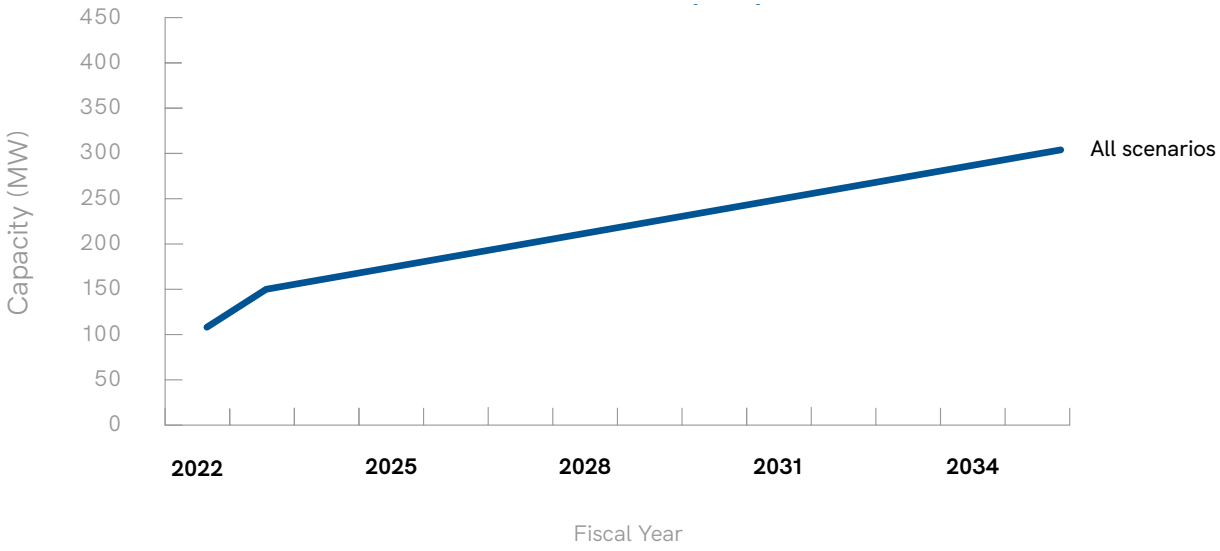


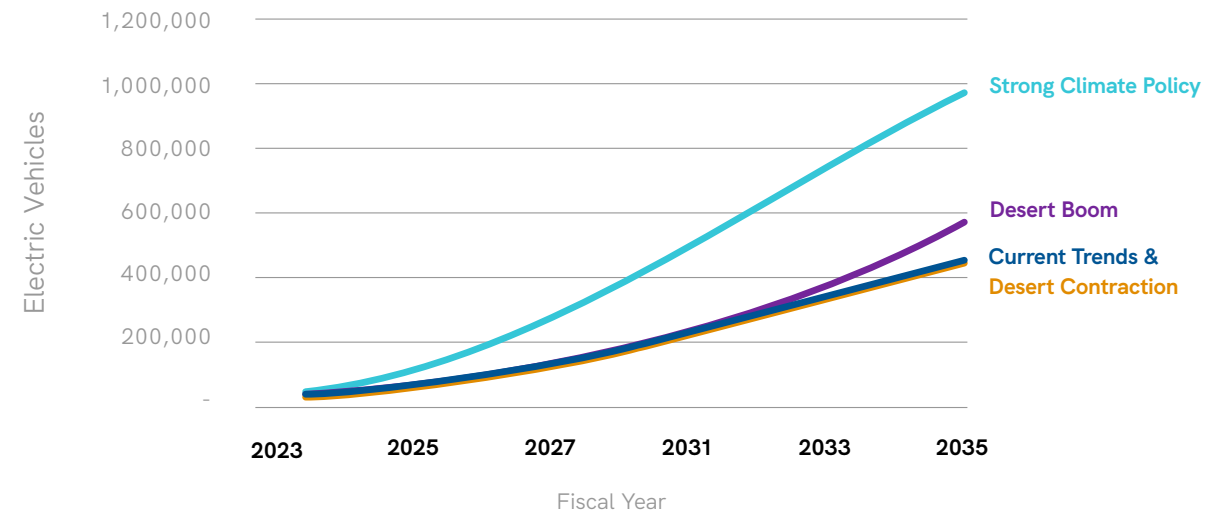
FIGURE 6.2: CUMULATIVE DEMAND RESPONSE CAPACITY ASSUMPTIONS



In addition to the energy efficiency and demand response programs, SRP's electric technologies programs, which serve commercial and industrial customers, grow meaningfully over time. The load impact from these programs grows from approximately 50,000 MWh today to levels consistent with SRP's goal of 300,000 MWh by 2035. The programs are varied and include electrification of material handling equipment (forklifts, scissor lifts, boom lifts, scrubbers, sweepers, etc.), truck stop and truck refrigeration equipment, industrial heating processes (melting, curing, steam, etc.), space and water heating processes, and commercial cooking equipment.

Figure 6.3 shows projected customer adoption of electric vehicles through 2035. Under the Current Trends and Desert Contraction scenarios, customers adopt 500,000 electric vehicles by 2035, consistent with SRP's 2035 goal for electric vehicle adoption. Under the Desert Boom scenario, customers adopt more electric vehicles due to increased economic and population growth. Under the Strong Climate Policy scenario, SRP assumed that increased federal support will result in greater customer adoption of electric vehicles at levels consistent with reaching net-zero economywide emissions by 2050.

FIGURE 6.3: ELECTRIC VEHICLE ADOPTION FORECAST



In addition to customer energy demand, customer adoption of generating resources also impacts the overall forecast for future energy demand. SRP forecasts customer adoption of rooftop solar and batteries to grow, reducing future energy demand (see figures 6.4 and 6.5).

In the Current Trends and Desert Contraction scenarios, rooftop solar and battery adoption increase steadily, reaching 1,296 MW and 75 MW, respectively, by 2035. In the Desert Boom scenario, an increased population and economic growth lead to stronger rooftop solar and battery adoption, reaching 1,804 MW and 157 MW, respectively, by 2035. In the Strong Climate Policy scenario, rooftop solar and battery adoption increase the most due to accelerated technology improvements and cost declines assumed in this scenario. By 2035, solar and battery adoption reach 2,257 MW and 250 MW, respectively, in the Strong Climate Policy scenario.

FIGURE 6.4: ROOFTOP SOLAR ADOPTION NAMEPLATE CAPACITY (MW) FORECAST

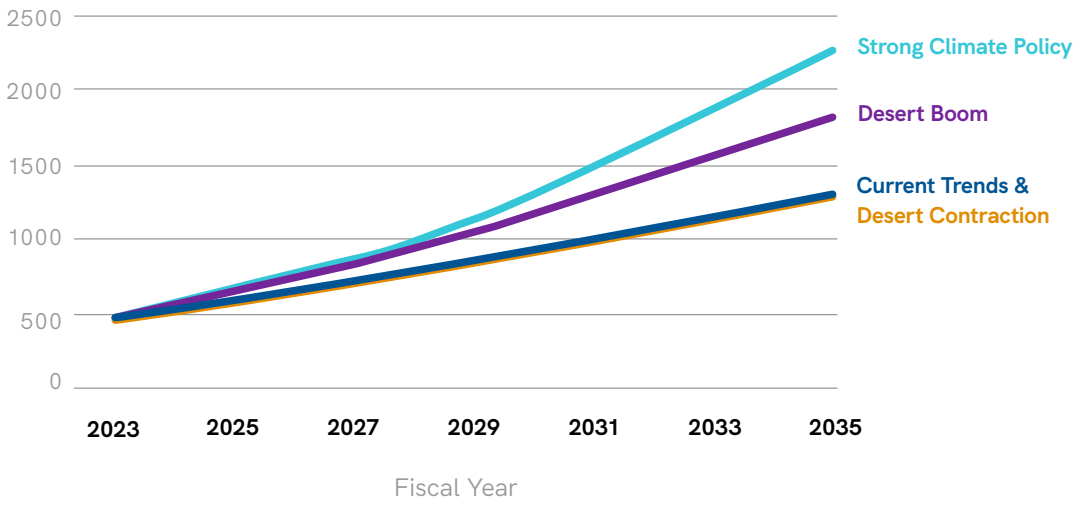
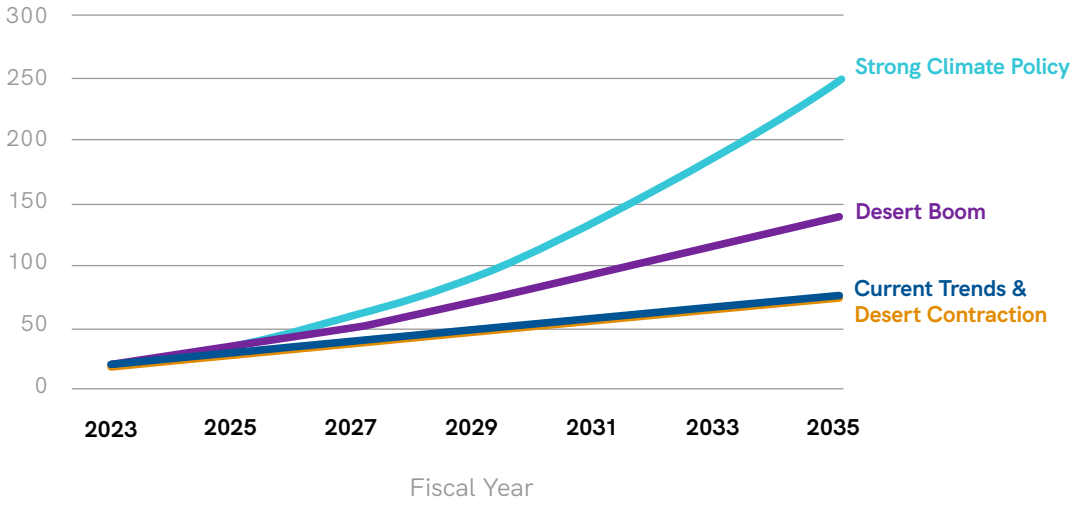


FIGURE 6.5: CUSTOMER-OWNED BATTERY ADOPTION NAMEPLATE CAPACITY (MW) FORECAST



Load Forecast

The load forecast is a key input to all the planning processes, as it is a main driver of future investment needs. This section presents the peak load and annual energy demand forecasts through 2035 for the four scenarios.

KEY FINDING

Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.

Figures 6.6 and 6.7 show peak load and energy demand forecasts for the four scenarios. SRP forecasts rapid load growth in the Current Trends, Desert Boom and Strong Climate Policy scenarios. In the Current Trends scenario, high economic and population growth lead to a substantial increase in both peak load and energy demand. In the Desert Boom scenario, accelerated migration into the Phoenix metropolitan area and increased economic development lead to even higher loads. In the Strong Climate Policy scenario, load growth from rapid electrification is offset by increased customer programs, resulting in a similar, but slightly lower, load forecast as for Current Trends. Across these three scenarios, between 2023 and 2035, peak load grows annually by 2.9%–4.0%, and annual energy demand grows annually by 3.1%–4.8%. The Desert Contraction scenario initially follows a rapid growth trajectory, but then peak load levels off and annual energy demand declines, reflecting a reversal of recent trends in migration and economic growth. Altogether, these load forecasts represent a wide range of future outcomes, from little to no growth in Desert Contraction to accelerated growth in Desert Boom.

FIGURE 6.6: PEAK LOAD (MW) FORECASTS BY SCENARIO

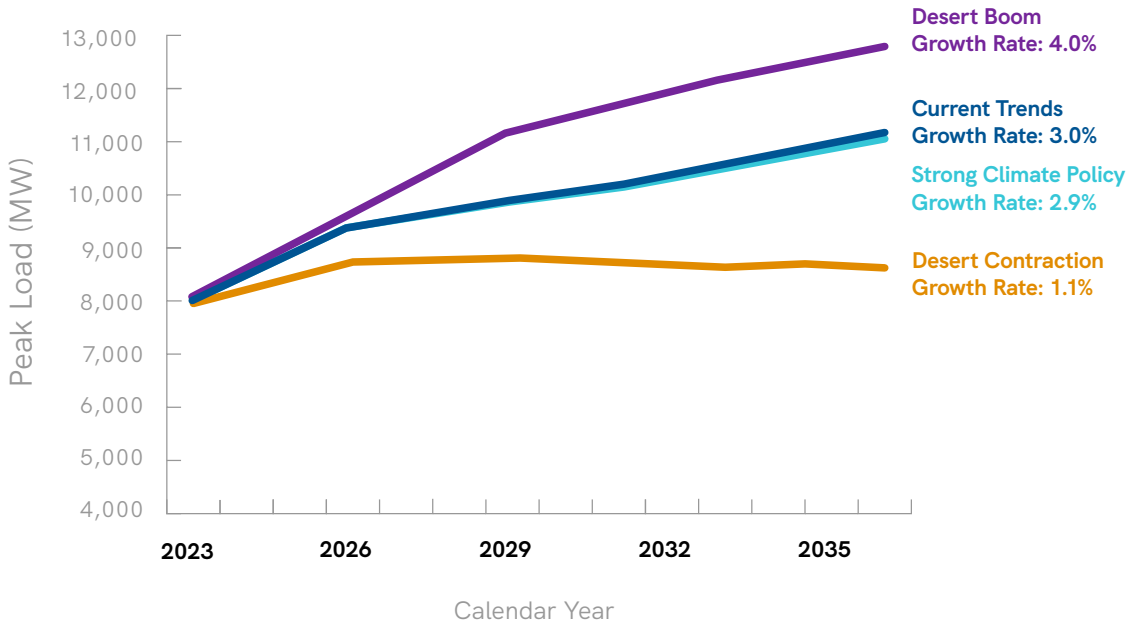
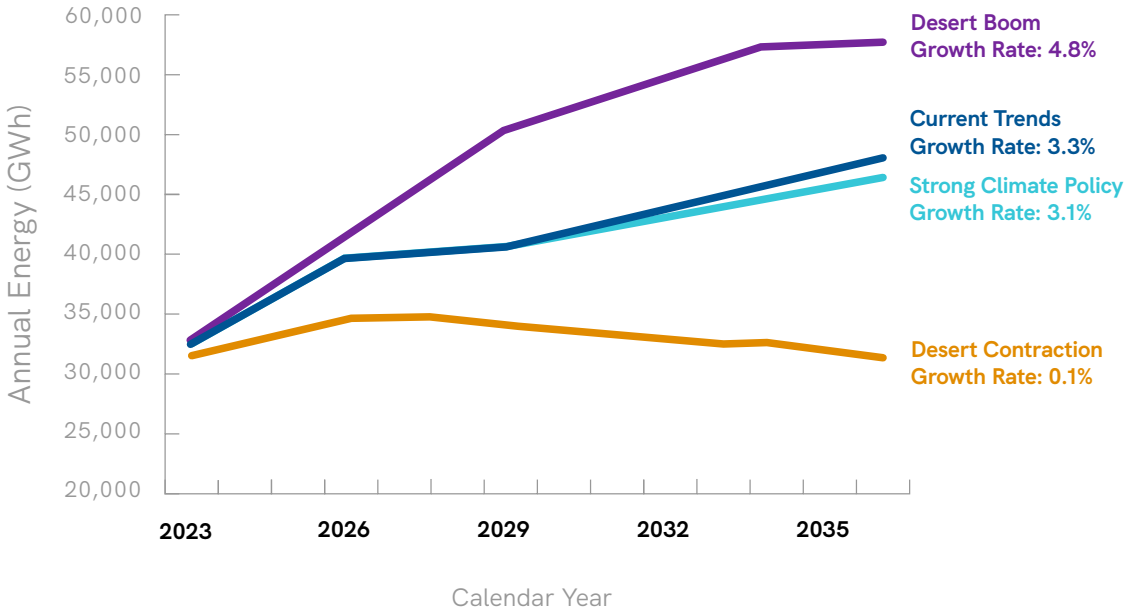


FIGURE 6.7: ENERGY DEMAND (GWH) FORECASTS BY SCENARIO

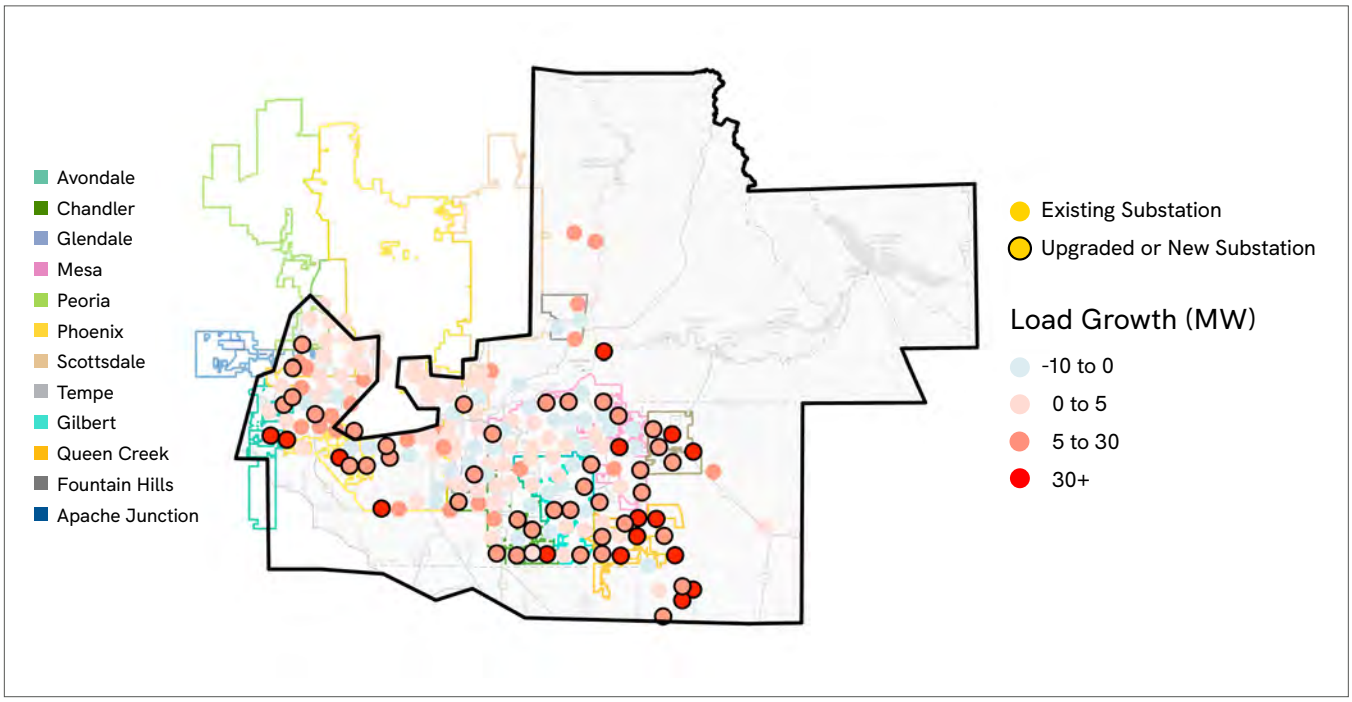


Distribution Investments

Future load growth and customer adoption of new technology increases the demand requirements on SRP's distribution system. SRP adapts to these changes through upgrades to existing infrastructure and investments in new infrastructure, such as distribution substations to serve new loads. This section describes the estimated distribution investments required to reliably serve customers across each scenario.

Figure 6.8 illustrates load growth changes in megawatts (MW) by distribution substation between 2022 and 2035 under the Current Trends scenario, highlighting new substation additions as well as upgrades required at existing substations (i.e., new substation bays added). Load growth and investment needs vary across SRP's service area. The Current Trends scenario results shown below are representative of the other scenarios' results and indicate the most significant load growth would occur in the Southeast Valley, requiring greater investments in that planning region. Additionally, the southwest portion of SRP's service territory sees relatively high load growth, requiring more investments. While these patterns are consistent across scenarios, the level of investments and upgrades needed by 2035 varies with load growth in each scenario, with more investments needed in the Desert Boom scenario and fewer investments needed in the Desert Contraction scenario.

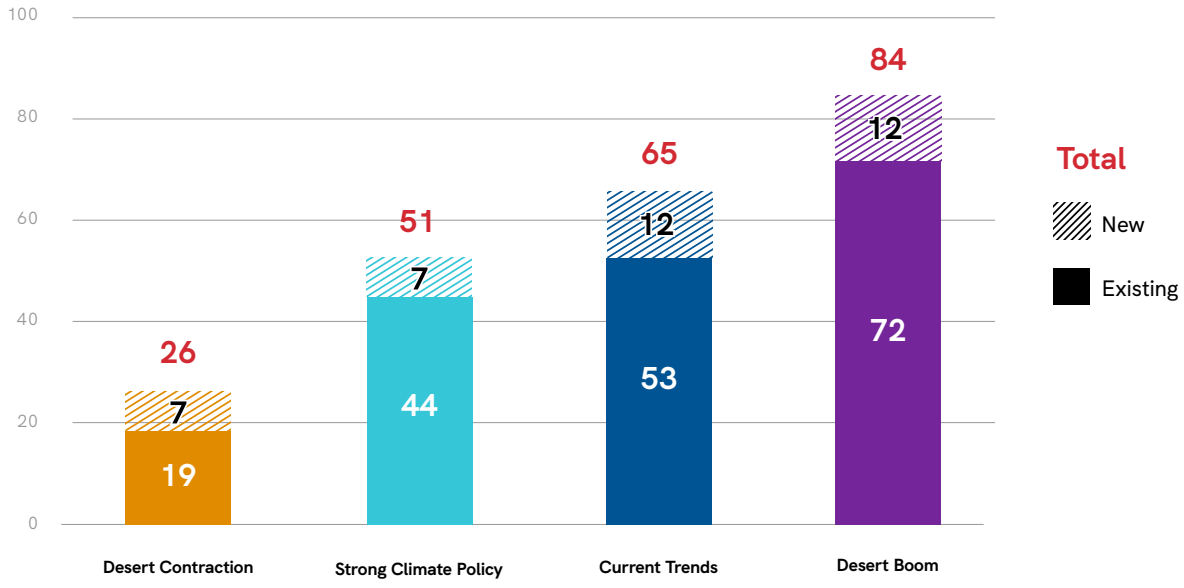
FIGURE 6.8: LOAD GROWTH BY DISTRIBUTION SUBSTATION THROUGH 2035 UNDER CURRENT TRENDS



See Figure 6.9 for the substation bay additions needed through 2035 across each of the scenarios and sensitivities. Across the scenarios, between 26 and 84 new substation bays are needed. A greater need for new distribution infrastructure is correlated with higher load growth across the scenarios. For example, substation bay additions more than triple in the Desert Boom scenario compared to what is required in the Desert Contraction scenario.

As electricity demand continues to grow in SRP's service territory, SRP will need to invest in the distribution system to enable this growth. The level of investments required will depend heavily on the rate of load growth.

FIGURE 6.9: SUBSTATION BAY ADDITIONS AT NEW AND EXISTING DISTRIBUTION SUBSTATIONS BY 2035

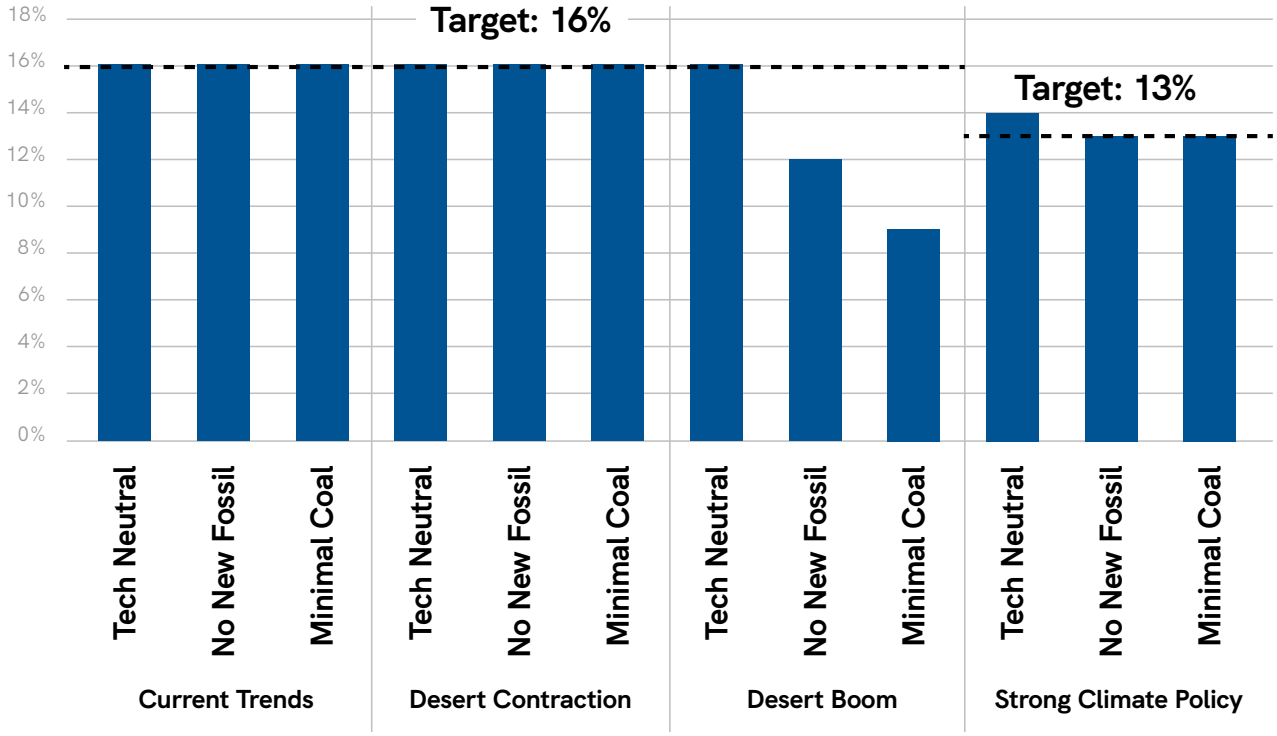


Resource Additions

SRP must add new resources to meet future energy demand, maintain system reliability, and meet the 2035 goals for carbon reduction and water resiliency. This section discusses the least-cost portfolios of generating resources selected by the long-term capacity expansion model across all scenarios and strategic approaches, as well as key reliability metrics.

For SRP to reliably serve customers across a wide range of system conditions, we must build sufficient resources to meet the planning reserve margin (PRM). The PRM is calculated using the load forecast and adding additional capacity to account for contingencies. This is a key metric because a plan that does not meet the PRM requirement is not reliable. Figure 6.10 shows the achieved PRM in 2035 across scenarios and strategic approaches compared with the requirement in each case. SRP's PRM requirement is 16% in all scenarios except for the Strong Climate Policy, where the PRM was reduced to 13% as a proxy to represent the potential benefits from expanded regional markets contributing to reliability.

FIGURE 6.10: ACHIEVED PLANNING RESERVE MARGIN IN 2035



All cases studied satisfy the PRM except for the No New Fossil and Minimum Coal strategic approaches in the Desert Boom scenario. Utilizing these two strategic approaches where firm resource options are limited[1], the accelerated load growth in Desert Boom compromises reliability as early as 2028. In these cases, there is insufficient capacity despite maximizing all available resource options. The third

KEY FINDING

Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.

[1] Firm resources include resources that can generate at sustained output for long periods of time. Firm resources studied in the ISP include natural gas, geothermal, biomass, natural gas with carbon capture and storage (CCS), biomass with CCS, nuclear small modular reactors (SMR), hydrogen and existing coal resources.

case, using a Technology Neutral strategic approach, is reliable in this scenario because it utilizes natural gas technology which was not an option in the No New Fossil and Minimum Coal strategic approaches. Because the No New Fossil and Minimum Coal cases do not meet SRP's reliability requirement, they are not viable in a Desert Boom scenario and were not evaluated further.

Figure 6.11 shows capacity additions through 2035 for all scenarios and strategic approaches. Customer programs, including energy efficiency, demand response and distributed generation, grow in all cases and offset the need for resource additions. Across all cases, renewable and energy storage resources make up a significant share of resource additions. In the Technology Neutral strategic approach, natural gas also accounts for a significant share of additions. In the No New Fossil and Minimum Coal strategic approaches, substantially more capacity is added as renewable and storage because these cases do not allow natural gas. This is because not all technology types contribute to reliability equally. Nearly all the capacity of a firm resource is counted toward the PRM while non-firm resources contribute a smaller portion. With fewer firm generation options, more total resources are needed to ensure reliability.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio.

Due to differences in load growth, the Desert Contraction cases require fewer resources than Current Trends, while the Desert Boom cases require more resources. The Strong Climate Policy cases add significant amounts of renewable and storage resources to meet the stringent federal emissions target in this scenario.

KEY FINDING

If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), SRP would need to significantly accelerate renewable and storage deployment.

FIGURE 6.11: CAPACITY ADDITIONS (MW) SELECTED BY MODEL BETWEEN 2025 AND 2035 UNDER ALL SCENARIOS

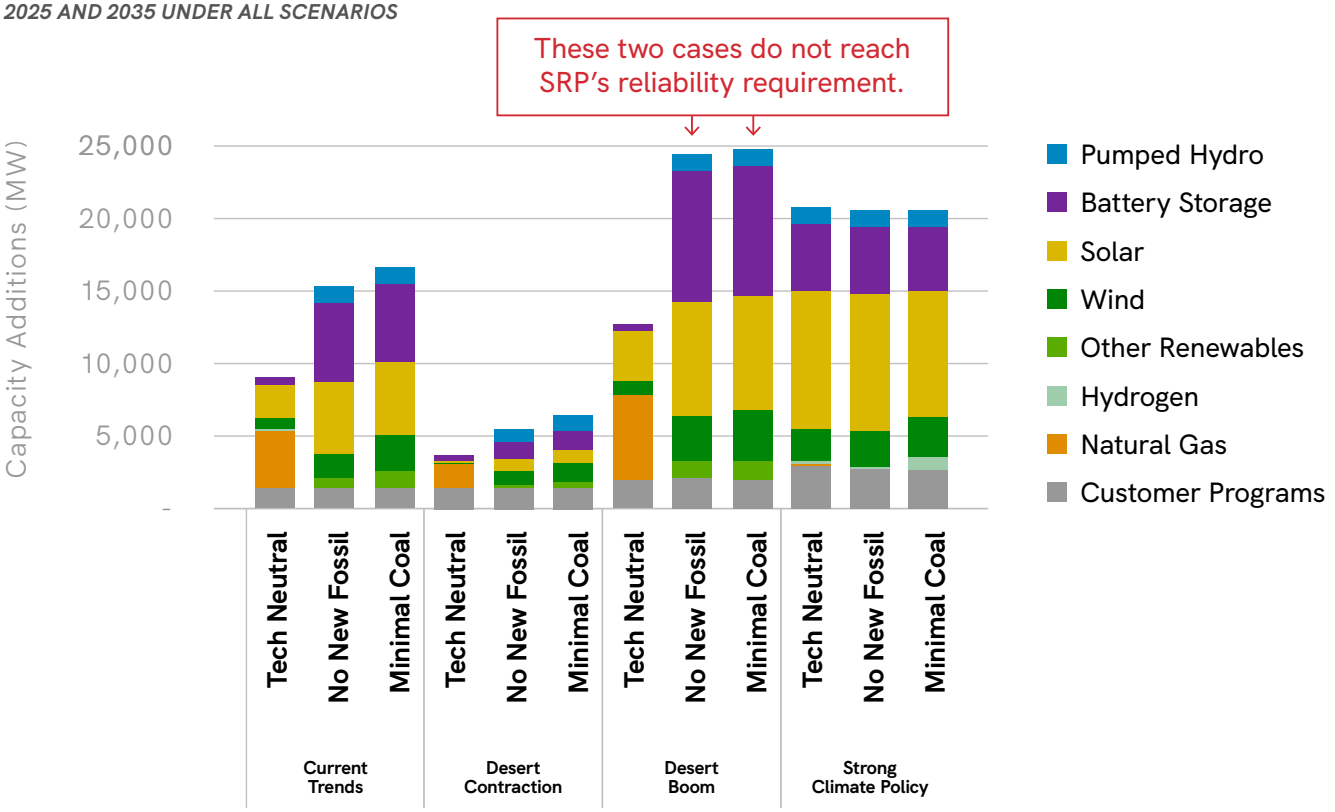


Figure 6.12 shows total installed capacity in 2035 for all scenarios and strategic approaches, as well as installed capacity in 2023 for reference. In the Technology Neutral and No New Fossil cases, more than 1,300 MW of coal capacity will be retired by 2035, with remaining coal capacity making up a small fraction of total capacity in 2035. In the Minimum Coal cases, all coal capacity retires by 2035. Looking across the system plans, there is a significant increase in total capacity between 2023 and 2035. Even the Desert Contraction scenario results in thousands of additional megawatts of capacity, while the other scenarios add more than 10,000 MW of capacity in many cases. Based on these results, SRP will likely need to double or triple its resource capacity in the next decade to serve customers to achieve reliability and sustainability goals, which marks an unprecedented rate of resource additions.

KEY FINDING

SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.

FIGURE 6.12: TOTAL INSTALLED CAPACITY (MW) IN 2023 AND IN 2035 UNDER ALL SCENARIOS

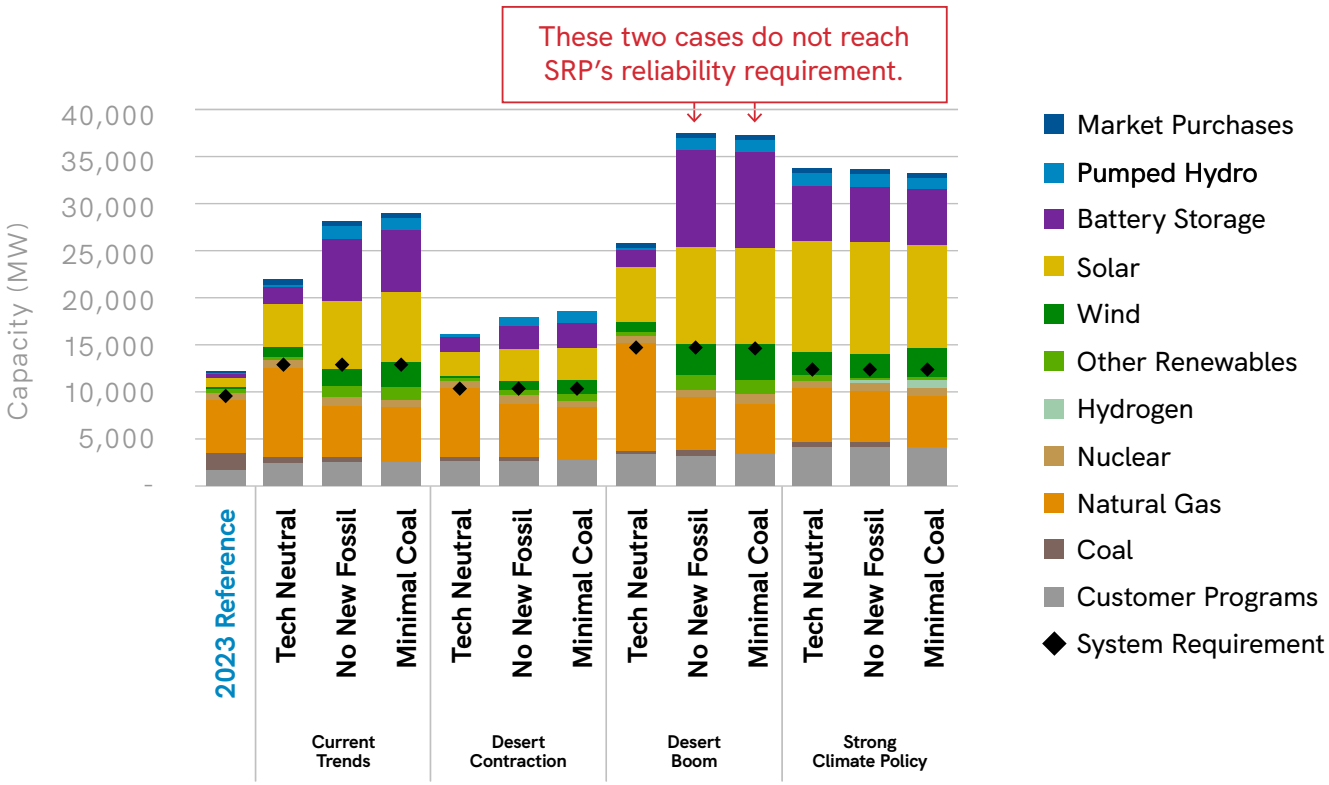
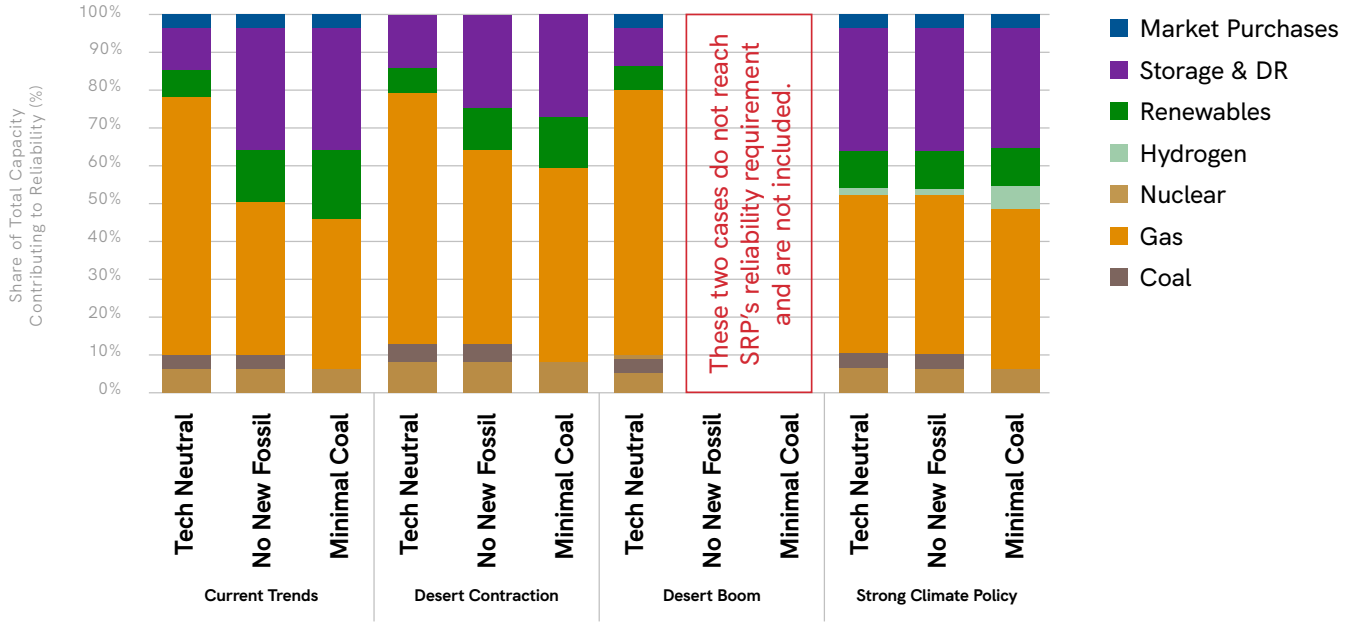


Figure 6.13 shows the contribution share of different resources toward satisfying the PRM requirement in each case. Firm resources are key to maintaining reliability; across all plans, firm resources (nuclear, coal, natural gas, geothermal, biomass and hydrogen) meet at least 55% of reliability needs in 2035, and more so in the Technology Neutral strategic approach. As noted previously, without new firm resources, reliability is compromised by 2028 in the Desert Boom scenario. New renewable and storage resources help contribute to reliability in all cases, and more so in the No New Fossil, Minimum Coal and Strong Climate Policy cases. Lastly, new firm capacity resources (natural gas or hydrogen), when included as an option per the scenario and strategic approach assumptions, are selected to help meet reliability needs at lower cost.

FIGURE 6.13: RESOURCE CONTRIBUTION TO RELIABILITY (RELIABILITY MIX) IN 2035



Note: Renewables includes solar, wind, geothermal, biomass and hydro. Storage & DR includes battery storage, pumped hydro and demand response (DR).

Relying on emerging technology can pose a risk in meeting future customer needs. Figure 6.14 shows the emerging technology selections across cases. The Strong Climate Policy scenario assumes accelerated availability of emerging technologies due to increased government support. Under this scenario, almost 200 MW of hydrogen are added in the Technology Neutral and No New Fossil cases and almost 800 MW in the Minimum Coal case, making up for lost capacity from the early retirement of Springerville Generating Station. This highlights again the value of a firm generation resource option and the potential for emerging technologies like hydrogen to provide firm generation. SRP acknowledges that to deploy 800 MW of hydrogen capacity, significant developments are needed in supply, storage and transportation infrastructure, which would require further advancements in the industry. While the ISP considers carbon capture and storage (CCS) and small modular reactor (SMR) options, these resources are not selected by the model in any of the cases by 2035.

FIGURE 6.14: RELIANCE ON EMERGING TECHNOLOGIES

	STRATEGIC APPROACH		
SCENARIO	Tech Neutral	No New Fossil	Minimum Coal
Current Trends	**No Emerging Technology Additions** Green hydrogen and nuclear SMR not available by 2035 CCS only available by 2035 in Tech Neutral		
Desert Contraction			
Desert Boom			
Strong Climate Policy	**178 MW** Green Hydrogen	**195 MW** Green Hydrogen	**790 MW** Green Hydrogen

Resource Operations

The changes in resource mix from coal retirements and new resource additions have significant implications for resource operations. This section describes the resource operations across cases as modeled in the production cost model, as well as key sustainability metrics.

Figure 6.15 shows the generation mix in 2035 across each scenario and strategic approach, including total generation in megawatt-hours (MWh) as well as the share of total generation for each resource type (%). Coal generation decreases significantly across all cases and only makes up a small share of generation in 2035. Customer programs and renewable generation increase across all cases. The total amounts of renewable and natural gas generation vary most significantly across cases and are explored further below.

FIGURE 6.15: TOTAL GENERATION (GWH) AND GENERATION MIX (%) IN 2035

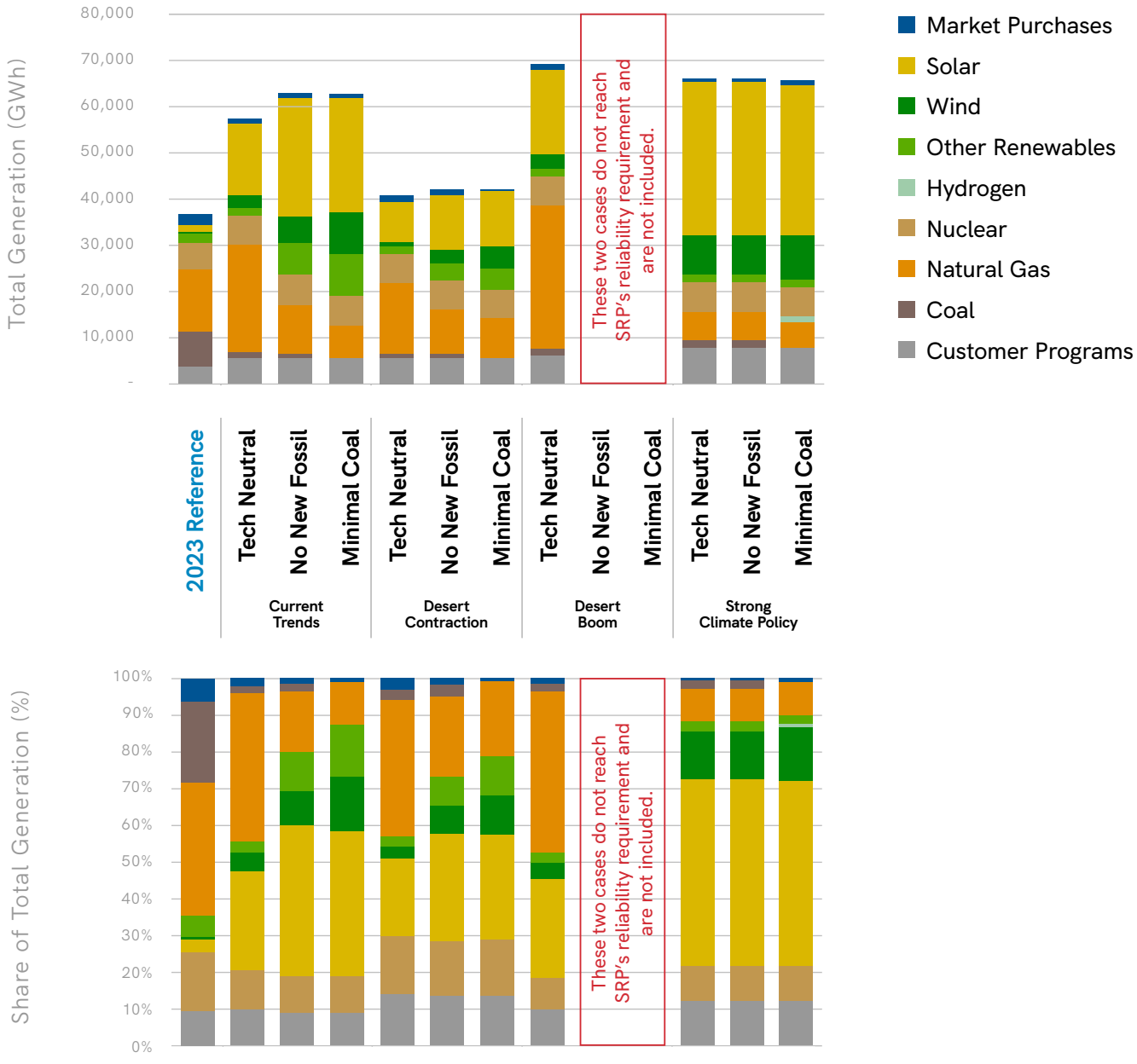
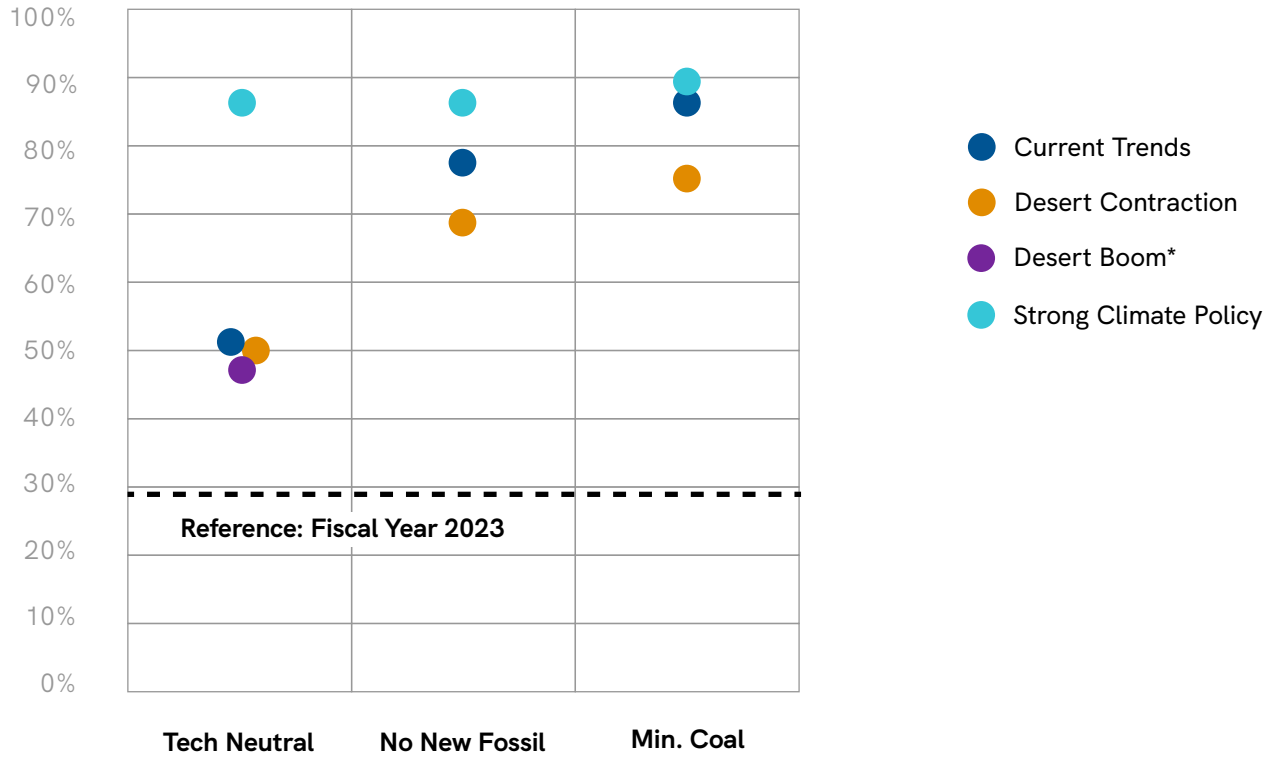


Figure 6.16 shows the percentage of generation coming from carbon-free resources, including nuclear, solar, wind, hydro, geothermal, biomass and hydrogen. Relative to 2023, the share of carbon-free generation increases across all system plans. System plans under the Strong Climate Policy scenario achieve the highest share of carbon-free generation across all strategic approaches, nearing 90%, driven by the more stringent federal emissions target. The No New Fossil and Minimum Coal strategic approaches result in more carbon-free generation compared with Technology Neutral because these cases add more renewable energy and storage to meet the PRM requirement.

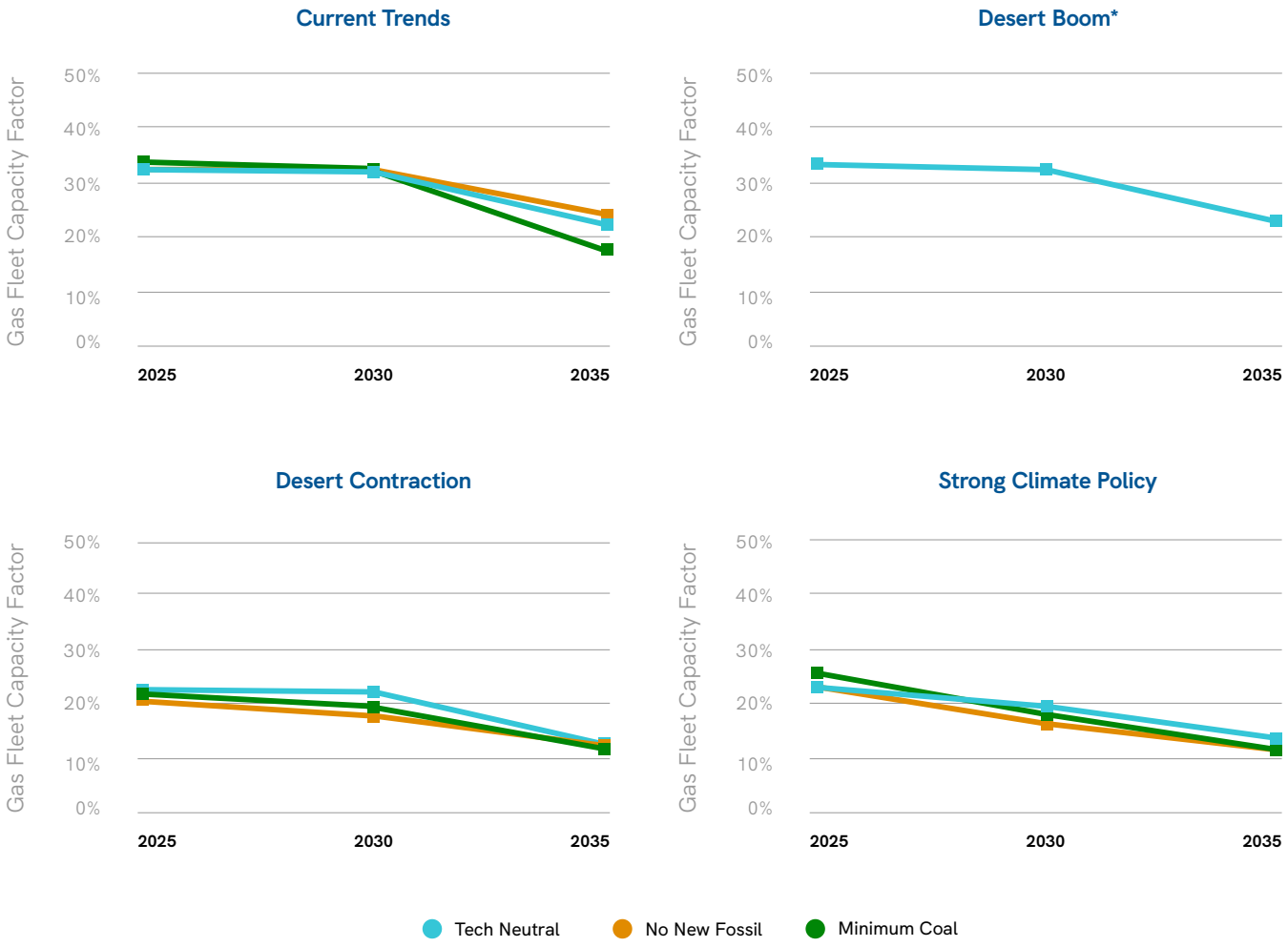
FIGURE 6.16: CARBON-FREE GENERATION BY 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

The extent to which the natural gas-fired power plant fleet is utilized relates inversely to the share of carbon-free generation. Figure 6.17 shows the average capacity factor[2] for SRP's gas fleet[3]. The utilization varies slightly between strategic approaches and scenarios, but in all cases, the average utilization of SRP's gas fleet is projected to decline through 2035 as the system relies increasingly on renewable energy. These resources are available to help ensure system reliability but generate less during the year, in line with integrating more carbon-free resources and decreasing emissions.

FIGURE 6.17: CAPACITY FACTOR FOR GAS FLEET

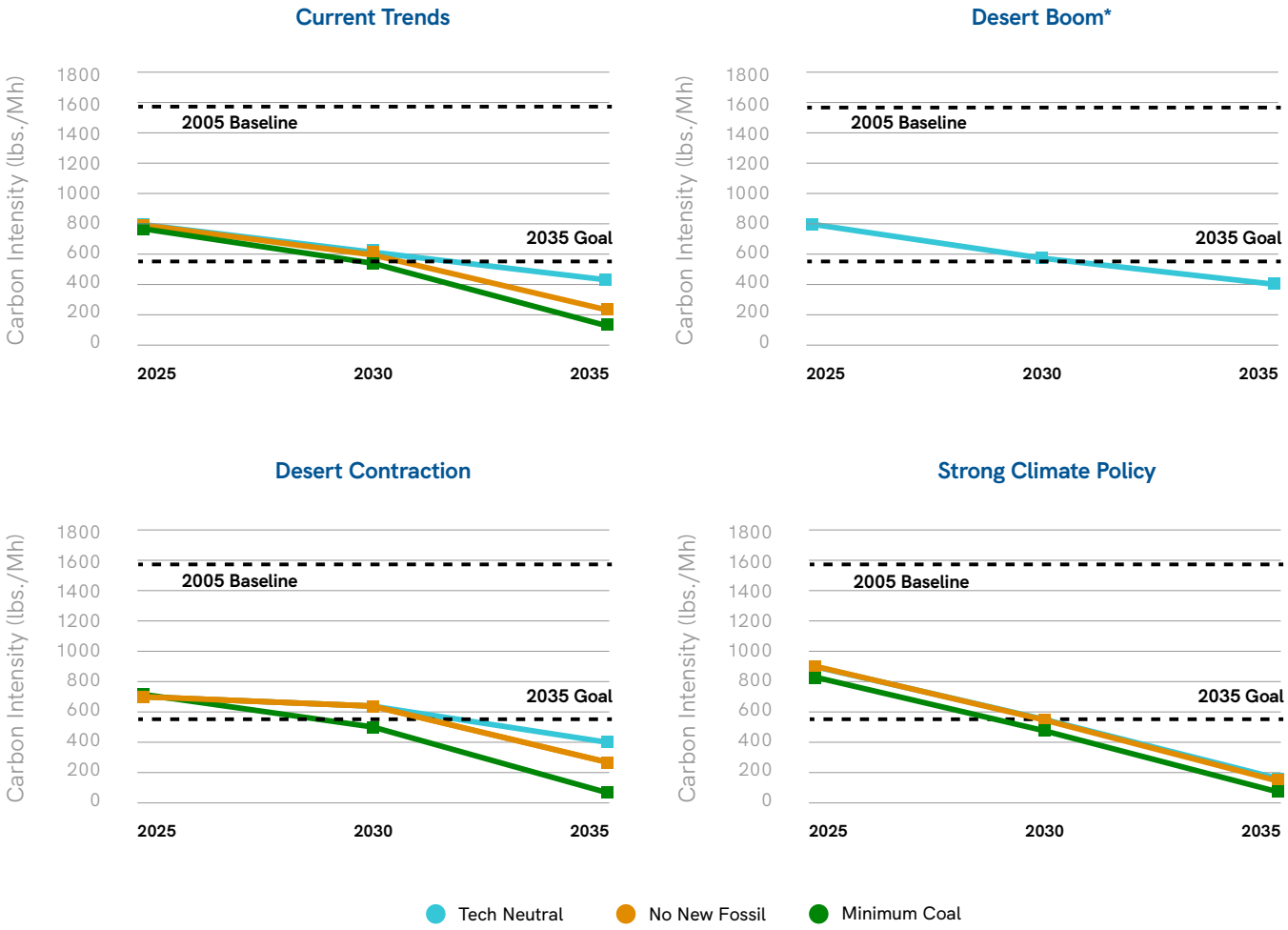


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[2] Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.
[3] SRP's gas fleet includes combined cycle units, simple cycle combustion turbines (peakers) and boilers. Capacity factor for each type of gas unit will vary.

A growing share of carbon-free generation offsetting generation from gas and coal-fueled resources drives reductions in system CO_2 emissions. Figure 6.18 shows CO_2 emissions on an intensity basis.[4] All cases exceed SRP's 2035 goal of reducing carbon emissions intensity by 65% relative to 2005 levels. The No New Fossil and Minimum Coal strategic approaches result in greater CO_2 emission reductions, while the Strong Climate Policy scenario results in the most CO_2 emission reductions.

FIGURE 6.18: CO_2 EMISSIONS (INTENSITY BASIS IN LBS. PER MWH)

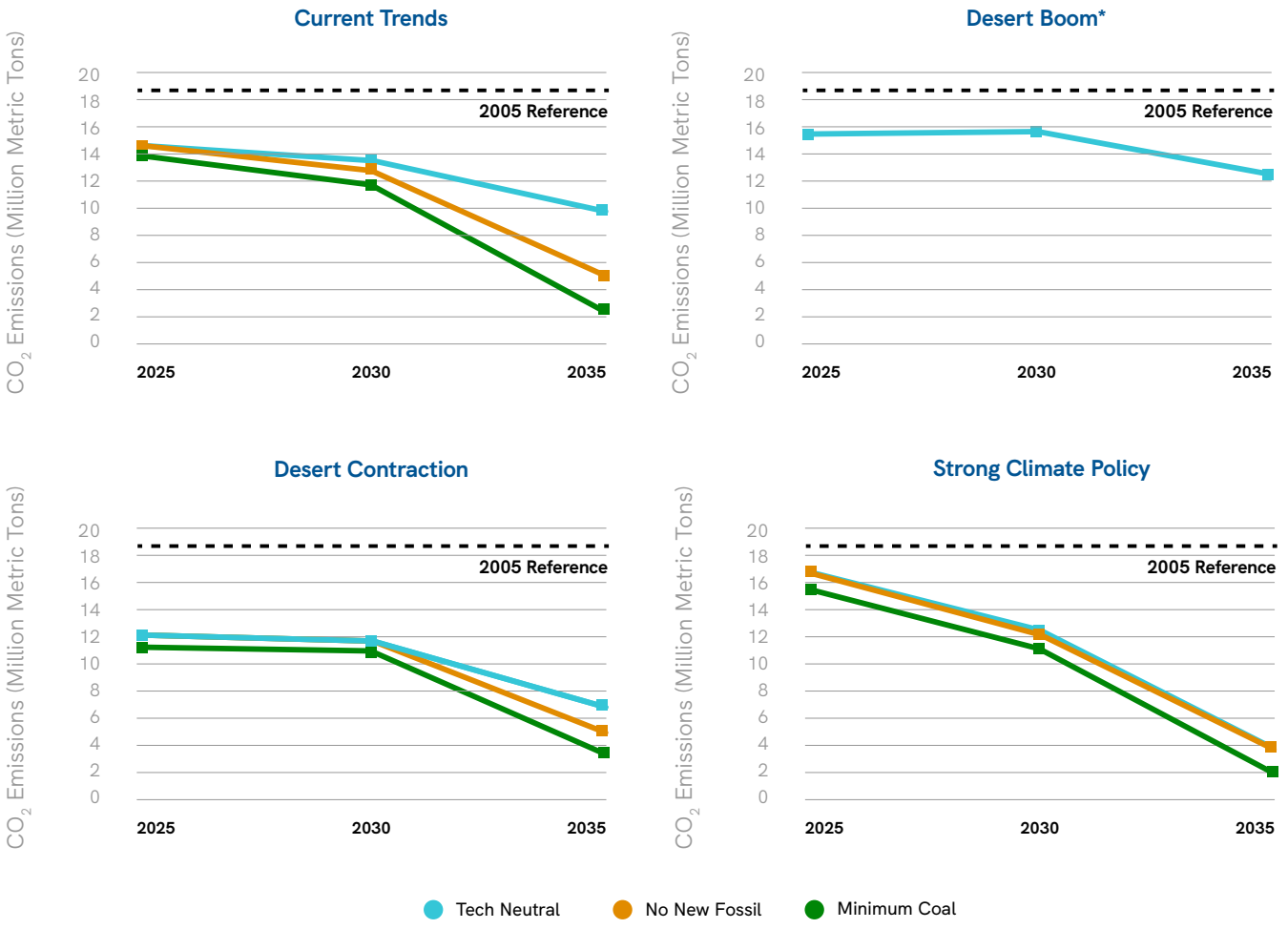


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[4] Carbon intensity is the amount of carbon dioxide emitted from generating electricity (in pounds), divided by the total generation required to serve SRP's customers (in megawatt-hours).

Figure 6.19 shows total annual CO_2 emissions on a mass basis. The trends within each scenario on a mass emissions basis align with the trends observed with CO_2 emissions intensity. However, the difference across scenarios is more pronounced for total CO_2 emissions because of differences in the load forecast: Higher load growth leads to an increase in total carbon emissions due to an increase in generation, some of which is carbon-emitting (when considering carbon intensity, higher emissions are offset when divided by a greater amount of energy generated). Total CO_2 emissions are higher in Desert Boom because load growth is higher, and emissions are lower in Desert Contraction because load growth is lower.

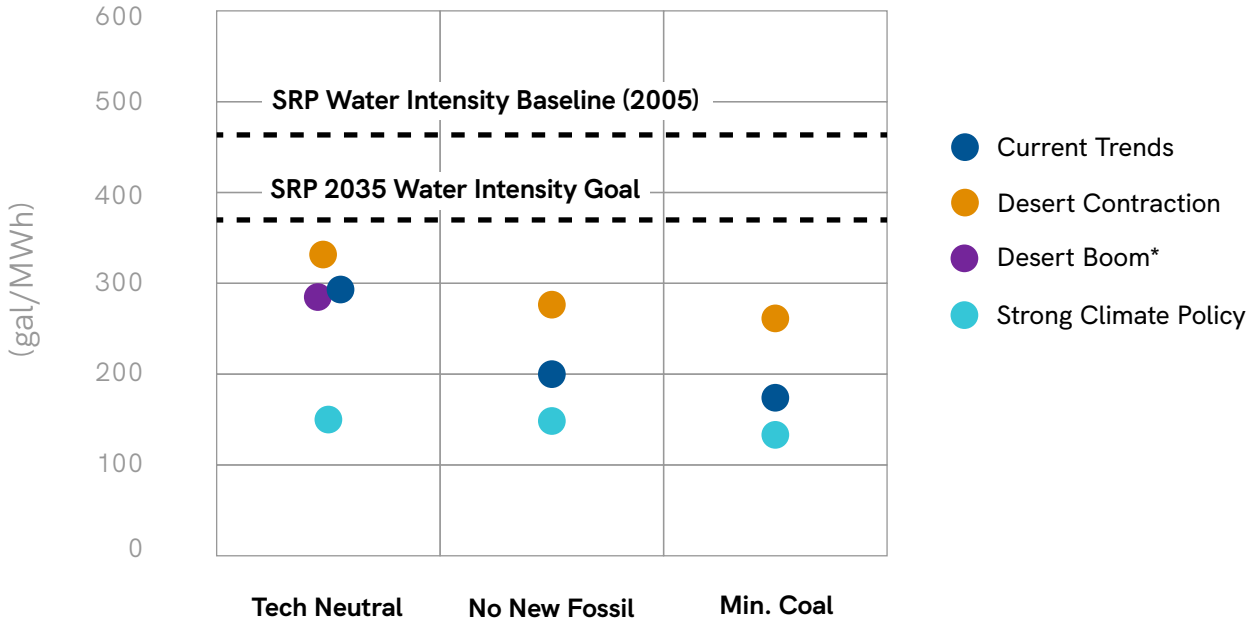
FIGURE 6.19: CO_2 EMISSIONS (MASS BASIS IN MILLION METRIC TONS)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

SRP also projected water consumption from power generation on an intensity basis[5] to evaluate performance with the 2035 goal of reducing water usage intensity by 20% relative to 2005 levels. As shown in Figure 6.20, all cases exceed the 2035 goal. The greatest reductions in water usage intensity occur under the No New Fossil and Minimum Coal strategic approaches, again due to a higher share of carbon-free resources that use little or no water.

FIGURE 6.20: WATER USAGE INTENSITY IN 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[5] This is the amount of water consumed (in gallons) from generating electricity, divided by the total generation required to serve SRP's customers (in megawatt-hours).

Lastly, in addition to carbon emissions and water usage, SRP estimated direct air emissions from the generation fleet for several criteria air pollutants, and their precursor pollutants, including particulate matter (PM), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and volatile organic compounds (VOC). Under all cases, emissions of all pollutants decline substantially by 2035 relative to 2025 levels. However, new biomass causes higher levels of NO_X and SO_2 emissions in the No New Fossil and Minimum Coal system plans.

FIGURE 6.21: DIRECT AIR EMISSIONS IN 2035

*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

System operations change significantly over time in all cases. Coal generation decreases, while customer programs and renewable generation increase across all cases, pushing down natural gas generation across the fleet and improving sustainability metrics. Reductions in carbon intensity ranged from 74% to 96% (compared to SRP's goal of 65%) while reductions in water usage intensity ranged from 31% to 71% (compared to SRP's goal of 20%), both relative to 2005 baseline levels. Cases with less renewable and storage additions resulted in smaller reductions in carbon and water usage intensity, while cases with higher renewable and storage additions resulted in larger reductions. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

KEY FINDING

The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.

Transmission Investments

Both load growth and changes in the resource mix influence investment needs for the transmission system. This section describes the transmission investment needs through 2035, including 230 kV lines, 500 kV lines and 500/230 kV transformers.

Figure 6.22 shows the transmission investment needs through 2035 for the three system plans analyzed (Technology Neutral Current Trends, Technology Neutral Desert Boom and Minimum Coal Current Trends) and the two resource location options analyzed (Pro-Rata and Hub). These cases are described in detail in Section 5.

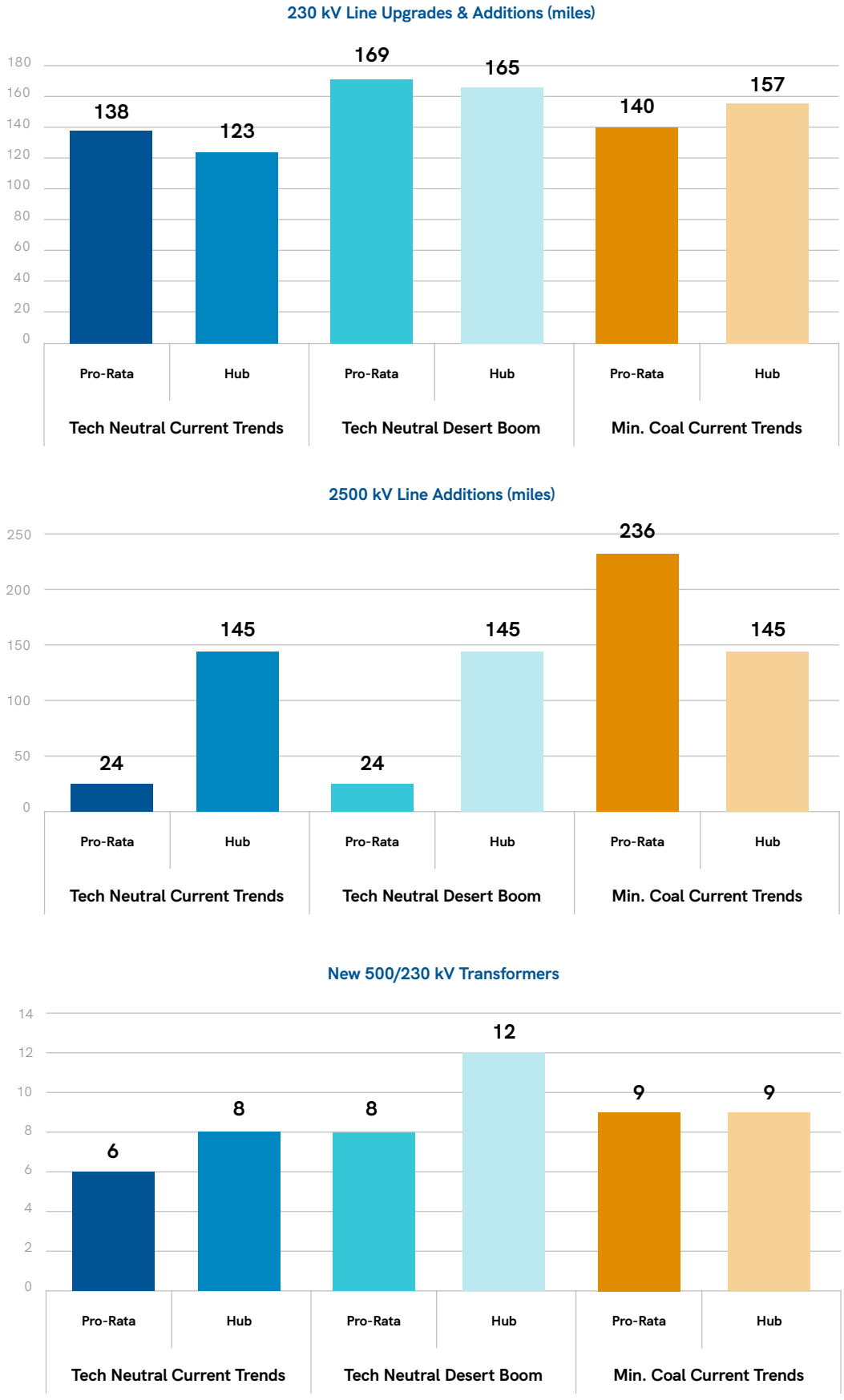
KEY FINDINGS

Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

In all cases, a significant amount of transmission investment is needed by 2035. The investments in 230 kV lines are primarily driven by load growth in all cases; however, where 230 kV lines need to be added and which lines need to be upgraded depends on the resource location assumptions used. The investments in 500 kV lines, as well as the investments in 500/230 kV transformers, vary for each system plan based on the resource location assumptions. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, the Hub resource location assumption requires far more 500 kV line-miles and more 500/230 kV transformers than the same cases using the Pro-Rata resource location assumption. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, more investment is needed in the 500 kV system to connect resources at the hub to the rest of the system. By contrast, in the Minimum Coal Current Trends case, fewer 500 kV line-miles are needed under the Hub resource location assumption than under the Pro-Rata resource location assumption. This is driven by the higher levels of solar and battery resources in this case further exceeding existing transmission capabilities when located using the Pro-Rata location assumptions. The differences in results across the Pro-Rata and Hub resource location assumptions highlight how the location of resources has a significant impact on transmission investment needs.

FIGURE 6.22: TRANSMISSION SYSTEM INVESTMENTS BY 2035



KEY FINDING

Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.

The transmission analysis shows that up to 380 miles of new or upgraded transmission lines and 12 new 500/230 kV transformers could be needed over the next decade. The lead times for siting, permitting, building and energizing transmission infrastructure are 5–9-plus years for 500 kV lines, 3–7 years for 230 kV lines and 3–5 years for 500/230 kV transformers. To add the needed transmission infrastructure given these long lead times will require a proactive approach to transmission planning.

Total System Cost

Because maintaining affordability for customers is a fundamental component of SRP's mission, we developed affordability metrics for each system plan analyzed to assess and compare opportunities and risks. This section describes the total system cost and average system cost metrics, while the next section describes the residential bill impact metric.

The total system cost is the estimate of total costs in 2035 to serve customers, including costs related to customer programs, distribution, generation, transmission and normal utility operations. The average system cost is derived by dividing the total system cost by the total retail sales in 2035. Because energy demand growth varies across the scenarios, the average system cost provides a more direct comparison between cases for how costs are changing over time.

While these metrics allow comparison across system plans, they are developed using a simplified ISP analysis model and are not a comprehensive assessment of future financial indicators for SRP. Furthermore, the average system cost metric is not a customer rate metric and should not be interpreted as the rate that customers would pay under different cases. Lastly, differences in results across scenarios reflect scenario assumptions for external factors that are out of SRP's control (e.g., economic growth, fuel prices, resource costs and federal government policy).

Figure 6.23 shows the total system cost in 2035, broken out between generation, transmission, distribution, customer program and other costs. It also provides total system cost in 2025 for reference. Generation costs are the primary driver of differences in cost between cases. Transmission costs follow similar trends as generation costs, as both are influenced by load growth and new resource additions. Distribution costs vary across scenarios due to differences in load growth. Lastly, customer program costs grow through 2035 and continue to mitigate needs for new infrastructure across all cases.

Within the Current Trends and Desert Contraction scenarios, Technology Neutral is the lowest-cost strategic approach. While Technology Neutral allows new natural gas as a resource option, the other strategic approaches (No New Fossil and Minimum Coal) do not have a firm capacity option and thus lead to higher costs due to increased resource additions and transmission investments.

In general, the Desert Contraction cases have lower system costs than Current Trends, and the Desert Boom cases have higher costs, driven primarily by the differences in energy demand. In the Strong Climate Policy scenario, all three strategic approaches have similar costs due to a few factors. First, the aggressive federal emissions requirement in this scenario is a major driver, resulting in significant renewable and storage additions across all three strategic approaches. Second, in this scenario, a firm capacity resource is available in all three strategic approaches due to the accelerated availability of hydrogen. The unavailability of a firm capacity resource was the major driver of cost increases for these two strategic approaches under the other scenarios.

FIGURE 6.23: TOTAL SYSTEM COSTS FOR SRP'S POWER SYSTEM IN 2035 ($ BILLION)

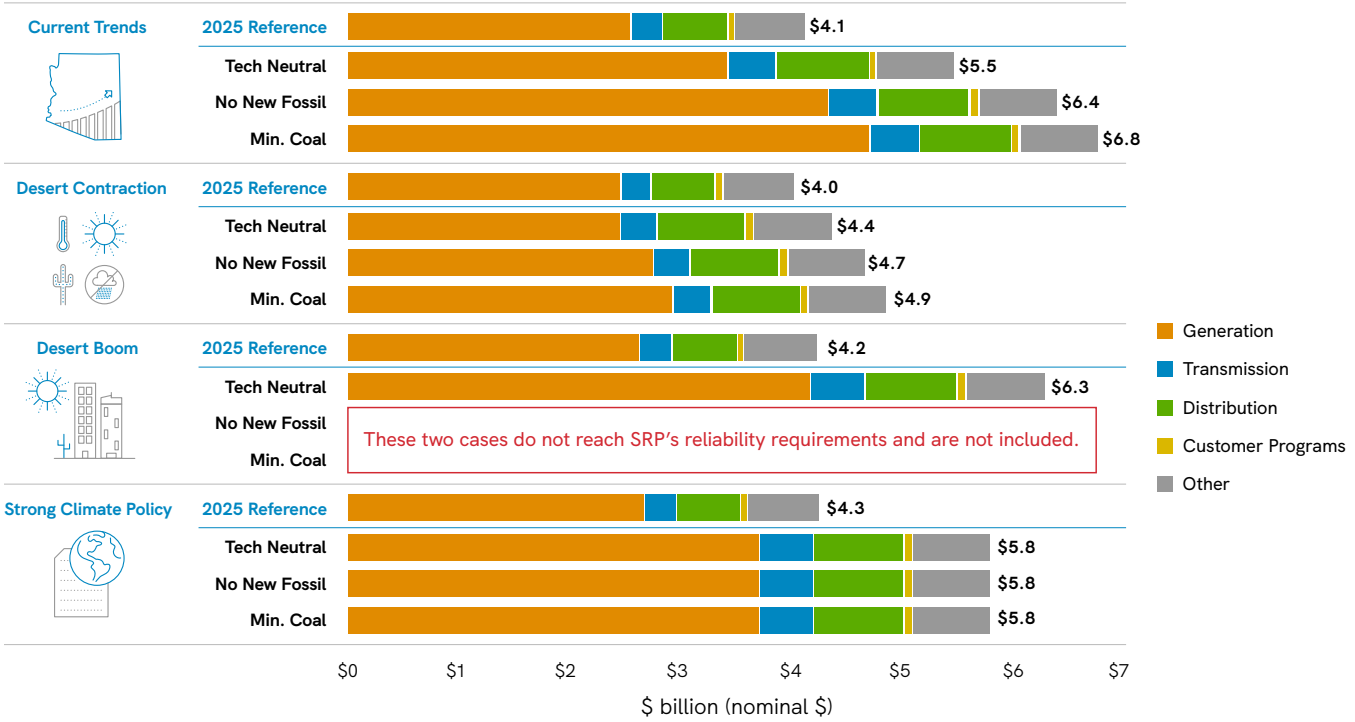
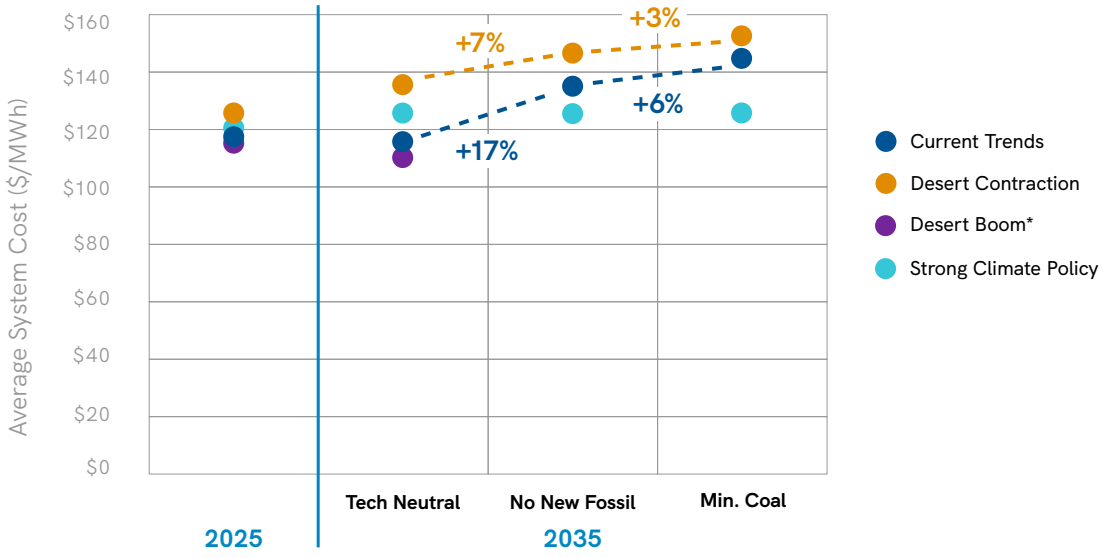


Figure 6.24 shows the average system cost in 2035, with 2025 provided for reference. The Technology Neutral strategic approach results in lower cost than the other strategic approaches with limited firm capacity options. In the Current Trends scenario, the No New Fossil and Minimum Coal approaches result in a 17% and 24% increase, respectively, in average system cost relative to Technology Neutral. In the Desert Contraction scenario, the No New Fossil and Minimum Coal approaches result in a 7% and 10% increase, respectively, in average system cost relative to Technology Neutral. The cost increase in Current Trends is greater than the cost increase in Desert Contraction because the higher load growth in Current Trends makes it more costly to reliably meet customer needs without new firm capacity resources.

FIGURE 6.24: AVERAGE SYSTEM COST ($/MWH)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

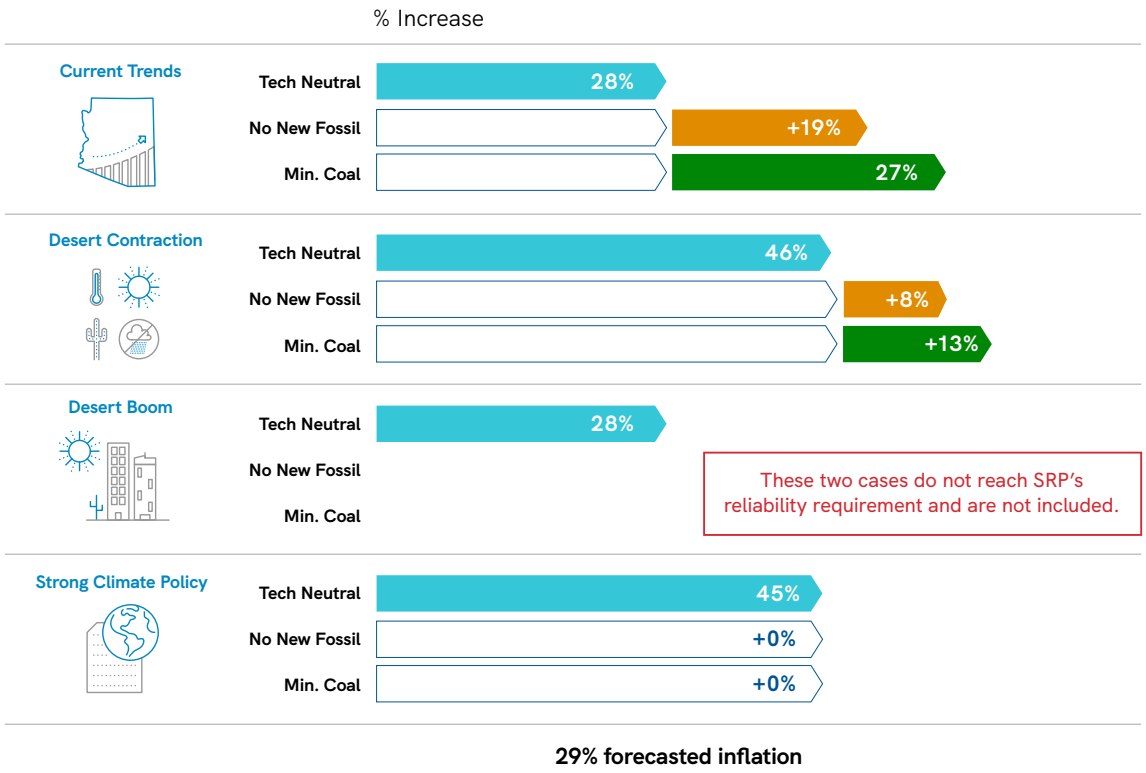
Residential Bill Impact

This section describes the residential bill impact metric across cases. This analysis does not necessarily reflect how future costs would be allocated and recovered from customers and therefore should not be considered a projection of customer rates. SRP will carry out pricing processes in the future that will determine future rates. Nevertheless, this metric is helpful for comparing across cases to understand relative differences.

Figure 6.25 shows the increase in average residential customer rates between 2023 and 2035 along with the forecasted inflation expected over this period for reference. The figure shows the increase in the Technology Neutral strategic approach and then shows the increase in the alternative strategic approaches relative to the Technology Neutral strategic approach. SRP projects the cumulative impact of inflation to be 29% between 2023 and 2035. The Technology Neutral Current Trends approach has an increase of 28% over this same period, meaning that rates increase by less than inflation in this case.

In all scenarios, the Technology Neutral strategic approach results in the lowest impact to average residential rates. The No New Fossil and Minimum Coal approaches are more costly, with the greatest increases relative to Technology Neutral under Current Trends. Under the Current Trends scenario, the No New Fossil strategic approach results in a 19% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 27% increase. Under the Desert Contraction scenario, increases are higher across the cases as the lower load growth leads to less revenue to offset costs. Comparing the cases in the Desert Contraction scenario, the No New Fossil strategic approach results in an 8% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 13% increase. Under the Strong Climate Policy scenario, the residential bill impact is similar across the three strategic approaches, for the same reasons discussed in the Total System Cost section.

FIGURE 6.25: INCREASE IN AVERAGE RESIDENTIAL CUSTOMER RATES BETWEEN 2023 AND 2035



Risk Assessments

The development and operational risk assessments identified risks and challenges that SRP could face for each of the system plans. It also identified potential mitigation options, which SRP is using to prepare its system and workforce for the future.

Development Risk

Because each of the ISP system plans requires significant development of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems, as well as mitigation options.

Development Risks and Mitigation Options

KEY FINDING

To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

Supply chain. SRP continues to observe inflation and supply chain disruptions that began during the COVID-19 pandemic. These disruptions led to rising costs and extended development timelines for new infrastructure projects, including solar projects, battery storage projects, transmission infrastructure, distribution infrastructure, etc. Future supply chain disruptions could also impact SRP's ability to develop new infrastructure, impacting ISP system plans with greater infrastructure additions the most. Mitigation steps that SRP is taking to address these risks include ordering key supplies as early as possible and seeking to develop a wider pool of potential suppliers to diversify supply chain risks.

Siting and permitting. Most infrastructure projects take several years for siting, permitting, construction and interconnection. Examples of projects with especially long and complex development processes include nuclear power plants, pumped hydro energy storage, gas pipelines and transmission. On the longer end of development timelines, some transmission projects can take well over a decade to site, permit, construct and energize. There are many variables that can impact the timing of developing projects, including stakeholder consultation, state and/or federal regulatory processes, development of enabling infrastructure (e.g., new transmission or gas pipelines), etc. If development timelines were to extend much longer than expected, this would limit the pace at which SRP can build out the system and put ISP system plans with greater infrastructure additions at more risk. To mitigate this risk, SRP strives to collaborate with government agencies, other utilities and key stakeholders as early as possible. We are also exploring multiple project options so that SRP is prepared to undertake any one of these options more readily should the need arise.

KEY FINDING

With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.

Multistate transmission. While any transmission can have long development timelines and face uncertainty in permitting, these challenges exist even more for transmission that spans multiple states. Such interstate transmission projects may span longer distances and require consultation with more landowners. They also require approvals from different state regulatory bodies and may require approval from multiple federal agencies. The complex nature of developing such projects results in risks to development timelines. These risks are greatest for ISP system plans that add geothermal or wind in states such as California and New Mexico. SRP is working to mitigate this risk by proactively pursuing regional transmission projects that facilitate integration of diverse renewable resources.

Technology maturity. Not all resource technologies have reached full maturity. Lithium-ion battery projects have proliferated in the last five years, but the total amount of capacity deployed is still limited relative to other technologies and they do not have a long track record of performance. Some battery projects, including a project contracted by SRP, have experienced fires that have rendered the resources unavailable. There are other technologies evaluated in the ISP that have not yet reached widespread commercialization, such as power plants powered by 100% hydrogen. There are still uncertainties in the cost, operations and enabling infrastructure for this technology. Given these risks and uncertainties, ISP system plans that rely more on less mature technologies have a greater amount of inherent risk. To mitigate these risks, SRP is actively gaining operational experience with newer technologies and monitoring advancements for emerging technologies. SRP is also balancing the development of newer technologies (e.g., battery storage) with the deployment of more mature technologies (e.g., pumped hydro storage).

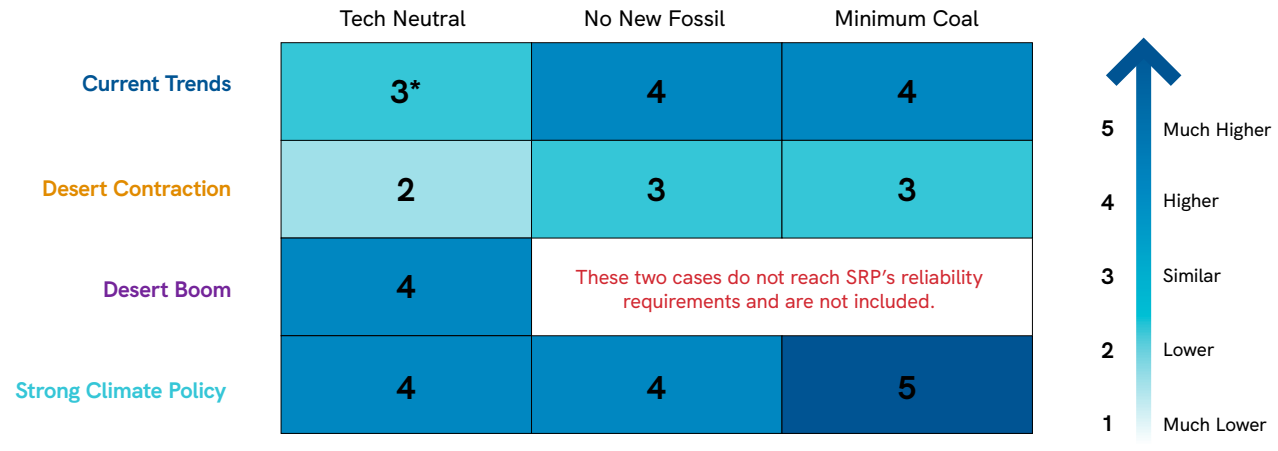
Diversification. The potential impact of any one of these development risks depends in part on the diversification of the system plan. If the system plan relies heavily on only a few technologies, then the entire system plan is at risk if one of those technologies encounters disruptions due to supply chain, permitting or other issues. To mitigate the risk associated with any one technology, SRP is pursuing a diverse system plan.

Development Risk Ratings

SRP identified a development risk rating for each of the core system plans in the ISP, as shown in Figure 6.26, using the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the development risk associated with that plan.

Technology Neutral Desert Contraction has a lower risk level because the system plan adds far fewer generating resources, transmission and distribution than the other plans. For the Desert Contraction scenario, the two other strategic approaches (No New Fossil and Minimum Coal) have a similar amount of risk as the baseline due to the amount of resource additions. All other system plans have higher risk levels due to the very rapid pace of resource additions, with some cases reaching between 25,000 and 35,000 MW of installed capacity. The Minimum Coal Strong Climate Policy case has the highest risk level not only due to the rapid pace of resource additions, but also because of the reliance on almost 800 MW of hydrogen capacity, which would require significant development of hydrogen infrastructure that doesn't currently exist. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

FIGURE 6.26: DEVELOPMENT RISK RATING



*Tech Neutral/Current Trends was the baseline case to which the development risk for all other cases were compared.

Operational Risk

Because each of the ISP system plans requires a meaningful shift in the future operations of the system, SRP also performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems, as well as mitigation options.

Operational Risks and Mitigation Options

KEY FINDING

A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Variability and uncertainty. The Inverter-Based Resources Integration Technical Working Session highlighted the profound changes that come with moving to a system that relies on more variable renewable generation to meet energy needs. Resources like solar and wind vary in output based on season and time of day. Also, this variability is not perfectly predictable, as the weather can impact solar generation due to cloud cover and wind generation due to changes in wind speed. Managing a system with higher penetrations of variable generation is more complex and comes with new risks in balancing energy demand, supply and market transactions. As a result, ISP system plans with higher penetrations of variable generation resources have greater operational risk. To mitigate these risks, SRP is taking several actions, including improving forecasts for variable renewable generation, increasing reserves to account for uncertainty and variability, pairing variable energy resources with flexible resources (e.g., energy storage) to reduce variability and increase dispatchability, managing resource curtailment to provide more flexibility to the system, and transacting with markets to provide more operational flexibility.

Ramping needs. With higher penetrations of variable generation, especially solar, the system experiences greater ramping needs for dispatchable generation. For example, on a system with a lot of solar generation, there is plentiful generation during the day. However, in the late afternoon and early evening, when electricity demand is high and solar generation rapidly declines, other resources need to ramp up output rapidly. This is a significant change in how the system must operate and creates new challenges. To mitigate these risks, SRP is working to add more flexible resources, such as battery storage, pumped storage hydro and natural gas, to maximize the flexibility from existing resources and from market transactions. SRP is exploring curtailing variable generation to help mitigate ramping needs and provide additional flexibility.

Natural gas plant operations. With increasing amounts of variable generation and increasing ramping needs, natural gas power plants operate differently than they have in the past. When variable renewable generation output is high and energy demand is low, natural gas plants ramp down output or even shut down. When variable renewable generation is low and/or energy demand is high, natural gas plants ramp up output. This may involve shutting down and starting up natural gas plants more frequently than in the past, potentially even daily, which puts increased wear and tear on the generating units. Some natural gas plants may shut down for extended periods of time before starting up again. Systems that cool completely can cause aging seals or fittings to shrink, which can increase risks for more frequent maintenance and repair.

Natural gas fuel transportation. SRP acquires transportation rights on regional natural gas pipelines to secure reliable delivery of natural gas fuel we purchase throughout the year. If natural gas fuel consumption were to increase significantly beyond today's level of consumption, such as in the Technology Neutral Desert Boom system plan, this could create risks in being able to deliver natural gas fuel during critical days for reliability.

Depending on the increase in fuel consumption and how the regional energy landscape evolves, this could require the need for new natural gas pipeline infrastructure. To mitigate this risk, SRP is deploying a diverse mix of additional generating resources such as solar and wind that help to offset natural gas fuel consumption. SRP may also explore fuel storage solutions that can allow natural gas plants to continue to have access to fuel without relying solely on pipelines during critical days.

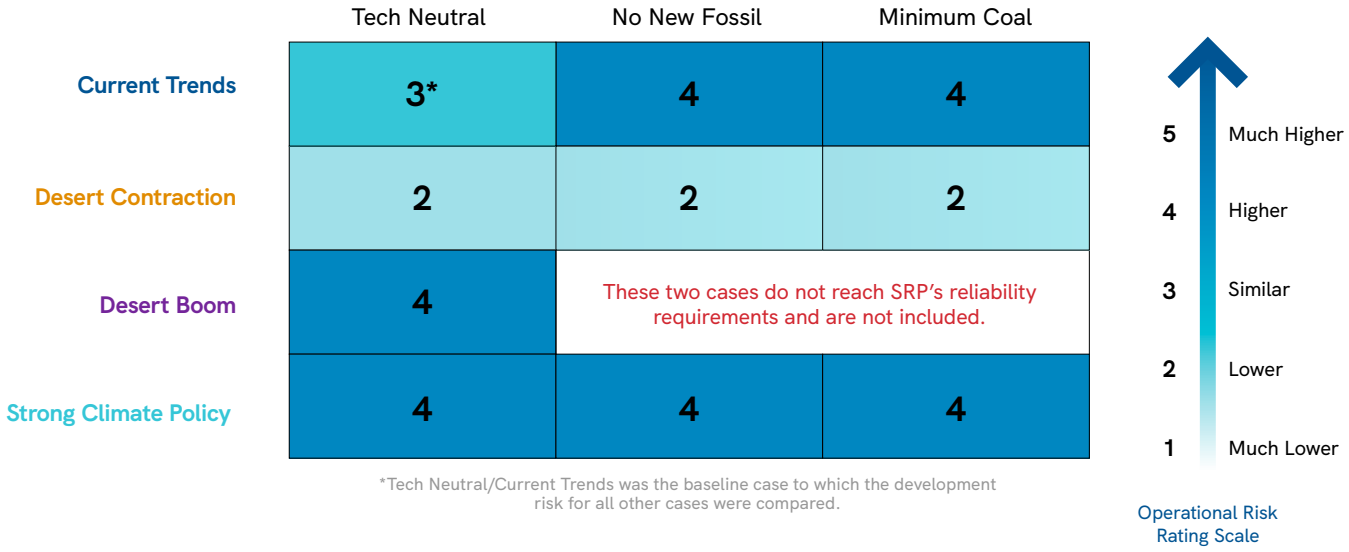
Curtailment. As variable renewable generation increases as a share of SRP's generation mix, there will increasingly be time periods when there is more renewable generation than can be delivered to customers, used to charge energy storage, or sold into markets. For example, during spring months, when energy demand is lower due to milder temperatures, solar generation is relatively high. The West already experiences higher levels of solar curtailment during these months, and this will become more pronounced as SRP and other utilities add more solar capacity. This will require changes in system operations to ensure the grid remains in balance. To accommodate these changes, SRP is making improvements to the dispatch of renewable resources to both curtail their energy production in a way that is most cost-effective and leverages their capabilities, when possible, and to provide ancillary services for controlling small mismatches between customer demand and generation. SRP is also exploring other uses for excess power generation, including storing in long-duration energy storage and generating hydrogen through electrolysis.

Operational Risk Ratings

SRP developed an operational risk rating for each of the core system plans in the ISP, as shown in Figure 6.27, using many of the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the operational risk associated with that plan.

The three Desert Contraction system plans have a lower operational risk level because annual energy demand is lower, variable generation penetration is lower, and natural gas fuel demand is lower. These three factors mitigate many of the identified operational risks. The three Strong Climate Policy plans have a higher operational risk level because these plans would require a complete transformation of system operations, including a high generation share from variable resources, increased ramping needs, and increased stress for natural gas-fired generators that would need to start up, shut down and ramp up output more frequently. The No New Fossil Current Trends and Minimum Coal Current Trends system plans also have a higher operational risk level for similar reasons, although the operational risk is slightly lower due to a higher share of generation from dispatchable resources. The Technology Neutral Desert Boom system plan has a higher operational risk level because this plan would require increased natural gas fuel consumption to a point that may not be feasible without significant expansion to the regional natural gas delivery system. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

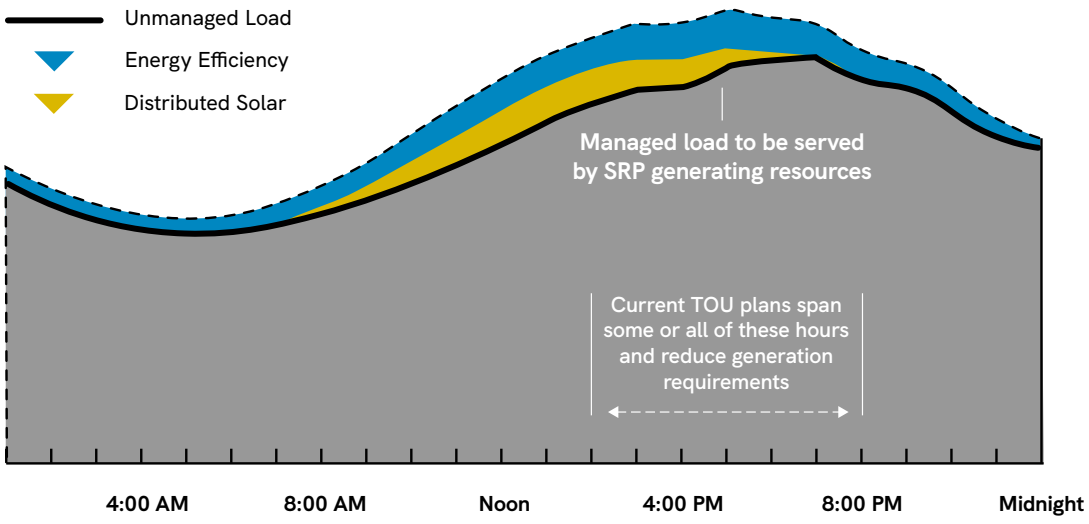
FIGURE 6.27: OPERATIONAL RISK RATING



Considerations for Future Customer Programs and Pricing Plans

Customer programs and pricing plans play an important role in managing SRP's load and peak energy demand. Figure 6.28 includes an illustrative projected peak day in 2035 and depicts how energy efficiency, distributed solar and time-of-use (TOU) programs can reduce SRP's load. Energy efficiency reduces total energy consumption throughout the day; distributed solar offsets generation from other resources during daytime hours; and TOU price plans can incentivize customers to reduce demand during peak hours. After accounting for these programs, the remaining load that SRP must serve is lower and shifted slightly later in the day.

FIGURE 6.28: ILLUSTRATIVE DEPICTION OF HOW CUSTOMER PROGRAMS AND PRICE PLANS HELP SRP MANAGE PEAK ENERGY DEMAND



SRP's existing customer programs work well for demand management in the current system. However, as increasing amounts of solar and wind are added to the system, the net load that is served by dispatchable resources begins to peak after the existing TOU window, as shown in Figure 6.29. This highlights the growing need for evening and overnight load reduction. However, the growth of mid-day renewable generation also presents the opportunity to shift load to these low-cost, low-emissions hours.

FIGURE 6.29: CUSTOMER PROGRAMS AND PRICING PLANS CAN HELP SRP MEET NEW SYSTEM NEEDS

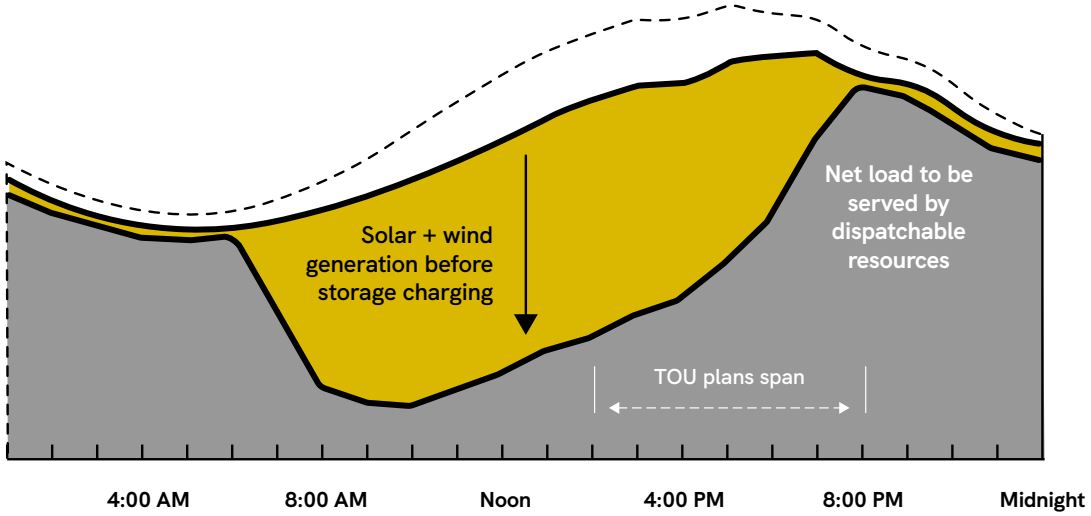


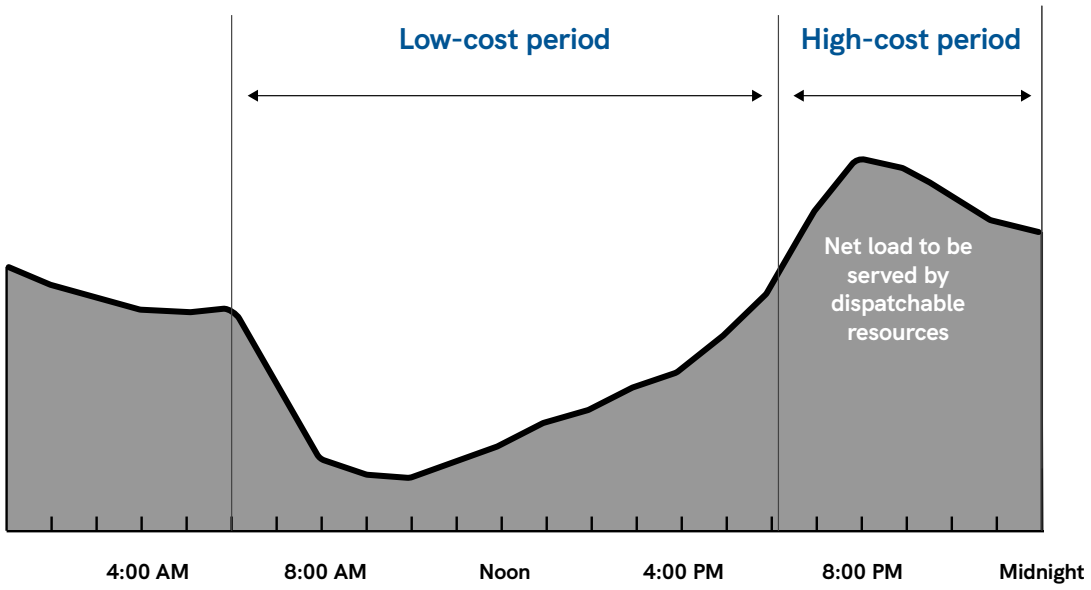
Figure 6.30 illustrates how system costs will change in the future system, with high-cost hours shifting to later in the evening, between 6 p.m. and midnight, and the low-cost period shifting to mid-day.

KEY FINDINGS

SRP will need to evolve programs and price plans to encourage shifts in consumer behavior, and further educate customers on when to consume and when to conserve energy.

Changes in how our customers use energy will require continued innovation and flexibility in planning.

FIGURE 6.30: AS THE SYSTEM TRANSFORMS, NET LOAD IS THE NEW TARGET FOR PRICING AND PROGRAMS.



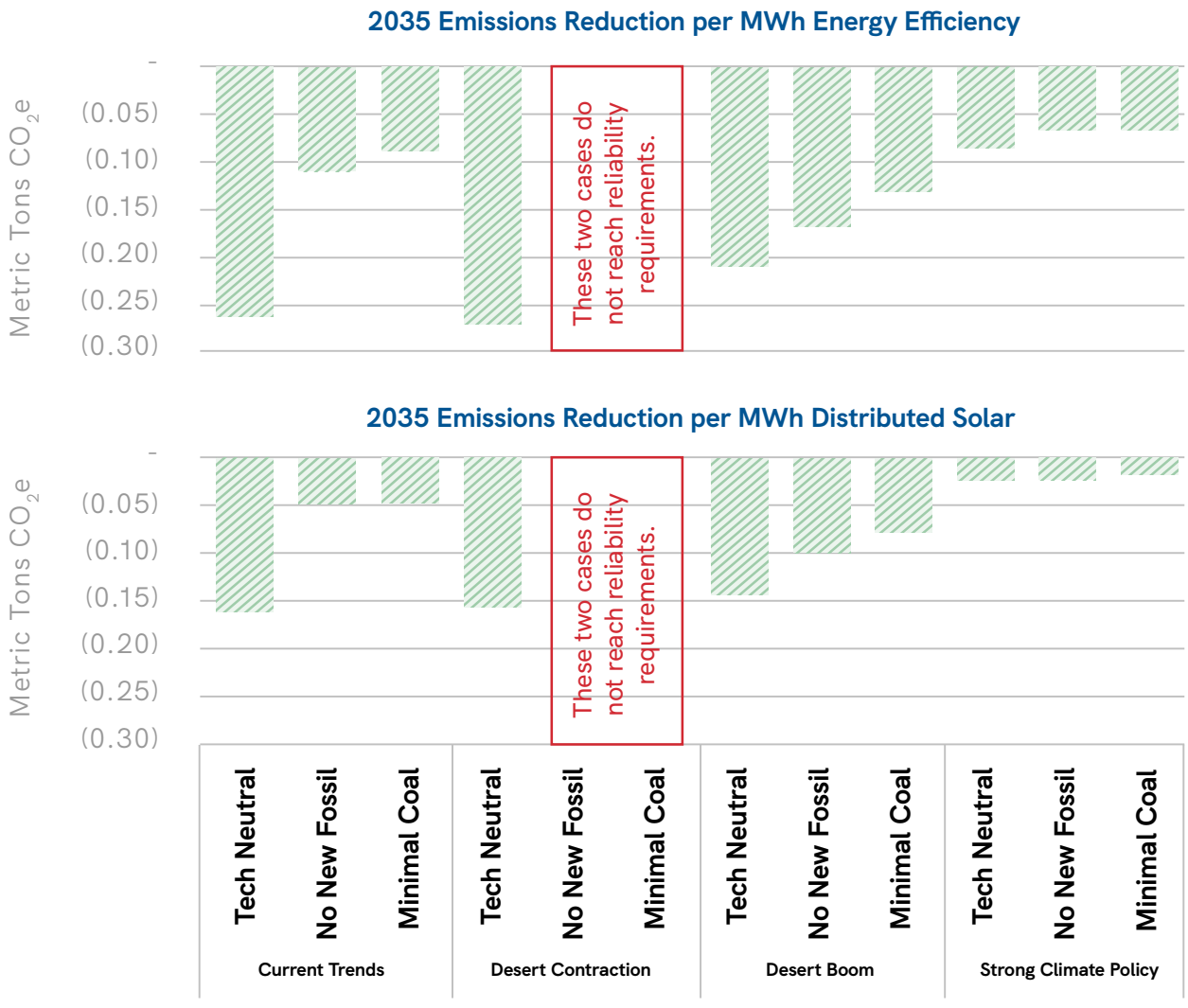
CO_2 Emissions Reductions from Energy Efficiency, Distributed Generation and Electrification

As customer programs reduce energy demand and peak load, they can also enable CO_2 emission reductions. Figure 6.31 first shows the avoided CO_2 per MWh of energy efficiency and distributed generation. Both programs result in avoided emissions without any increased grid emissions. The programs result in greater avoided CO_2 under Technology Neutral (except for under Strong Climate Policy) because the energy mix comprises a greater share of carbon-emitting sources in those cases. As the power sector decarbonizes, marginal carbon emission reductions from energy efficiency and distributed generation will diminish over time because the impacts of these programs tend to align with hours of lower marginal emissions. This finding is particularly prominent under Strong Climate Policy cases due to the more stringent carbon targets. However, continuing to offer programs that reduce load during high-demand hours will lead to greater emissions reductions.

KEY FINDING

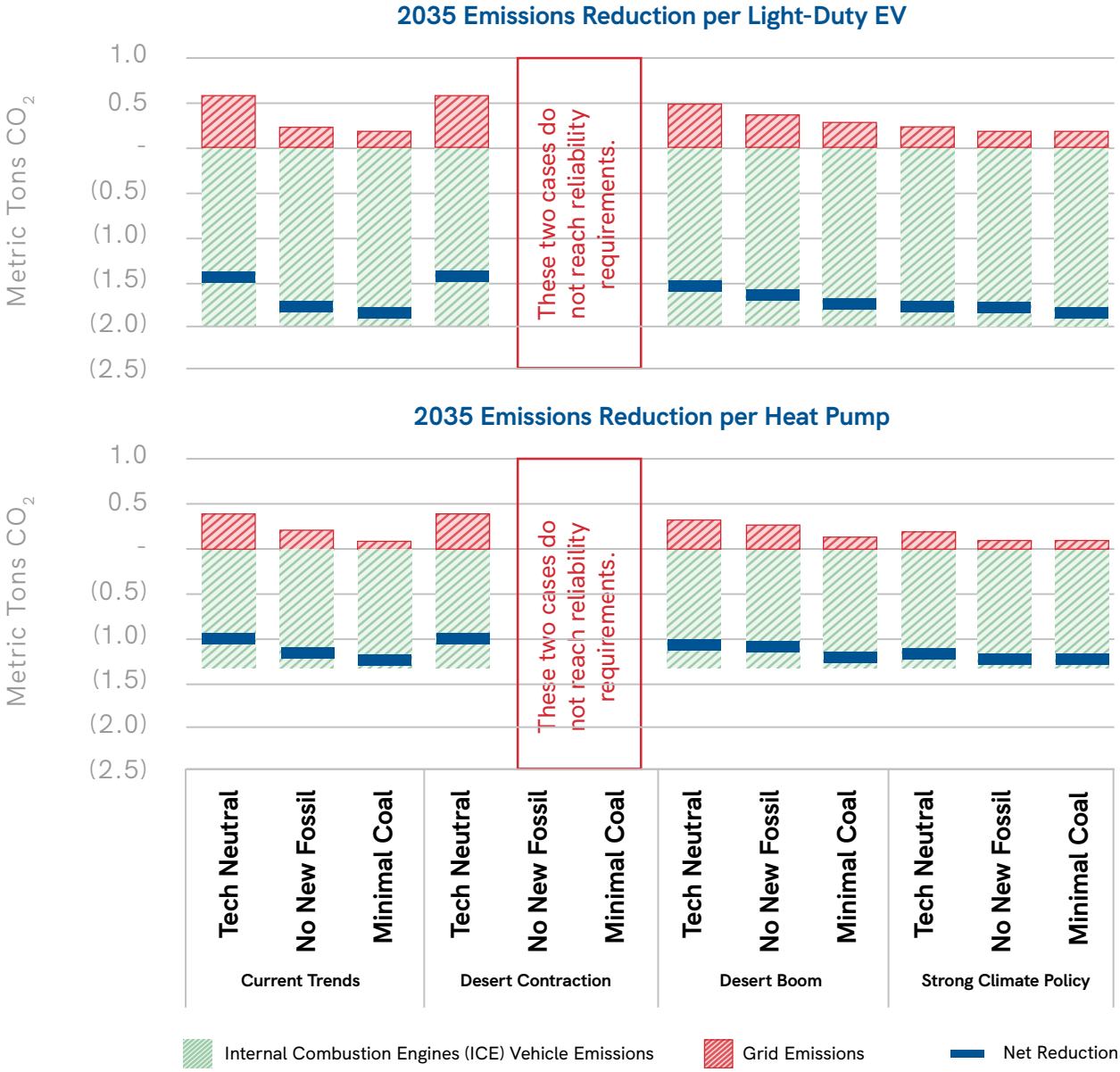
Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

FIGURE 6.31: AVOIDED CO_2 FROM ENERGY EFFICIENCY AND DISTRIBUTED GENERATION



Transportation and building electrification can also result in economywide carbon reduction, such as through greater adoption of electric vehicles and heat pumps. However, as these measures shift energy consumption to the electricity system, potential increases in grid emissions need to be accounted for. Figure 6.32 shows the marginal emission reductions, grid emissions and net reductions from light-duty electric vehicles and heat pumps in each scenario in 2035. The reduction in carbon emissions by replacing internal combustion engine vehicles outweighs the incremental emissions from EV charging loads. Under the current rate structure, light-duty and heavy-duty vehicles primarily charge overnight, when grid emissions are higher. However, shifting EV charging to daytime periods, when emissions are lower, through managed charging programs and/or pricing plans, could lead to further emissions reductions. Similarly, although incremental load from heat pumps increases carbon emissions on the grid, carbon emission reductions from offsetting gas usage is much more significant. In this case, heat pump usage concentrates in the morning when grid emissions are relatively high.

FIGURE 6.32: AVOIDED CO_2 FROM ELECTRIC VEHICLES AND HEAT PUMPS



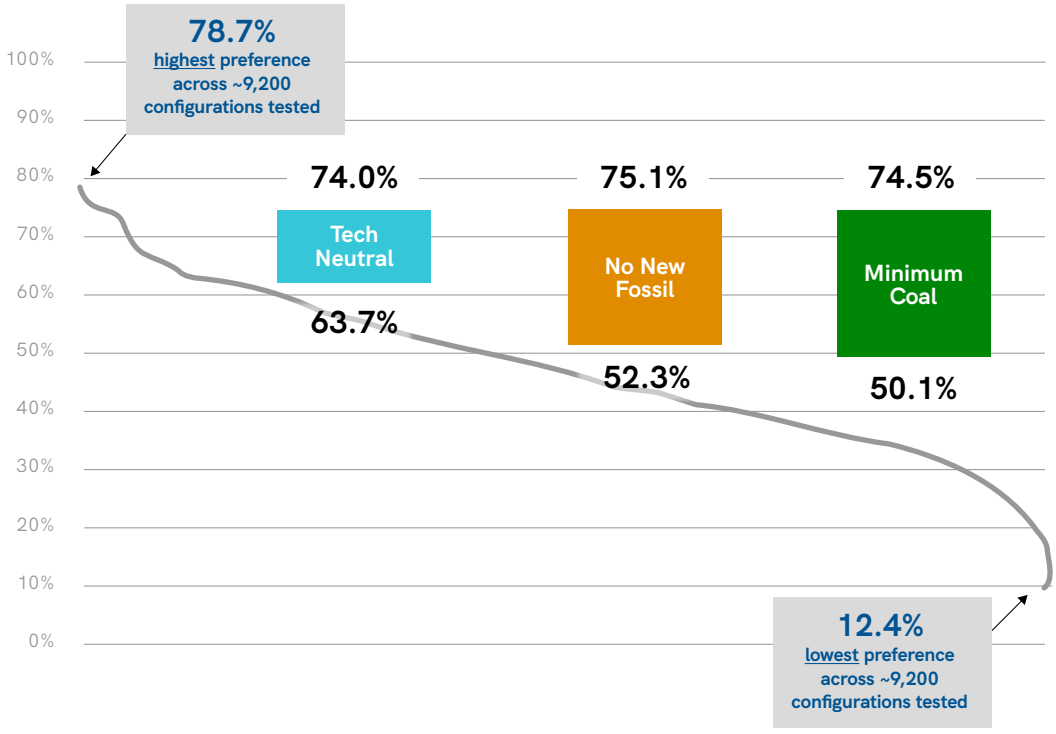
Residential Customer Research

Research consultant Bellomy assisted in the development of a Customer Preference Rating for each of the core system plans in the ISP, as shown in Figure 6.33. This metric was developed using over 1,000 residential customers' responses in a conjoint survey designed to understand how they value different aspects of the power system.

Residential Customer Preference Ratings represent the percentage by which customers expressed preferences of each strategic approach in various future scenarios relative to SRP's current system. Based on the results of the residential customer surveys, the preference ratings ranged between 12% and 79% versus the current system when all potential configurations were considered. System plans analyzed in this research that represented the ISP strategic approaches all achieved preferences over 50% versus SRP's energy system today.

Key findings from the research revealed that Technology Neutral was the most favorable strategic approach by SRP residential customers in futures with higher load growth such as Desert Boom and Current Trends. On the other hand, Minimum Coal and No New Fossil strategic approaches had a greater preference in futures where load growth was low, such as Desert Contraction, and additional federal incentives for carbon-free and hydrogen technologies were assumed, like in the Strong Climate Policy future scenario. Overall, there were more consistent preferences for Technology Neutral across the various futures when compared to the other strategic approaches.

FIGURE 6.33: CUSTOMER PREFERENCE RATINGS - SHARE OF PREFERENCE VERSUS CURRENT ENERGY SYSTEMS



Note: Within the Strong Climate Policy scenario, cases for Tech Neutral and No New Fossil are identical. Only one illustrative mix was shown to customers to represent both cases, thus data shown are identical for these two cases. No New Fossil and Minimum Coal cases were not tested in Desert Boom because they did not reach reliability targets.

Key findings from Residential Customer Research

Top factors – affordability and bill impacts: Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes, who make up approximately a third of SRP's residential customer base, put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change: Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy and overall quality of life. Thus, they understood the need for a lower-carbon future energy system. Across scenarios, however, lower-cost strategic approaches were preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage: Customers reported positive experiences with SRP's current programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts and infrastructure improvements.

Recommendations from residential customers for SRP's ISP

Findings revealed that from the residential customer's perspective, the ideal future energy system should:

- Manage cost, first and foremost.
- Keep monthly bill impacts below a 10% increase (from current electricity bills).
- Include a diverse energy mix to ensure reliability.
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase (from current electricity bills).

For additional details about the ISP customer research effort and key findings, please refer to the full reports for phases 1, 2 and 3 provided as appendices to this report.

Sensitivities

This section presents results for the 10 sensitivities that SRP analyzed for each strategic approach in the ISP.

- High Energy Efficiency
- High Distributed Generation Adoption
- High Demand Response
- Increased Load Management
- High Gas Price
- Low Gas Price
- Volatile Gas Price
- High Technology Cost
- Low Technology Cost
- Regional Diversity

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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

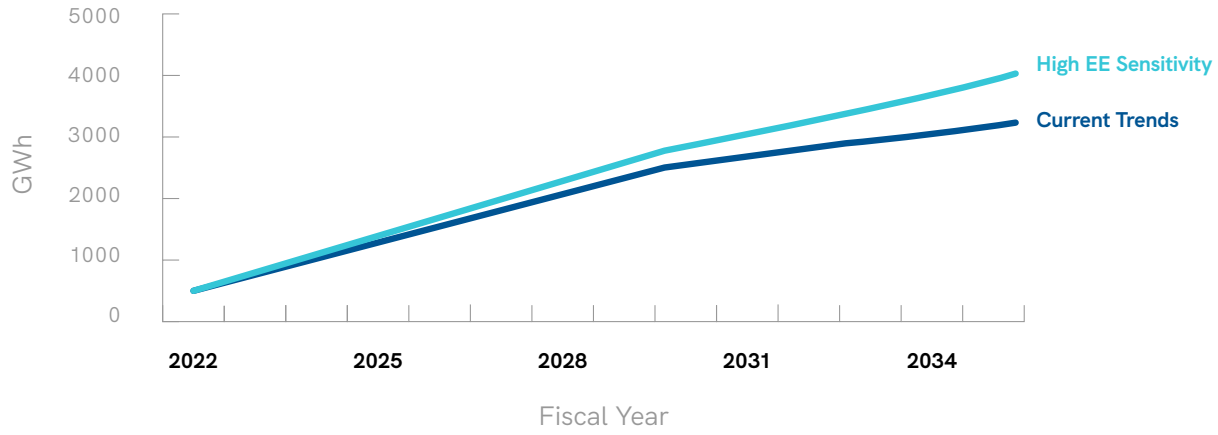
Exhibit 2-100b:
Salt River Project 2023 IRP

Each sensitivity is conducted relative to the Current Trends scenario as that scenario reflected the central planning assumptions. For presentation of the results, the three gas price sensitivities (High, Low and Volatile Gas Prices) are grouped together, as well as the two technology cost sensitivities (High and Low Technology Costs), yielding seven groups of sensitivities.

High Energy Efficiency

In the High Energy Efficiency (High EE) sensitivity, expansion of requirements pursuant to federal codes and standards lead to approximately 700 additional GWh of energy efficiency by 2035 relative to Current Trends. With this higher energy efficiency growth, total energy efficiency savings reach 4,471 GWh by 2035.

FIGURE 6.34: ANNUAL ENERGY EFFICIENCY ASSUMPTIONS



Figures 6.35 and 6.36 show peak load and energy demand forecasts for the High EE sensitivity, compared to Current Trends. In addition to reducing annual energy demand and overall load growth rates through 2035, these expanded energy efficiency customer programs reduce peak load by 395 MW in 2035 relative to Current Trends.

FIGURE 6.35: PEAK LOAD (MW) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

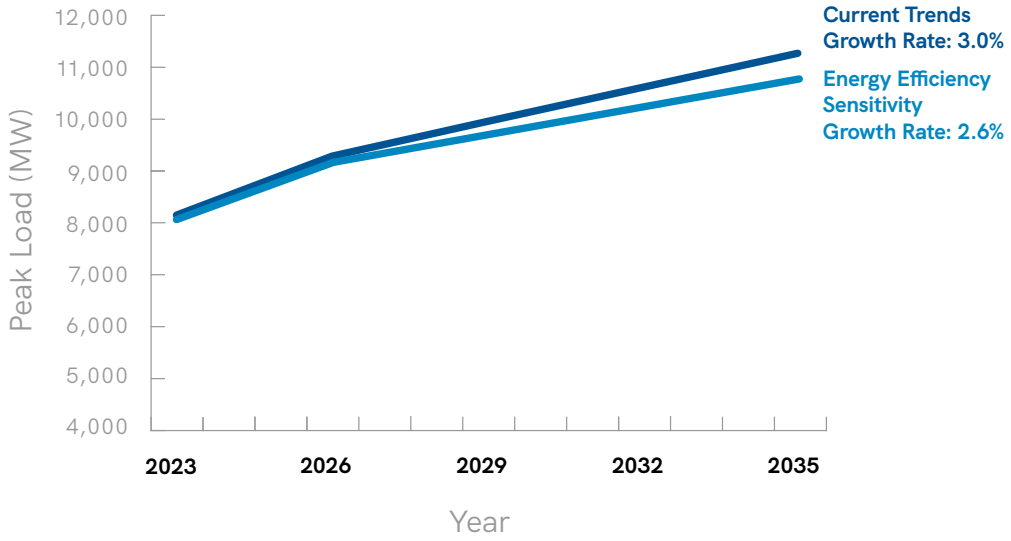


FIGURE 6.36: ENERGY DEMAND (GWH) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

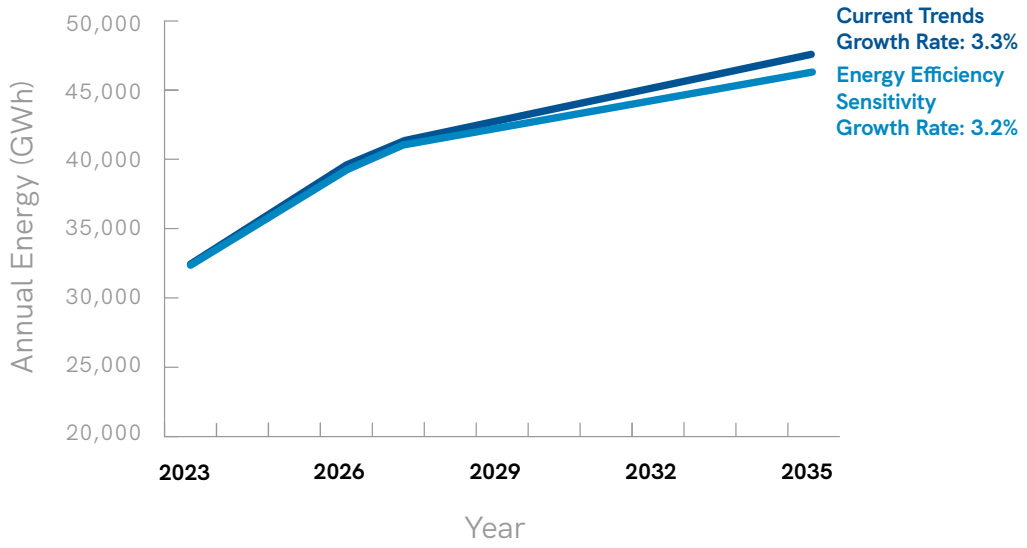
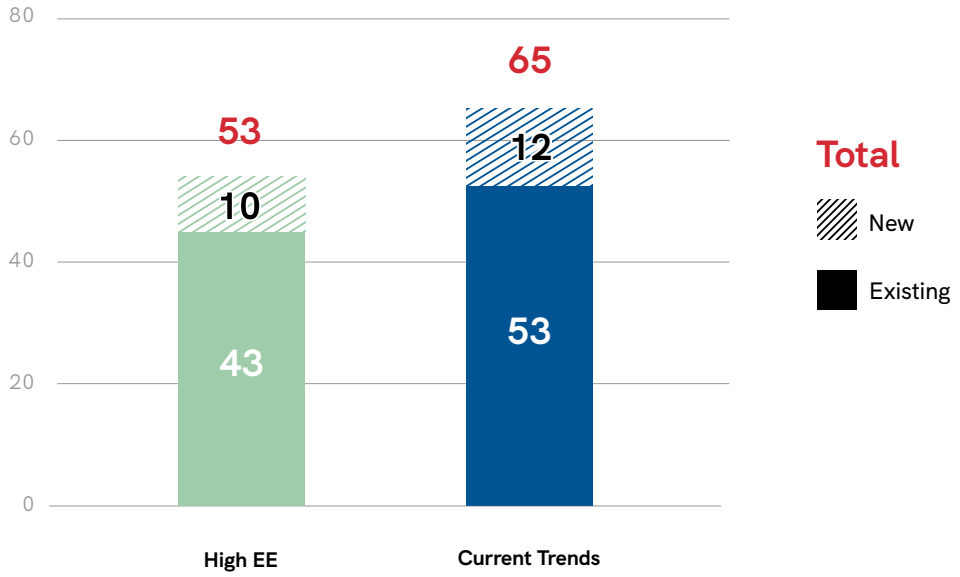


Figure 6.37 shows the distribution substation bay additions under the High EE sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High EE sensitivity results in slightly fewer substation bay additions than in Current Trends. The investment needs are similar to the Strong Climate Policy scenario, however, because the load forecasts are similar. The sensitivity results demonstrate a potential for energy efficiency to help defer distribution investment needs. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.37: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH ENERGY EFFICIENCY SENSITIVITY



As shown in Figure 6.38, the additional energy efficiency in the High EE sensitivity case reduces the need for resources across all strategic approaches. In the Technology Neutral case, there are about 400 MW less new gas peaker builds in the High EE sensitivity than in Current Trends. In the No New Fossil and Minimum Coal cases, there are even fewer resource builds, particularly batteries (which had been the primary resource selected to meet capacity needs) and solar (which is less economic to add with fewer batteries to integrate the solar).

FIGURE 6.38: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH ENERGY EFFICIENCY SENSITIVITY

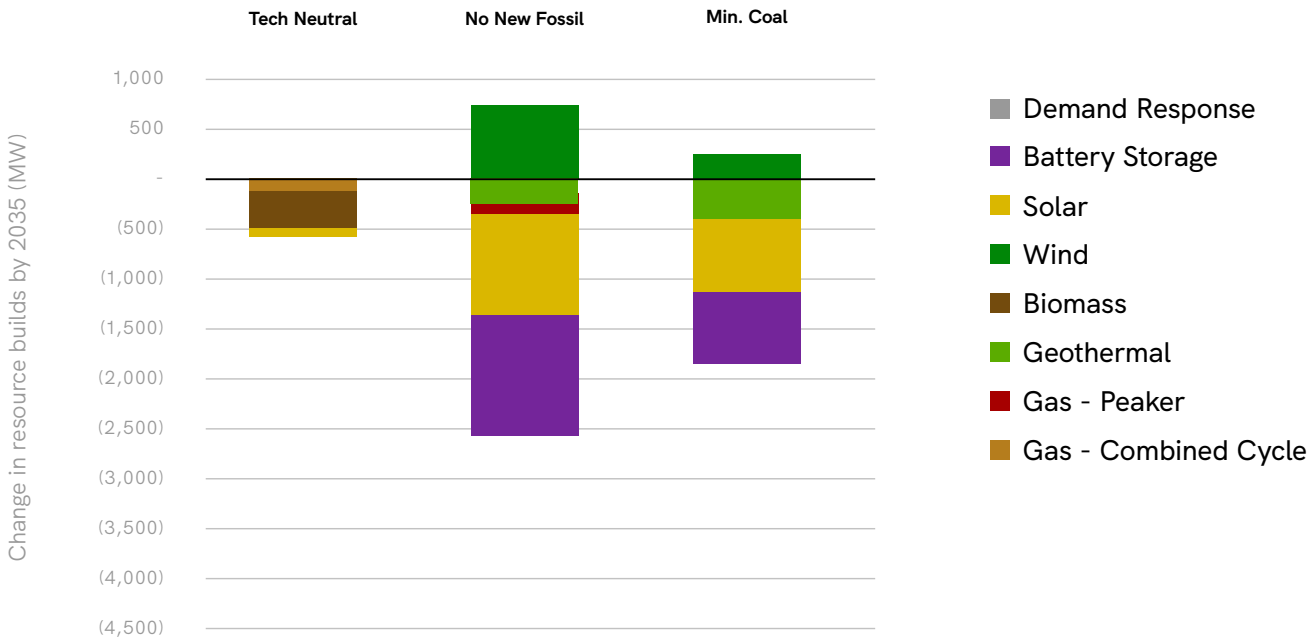
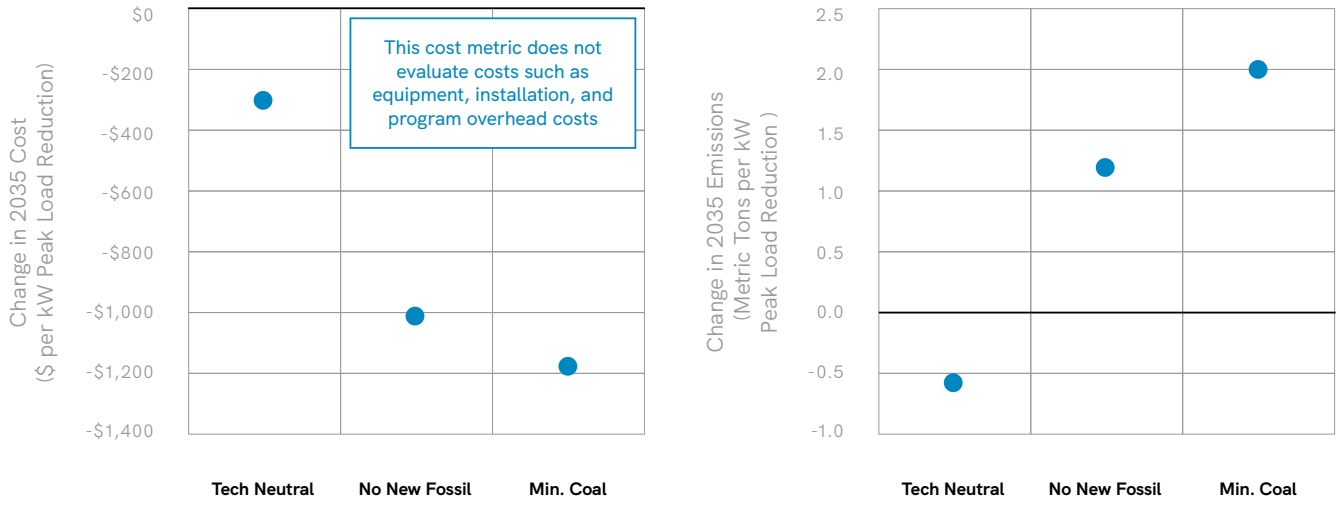


Figure 6.39 shows the resulting changes in total system cost and emissions under the High EE sensitivity, normalized by the kW reduction in PRM from the increased energy efficiency. It is important to note that the results do not include costs such as equipment, installation and program overhead, nor incentive payments or lost revenue that are relevant to ratepayer benefits and costs (such as those captured in the Ratepayer Impact Measure test). Because higher energy efficiency reduces the PRM requirement and the cost of meeting the PRM requirement under No New Fossil and Minimum Coal is higher without new firm resource options, additional energy efficiency results in greater cost savings in the Minimum Coal and No New Fossil cases. Conversely, additional energy efficiency results in relatively lower savings in the Technology Neutral case, where there are new firm capacity options. The Minimum Coal and No New Fossil cases also experienced emissions increases with more energy efficiency due to a net offset in renewable resource capacity and greater natural gas generation and market purchases, while the Technology Neutral case saw a decline in emissions due to a reduction in natural gas generation.

FIGURE 6.39: HIGH ENERGY EFFICIENCY: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, the High EE sensitivity case demonstrates the ability for energy efficiency to not only offset overall energy demand but also demand during peak periods, which in turn can help mitigate the need for incremental investments in the distribution system and firm capacity resources. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

High Distributed Generation Adoption

The High Distributed Generation sensitivity included approximately 960 additional MW of distributed solar and approximately 175 MW of distributed storage by 2035. The expanded distributed generation reduces annual peak load and energy demand growth relative to Current Trends, as shown in Figure 6.41.

FIGURE 6.40: HIGH DISTRIBUTED GENERATION SENSITIVITY CAPACITY (MW)

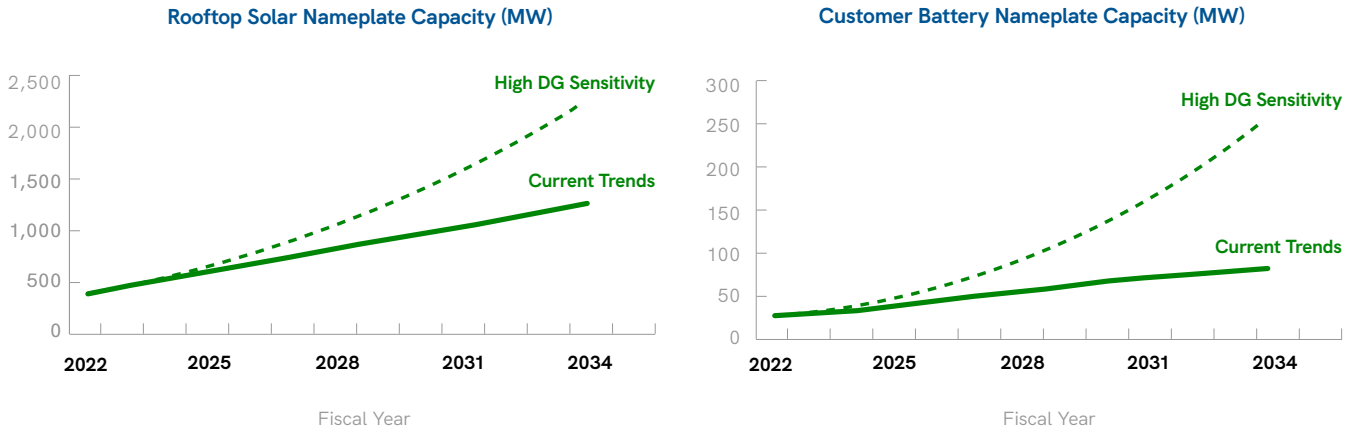


FIGURE 6.41: PEAK LOAD (MW) AND ENERGY DEMAND (GWH) FORECASTS - HIGH DISTRIBUTED GENERATION SENSITIVITY

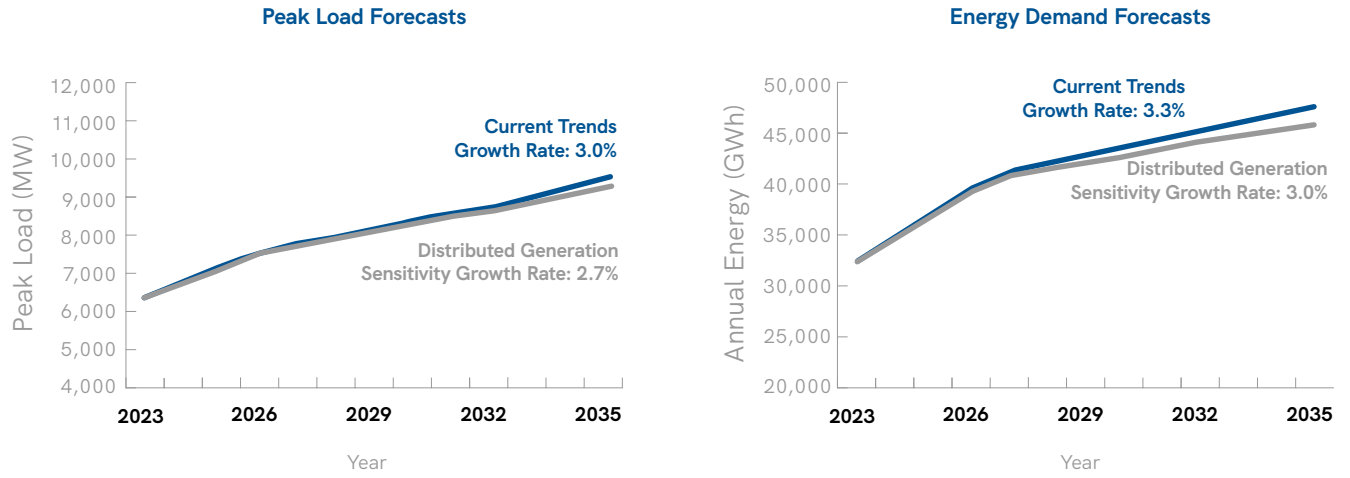
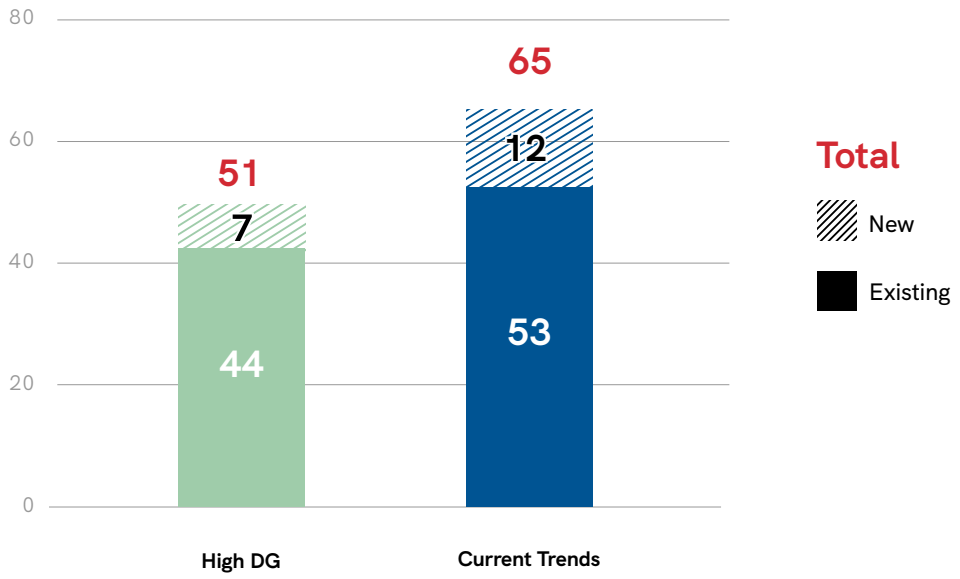


Figure 6.42 shows the distribution substation bay additions under the High Distributed Generation sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High Distributed Generation sensitivity results in slightly fewer substation bay additions than in the Current Trends scenario. The load forecast for this sensitivity is similar to that in the Strong Climate Policy scenario, which is why the investment needs are similar between these two cases. This result reflects the potential for distributed generation to help defer distribution investment needs generally. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.42: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH DISTRIBUTED GENERATION SENSITIVITY



Additional distributed generation reduces the overall need for new resources, as shown in Figure 6.43. In the Technology Neutral case, increased distributed solar primarily displaces utility-scale solar, while distributed storage displaces some natural gas capacity. In the No New Fossil and Minimum Coal cases, increased distributed generation primarily displaces utility-scale solar and storage.

FIGURE 6.43: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DISTRIBUTED GENERATION SENSITIVITY

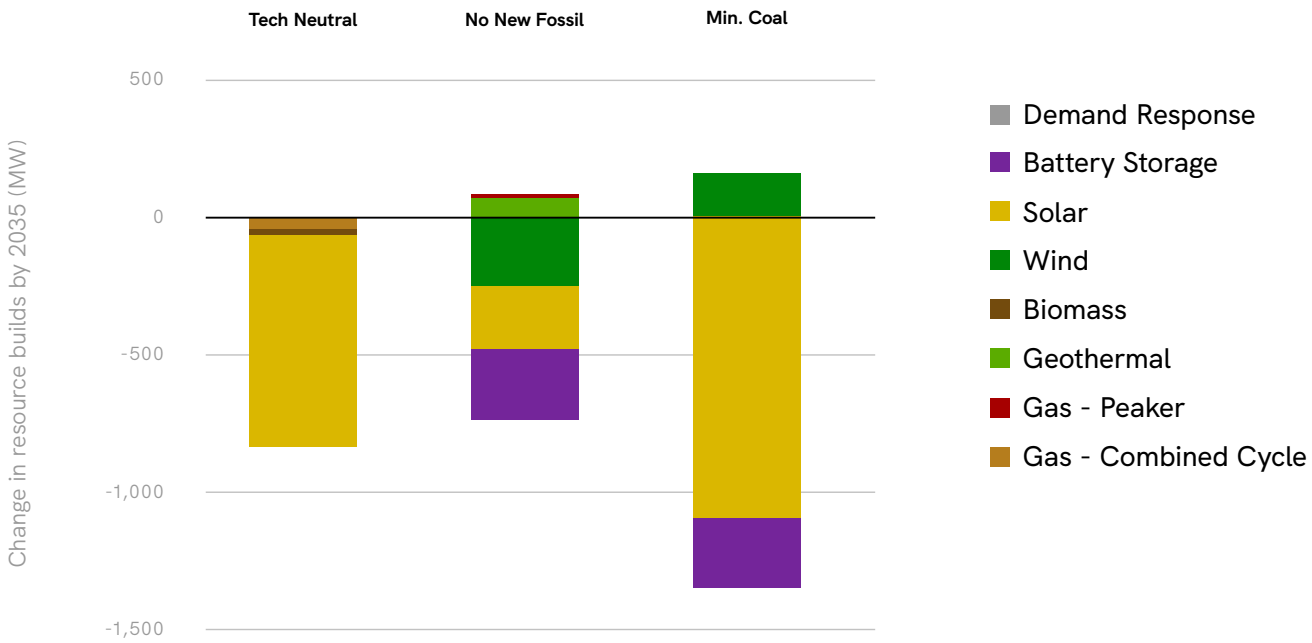
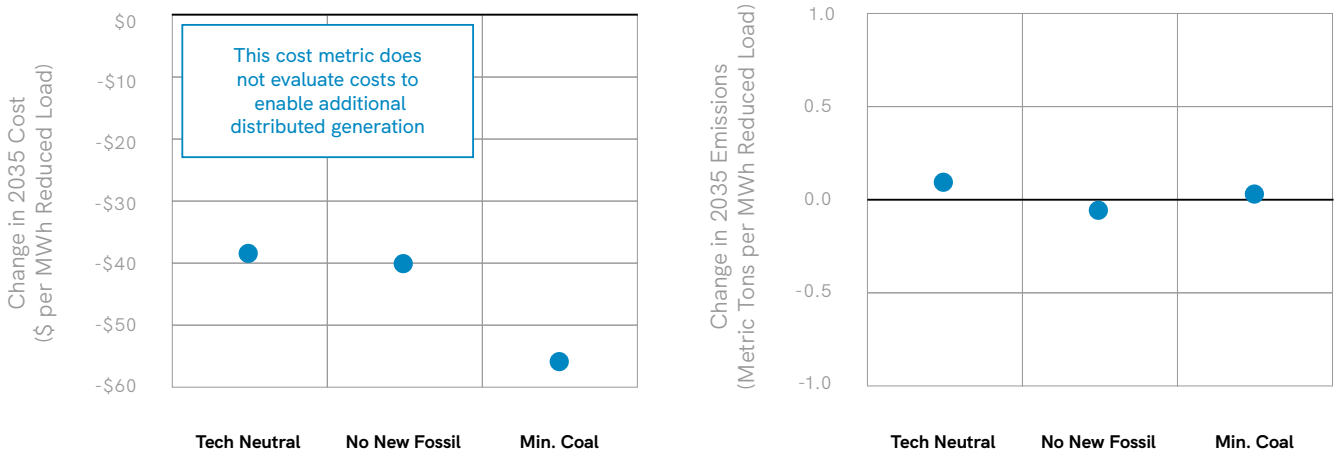


Figure 6.44 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the MWh of reduced load from additional distributed generation. It is important to note for these results that there is uncertainty as to how well distributed storage dispatch would align with grid needs and that these results do not include the costs to SRP or its customers of adding the distributed generation. Adding distributed generation generally leads to total system cost reductions, with the greatest reductions in the Minimum Coal case due to the greatest offset of capacity. However, there was very little impact of distributed generation on emissions across all cases, given it primarily substituted distributed solar generation for utility-scale solar generation.

FIGURE 6.44: HIGH DISTRIBUTED GENERATION: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY MWH REDUCED LOAD

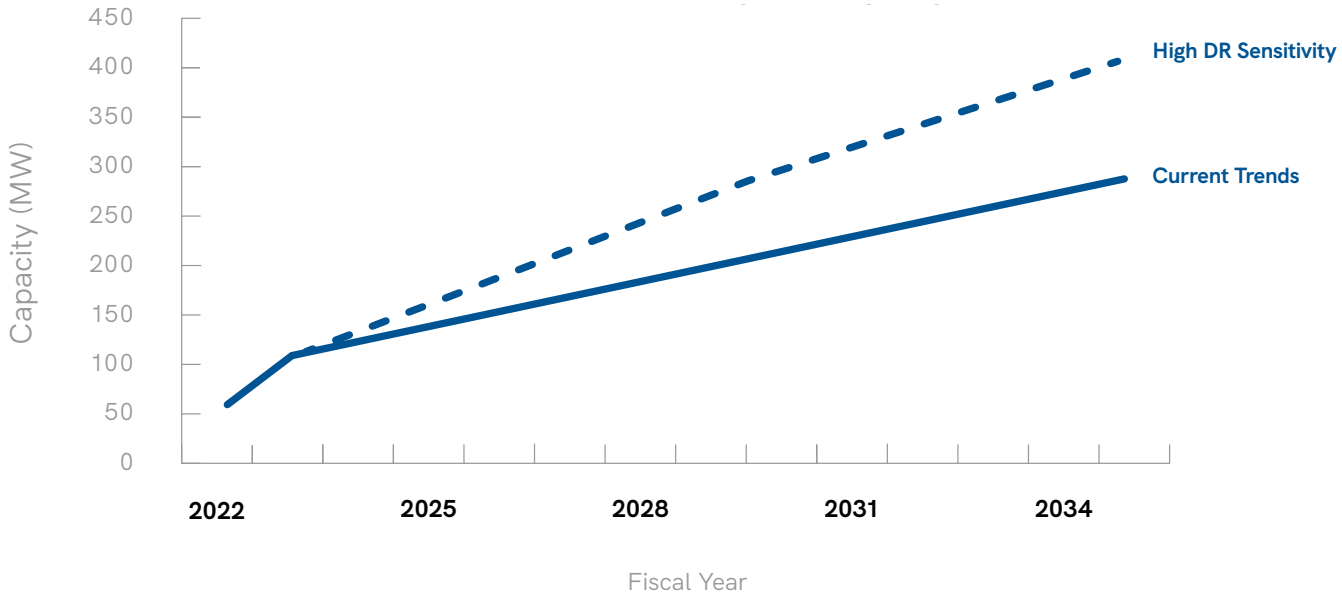


Overall, increased levels of distributed generation resources (solar PV and battery storage) reduce overall energy demand as well as energy demand during peak periods that need to be served by utility-scale resources. As a result, increased adoption of these resources helps mitigate the need for incremental distribution system investments and offsets the need for some utility-scale generation resources: Distributed solar primarily helps offset utility-scale solar, while increased distributed storage is able to offset a portion of capacity resources (gas and/or batteries). The analysis finds that increased adoption of distributed resources leads to the greatest reductions in total system costs in the Minimum Coal strategic approach due to the greatest offset of utility-scale resources and a relatively small impact on emissions across all cases.

High Demand Response

The High Demand Response sensitivity assumes an additional 100 MW of demand response by 2035, reaching a total of 400 MW (compared to 300 MW under the Current Trends scenario).

FIGURE 6.45: ANNUAL DEMAND RESPONSE CAPACITY ASSUMPTIONS



The additional demand response capacity results in a change in resource builds relative to the Current Trends scenario, as shown in Figure 6.46. Increased demand response displaces capacity resources in all strategic approaches. In the Technology Neutral case, adding an additional 100 MW of demand response reduces over 30 MW of natural gas peaker builds.
In the No New Fossil and Minimum Coal cases, the additional demand response substitutes for 50 MW of battery storage builds. The outcome that the reduction of battery capacity is equal to half of the demand response additions reflects the assumption that demand response provides less reliability capacity to the system than batteries; while demand response and battery resources provide similar services to the system, demand response is more limited in number and duration of dispatch events. Because some of the storage resources that are offset are battery storage paired with solar, there is a reduction in solar capacity and a corresponding increase in wind (and biomass in No New Fossil). Less capacity is offset in the Technology Neutral case because natural gas capacity has a greater contribution to reliability needs relative to demand response, battery storage and solar.

FIGURE 6.46: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DEMAND RESPONSE SENSITIVITY

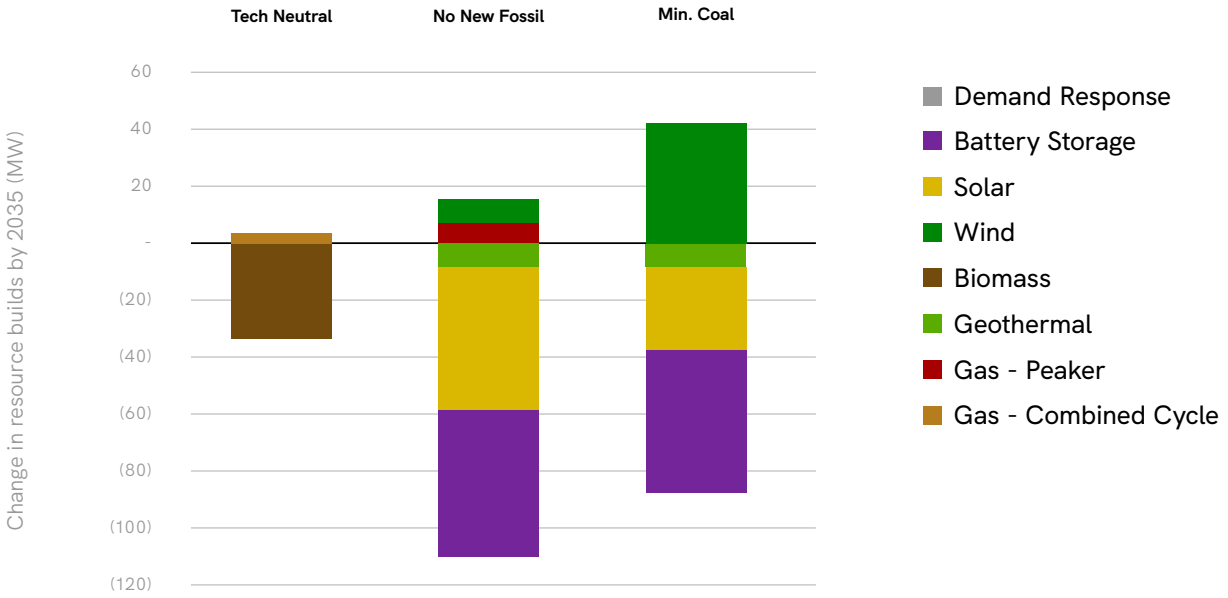
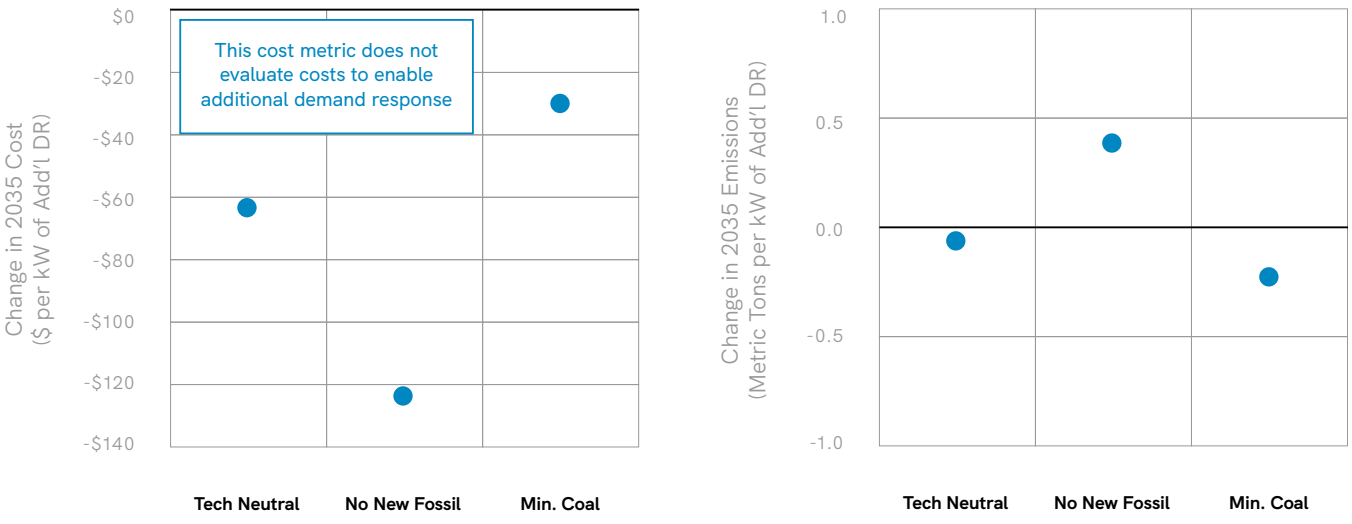


Figure 6.47 shows the resulting change in total system cost and emissions under the sensitivity, normalized by the additional demand response capacity. Note that the total system cost metric does not include the incremental costs needed to enable this additional demand response capacity, so the change in total system cost only reflects gross savings and not net savings. Additional demand response results in the greatest gross savings under the No New Fossil case due to larger offsets in capacity additions. The Technology Neutral case has a smaller reduction in costs because a relatively small amount of natural gas capacity is offset. Emissions increase in the No New Fossil case when demand response is added due to a slight increase in gas emissions to compensate for the net reduction in clean energy capacity. There are small emissions reductions in Technology Neutral due to the reduction in gas capacity and in the Minimum Coal case due to the greater additions of wind capacity offsetting the displaced capacity.

FIGURE 6.47: HIGH DEMAND RESPONSE: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW OF ADDITIONAL DEMAND RESPONSE



Overall, increased levels of demand response largely help mitigate the need for capacity resources (gas and/or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees an uptick in emissions.

Increased Load Management

The Increased Load Management sensitivity assumed that there is an additional 200 MW of aggregate flexibility through managed EV charging or other flexible loads, allowing SRP to shift up to 800 MWh of energy demand each day.

SRP found that increased load management displaces a portion of resources needed for reliability. In the Technology Neutral strategic approach, additional load management reduces gas builds and helps integrate more solar capacity by shifting energy demand from evening hours to daytime hours. In the No New Fossil and Minimum Coal cases, load management substitutes one for one for battery storage capacity, offsetting the paired battery storage and solar that is otherwise built and leading to a small increase in wind.

FIGURE 6.48: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - INCREASED LOAD MANAGEMENT SENSITIVITY

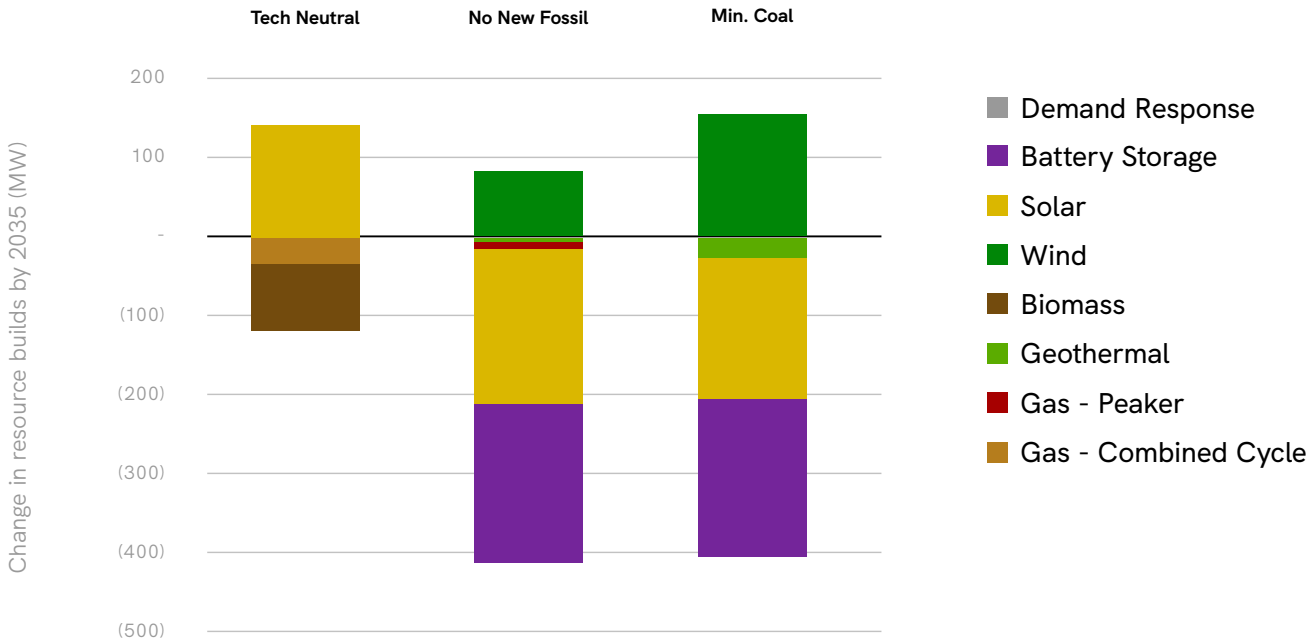
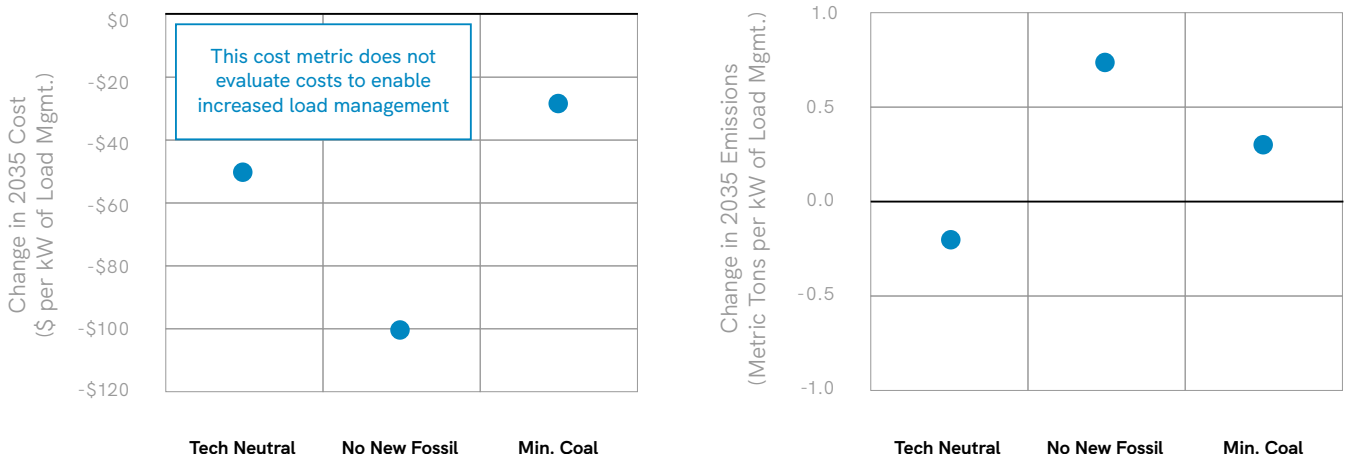


Figure 6.49 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by kW of increased load management. This sensitivity assumes that SRP has sufficient control or can incentivize customers to get desired performance. Additionally, this sensitivity does not evaluate costs to enable increased load management. The dynamics of increased load management are similar to that of demand response, resulting in similar cost and emissions impacts. Relative to the Current Trends scenario, increased load management generally leads to reductions in total system costs, with the greatest impact on the No New Fossil case. The Minimum Coal case has the smallest reduction in costs because greater amounts of wind capacity are added to make up for the reduced solar and battery capacity. While emissions decrease in Technology Neutral due to the reduction in gas generation, emissions increase under No New Fossil and Minimum Coal due to the larger decline in clean energy capacity.

FIGURE 6.49: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW OF INCREASED LOAD MANAGEMENT



Overall, increased levels of load management such as managed EV charging largely help mitigate the need for firm capacity resources (gas or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees the highest uptick in emissions.

High, Low and Volatile Gas Prices

The high and low gas price sensitivity cases were based on the 2022 EIA AEO Low and High Oil & Gas Supply Cases, respectively. SRP found that additions of natural gas and renewable/storage resources depend on gas prices, but in all cases, both new renewables and firm capacity are part of a least-cost portfolio. For example, higher natural gas prices (HGP) increase total capacity additions, driving increases for solar, wind and storage while offsetting some gas capacity. On the other hand, lower natural gas prices (LGP) reduce total capacity additions, driving higher additions of natural gas while offsetting solar and wind additions.

FIGURE 6.50: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO – HIGH AND LOW GAS PRICES SENSITIVITY

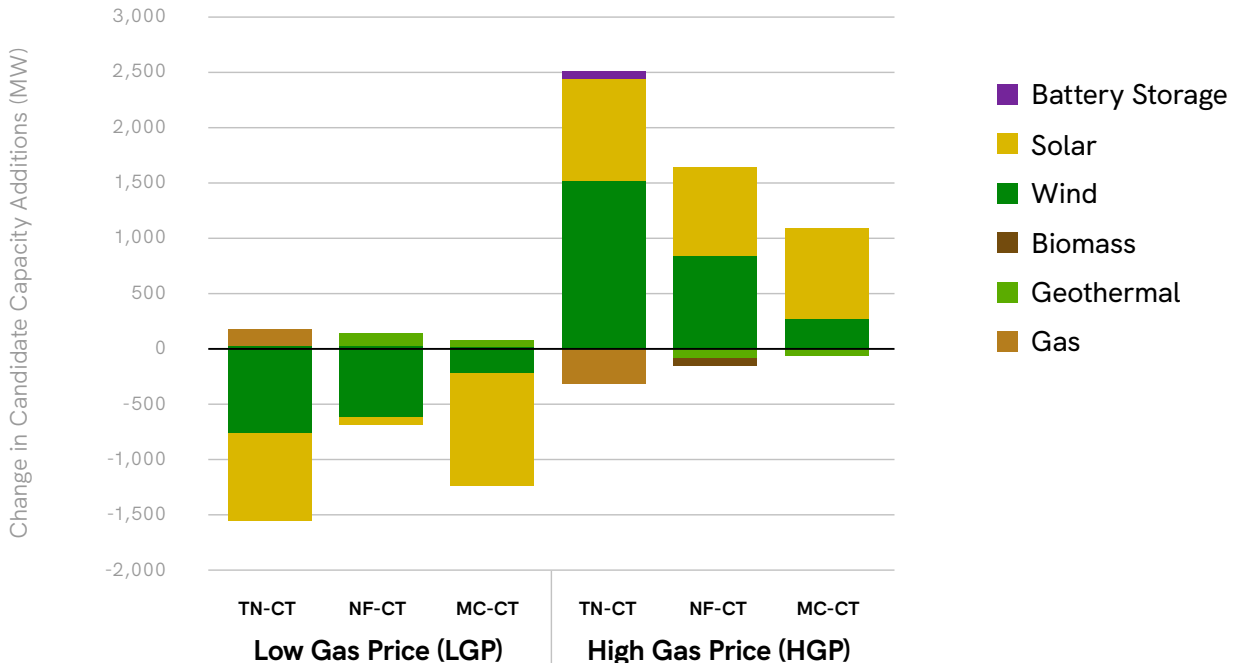


Figure 6.51 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. High Gas Prices had the strongest impact on total system cost for the Technology Neutral approach, while the costs for the No New Fossil and Minimum Coal cases were relatively stable. For Technology Neutral, the High Gas Price sensitivity caused a larger change in cost than the Low Gas Price sensitivity because the high gas prices increased more than the low gas prices decreased. Cost impacts under No New Fossil and Minimum Coal were mild for both the High Gas and Low Gas price sensitivities. Emissions increased in the Low Gas Price sensitivity and decreased in the High Gas Price sensitivity for all strategic approaches, but to a lesser extent for No New Fossil.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas prices.

FIGURE 6.51: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO

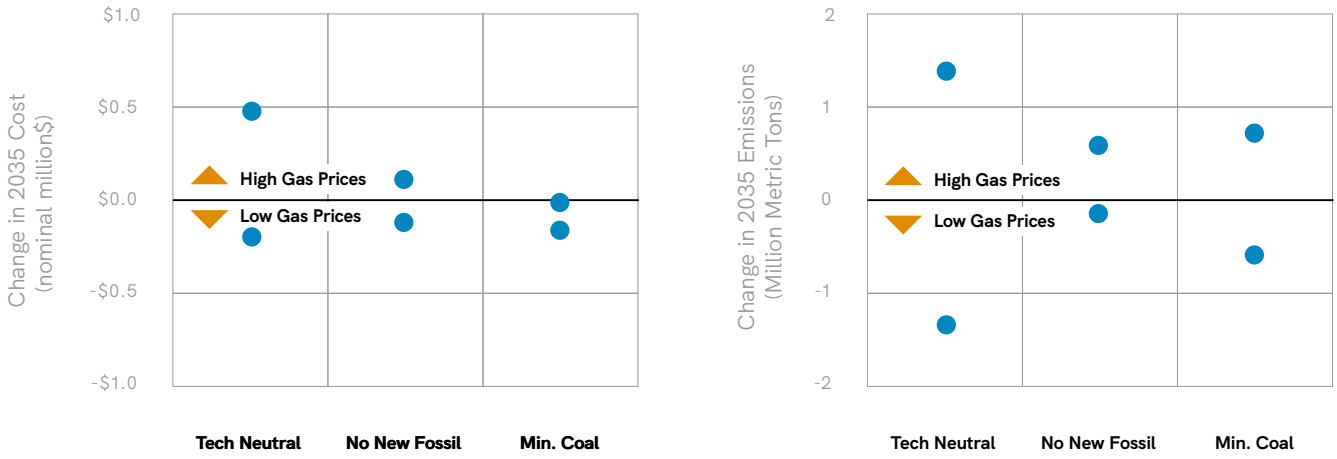
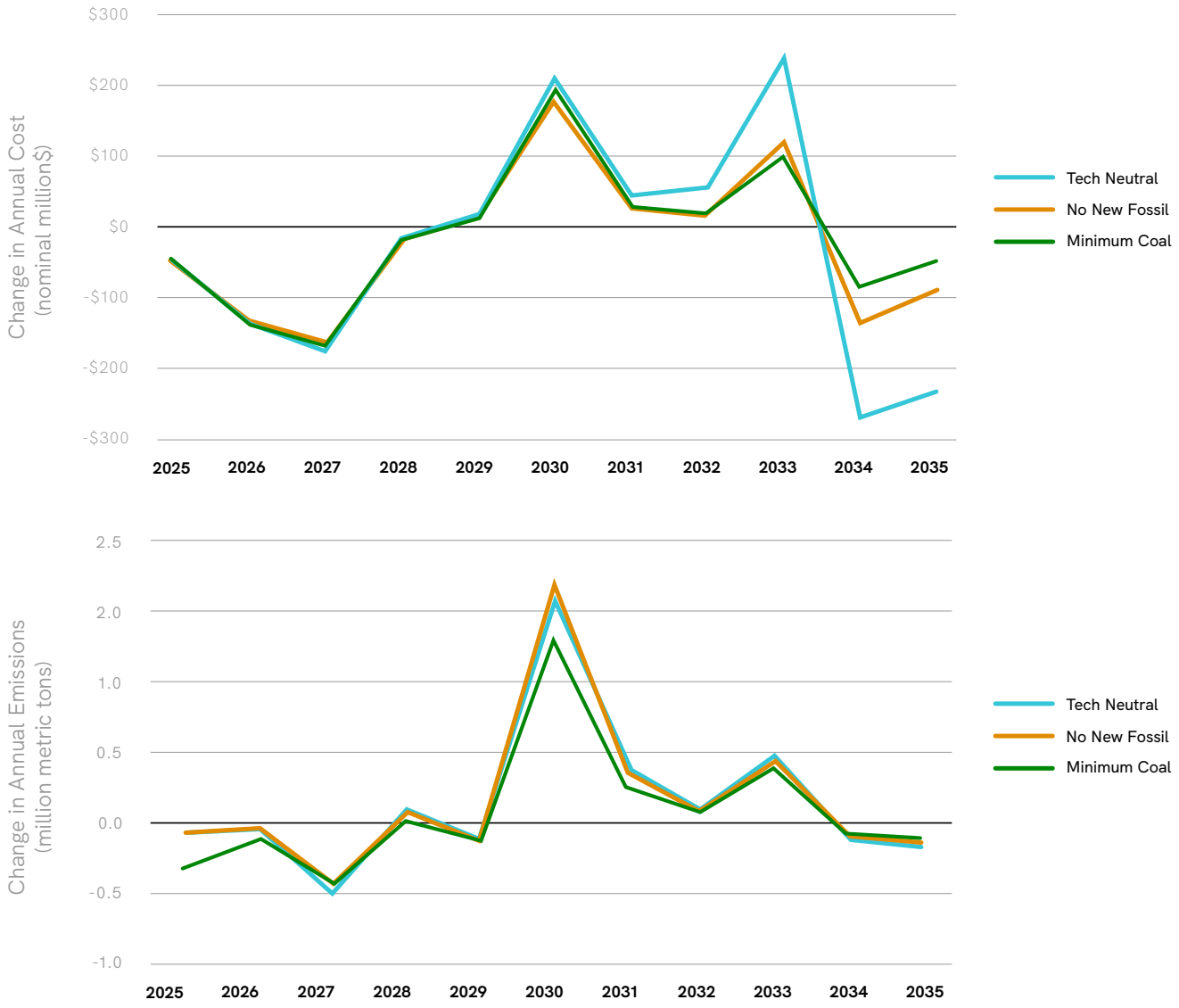


Figure 6.52 shows the impacts of the variable gas price sensitivity on total system cost and emissions between 2025 and 2035, relative to the Current Trends scenario. This sensitivity did not vary resource buildouts, so the changes over time are only a result of changes to gas prices (and associated impacts on market prices). The variability in natural gas prices leads to fluctuations in total system costs, particularly in the 2030s, with total system cost increasing or decreasing by over +/- $200 million in a given year and emissions increasing by over 2 million metric tons in a given year.

FIGURE 6.52: VARIABLE GAS PRICES: ANNUAL CHANGE IN TOTAL SYSTEM COST (TOP) AND EMISSIONS (BOTTOM), RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future natural gas can have important implications for SRP's resource portfolio. Higher natural gas prices result in increased additions of renewables and storage (offsetting a smaller amount of natural gas builds in Technology Neutral), higher total system costs and lower emissions in 2035. Lower natural gas prices result in lower renewable additions (with a slight uptick in natural gas builds under Technology Neutral), lower total system costs and higher emissions. The potential for unexpected gas price volatility in the future could result in higher system costs or emissions.

High and Low Technology Costs

The High and Low Technology Cost sensitivities were based on the 2022 NREL ATB High and Low Cases, respectively. Lower Technology Costs (LTC) increase total capacity additions, driving increases in solar and battery storage while offsetting some natural gas capacity. On the other hand, Higher Technology Costs (HTC) reduce total capacity additions, primarily offsetting solar additions.

FIGURE 6.53: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH & LOW TECHNOLOGY COSTS

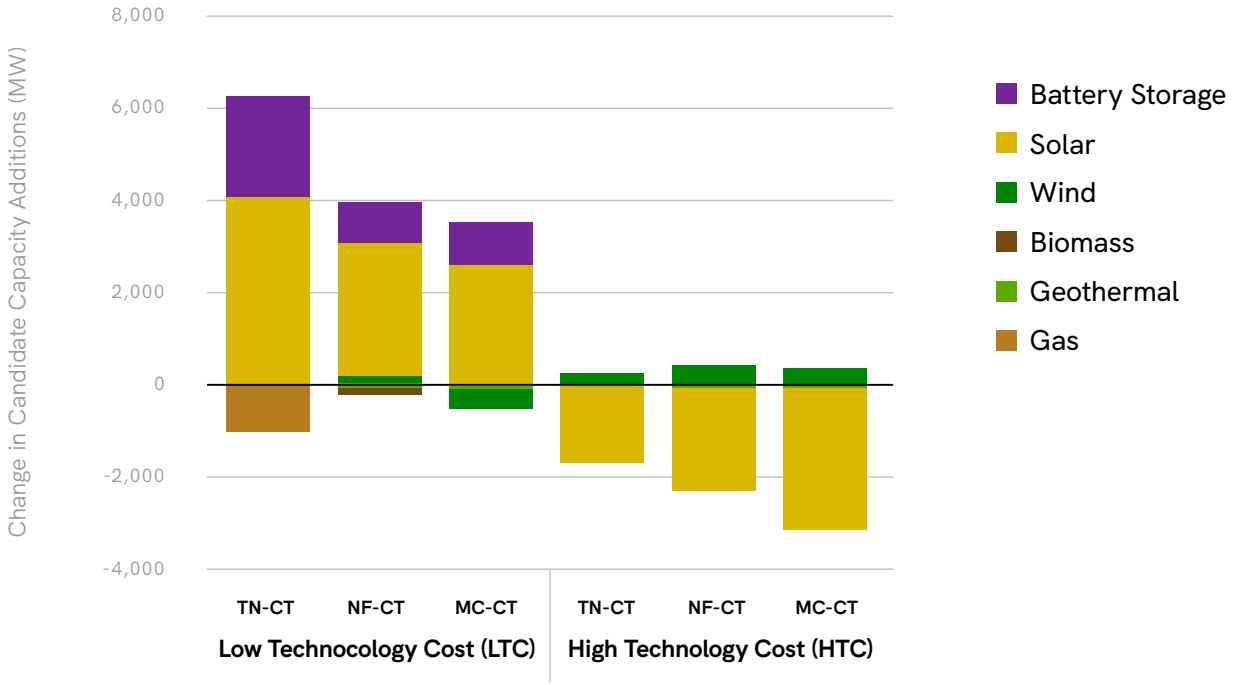
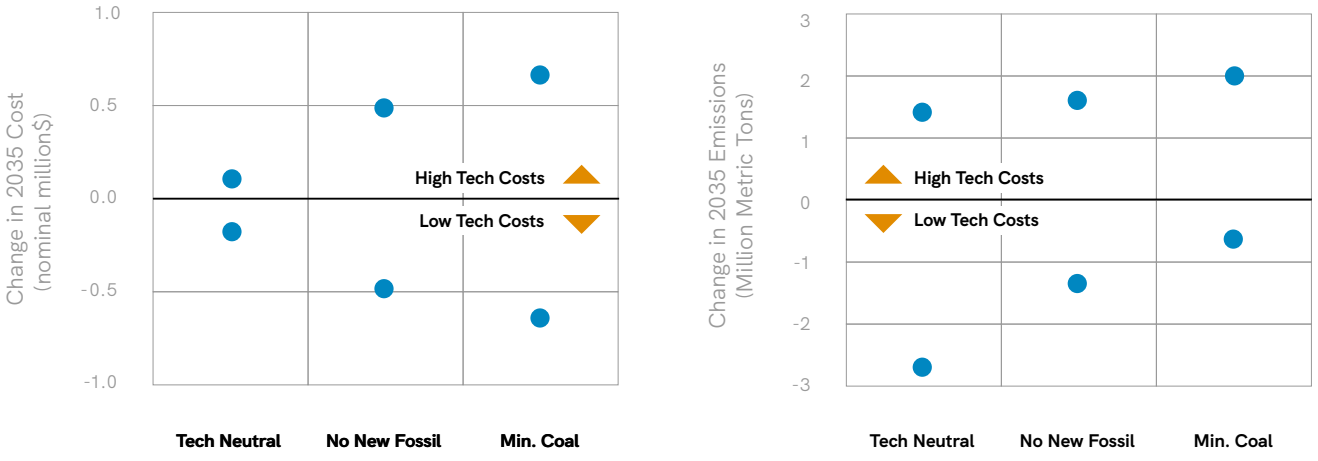


Figure 6.54 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. The change in technology costs causes the greatest cost impact on the Minimum Coal case, while the Technology Neutral case experiences relatively low impacts to cost. Across all cases, higher technology costs lead to higher emissions and lower technology costs lead to lower emissions.

FIGURE 6.54: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future technology costs can have important implications for SRP's resource portfolio. Lower renewables and storage technology costs result in increased additions of solar and storage (and higher total capacity additions), lower total system costs and lower emissions in 2035. Higher technology costs result in lower renewable additions, higher total system costs and higher emissions. In all cases, new firm capacity is still needed.

Regional Diversity

In the Regional Diversity sensitivity, SRP reduced the target planning reserve margin (PRM) from 16% to 13% (338 MW reduction by 2035) to serve as a proxy to represent the assumption that expanded transmission and regional coordination allow for increased resource and load diversity. The lower PRM reduces the need for resources on SRP's system. In the Technology Neutral strategic approach, there are fewer gas peaker builds. In the No New Fossil and Minimum Coal cases, larger amounts of resources are offset. The most impacted resources are batteries (due to the lower total PRM requirement) and solar (which is less economic to add with fewer batteries to integrate the solar). These resources are partially replaced by wind in both cases.

FIGURE 6.55: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - REGIONAL DIVERSITY

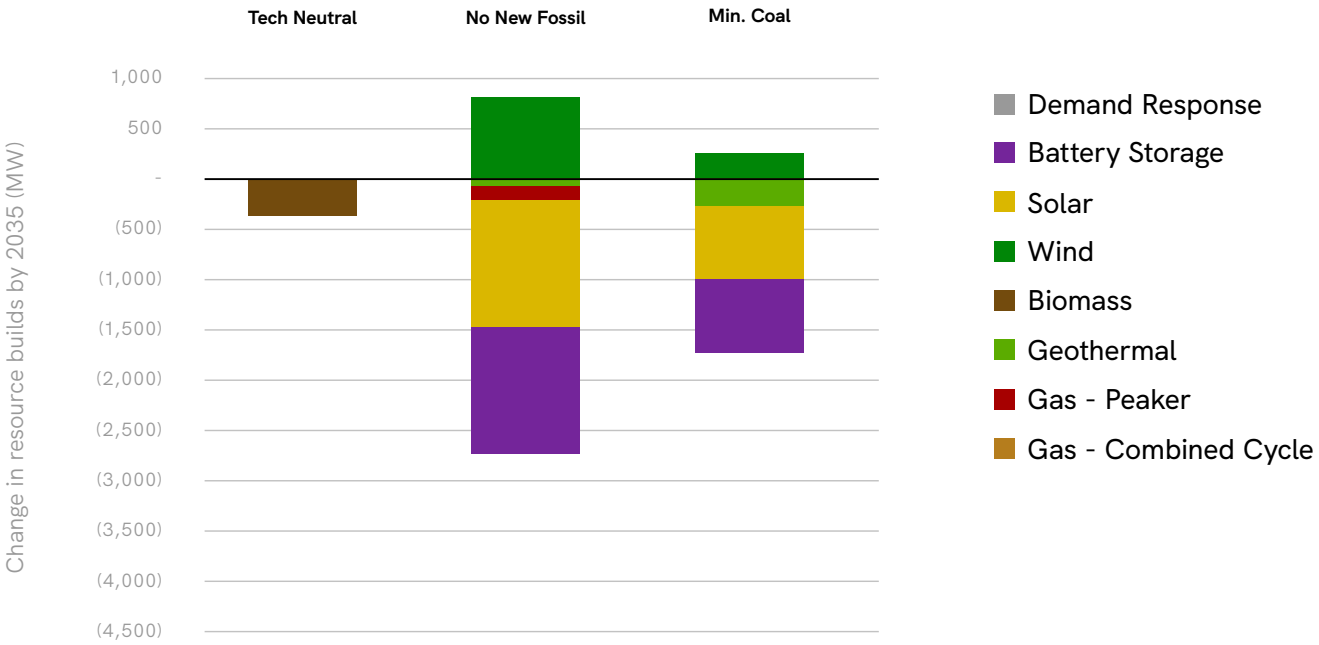


Figure 6.56 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the kW PRM reduction. For this sensitivity, the 3% PRM reduction is hypothetical, and the results do not consider any trade-offs or costs to realize greater regional diversity benefits for capacity planning. Because No New Fossil and Minimum Coal have higher costs of meeting the PRM due to the lack of new firm capacity resources, Regional Diversity results in the greatest cost reductions for these cases and the lowest cost reductions for Technology Neutral, in which there are new firm capacity resource options. While the Technology Neutral case experiences a very slight decrease in emissions, No New Fossil and Minimum Coal have increases in emissions due to natural gas generation and market purchases compensating for the reduction in renewable generation.

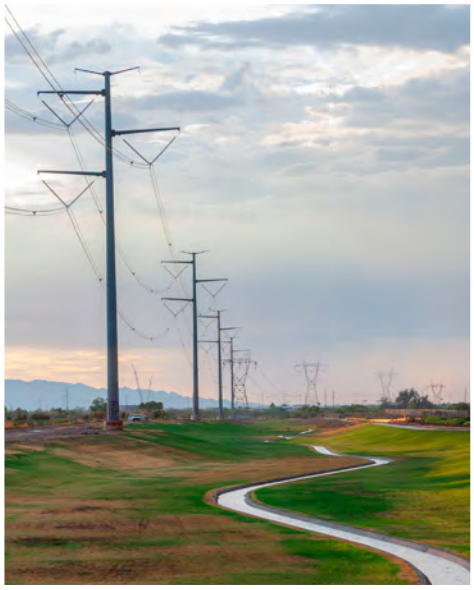
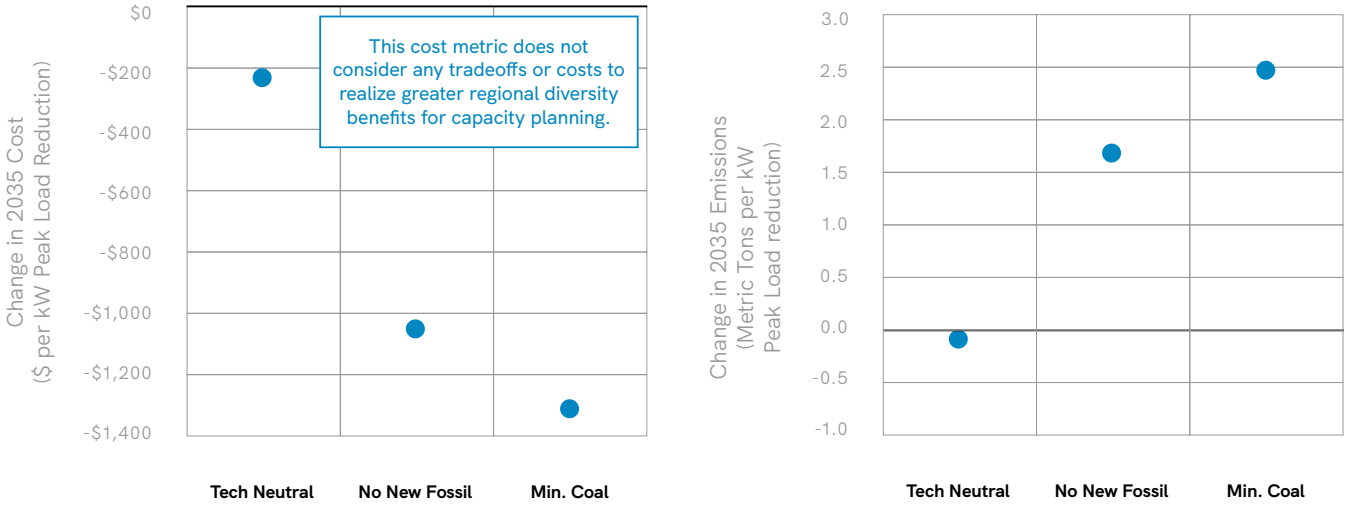


FIGURE 6.56: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, increased regional market participation largely helps mitigate the need for firm capacity resources (gas and/or batteries) due to increased resource and load diversity. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

Summary of ISP Key Findings

The key findings from the analysis described above are summarized here for reference. These key findings served as the foundation to inform the ISP System Strategies described in Section 8.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

SECTION 7

System Strategies

System Strategies

SRP faces an uncertain future that will continue to change at a rapid pace. In this dynamic and evolving environment, we must establish diverse strategies that can stand up to these changes while allowing for flexibility and adaptation. Utilizing our analysis and key findings, we have established seven System Strategies that will allow us to deliver the best value to our customers under future uncertainty and a wide range of potential outcomes.

The **System Strategies** are the Board-approved long-term strategies for planning and operating the power system in an integrated manner. These are strategies for all power system areas, including customer programs, distribution planning, resource planning, transmission planning, pricing and system operations. The strategies will guide us today through 2035, and they consider system developments needed beyond 2035 to meet SRP's 2050 goals. As a whole, these strategies will help to:

- Guide how we plan the system for the future and serve as the focal point for prioritizing our investments.
- Provide direction while maintaining flexibility to allow us to respond to future conditions.
- Guide our decisions on day-to-day planning activities.
- Signal to stakeholders and customers how we plan to evolve the system and meet the changing needs of our customers.

The System Strategies are also the starting point for developing the ISP Balanced System Plan and the ISP Actions, which are covered in detail in sections 8 and 9.

SRP used key insights from the ISP analysis, as discussed in Section 6, to develop the System Strategies that will help us maintain reliability and affordability while driving increased sustainability across a wide range of potential future scenarios. We also gathered and incorporated feedback from the Advisory Group members on these strategies before bringing them to SRP's Board. On Oct. 2, 2023, the Board approved the System Strategies.

Below are the seven interdependent System Strategies. Each strategy is reliant on the other strategies also being in place to ensure success and achievability. These are the strategies we can begin to implement now. Some strategies may take longer to implement than others, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 Sustainability Goals, manage costs for customers, achieve an adequate and reliable power system, and adapt to a more sustainable future regardless of what the future may be in 2035.

Below is a detailed description of the seven System Strategies and discussion of the key findings from the ISP analysis that support them.

Energy Investments

Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

The ISP analysis demonstrated that new renewables combined with firm generation are part of a least-cost power generation portfolio. Across the different future scenarios, we saw the least-cost system plans add an average of 4,800 MW of renewables and storage.

Renewables do more than just contribute to a least-cost portfolio. They help reduce fossil fuel consumption and contribute to improved sustainability, helping SRP meet its 2035 carbon reduction and water use goals. Our customers also want more renewables. We found from the residential customer research that customers want us to provide the most sustainable energy portfolio possible without significantly increasing their costs or compromising reliability. This strategy focuses on investing in renewables and storage to deliver exceptional value to our customers and help drive carbon and water reductions.

Capacity Investments

Invest in firm generation, including natural gas, to support reliability and manage affordability while also supporting the advancement of emerging firm technologies.

The ISP analysis shows that firm generation, such as natural gas, is key to maintaining reliability. Firm generation includes resources that can dispatch on demand and generate over long periods of time (e.g., multiple days). Without new firm generation, reliability is compromised by 2028 under a high load growth scenario.

Firm generation resources, when added along with renewable and storage resources, are also key to maintaining affordability. On average, the least-cost system plan adds more than 2,000 MW of natural gas capacity by 2035, helping to offset losses in firm generation from coal plant retirements and the expiration of a natural gas tolling agreement. When new natural gas is not allowed to be added, total system costs are 17%–24% higher under the Current Trends scenario and 7%–11% higher under the Desert Contraction scenario. The addition of firm generation allows SRP to mitigate these cost impacts and maintain affordability.

While adding new firm generation is key to maintaining reliability and affordability, it does not mean that these resources will have high utilization. The Energy Investments system strategy envisions adding renewable and storage resources to reduce fuel consumption from fossil fuel-fired resources, which is reflected in the ISP analysis. As a result, new and existing natural gas generation resources are projected to operate less over time, with the anticipated systemwide capacity factor declining to roughly 25% by 2035.

This strategy recognizes the need for the advancement of other emerging firm technologies (such as hydrogen, new nuclear and long-duration storage) and the role that emerging technologies can play in helping meet a portion of firm resource needs in the future. We expect the new investments in natural gas generation to be hydrogen-ready to allow SRP to transition those resources to hydrogen if and when hydrogen becomes a commercially viable fuel option.

Proactive Transmission

Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.

The ISP analysis showed that a significant investment in transmission is needed over the next decade, driven by the large amount of generation required to meet our growing loads. By 2035, SRP could need hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers relative to today. The location of this new generation capacity matters and has a significant impact on the buildout of the 500 kV transmission system. We must strategically locate and build out new grid infrastructure to connect new resources and customers. It is in our best interest to strategically find the best location for new-generation resources and transmission. Siting and permitting transmission can be a decade-long process, necessitating a proactive approach in transmission planning.

Distribution Innovation

Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.

The distribution innovation strategy is focused on ensuring we are prepared for anticipated growth while maintaining reliability and enabling customer innovation. Load growth will drive additional infrastructure needs, while changes in how our customers use energy will require innovation and flexibility. This strategy allows us to understand and adapt to the complexities of balancing energy load growth with innovation that may reduce customer demand, such as managed EV charging, expanded deployment of distributed solar, and next-generation demand response programs.

This strategy helps enable us to provide a dependable supply of electricity to all SRP customers and provide a reliable grid that can prepare for and recover from unanticipated disruptions to ensure energy availability, while at the same time helping us meet evolving customer needs.

Partnerships & Suppliers

Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.

SRP anticipates the need to double or triple resource capacity in the next decade to be able to best serve our customers while achieving our 2035 Sustainability Goals. This is an unprecedented pace of resource development, with potential additional needs for hundreds of miles of new transmission lines and numerous transformers on the transmission and distribution system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc. With the amount of future infrastructure and resources needed and long lead times for certain assets, external partnerships will be essential to build the future system and maintain high customer value.

Customers and community partnerships will also be critical to achieving the transformation of the power system. To enable construction of the large amount of infrastructure SRP is planning, we must proactively build relationships and partnerships with communities, cities, counties, towns, government agencies and tribes, and engage with advocacy organizations to understand their perspectives. We can then better identify, prepare and preserve options for feasible sites for future system infrastructure. Through these partnerships, SRP can respond to evolving customer needs by providing safe, reliable, affordable and sustainable power while recognizing the different needs, challenges and perspectives of our customers.

In addition to partnering with customers and communities, supply chain disruptions and delays that are still being felt following the pandemic necessitate the need to find supply chain and development solutions. Future supply chain disruptions could further impact our ability to develop new infrastructure. This strategy helps enable supply chain solutions essential to managing costs for our customers and to meeting the pace of transformation needed which could include ordering key supplies as early as possible and developing a wider pool of potential suppliers to diversify supply chain risks.

Evolution of Customer Programs & Pricing

Evolve pricing and customer programs to improve economywide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.

SRP will need to evolve programs and price plans to deliver the best value to our customers. We saw in our Time-of-Use Exploratory Study, existing customer programs and price plans are effective at managing peak energy demand today, but as our energy mix changes, so must our customer programs and price plans. Adding significant amounts of solar energy will mean abundant, low-cost energy is often available during daytime hours. The more expensive peak period will then shift later into the evening once the sun sets.

This also creates new opportunities to shift energy from increased electrification programs to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

During our transition to a more sustainable future, the timing and availability of low-cost resources will change with the increased adoption of renewable resources. We strive to strike the right balance of reliable, affordable and sustainable power for our customers. Currently, we have targets for Energy Efficiency and Demand Response adoption in our 2035 goals. We will continue studying options to accelerate and adapt to meet changing patterns in our customers' electricity use and help address significant load growth and capacity constraints over the next several years.

This strategy allows us to adapt to the needs of a changing grid and gives us an opportunity to recognize the different needs, challenges and perspectives of our customers and reflect that through new customer offerings that will help us maintain industry-leading customer satisfaction.

Strategic Investment & Reinforcement of Existing Assets

Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.

SRP's existing assets and generation are the foundation for our future. Our existing and contracted generating assets will make up 50% of our capacity, 70% of our reliability needs and 45% of our carbon-free energy in 2035. Additionally, our existing transmission lines will make up an estimated 90% of the total number of 230-plus kV line miles in 2035, and our distribution substation bays will make up 85% of the substation bays we need in 2035. The existing system is important, and we must strategically reinvest in the system we have today by continuing to perform routine maintenance to extend the life of our assets. Existing resources are needed to meet future customer needs and maintain a reliable grid that can prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability. This will ensure continued grid security, safety and performance.

We must also explore repurposing existing or retired coal plants with other emerging technologies and making more strategic generation investments to connect and use existing transmission whenever possible.

This strategy allows us to deliver exceptional system and energy value by minimizing the need for additional grid resource investments, which helps keep costs lower for our customers.

The System Strategies discussed in this section will guide SRP's planning activities and investment decisions in a way that balances all important considerations in developing a reliable, affordable and sustainable power system. Through robust analysis in the ISP, SRP developed a detailed understanding of the inherent trade-offs between reliability, affordability and sustainability and sought to establish an Integrated System Plan that fully balances all considerations.

It is important to reiterate that none of the System Strategies above can stand on their own. These strategies are intertwined and need to be executed simultaneously to best serve our customers and ensure that we will continue to provide reliable, affordable and sustainable power regardless of what the future brings.

SECTION 8

Balanced System Plan

Balanced System Plan

The ISP Balanced System Plan is an illustration of what SRP's power system may look like in 2035 by implementing the seven System Strategies. We constructed the **Balanced System Plan** to help customers and stakeholders visualize the future power system based on what is known today. However, as discussed in previous sections, the entire utility industry faces a lot of change and uncertainty. As a result, we will inevitably need to adapt and evolve this plan as new information (e.g., updated economic development forecasts and technology cost projections) becomes available and as circumstances change, such as new laws or regulations being enacted.

Developing the Balanced System Plan

The ISP System Strategies detailed in Section 7 are the foundation for the Balanced System Plan. To identify how the system could evolve in a manner consistent with the System Strategies, SRP leveraged the results and key findings from the ISP analysis.

Of the strategic approaches analyzed, it was clear that no individual strategic approach performed best across all metrics. For example, the Technology Neutral strategic approach resulted in the lowest system cost and lowest residential customer bill impacts, whereas the Minimum Coal strategic approach performed best across multiple sustainability metrics. Separately, results from the ISP residential customer research found that customers want it all. They want SRP to advance sustainability performance while maintaining high levels of reliability and limiting cost increases.

In building out the Balanced System Plan, we considered the results of the various analyses, findings from the different strategic approaches and feedback from our customers to strike a balance between sustainability, affordability and various power system reliability risks.

Specific considerations used in developing the Balanced System Plan included the following goals:

- **Reliability:** Maintain firm generation capacity and expand grid needs while preparing for emerging grid technologies.
- **Affordability:** Utilize an all-of-the-above approach to diversify and moderate the pace of investments.
- **Sustainability:** Significantly expand investments in renewable energy and storage to drive carbon reductions and reduce water consumption.
- **Customer Focus:** Focus on managing costs and advancing sustainability and customer programs without sacrificing reliability.

FIGURE 8.1: GOALS OF THE BALANCED SYSTEM PLAN

Reliability

Maintain firm generation capacity and expand grid needs, while preparing for emerging grid technologies

Affordability

Utilize an all-of the-above approach to diversify and moderate pace of investments

Sustainability

Significantly expand renewable and storage development to drive emissions reductions and reduce water consumption from power generation

Customer Focus

Focus on managing costs, advancing sustainability and customer programs without sacrificing reliability

Resources and Customer Programs

The Balanced System Plan envisions significant resource additions between 2025 and 2035. By implementing the Energy Investment System Strategy, SRP could triple the total installed capacity of renewable and storage resources by 2035. Solar, being a low-cost renewable resource that helps displace fossil fuel generation, makes up the majority of the renewable energy additions in the Balanced System Plan, with 6,000 MW added. Other renewable additions include 800 MW of wind located in eastern Arizona to leverage existing transmission that becomes available when Coronado Generating Station retires in 2032, as well as 50 MW of geothermal and 50 MW of biomass to help provide resource diversity. The Balanced System Plan also includes 2,500 MW of additional energy storage, split between four-hour lithium-ion batteries and pumped hydro storage.

By implementing the Capacity Investment System Strategy, SRP would maintain similar levels of thermal generation as today to provide firm capacity. This includes investing in 2,000 MW of new natural gas generation to replace 1,300 MW of retiring coal generation and a 975 MW gas tolling agreement that expires in 2031. We did not include advanced nuclear or hydrogen in the Balanced System Plan due to development risks with those technologies becoming commercially available by 2035.

In addition to the utility-scale resource additions, the Balanced System Plan includes customer programs and customer-sited resources, which will help displace the need for utility-scale resources. Specifically, the Balanced System Plan envisions 700 MW of combined capacity from energy efficiency and demand response (labeled Customer Programs in figures 8.2 and 8.3) as well as 750 MW of customer-sited solar, demonstrating SRP's implementation of the Evolution of Customer Programs & Pricing System Strategy. While the Balanced System Plan does not reflect changes to customer pricing over time, SRP's evolution of price plans can help further mitigate resource additions by providing price signals to customers to moderate their demand during periods of lower supply.

FIGURE 8.2: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY 2025-2035

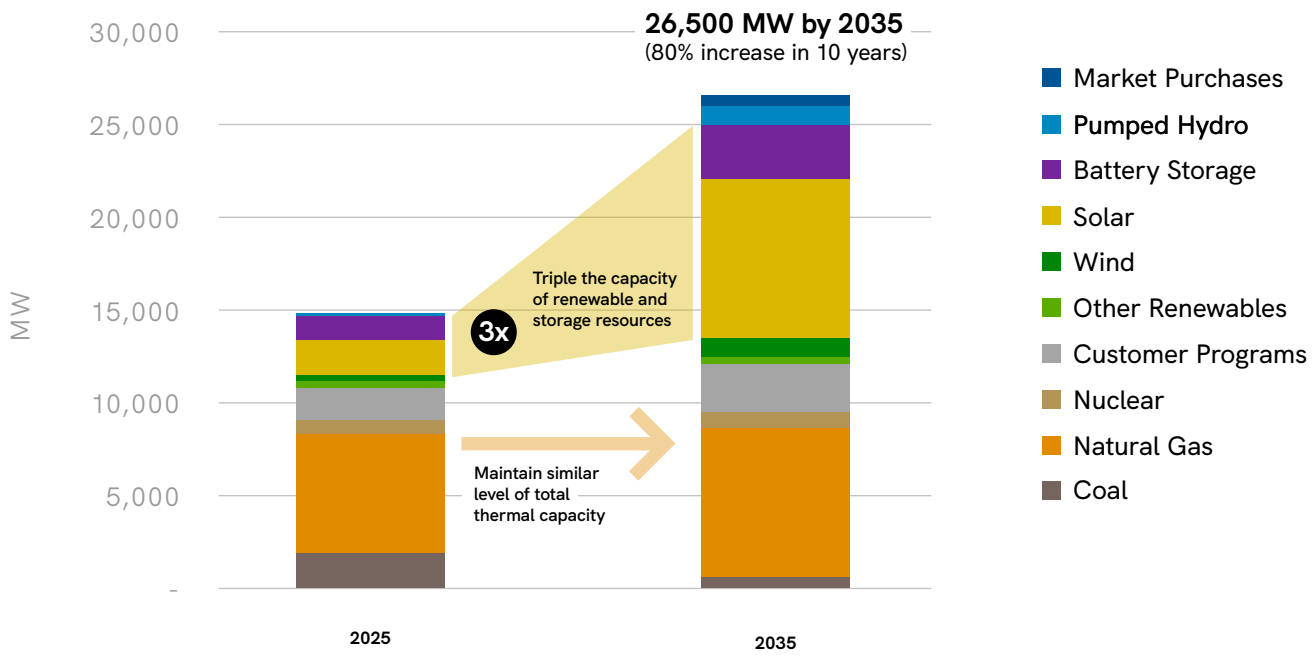


FIGURE 8.3: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY ADDITIONS BY 2035 (MW)

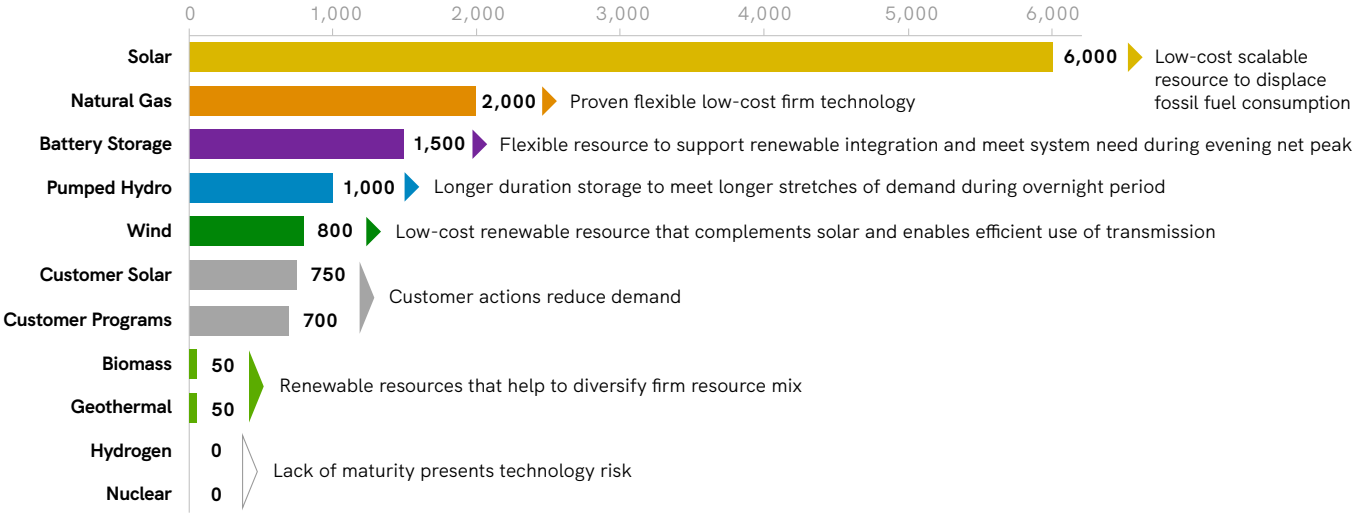
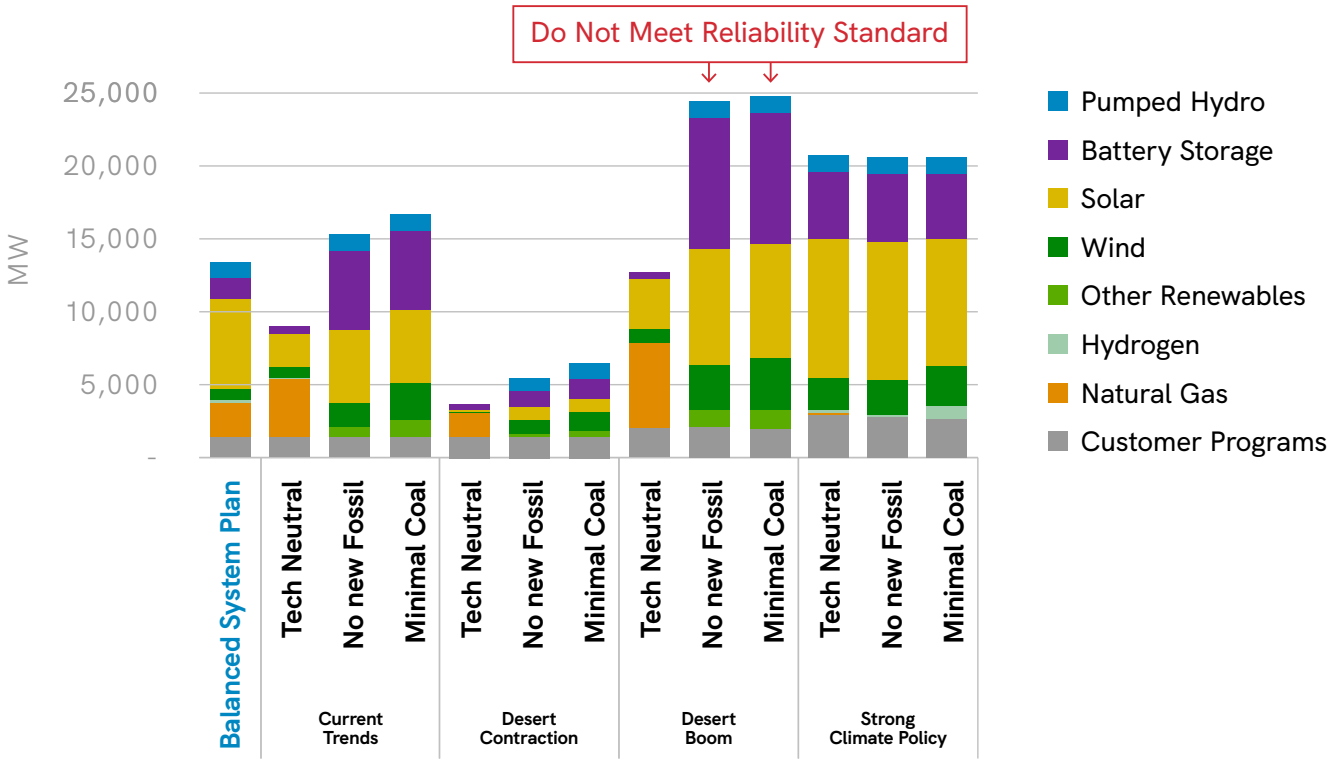


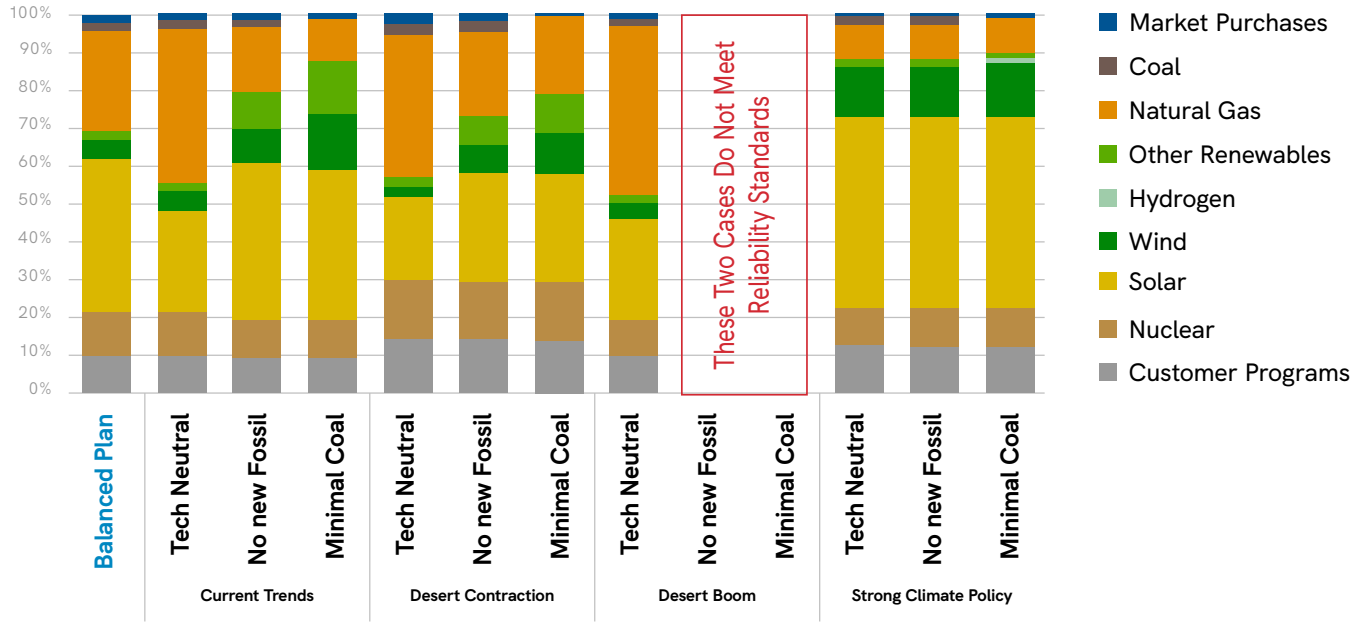
Figure 8.4 shows the nameplate capacity additions for the Balanced System Plan alongside those for the ISP cases for comparison. While we considered the full range of scenario analysis when constructing the Balanced System Plan, we used the Current Trends scenario assumptions to illustrate specific infrastructure requirements. In comparison to the other system plans under the Current Trends scenario, the Balanced System Plan includes approximately 6,000 MW of additional carbon-free resources and over 1,000 MW less gas than the Technology Neutral strategic approach (i.e., least-cost system). Natural gas is still included in the Balanced System Plan to help mitigate costs, unlike the No New Fossil and Minimum Coal strategic approaches, which were found to be considerably more expensive with natural gas not being included in the strategic approach assumptions. The Balanced System Plan thus results in less carbon-free resource additions compared to the No New Fossil and Minimum Coal cases in the Current Trends scenario.

FIGURE 8.4: NAMEPLATE CAPACITY ADDITIONS BY 2035



On an energy basis, for the Balanced System Plan, 70% of SRP's customer energy needs would come from carbon-free sources, which is in the middle of the range when compared to the other Current Trends scenario system plans, as shown in Figure 8.5.

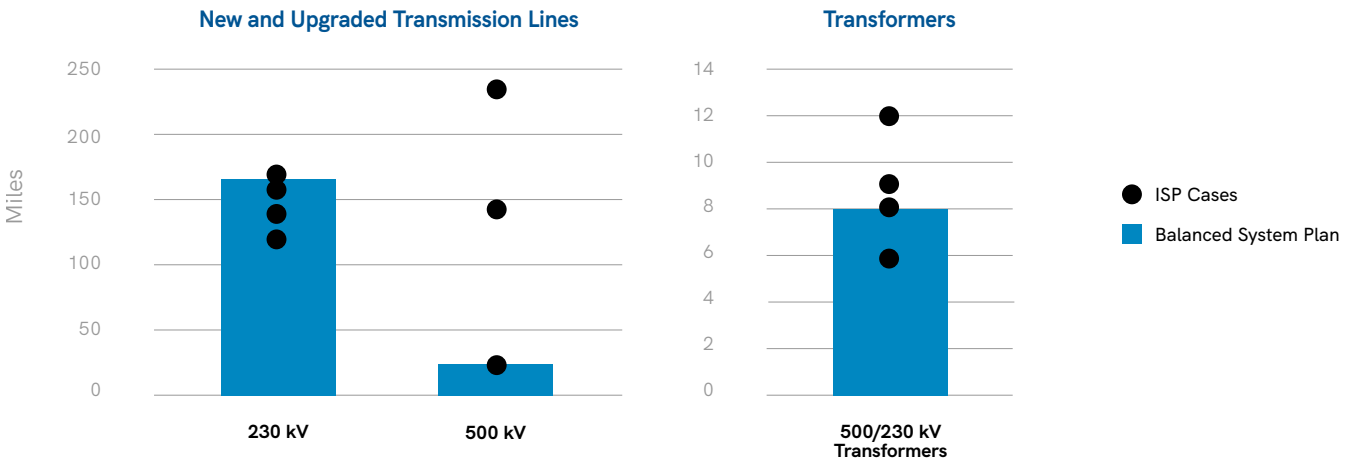
FIGURE 8.5: ENERGY MIX IN 2035



Transmission

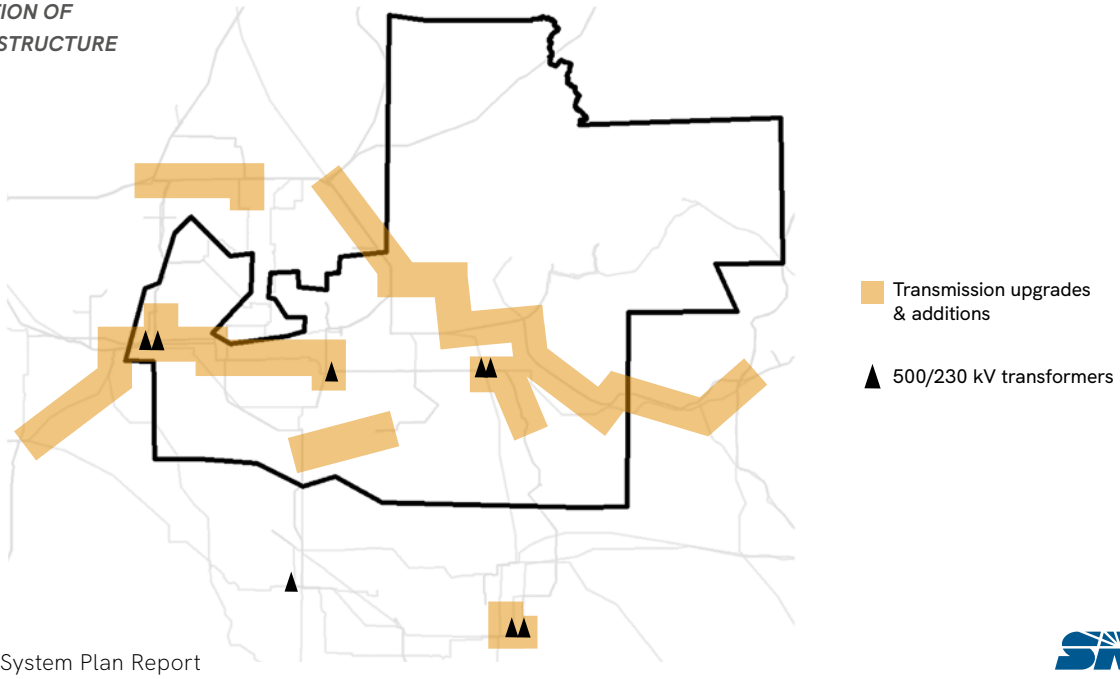
To connect the significant amount of new generation resources included in the Balanced System Plan to our customers, additional high-voltage transmission infrastructure would be needed at both the 500 kV and 230 kV levels. The additional transmission needs for the Balanced System Plan compared to the scenario-based system plans analyzed are shown in Figure 8.6. As detailed in Section 5, we evaluated two different location sensitivities for where the generation resources would be located (Pro-Rata and Hub). For the Balanced System Plan, we utilized a hybrid approach where resources were distributed across the transmission system, but certain areas that required significant upgrades were avoided. This resulted in 165 miles of new or upgraded 230 kV lines, 25 miles of new or upgraded 500 kV lines, and eight new 500/230 kV transformers by 2035. The long lead times for siting, permitting and procuring this transmission infrastructure emphasize the need to implement the Proactive Transmission System Strategy.

FIGURE 8.6: TRANSMISSION SYSTEM ADDITIONS BY 2035



An illustration of where this new transmission infrastructure could be located, overlaid with SRP's electric service area, is included in Figure 8.7.

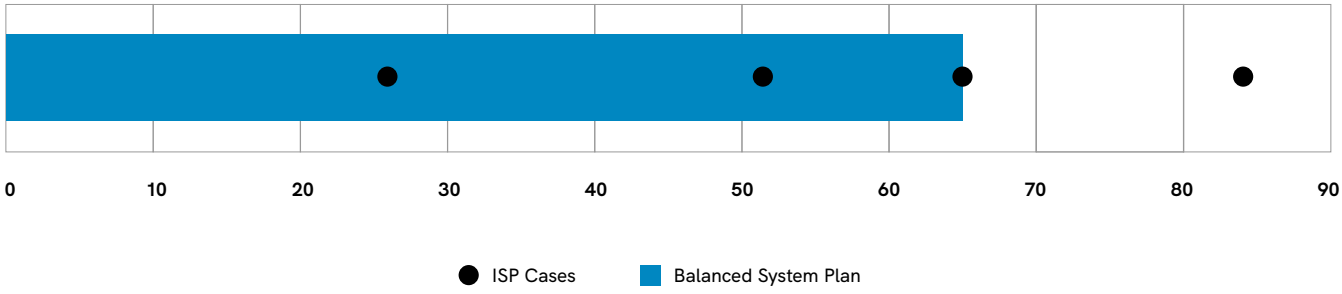
FIGURE 8.7: ILLUSTRATION OF TRANSMISSION INFRASTRUCTURE ADDITIONS



Distribution

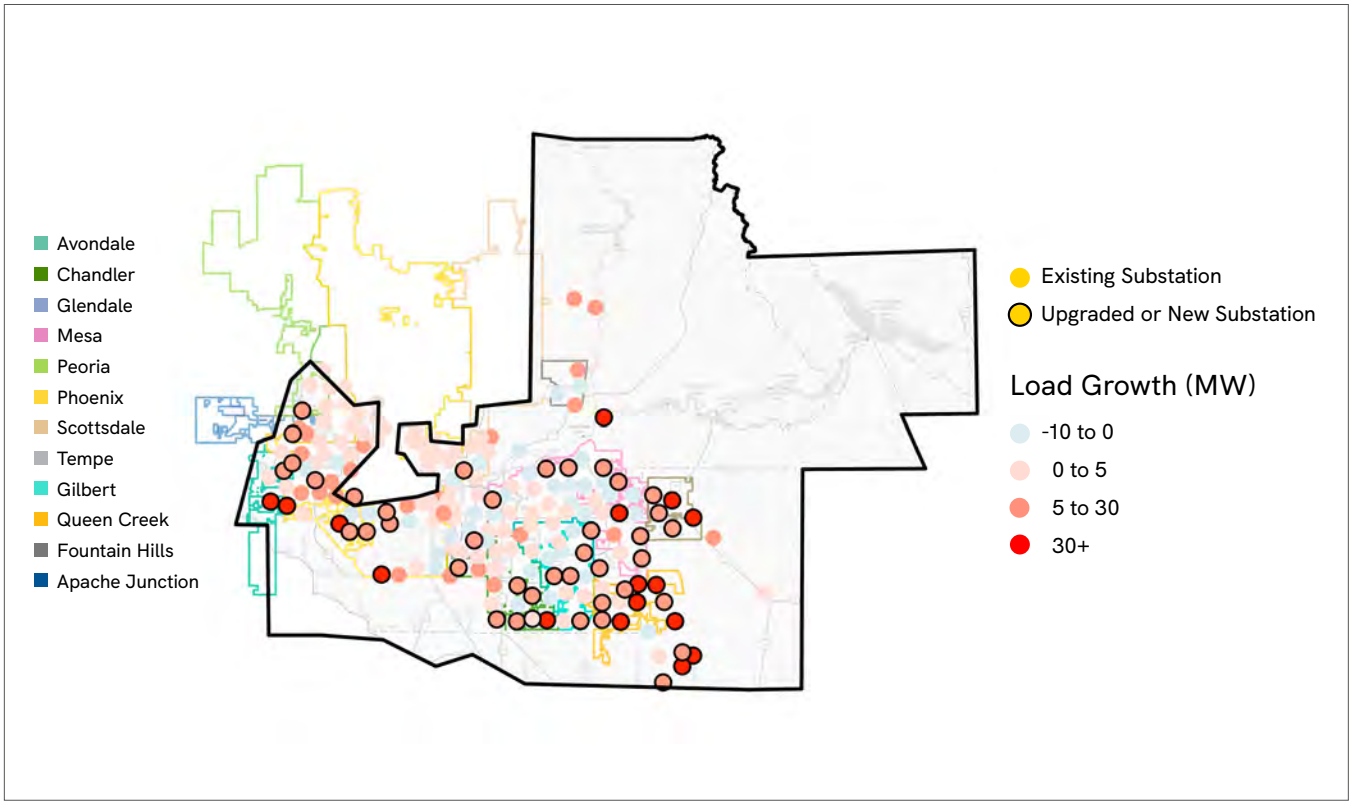
By implementing the Distribution Innovation System Strategy, SRP will need to add a number of additional distribution substation bays to ensure reliability. For the Balanced System Plan, this includes 65 additional substation bays to meet growing customer energy needs.

FIGURE 8.8: DISTRIBUTION SUBSTATION BAY ADDITIONS



We anticipated most of this substation bay addition will be located in the southeastern and western portion of the SRP electric service territory where there is the most potential for growth, as shown in Figure 8.9 below. However, additional substation bays will also be needed in central parts of SRP's electric service territory due to urbanization and growth in electric vehicles.

FIGURE 8.9: ILLUSTRATION OF DISTRIBUTION INFRASTRUCTURE ADDITIONS



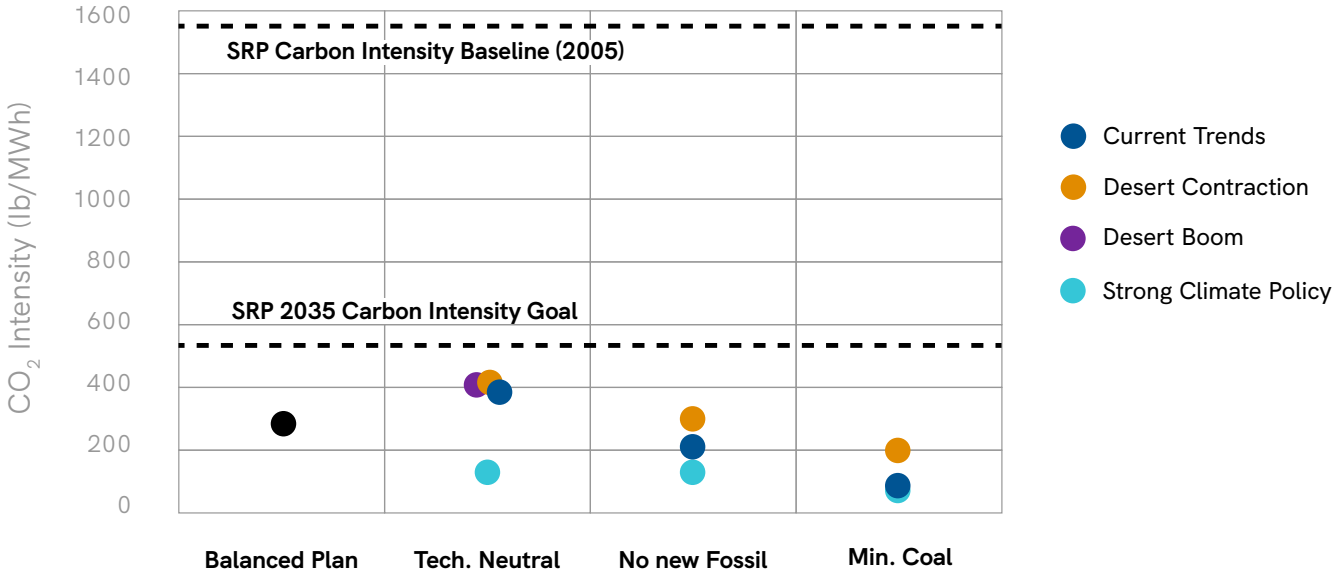
Balanced System Plan Performance

When developing the Balanced System Plan, we evaluated the plan's performance by quantifying the same metrics used to analyze each of the ISP cases. As noted earlier, we used findings from the ISP analysis and residential customer research to develop a system plan that advanced sustainability performance while avoiding significant cost increases to SRP and its customers. The following subsections discuss key metrics for the Balanced System Plan and show how it achieves this objective.

CO_2 Reductions

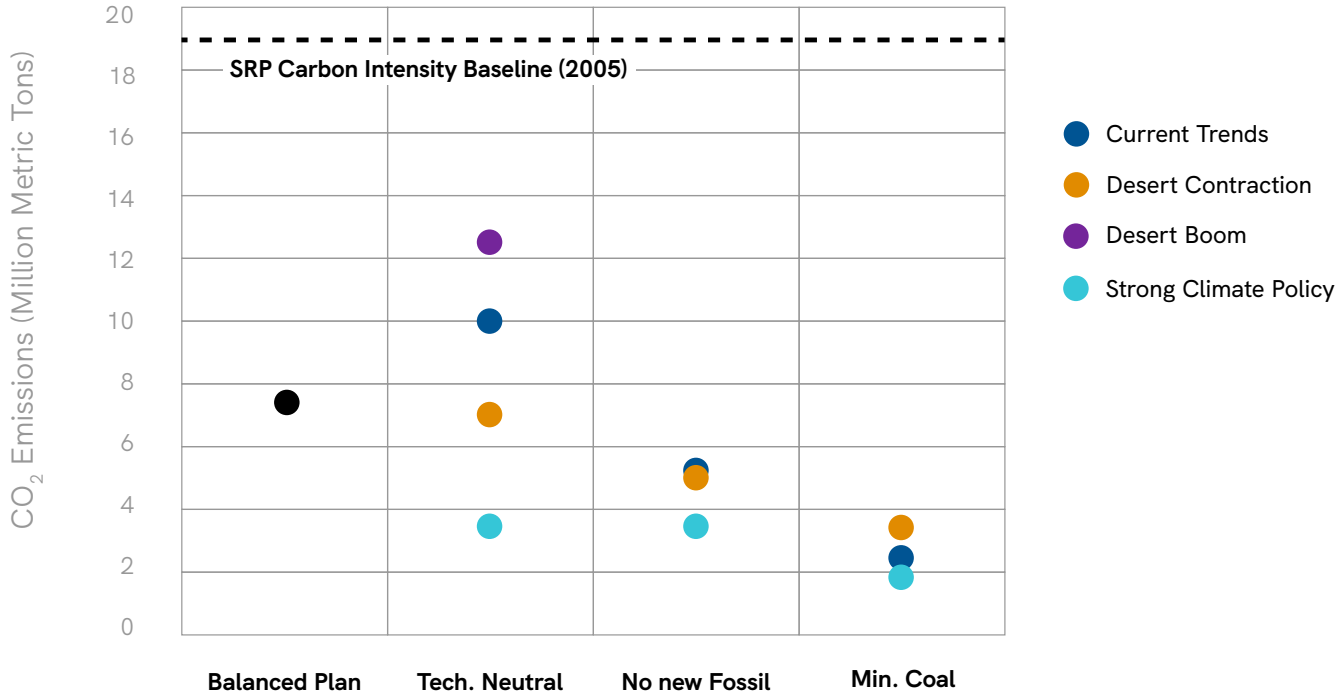
The CO_2 intensity and mass emissions for the Balanced System Plan in 2035 are included in figures 8.10 and 8.11, respectively, and are shown alongside the core system plans for comparison. The Balanced System Plan exceeds SRP's 2035 goal by achieving a CO_2 intensity rate of 284 lbs./MWh, an 82% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends scenario (the scenario used for the Balanced System Plan), the Balanced System Plan carbon intensity is 28% lower than that of the Technology Neutral strategic approach at 396 lbs./MWh but is not as low as that of the No New Fossil and Minimum Coal strategic approaches at 202 lbs./MWh and 94 lbs./MWh, respectively.

FIGURE 8.10: BALANCED SYSTEM PLAN CO_2 INTENSITY IN 2035



Similarly, for CO_2 mass emissions, the Balanced System Plan performs in the middle of the range when compared to the core system plans, with a CO_2 emission rate of 7.39 million metric tons in 2035. This is a 61% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends cases, the Balanced System Plan achieves 25% lower carbon emissions than the Technology Neutral strategic approach (9.83 million metric tons) but not as low as the No New Fossil and Minimum Coal strategic approaches (5.11 million metric tons and 2.40 million metric tons, respectively), as shown in Figure 8.11 on the next page.

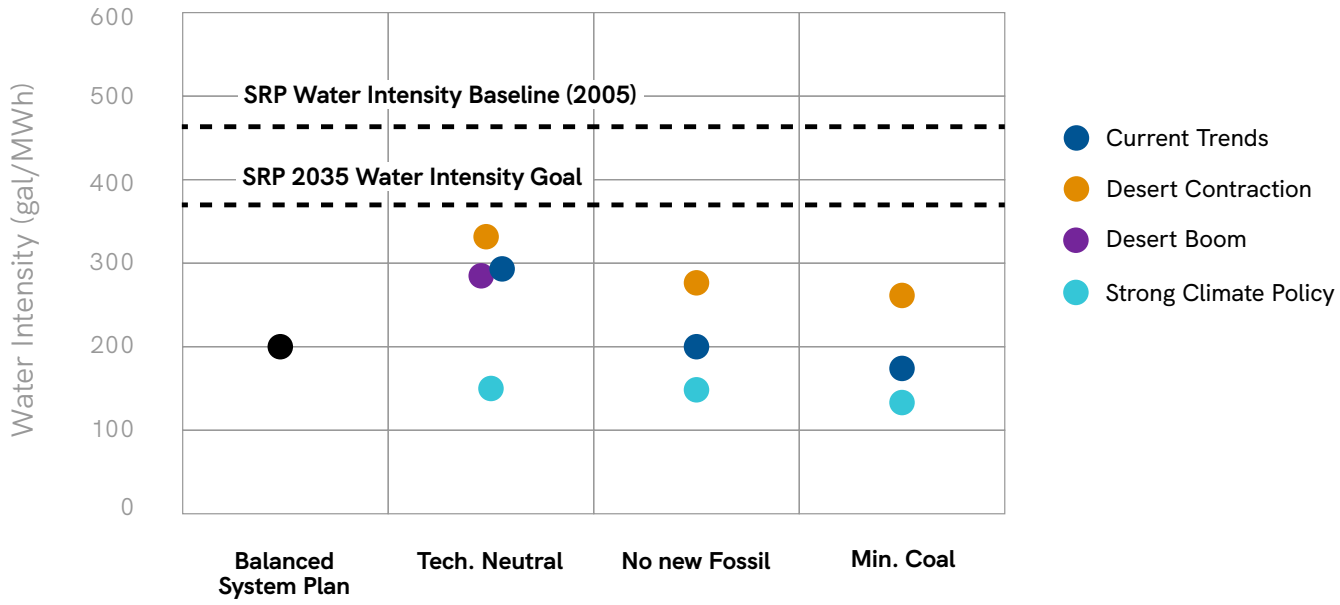
FIGURE 8.11: BALANCED SYSTEM PLAN CO_2 EMISSIONS IN 2035



Water Use

As shown in Figure 8.12, the Balanced System Plan also achieves a significant reduction in water consumption by 2035 with a water consumption rate of 204 gal/MWh (56% reduction from SRP's 2005 baseline levels), exceeding SRP's 2035 Sustainability Goal (20% reduction from 2005 baseline) and falling toward the lower end of the range of the core system plans analyzed in the ISP. Compared to the Current Trends cases, the Balanced System Plan achieves a 30% lower water consumption rate than the Technology Neutral strategic approach (293 gal/MWh), but not as low as the No New Fossil and Minimum Coal strategic approaches (199 gal/MWh and 171 gal/MWh, respectively).

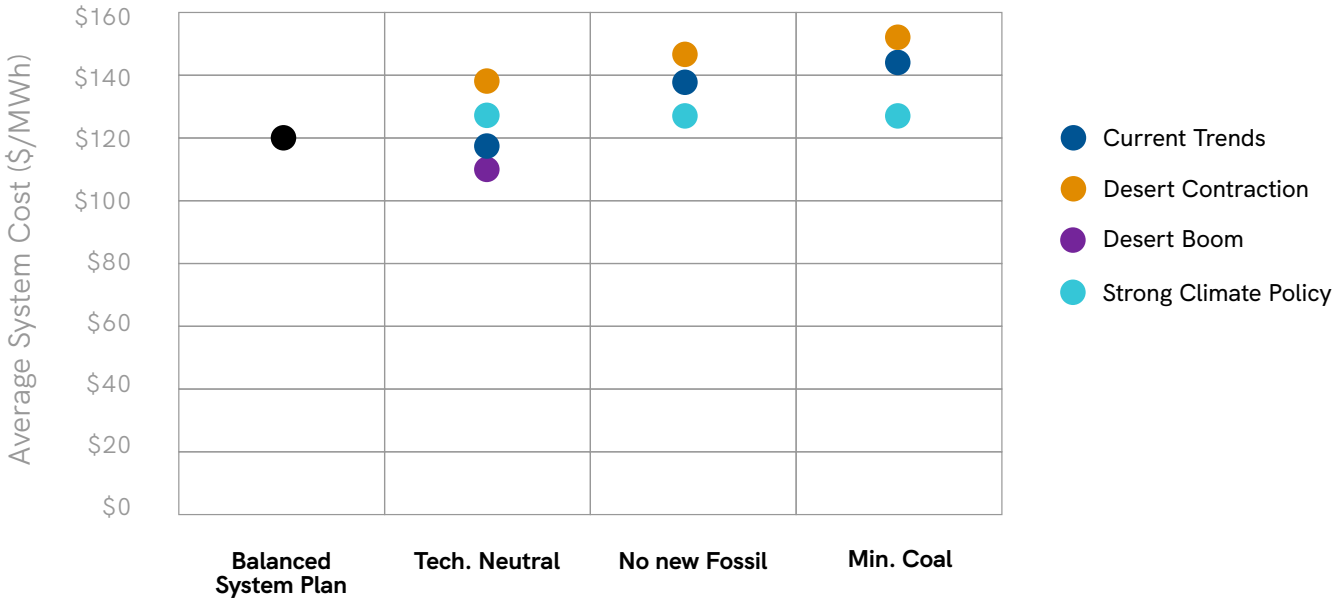
FIGURE 8.12: BALANCED SYSTEM PLAN WATER CONSUMPTION



Average System Cost

The average system cost for the Balanced System Plan, with comparisons to the core system plans from the ISP analysis, is shown in Figure 8.13. The Balanced System Plan results in an average system cost of $121/MWh, which is near the lower end of the range of costs observed from the ISP analysis. Compared to the Current Trends cases, the Balanced System Plan is only 4% higher than the Technology Neutral strategic approach ($116/MWh), despite adding more than double the amount of carbon-free resources and having a 28% lower carbon intensity. Meanwhile, the addition of 2,000 MW of firm natural gas in the Balanced System Plan allows the average system cost to be considerably lower than the No New Fossil and Minimum Coal strategic approaches ($136/MWh and $144/MWh, respectively).

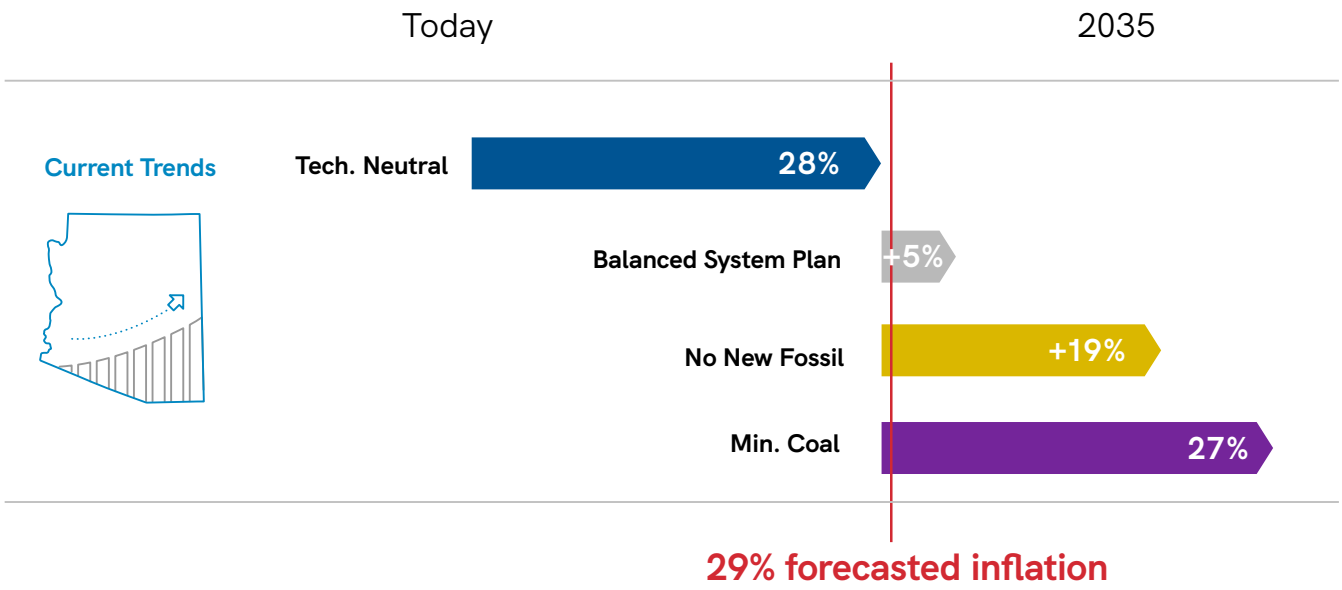
FIGURE 8.13: AVERAGE SYSTEM COSTS IN 2035 ($/MWH)



Residential Bill Impact

There are many factors that will impact costs in the future such as customer growth, inflation, the Inflation Reduction Act (IRA) funding and technology costs. Figure 8.14 shows the residential bill impacts for the Balanced System Plan compared to the other strategic approaches under the Current Trends scenario. This is a simplified look of what a base rate increase could look like in 2035, and we selected the Current Trends scenario because it reflects a central case for how the future might unfold. As shown in Section 6, the least-cost strategic approach, Technology Neutral, results in a price increase of 28% by 2035, just below inflation (estimated at 29% over the same time period). The Balanced System Plan results in a 5% increase in cost over the Technology Neutral strategic approach but is well below the residential price increases for the No New Fossil and Minimum Coal strategic approaches.

FIGURE 8.14: RESIDENTIAL PRICE INCREASE BY 2035



These are representative results based on ISP analysis modeling, not projections of SRP's future prices, and are not inclusive of factors beyond the scope of ISP analysis.

SECTION 9

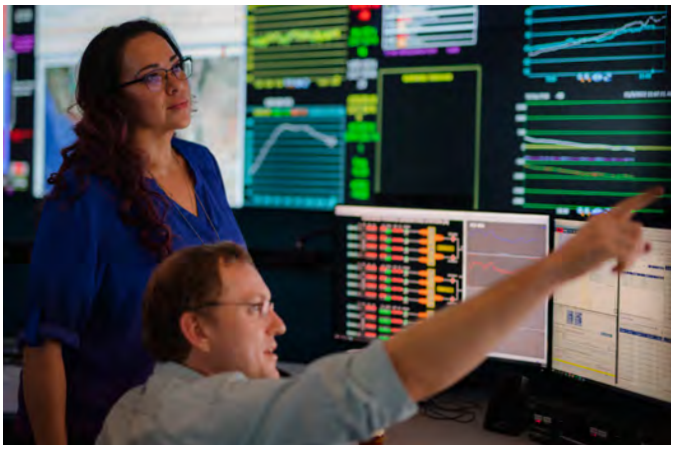
ISP Actions

ISP Actions

SRP's planning processes do not stop with the ISP. In many ways, the conclusion of this ISP represents new beginnings as our planning groups begin to execute the System Strategies. To further progress toward implementing the System Strategies, we have defined 10 ISP Actions that we will take over the next few years.

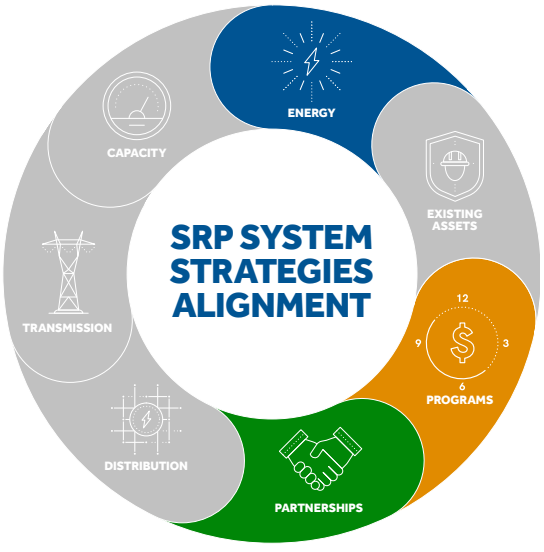
We developed the ISP Actions based on the ISP key findings, the System Strategies and the Balanced System Plan. They include actions for all aspects of system planning, including pricing, customer programs, customer resources, utility-scale resources, distribution and transmission. Just as the seven System Strategies are integrated and interdependent, so are the ISP Actions. Each action furthers multiple System Strategies and requires collaboration across our planning groups. In this section, we will describe each of the 10 **ISP Actions** and show how each one furthers specific System Strategies.

We are committed to pursuing diverse actions, establishing a roadmap for implementing the System Strategies and making progress toward our 2035 Sustainability Goals with the development of the ISP Actions.

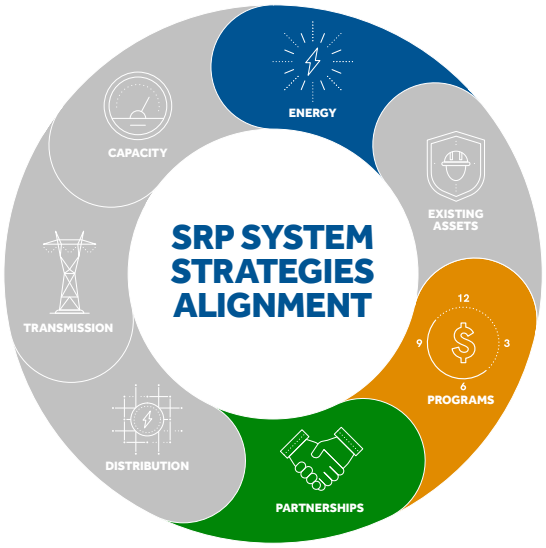


ISP Action #1: Residential Time-of-Use Pilot

We will execute a residential time-of-use price plan pilot and perform customer research to evaluate customers' responses to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform our load forecast for long-term system planning and our pricing process.



ISP Action #2: Time-of-Use Evolution



We will engage commercial, small business, large industrial, and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods and develop a roadmap for implementing new time-of-use periods.

To accomplish Action #2, we will:

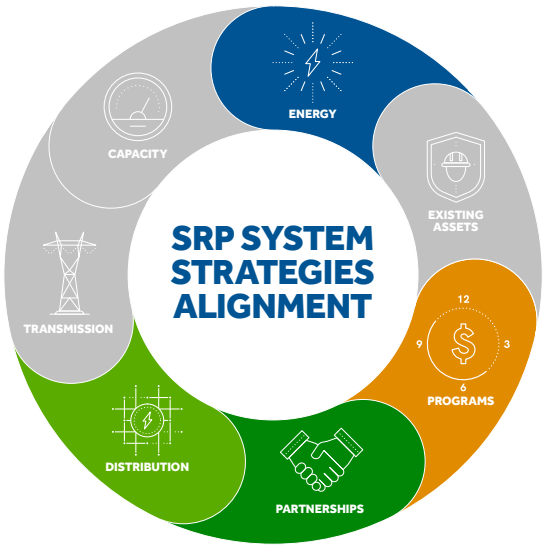
- Undertake a pricing process informed by the ISP to determine how time-of-use plans should evolve.
- Propose new time-of-use hours, including a super off-peak period when the cost to serve customers' needs is lowest and on-peak hours updated for the modern grid.
- Develop communication plans for all customer types and segments to educate about any new time-of-use price plans focusing on promoting affordability and potential sustainability benefits.

ISP Action #3: Customer Programs

We will continuously refresh program plans and take steps to drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from our initial 2035 Sustainability Goal for Energy Efficiency.

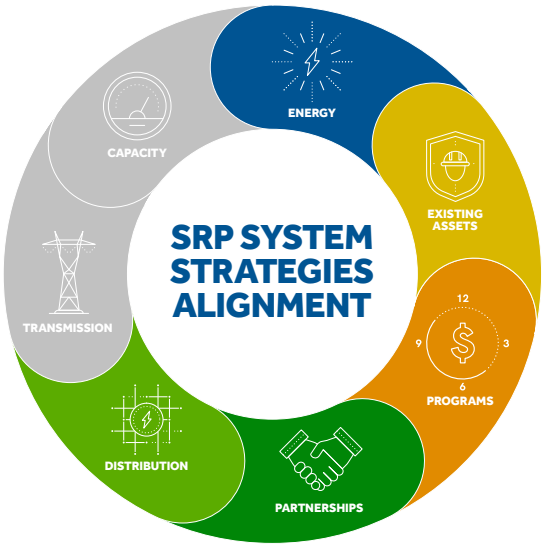
Steps will include:

- Evaluating the cost-effectiveness and emissions impacts of different customer program measures using the avoided costs and emissions impacts results from the ISP.
- Determining whether any changes to the customer programs portfolio are warranted based on this information, considering that these results must be weighed against other important factors such as customer access, equity, cost and satisfaction.



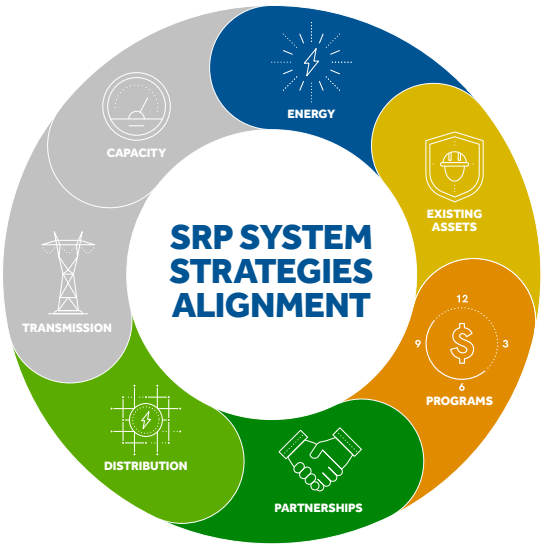
ISP Action #4: Electric Vehicle Management

We will develop an EV roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing electric vehicle charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.



ISP Action #5: Electrification

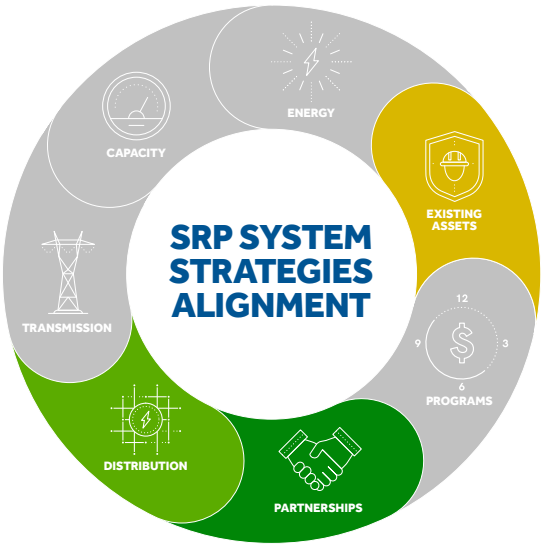
We will analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on our operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.



ISP Action #6: Distribution Enablement Roadmap

We will continue implementing our Distribution Enablement (DE) Roadmap, which includes:

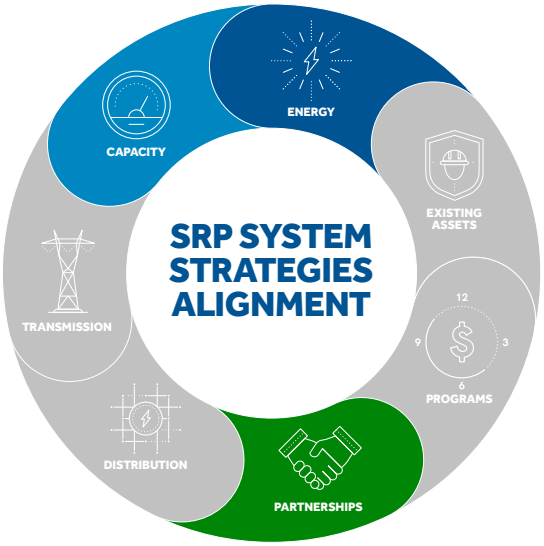
- Deploying the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024. These systems are the foundational platforms needed to integrate distributed energy resources (DERs) with the existing distribution system. We will monitor signposts for the need to deploy more advanced capabilities to support the integration of customer-side resources.
- Implementing advanced planning tools, such as locational value maps and the ability to anticipate and plan solar, storage and electric vehicle adoption at specific customer locations.
- Advancing the interconnection process to enhance the customer experience and technical integration of customer-sited resource interconnections.



- Executing the DE Research and Development plan, which leverages R&D resources, including staff, lab facilities and standardized processes, to execute projects that will ensure readiness to onboard new distribution grid capabilities.
- Sharing the Distribution Enablement Roadmap with external stakeholders to build awareness and support for SRP's approach to transforming the distribution grid.

ISP Action #7: Resource Selection

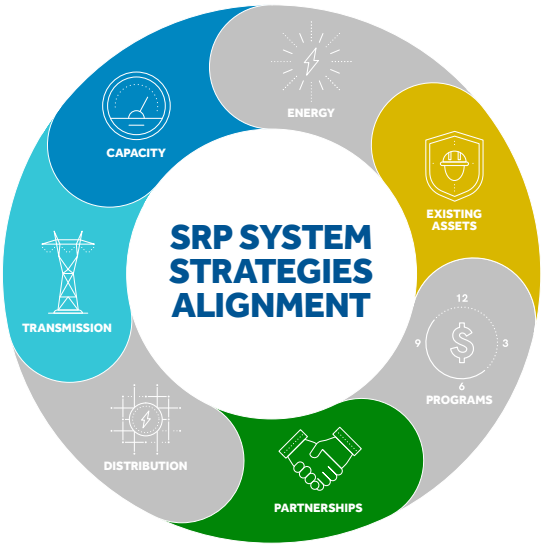
We will issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that we can agnostically select resource technologies that minimize total system costs while meeting our reliability and 2035 Sustainability Goals.



ISP Action #8: Coal Transition Action Plan

We will develop a coal repurposing action plan, which will include:

- Coordinating with co-owners to develop a path forward for the Springerville Generating Station, incorporating the need for replacement firm capacity to enable retirement and engagement with the community on a transition plan.
- Preparing plans for repurposing the Coronado Generating Station site, continuing development of system solutions that repurpose transmission following the retirement of coal plants.
- Developing solutions that preserve transmission access following the retirement of coal plants.
- Testing strategies for minimizing emissions from coal power plants, including dispatch strategies and seasonal operations, while leveraging their capacity to maintain reliability prior to retirement dates.

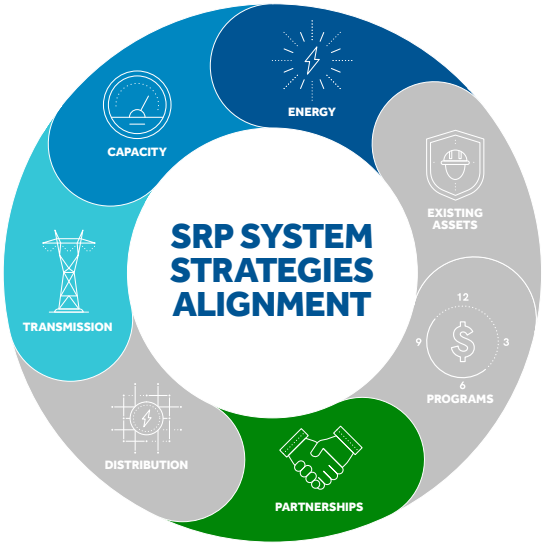


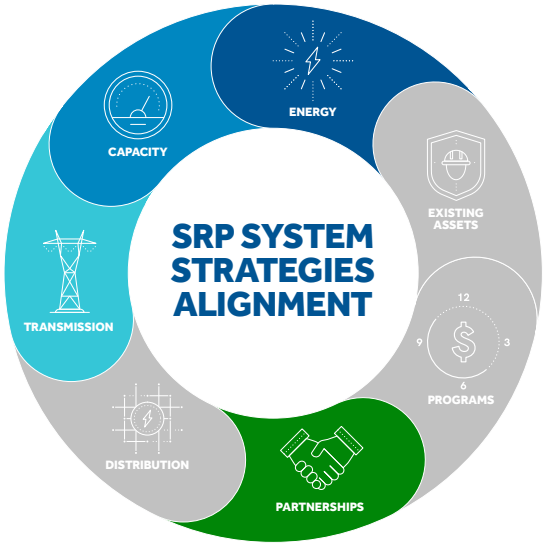
ISP Action #9: Proactive Siting

We will develop and initiate a collaborative community engagement, land, resources and transmission siting research process to proactively identify, prepare and preserve options for feasible sites for future system infrastructure.

ISP Action #10: Regional Transmission

We will pursue transmission projects to enable us to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.





By implementing these 10 ISP Actions, we are confident that we can meet both the changing power needs of our growing customer base and evolving grid complexity. Many challenges lie ahead, but the actions related to customer programs, time-of-use price plans and EV management will help ensure our customers are provided with options to manage their energy costs while bolstering new clean energy technologies. Other ISP Actions related to phasing out coal resources, proactive siting and regional transmission flexibility will ensure SRP can provide sustained reliable power for the Valley while pursuing the best resource options for the future. These ISP Actions all work together to achieve a balance of reliability, affordability and sustainability for our future energy grid.

Future ISP Cycle and Next Steps

The first ISP was a significant advancement in our planning practices. For the first time, we performed integrated systemwide planning through 2035 and established a process for integrating planning activities across the organization. To continue to improve system planning practices and adapt plans to new information, we plan to complete an ISP on a regular cycle. We will continue to perform comprehensive systemwide modeling and engage SRP elected officials, customers and other stakeholders through a robust public process for future ISP cycles. While we have not yet established a schedule for the next ISP, we are targeting releasing an ISP every three to four years initially, recognizing that future ISP cycles may condense with technological and staff advancements.

SRP management and staff express appreciation for stakeholders and their participation in this first-ever Integrated System Plan process. Maintaining this open communication with customers and stakeholders will continue to produce a sound long-term strategic direction for future resources that balances system reliability, affordability and sustainability measures.

For more information and future updates on the progress of the ISP strategies and actions, refer to our website: srp.net/isp.

APPENDIX A

SRP's Integrated System Plan Assumptions Summary

SRP INTEGRATED SYSTEM PLAN STUDY PLAN APPENDIX – ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES

This appendix details the assumptions underlying the key drivers outlined in the Integrated System Plan (ISP) Summary Study Plan document for the scenarios, sensitivities and strategic approaches that SRP will analyze. These assumptions were developed in collaboration with the ISP Advisory Group during the *Prepare* Phase of the ISP (November 2021–April 2022). SRP subsequently updated the assumptions in February 2023 to incorporate impacts from the Inflation Reduction Act of 2022. Additional details on these assumptions are included in the meeting materials from the *Advisory Modeling Subgroup Meeting 2: Inputs for the ISP Study Plan, Advisory Modeling Subgroup Meeting 3: Inputs for the ISP Study Plan – Part 2* and *Advisory Group Meeting 9: Continuing Forward*.[1]

Scenarios

Current Trends

Key Drivers	Assumptions
Economic Growth	Economic load grows 1,645 MW by 2035 and residential and commercial load grows by 1,776 MW by 2035, driven by an average population growth of 1.5% per year. The resulting total load growth is 2.9% per year.
Temperature Rise	"RCP[2] 4.5" climate scenario from the Intergovernmental Panel on Climate Change (IPCC)
Carbon Reduction Policy	No federal or state policy beyond SRP's 2035 Sustainability Goals (reduce the emissions intensity [CO2 per MWh] by 65% from 2005 levels by 2035)
Electrification	500,000 electric vehicles by 2035; 83% residential electric heating adoption by 2035
Distributed Generation	1,300 MW distributed solar by 2035
Energy Efficiency	3,800 GWh total energy efficiency by 2035
Renewable and Battery Storage Costs	Midpoint between low cost (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below)
Gas Resource Costs	Energy Information Administration 2022 Annual Energy Outlook (AEO)
Emerging Technology Availability	Carbon capture and sequestration (CCS) available in 2035. 100% hydrogen and nuclear (small modular reactors) are not available by 2035.
Emerging Technology Cost	Gas with CCS costs are midpoint between low costs (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below). 100% hydrogen and nuclear are not available by 2035.

[1] https://www.srpnet.com/grid-water-management/grid-management/integrated-system-plan
[2] Representative Concentration Pathway- RPC

Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from solar (blend between Arizona and Utah using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (blend between optimistic and conservative cost declines from California Energy Commission publication CEC-500-2019-055), hydrogen storage (using costs from Department of Energy project ST-001), and hydrogen transport (blend between AZ and UT transport costs, using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 85% monetization.
Gas Prices	Energy Information Administration (EIA) 2021 AEO "Reference" case regionalized based on SRP's gas supply
Hydro Availability	Hydro capacity and energy availability remain relatively constant at current drought conditions.
Market Support	Due to near-term capacity constraints, actions taken to contract maximum market capacity through 2032; afterwards 525 MW of market potential available.

Desert Boom

Key Drivers	Assumptions
Economic Growth	Economic development load grows by 2,900 MW by 2035 and population grows by an average rate of 1.8% per year.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	600,000 electric vehicles by 2035; 86% residential electric heating adoption by 2035
Distributed Generation	1,800 MW distributed solar by 2035
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	*Same as Current Trends*
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	*Same as Current Trends*
Hydrogen Prices	*Same as Current Trends*
Gas Prices	*Same as Current Trends*
Hydro Availability	*Same as Current Trends*
Market Support	*Same as Current Trends*

Desert Contraction

Key Drivers	Assumptions
Economic Growth	Economic development load growth rate peaks in 2026 before declining, resulting in a total of 597 MW added by 2035 compared to 2022. Population growth rate follows a similar trend, peaking in 2027 before declining. This results in an average population growth rate of 0.4% per year between 2023 and 2035.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	*Same as Current Trends*
Distributed Generation	*Same as Current Trends*
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act Investment Tax Credit (ITC) and Production Tax Credit (PTC) monetized at 80%.[3] Cost increases for solar (15%), wind (30%) and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[4]
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	Gas with CCS based on Energy Information Administration 2022 AEO +20%. 100% hydrogen and nuclear are not available by 2035.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from UT solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (conservative cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in UT (using costs from Department of Energy project ST-001) and hydrogen transport to AZ (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 80% monetization.
Gas Prices	*Same as Current Trends*
Hydro Availability	Glen Canyon Dam generation production is unavailable at the beginning of the study period (2025). Other hydrogeneration on the Colorado River and Salt River remain consistent with Current Trends assumptions.

[3] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[4] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

Market Support	Loss of Glen Canyon Dam and other hydrogeneration facilities in the West results in 0 MW of market support available. Existing market purchases currently contracted by SRP are honored.

Strong Climate Policy

Key Drivers	Assumptions
Economic Growth	*Same as Current Trends*
Temperature Rise	*Same as Current Trends*
Carbon Reduction Policy	Federal policy that requires a CO2 mass emissions (tons) reduction by 85% from 2005 level by 2035.
Electrification	Electric vehicle adoption consistent with reaching economy-wide net-zero emissions by 2050 (975,000 by 2035); 86% residential electric heating adoption by 2035
Distributed Generation	2,300 MW of distributed solar by 2035
Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[5,6]. All near-term supply chain impacts are fully resolved by 2025.
Gas Resource Costs	Energy Information Administration 2022 AEO
Emerging Technology Availability	Gas with CCS available in 2030, 100% green hydrogen available in 2034, and nuclear (small modular reactors) available in 2034
Emerging Technology Cost	Energy Information Administration 2022 AEO. Inflation Reduction Act ITC applied to nuclear and 100% hydrogen, and CCS tax credit applied to gas with CCS all at 90% monetization.[4] 100% hydrogen unit based on frame combustion turbine.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from AZ solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (optimistic cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in AZ (using costs from Department of Energy project ST-001) and hydrogen transport (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 90% monetization.
Gas Prices	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Hydro Availability	*Same as Current Trends*

[5] ITC and PTC include *the base credit and 5x multiplier for satisfying wage and apprenticeship requirements. 90% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[6] *Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach).*

Market Support	Favorable regional resource and load diversity allows for the potential for the wider region to carry slightly less total resource capacity while maintaining the same level of reliability. SRP assumes a regional coordination program and a regional diversity benefit and tests this assumption by reducing its Planning Reserve Margin requirement from 16% to 13%. Capacity (MW) market availability assumptions are consistent with Current Trends.

Sensitivities

Sensitivity	Assumptions
High Demand Response	Increased expansion in demand response over time, reaching 400 MW total Demand Response by 2035.
High Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
High Distributed Generation	Distributed solar and battery adoption reach 2,300 MW and 249 MW, respectively, by 2035.
Increased Load Management	Increased load flexibility through managed electric vehicle (EV) charging or other flexible loads. Modeled as a virtual battery addition with limitations on when it can charge or discharge.
Regional Diversity	Favorable regional resource and load diversity allows for the potential of a reduced loss of load probability on SRP's system. SRP tests this assumption by reducing the minimum Planning Reserve Margin requirement from 16% to 13%.
High Gas Price	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Low Gas Price	EIA 2021 AEO "High Oil and Gas Supply" case regionalized based on SRP's gas supply
Volatile Gas Price	EIA 2021 AEO "Reference" gas regionalized based on SRP's gas supply, adjusted to reflect gas price volatility observed from 2000-2010
High Technology Cost	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 80%.[7] Cost increases for solar (15%), wind (30%), and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[8]
Low Technology Cost	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[9]. All near-term supply chain impacts are fully resolved by 2025.

[7] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

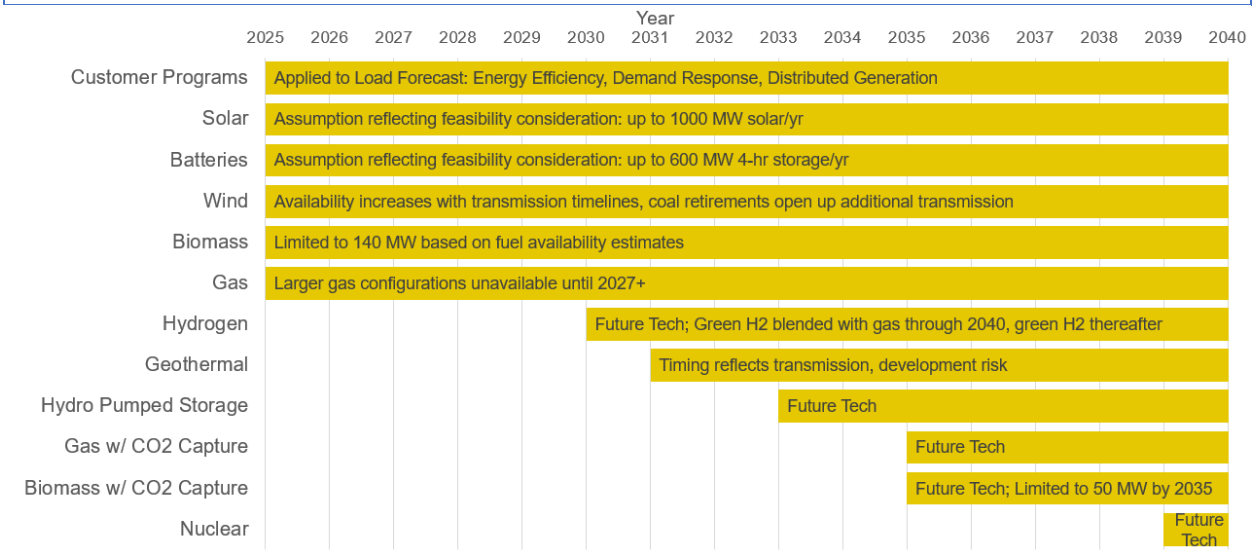
[8] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

[9] *Includes the base credit and 5x multiplier for satisfying wage and apprenticeship requirements for ITC and PTC. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). Monetization range reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

Strategic Approaches

Tech Neutral

Key Drivers	Assumptions
Technology Availability	All resource technologies available, limits based on technical feasibility availability of new resources (chart below). Strong Climate Policy Scenario includes accelerated availability dates for CO2 capture (2030), 100% green H2 (2034), and nuclear (2034).



No New Fossil

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies

Minimum Coal

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies
Coal Plant Operational Changes	Evaluates impacts from Coronado Generating Station Units 1 and 2 and Springerville Generating Station Unit 4 operating seasonally beginning in 2025 (off-line for three months of the year during non-peak periods) and SRP fully exiting coal by 4/30/2034.

Revision History

Revision	Date	Description
0	August 2022	Original
1	March 2023	Updated to incorporate impacts from the Inflation Reduction Act into technology costs.
2	April 2023	Corrected understated High DG sensitivity assumption and economic growth assumption in the Desert Boom scenario.

APPENDIX B

SRP Customer Research Future of Energy Phases 1 & 2 Report

Future of Energy

Phase I & II Report

June 30, 2022

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Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from customers.

Looking into the future, SRP expects there to be many disruptions to the energy industry with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perspectives on this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about sustainability, affordability, and reliability related to power provision and gauge their reactions to a potential energy plan. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement with SRP on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach is being applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and a choice exercise (planned for Fall 2022). This report addresses Phase I and Phase II.

All customers included in the research were SRP residential customers, energy decision makers, who did not work for a competing industry, and were over 18 years old.

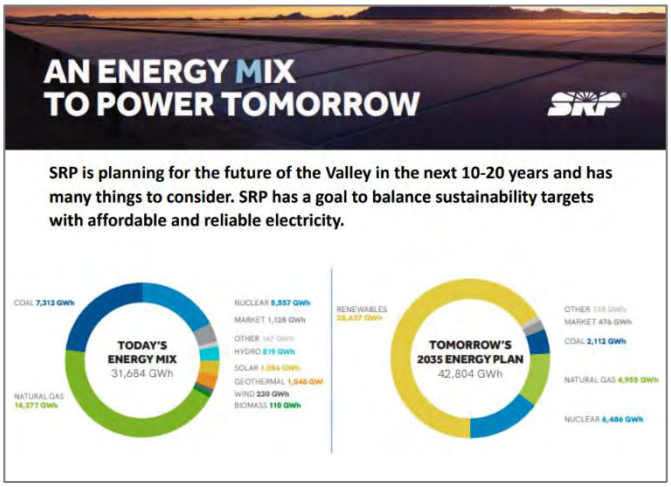
Phase I: Virtual Focus Groups

Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and extract observations.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.



Customers evaluated SRP's proposed energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. Customers were provided background on SRP's priorities.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more)
- **Gender** (Male/ Female)
- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (Preferred/ New Customer/ Satisfactory/Slow/Unsatisfactory)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary

The illustrative plan was rated positively

Most customers reacted positively to the energy plan while a quarter felt it was excellent. Additionally, a majority expressed positive perceptions of SRP and cited outstanding customer service and reliability as reasons for this.

Affordability & reliability were top priorities for the future

Affordability was one of the most-selected future issues facing Arizona and customers felt that affordability should be prioritized.

Both affordability and reliability surpassed sustainability in importance. Customers noted that sustainable electricity was meaningless if not affordable and reliable, especially with rising inflation and increased usage during the Arizona summer heat.

- SRP might increase energy plan acceptance by anticipating and addressing questions on affordability and reliability.

A majority agreed SRP should prioritize the illustrative energy plan

Further, about half felt the plan fit with SRP's brand, was easy to understand, and seemed achievable. Customers reflected that the plan could be improved by providing more details on how it would be achieved and its impacts on affordability.

Respondents also hoped to ensure that SRP selected the best sources of electricity, though opinions on what sources were best varied. Customers were unclear on which sources of electricity SRP would use.

- Emphasizing transparency with customers as SRP solidifies energy sources, including cost impacts, may bolster trust.

Customers wanted to continue to hear about ways to save from SRP

Customers exhibited strong positive feedback on the benefits and effectiveness of SRP's cost saving offerings.

Customers most wanted to hear more about programs that can help them save money, including rebates and energy efficiency programs, which aligned with affordability priorities.

- Continuing to showcase and optimize offerings geared towards energy and cost savings may increase enrollment and contribute to positive overall perceptions of SRP.

Detailed Findings

Future Issues and Priorities

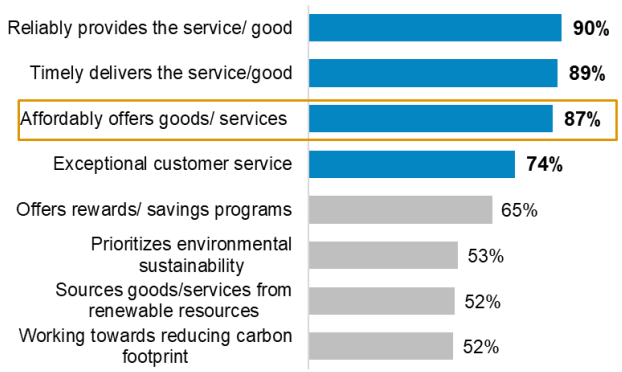
Customers demonstrated affordability concerns

Affordability was rated as a top need for companies to prioritize in the future, with nearly 9 in 10 believing it was important for companies to prioritize the need.

This accompanied reliably providing goods and services, and providing them in a timely manner.

Company Priorities – Importance

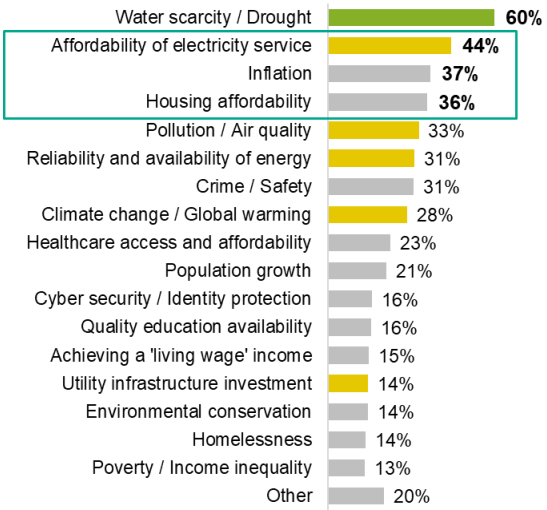
Top-Box



Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

- The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by several items SRP is most able to impact related to pollution, energy reliability, and climate change (highlighted in yellow).
- Lower income customers (earning under $75k/year) reflected greater concern for affordability.

Future Issues Facing Arizona



- *Year-round residents are more likely to prioritize housing affordability.*
- *Those with a household income of $75k or more were more likely to prioritize water scarcity but were less likely to prioritize housing affordability.*
- *Non-Hispanic customers were more likely to prioritize water scarcity.*

Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

*Groups **more likely** to be concerned about others' ability to pay their electric bill include:*

- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Similar concerns were seen across top issues

When asked to rank selected issues on importance, rankings mostly mirrored the most-selected future issues facing Arizona. Customers were most likely to rank the following first: Water scarcity (22%), Inflation (13%), Housing affordability (10%), Affordability of electricity (9%)

- *Younger customers (aged 18-44), those with a household income under $75k, females, and Hispanic customers were more likely to rank housing affordability first.*
- *Non-Hispanic customers were more likely to rank water scarcity first.*

Customers mentioned population growth/city sprawl and rising prices added to their concern about top-ranked Issues.

Ranked 1st: Water Scarcity/Drought

*"**Having enough water to sustain the millions of people within the state.** And the temperature increase due to global warming coupled with heat island effects from Phoenix and Tucson sprawl." – Survey Respondent*

Ranked 2nd: Inflation

*"Population growth and cost of living. Being senior citizen on set income inflation has hit hard, **gas prices and growing energy prices concern me**." – Survey Respondent*

Ranked 3rd: Housing Affordability/ Availability

*"**The housing prices are going up but the pay in work is not**, who makes 3x the rent anymore. Nobody and it's ridiculous." – Survey Respondent*

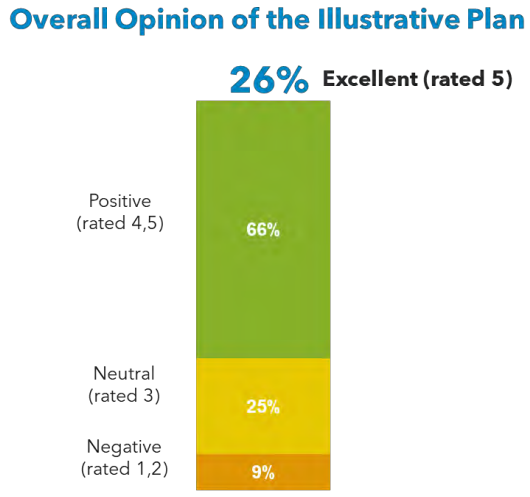
Ranked 4th: Affordability of Electricity Service

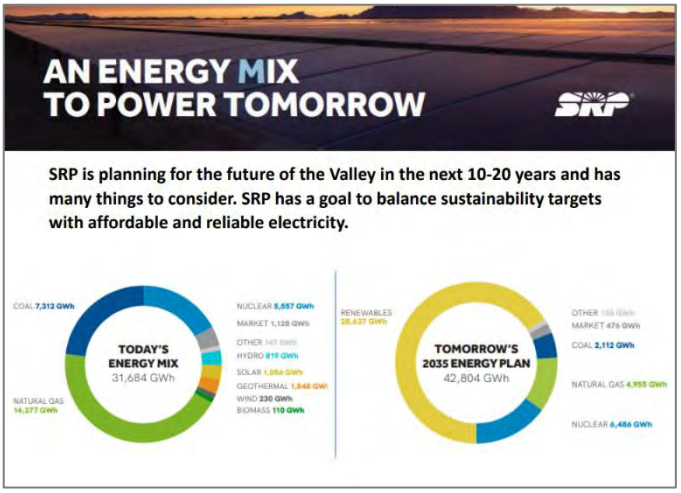
*"**Providing the uninterrupted service at an affordable price** for the growing population, taking inflation into consideration." – Survey Respondent*

SRP Energy Plan

Two thirds rated the energy plan positively

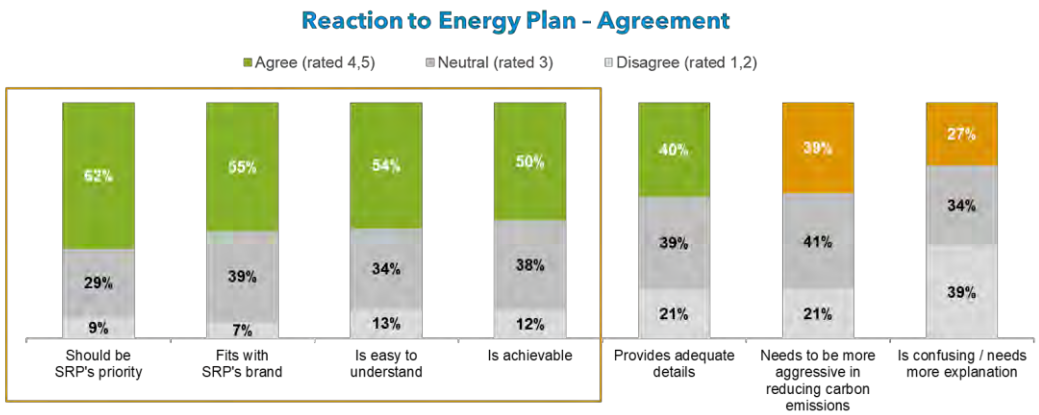
When evaluating SRP's energy plan, one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.





- *Those ranking sustainability first had a more positive impression of the energy plan.*
- *Those with high electricity usage were less likely to rate the plan positively.*

Additionally, at least half agreed the plan should be SRP's priority (62%), fit with the brand (55%), is easy to understand (54%), and is achievable (50%).



- *Year-round residents were more likely to agree that the plan is achievable, fits with the SRP brand, is easy to understand, and provides adequate details.*
- *Customers with a household income under $75k and Hispanic customers were more likely to agree the plan fits with SRP's brand.*

Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
  *"**Renewable energy is fine, but solar and wind require lots of area to house enough energy to power cities.** Still have to maintain natural gas…and some coal. Nuclear power is the way to go, folks." – Survey Respondent*

- Nineteen percent (19%) shared affordability and cost concerns.
  *"I like the direction of the plan **but have my doubts that SRP will follow through on this plan in a way that is still affordable**." – Survey Respondent*

- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.
  *"How long will it take to achieve this? **Needs to be sooner rather than later**." – Survey Respondent*

  *"I don't view it as a plan. Rather strategic long-term objectives. **What is the road map to achieve, timing phases, costs, resources in the land?**" – Survey Respondent*

One-quarter (22%) felt that SRP should prioritize another goal (not already stated in the energy plan) and emphasized thoughts on specific energy sources.

*"**I did not see water conservation listed**, although I know it is on the SRP agenda." – Survey Respondent*

*"**Nuclear power is in my view, the only way forward**, renewable, wind, solar are efforts in futility. Sounds good to a few but a majority know better." – Survey Respondent*

*"**Making solar more affordable to the population**. This would increase the power grid, creating a partnership with the community. Making it more enticing for consumers to provide SRP with power." – Survey Respondent*

*"**Include hydrogen power** for vehicles in use." – Survey Respondent*

*"Since Arizona is a very hot state. **I believe solar panels would be excellent for SRP.** That should be the number one priority for SRP." – Survey Respondent*

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

> *"Accelerate.* ***I want to see the short-term goals.*** *What, specifically, are we doing right now?" – Customer Focus Group Participant*

> *"****I feel like if we can reduce how much coal and other sources that we use at the moment****… So, if this is the company's goal and they want to focus on that, then I would be all for it." – Customer Focus Group Participant*

> *"****Why is it going to take us another 30 years*** *when I've gone to professional developments thrown by SRP about using renewable resources and whatnot?…I like that it's out there and that you have it projected. I also wish that you could be like the Lego corporation and be 100% renewable 20 years before your said date." – Customer Focus Group Participant*

> *"The thing that immediately stuck in my brain is the "Oh, solar isn't available 24 hours." And that's a really old talking point. And it's also not necessarily true anymore…So,* ***I feel like some of the messaging is based on talking points that are out of date and not necessarily forward-thinking****." – Customer Focus Group Participant*

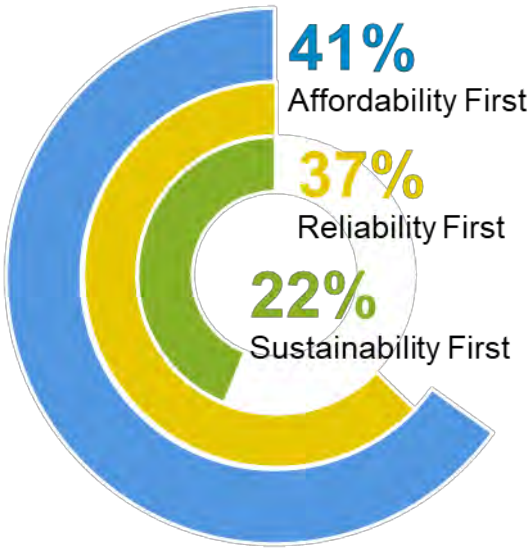
> *"****It's kind of curious why it would take so long to get more solar.*** *I mean, we're in the Valley of the Sun." – Customer Focus Group Participant*

> *"****I wonder how they could include in there something to do with conserving energy, wiser use****. I mean, I know there's been a lot of improvement like in the effectiveness of AC, with LEDs, and stuff like that. It would just be helpful…to consider the conserving side of it. And also, I wonder if the time has come to include in that chart an energy generated from the home, solar panels, whatever, like that. Because most of the people looking at the chart are homeowners like us." – Customer Focus Group Participant*

> *"What does all of this mean? And then, of course,* ***the financial piece of it, just like, okay, how would that even work, honestly, with thinking of all of it?*** *Like what could I do now to make a change? How is that going to develop over the years, just what that would all even look like?" – Customer Focus Group Participant*

Affordability and reliability were most ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, two-fifths (41%) ranked affordability first, with 37% prioritizing reliability, and only 22% prioritizing sustainability.



In the focus groups, while a majority of customers ranked reliability first , they discussed a tough tradeoff between reliability and affordability

> *"If it's not on, it doesn't work, right? It doesn't matter what you spend. Again, we all have budgets, and we all try to stay within them." – Customer Focus Group Participant*

When asked reasons for ranking affordability, reliability, and sustainability as they did, customers responded as follows:

Affordability: Reasons Ranked First

23% Mentioned keeping energy costs down, the rising cost of living, and/or that if electricity isn't affordable, other priorities are meaningless.

*"I only have so much money, and already have seen enough scenarios where **people can't afford to run their air conditioning in summer due to costs**. I have been in valley 23 years and that's an issue every year." – Survey Respondent*

- *Both those with a satisfactory/low/unsatisfactory credit rating and those with a negative experience with SRP were significantly more likely to rank affordability first.*
- *Those with a household income less than $75k and Hispanic customers were more likely to rank affordability as first.*

Reliability: Reasons Ranked First

25% Mentioned that consistent energy is needed to maintain the status quo, and/or that if electricity isn't reliable, other priorities don't matter.

***"Residents and business are dependent upon a steady source of power.** Some uses are essential to life in the case of those who rely on devices to stay alive. Because of the summer heat, a break in power could be fatal to some." – Survey Respondent*

Sustainability: Reasons Ranked First

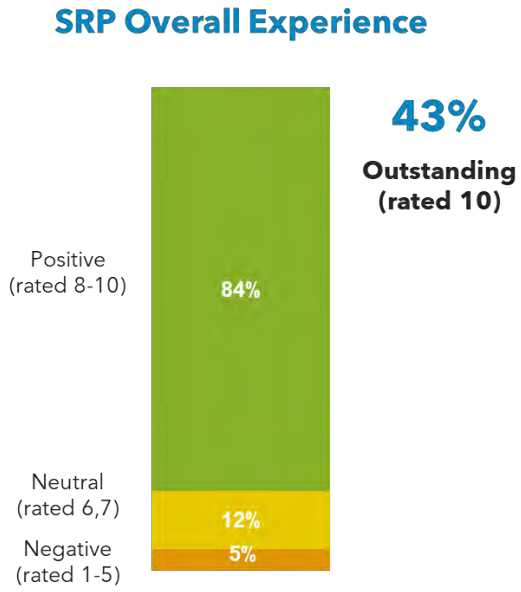
10% Mentioned the need to take care of the earth/ future energy needs.

***"Without sustainability there is no future."** – Survey Respondent*

Those who have lived at their address 2 years or less and those with a positive opinion of the energy plan were more likely to rank sustainability first.

Perceptions of SRP and Topics of Interest

Over four-fifths rated their experience with SRP positively



In qualitative findings, customers noted a highly positive perception of SRP, specifying that reliability of service and helpful customer service were key factors.

"Honestly, I'd give SRP a 10. I haven't had any major issues. Any time I've had anything that's come up, ***I'm able to get someone on the phone, speak with them****, … So, I've had a really good relationship with them." – Customer Focus Group Participant*

"I think the ***consistency of the service****. Being in Arizona, we do have the so hot weather all the time and having air conditioning is definitely a must…* ***And the consistency of them being able to provide that to us without any issues so far is something that I really appreciate****." – Customer Focus Group Participant*

- *Those with a household income under $75k were more likely to rate their experience as outstanding.*
- *Those who had a negative impression of the energy plan and those categorized with high usage were less likely to be satisfied with SRP.*

Over half had interest in ways to save

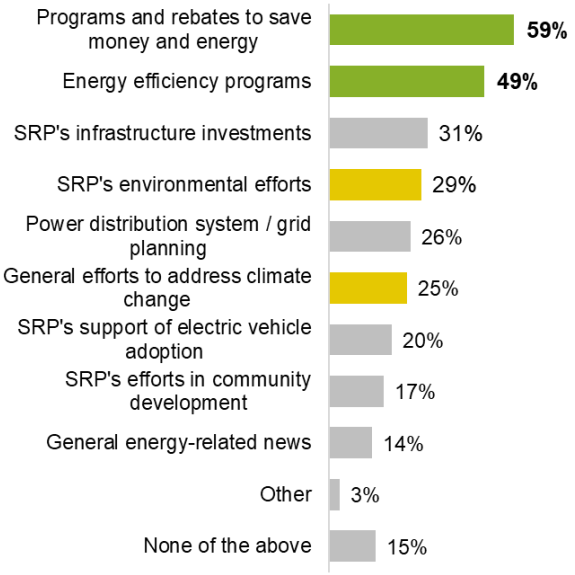
Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their bills.

"I do have the M-Power so I do have prepaid electricity, so I am very acutely aware of my usage. ***I can see what I'm spending per day****." – Survey Respondent*

"I do like the idea that SRP does provide that time of use plan or ***keeps your bills consistent*** *throughout the month or throughout the year." – Survey Respondent*

Topics of Interest

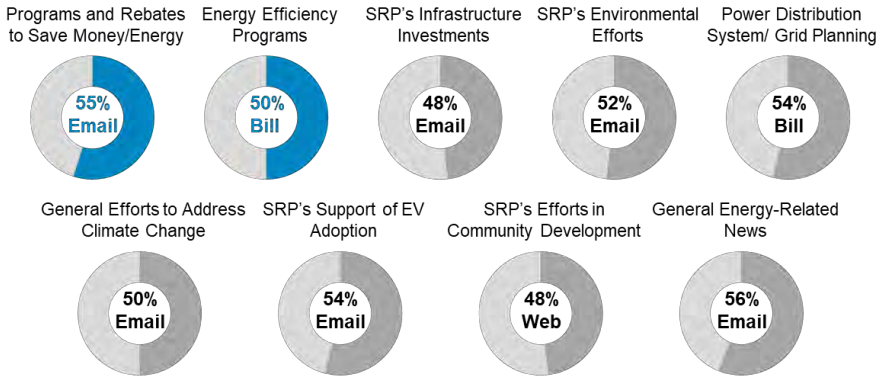


- *Those with a negative overall opinion of the energy plan were significantly more likely to want to hear about SRP's infrastructure investments and the power distribution system; they were less likely to want to hear about SRP's environmental efforts and general efforts to address climate change.*
- *Those with a household income less than $75k were more likely to want to hear about cost saving options.*

Across communication topics, customers most preferred to receive communication via bill insert and email.

Males were more likely to prefer email communications about programs and rebates to save money/energy.

Channel Preference



Appendix

Demographics

	Focus Group (n=24)	Online Survey (n=400)
GENDER		
Female	13	45%
Male	10	51%
Non-binary	1	0%
Prefer not to answer	-	4%
HOUSEHOLD INCOME		
Under $75k	15	41%
$75k or more	9	39%
Prefer not to answer	-	20%
CREDIT RATING		
Preferred	19	67%
Satisfactory/Slow/Unsatisfactory	3	12%
New Customer	2	21%
ETHNICITY (MULTIPLE SELECTIONS)		
White	20	69%
Black or African American	3	4%
Other	3	13%
Prefer not to answer	-	18%
HISPANIC ORIGIN		
Hispanic	2	15%
OWN/RENT HOME		
Own	18	73%
Rent	6	28%

	Focus Group (n=24)	Online Survey (n=400)
AGE		
18-44	13	30%
45-64	6	37%
65+	5	34%
EMPLOYMENT		
Ful-time/Part-time	-	51%
Self-employed	-	6%
Retired	-	33%
Unemployed/seeking employment/student	-	4%
Not working/not seeking	-	2%
N/A / Prefer not to answer	-	5%
YEARS AT ADDRESS		
2 or less	-	7%
3-5	-	10%
6-20	-	30%
21-39	-	30%
40+	-	15%
USAGE		
Low (6,000 kWh or less)	3	19%
Moderate (6,001-12,000 kWh)	8	33%
Medium (12,001-18,000 kWh)	8	29%
High (More than 18,000 kWh)	5	20%

Illustrative Plan Description and Background

In addition to the visual depiction of the illustrative plan, respondents were provided the following additional description and background:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

APPENDIX C

SRP Customer Research Future of Energy Phase 3 Report

Future of Energy: ISP Residential Customer Research

Phase III Report

Revised: December 13, 2023

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

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Appendix 18

Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on a new way of planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from residential customers.

Looking into the future, SRP expects there to be many changes and disruptions to the energy industry including evolving customer needs and expectations with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perception of this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about, and value sustainability, affordability, and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach was applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and culminating in a choice exercise (May 2023).

All customers included in the research were SRP residential customers, who were energy decision makers for their household (make decisions about their utility service and pay the bill), did not work for a related industry, and were over 18 years old.

Phase I: Virtual Focus Groups

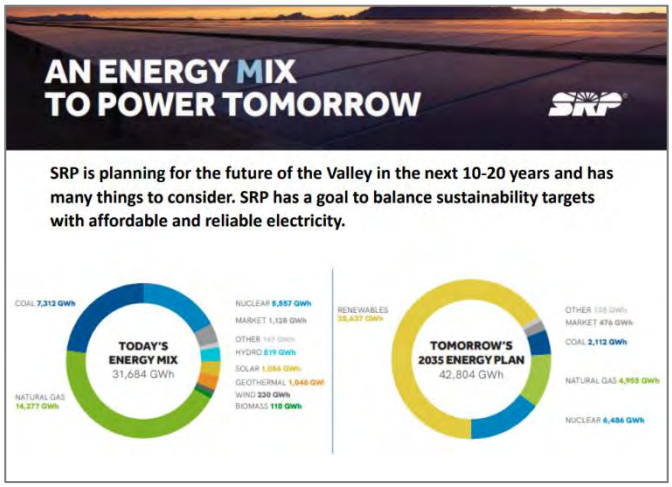
Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and have a meaningful conversation.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.

Customers evaluated a visual example of SRP's future potential energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. The illustrative energy plan shown in Phase II did not include details on bill impacts, water reduction, carbon emission reduction, or timing to meet the sustainability goals. Customers were provided background on SRP's priorities prior to evaluating energy mix; this wording is included in the Appendix on page 20.



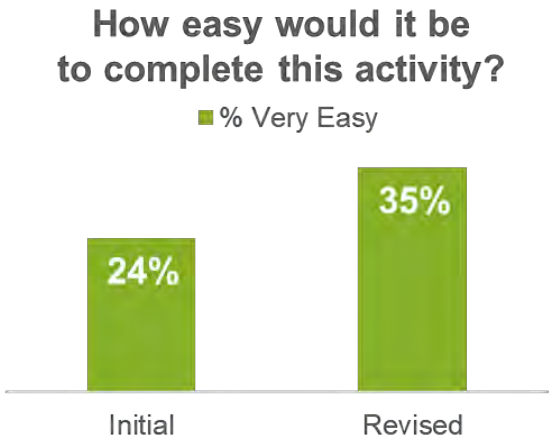
Pre-Test Research: Optimizing Survey Materials

Prior to the Phase III survey, a multi-staged pre-test study was conducted to test education materials, survey instructions, and choice exercise design among non-SRP customers. The pre-test research included an initial pre-test survey, qualitative ride-along interviews, and a revised pre-test survey.

Throughout the three pre-test phases, respondents identified areas of the instructions and educational materials that were difficult to understand. Based on feedback from this pre-test, instructions for the choice exercise were crafted with clear tasks respondents could understand and accurately complete.

This confirmation helped secure the highest quality of actionable data. Changes made to the choice exercise included:

- Impactful phrase rewording which resulted in less confusion (~40% reduction in confusion)
- Redesign of the choice activity which created an easier survey experience.



This testing ensured SRP's diverse customer base would be able to understand and easily complete the choice exercise in Phase III.

Phase III: Choice Exercise Online Survey

In this 20-minute survey fielded between May 9 and May 29, 2023, offered in English and Spanish, respondents completed a choice exercise to assess their preferences for SRP's potential future energy system. Quotas were set to mirror the true population split for SRP's customer base. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the Integrated System Plan.

Conjoint methodology is used to optimize a product or service of interest by asking respondents to make a series of choices though an exercise simulating real-life situations, determining what tradeoffs they are willing to make.

The following best practices were used in development of the choice exercise for the Phase III survey:

- Exposing respondents to educational information regarding system inputs prior to asking them to make a choice (e.g., explaining energy mixes and defining carbon reduction)
- Ensuring complex inputs are positioned in customer-friendly terms (e.g., showing carbon reduction in terms of the number of gas-powered vehicles)
- Utilizing visuals where possible to "show" rather than "tell" (e.g., including a graphical representation of the energy mix)
- Creating precise levels for each system input (e.g., utilizing data outputs from other ISP research efforts to build levels)
- Ensuring system configurations are realistic to respondents to avoid asking them to make a non-sensical choice

- Including no more than seven inputs per system to ensure ease of comprehension
- Limiting the number of screens in the exercise to no more than twelve to minimize respondent fatigue

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a “none of these” option representing the current energy system and choose the plan they would most prefer SRP to pursue. Through selections made, a customer preference rating was produced for each potential future energy system. An example of the choice exercise is shown on the following page.

The ISP's analytical framework and outputs from the system planning informed the following system inputs for the choice exercise:

- Illustrative energy mix (9 mixes tested)
- When SRP will meet its sustainability goals (2030 or 2035)
- Percent reduction in carbon emissions (4 levels for each energy mix)
- Percent reduction in water usage (4 levels for each energy mix)
- If SRP will build new gas power plants (yes or no)
- Monthly bill impact (4 levels calculated on customers' average bill)
- Number of 2-hour power outages (0, 1, 2, or 3)

Illustrative mixes and variations in options for the inputs shown were representative of the resource builds and implications for each strategic approach under the future scenarios from the ISP system plans. Various levels (or options) were shown for each component resulting in evaluation of over 9,200 possible system configurations. An example of the choice exercise screen respondents completed is located in the Appendix on page 21.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more) (Phase II Only)
- **Limited Income** (200% of HHS Poverty Guidelines/ Non-Limited at 200%)
- **Gender** (Male/ Female/Nonbinary)

- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (5 levels)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Analysis Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary

In Phase I & II, most customers reacted positively to SRP's initial path forward, and a quarter felt it was excellent. A majority agreed the plan should be prioritized by SRP. Phase III revealed residential customers' preferences for the future energy system.

Top factors: affordability & bill impacts

Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change

Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy, and overall quality of life. Thus, they understood the need for a lower-carbon future energy system, however, across scenarios, lower cost strategic approaches were more preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage

Customers reported positive experiences with SRP's programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts, and infrastructure improvements.

Recommendations

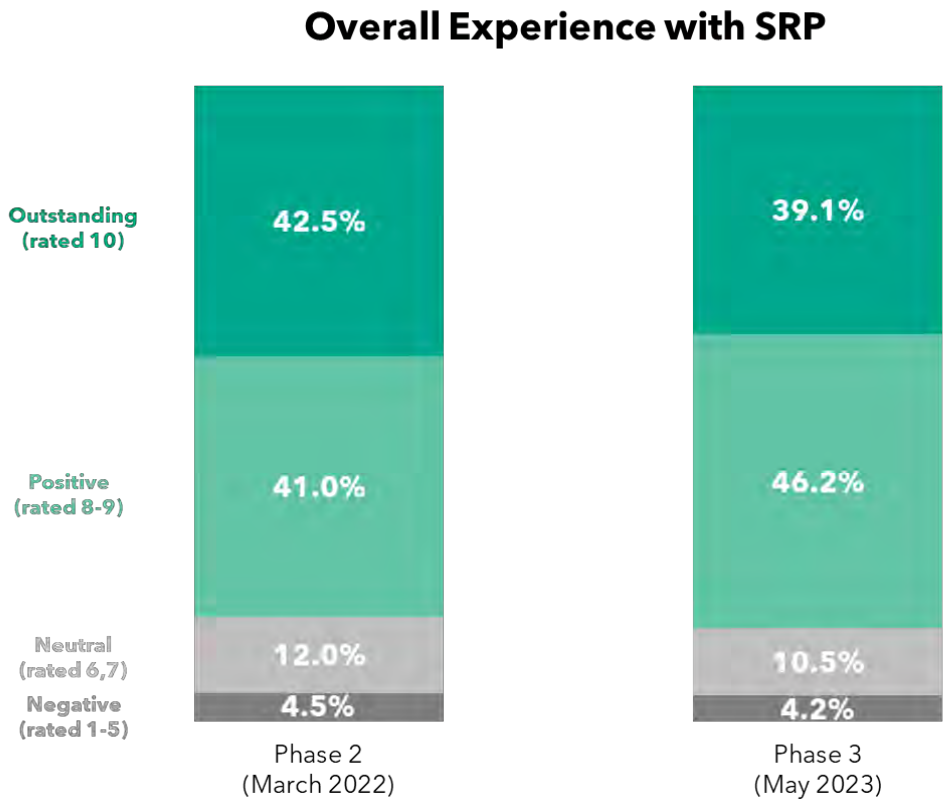
- **For SRP's ISP, focus investment on a least-cost portfolio:** With cost being the top driver of customer preference, it will be critical to ensure system costs are managed and explained to customers proactively and transparently.
- **For SRP's ISP, highlight and maintain grid readiness and resiliency:** Reliability was the second highest ranked priority.
- **In ISP implementation, utilize a targeted approach to customer programs:** Customers expressed a willingness to engage with SRP via customer programs. These programs should be designed to meet the varying needs of customers.

Detailed Findings

Experiences with SRP, Concerns, and Priorities

Most rated their experience with SRP positively

Similar to March 2022, in May 2023 surveying, over 4 in 5 customers rated their experience with SRP positively. While about 2 in 5 provided an "Outstanding" rating.



In qualitative focus groups, customers attributed their highly positive perception of SRP to the reliability of service and helpful customer service. Additionally, participants felt positively about SRP's customer programs, agreeing that programs help them manage
and reduce their electricity bills.

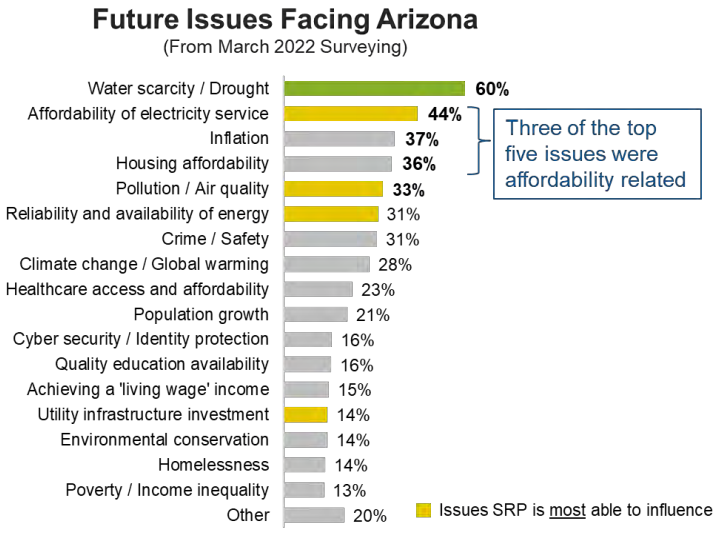
*Groups **more likely** to provide a positive rating of their experience with SRP included:*

- *Customers aged 55 or older*
- *Non-Hispanics*

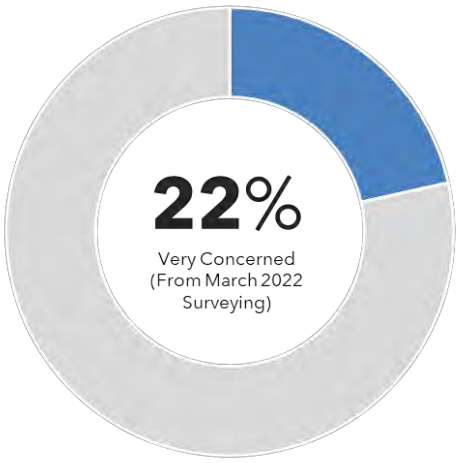
Customers demonstrated affordability concerns

Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by some items related to energy service, including pollution, energy reliability, and climate change.



- ***Lower income*** *customers (earning under $75k/year) reflected* ***greater concern for affordability****.*
- ***Year-round*** *residents are more likely to* ***prioritize housing affordability****.*
- *Those with a household* ***income of $75k or more*** *were more likely to* ***prioritize water scarcity*** *and were less likely to prioritize housing affordability.*
- ***Non-Hispanic*** *customers were more likely to* ***prioritize water scarcity****.*



Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

Groups ***more likely*** *to be concerned about others' ability to pay their electric bill include:*

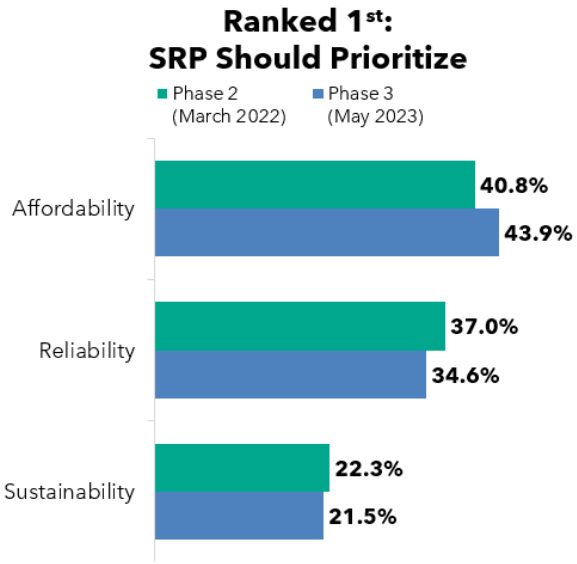
- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Affordability and Reliability were most often ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, affordability was the top priority in both Phase II & III for over two-fifths of customers. Over one-third prioritized reliability, and less than one-quarter prioritized sustainability.

In the focus groups, while a majority of customers ranked reliability first, they discussed a tough tradeoff between reliability and affordability.

While the ranking of priorities was similar across Phases, reasons for these rankings in May 2023 highlighted greater emphasis on the rising cost of living and a need for consistent electricity.



Affordability: Reasons Ranked First

Almost half (46%) of those who ranked affordability first in Phase III mentioned keeping energy costs down and the rising cost of living. This was more than in Phase II where only one-third ranked affordability first for the same reason. The increase in concern over rising cost of living and keeping energy costs down may be due to the rise in inflation and increased conversation about rising prices across products and services in 2023.

*In Phase III surveying, groups **more likely** to rank **affordability first** included:*

- ***Limited income** customers (200% of HHS Poverty Guidelines)*
- *Females*
- *Hispanics*
- *Those enrolled in **M-Power for Pre-Pay***

Reliability: Reasons Ranked First

In Phase III, half (51%) of the customers who ranked reliability first noted a need for consistent electricity to maintain the status quo. This increased from about one-quarter (23%) ranking reliability first in Phase II for the same reason.

*In Phase III surveying, groups **more likely** to rank **reliability first** included**:***

- *Non-Limited income customers*
- *Males*
- *Those with Preferred Credit Ratings*

Sustainability: Reasons Ranked First

While the smallest proportion of customers ranked sustainability first, three-fifths (62%) of those who did in Phase III noted the importance of taking care of the Earth and future energy needs. This was higher than the almost half (45%) who ranked sustainability first for the same reason in Phase II.

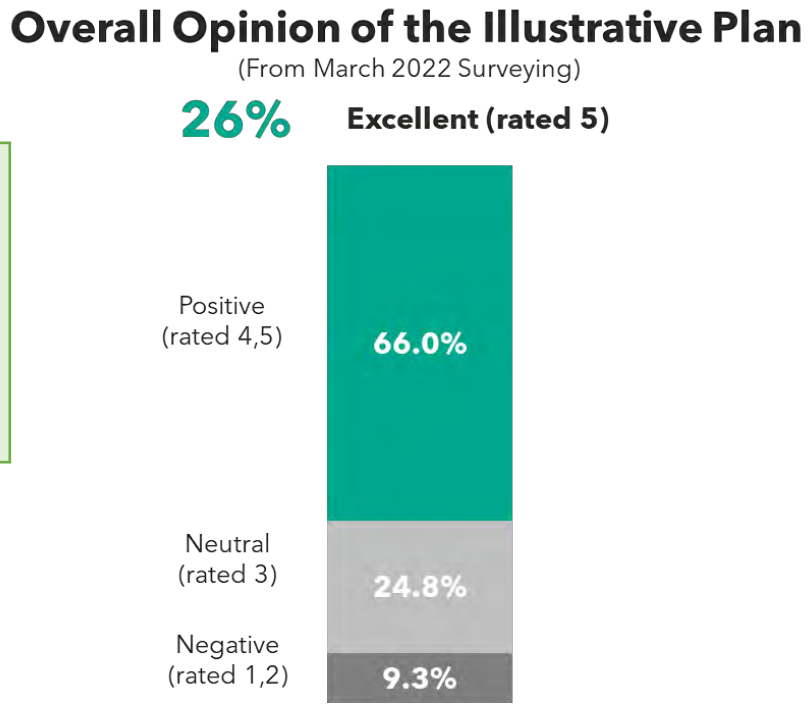
*Customers **aged 55 to 64 were less likely** than all other age groups to rank **sustainability first**. In Phase III surveying.*

SRP Energy Plan: Initial Reactions (Phase I & II)

Two thirds rated the initial energy plan positively

When evaluating an illustrative example of SRP's energy plan during initial phases of research (visual and background evaluated can be found in the Appendix on page 20), one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.

- *Those ranking **sustainability first** had a **more positive** impression of the energy plan.*
- *Those with **high electricity usage** were **less likely** to rate the plan positively.*



Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
- Nineteen percent (19%) shared affordability and cost concerns.
- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

Phase III Customer Preference for Future Energy System

Monthly bill impact of most importance when selecting an energy system

After completing the exercise, over one-third of respondents (37%) reported the monthly bill impact was the most important input when choosing a preferred future energy system.

*Groups **more likely** to rank **monthly bill impact first** included:*

- *Year-round residents*
- *Those **employed part-time***

Among those ranking the **energy mix first (14%)**, top ranked priorities were evenly split:

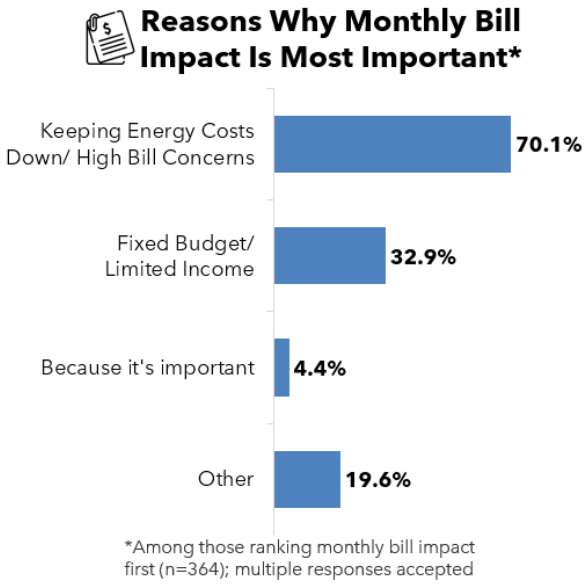
- Affordability – 31% ranked 1st
- Reliability – 36% ranked 1st
- Sustainability – 34% ranked 1st

This suggested the energy mix was seen as a component related to all three priorities.

Attribute	Ranked 1st Most Important
Monthly bill impact	36.8%
Reduction in carbon emissions	15.9%
Number of 2-hour power outages	14.5%
Energy mix	13.9%
Reduction in water usage	11.4%
If SRP will build new gas power plants	5.0%
When SRP will meet its sustainability goals	2.5%

Reasons for ranking inputs first varied

Customer open-ended comments highlighted concerns regarding financial constraints due to changing socio-economic conditions and future uncertainty stemming from inflation and escalating energy expenses. Looking to the future, customers attributed greater costs to the anticipated new infrastructure needed to meet growing demand for electricity and expressed concerns that cost increases could impact quality of life. Additionally, the viability and affordability of future green energy initiatives raised doubts for some given the present economic context.



*The following groups were **more likely** to mention **"fixed budget/ limited income"**:*

- *Customers **aged 55+***
- *Retirees*
- *Those with **limited incomes** (200% of HHS Poverty Guidelines)*

Among those ranking carbon reduction first, about a third mentioned reducing carbon via the use of cleaner energy sources (like solar or nuclear) while nearly half of those ranking energy mix first mentioned these topics as reasons for ranking energy mix as most important.

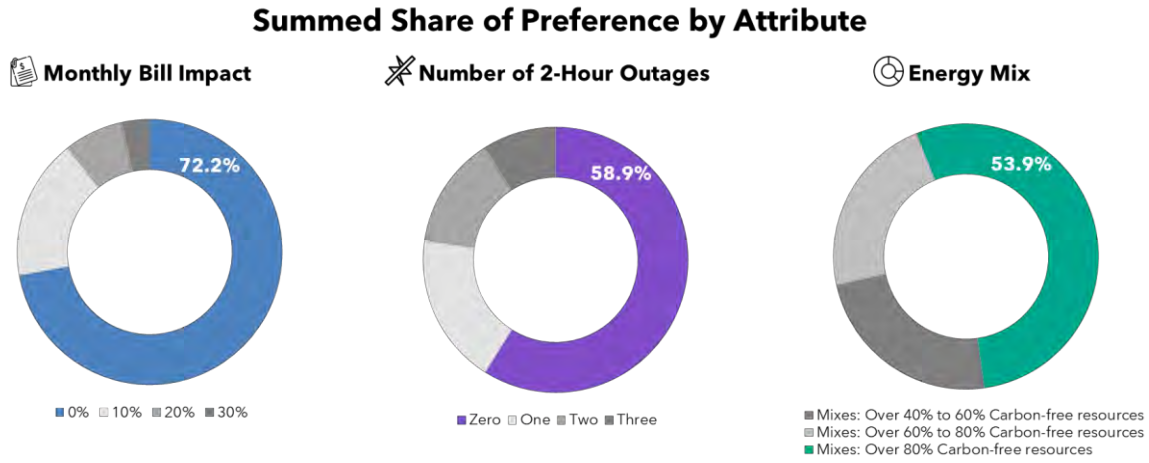
Reasons Why Most Important

Reduction in carbon emissions *(n=169)	Number of 2-hour power outages *(n=139)	Energy mix *(n=147)
37% Reducing carbon has direct impact on climate change	**58%** Dangers associated with outages (hot climate, health concerns, etc.)	**46%** Emphasis on reducing carbon and/or increasing solar or nuclear
32% Emphasis on reducing carbon and/or increasing solar or nuclear	**34%** General reliability concerns	**33%** Some energy sources are limited/ need a mix

Choices indicate a desire to "have it all"

The choice exercise also revealed the preference for each level of key factors in isolation.

- Bill Impact: a majority preferred 0% increase
- Outages: a majority preferred zero 2-hour outages
- Energy Mix: a majority preferred energy mixes with over 80% carbon-free sources



While monthly electricity bills have the largest impact on preference (72%), these preferences indicate that customers want the cleanest, greenest energy at the lowest cost with no implications to reliability.

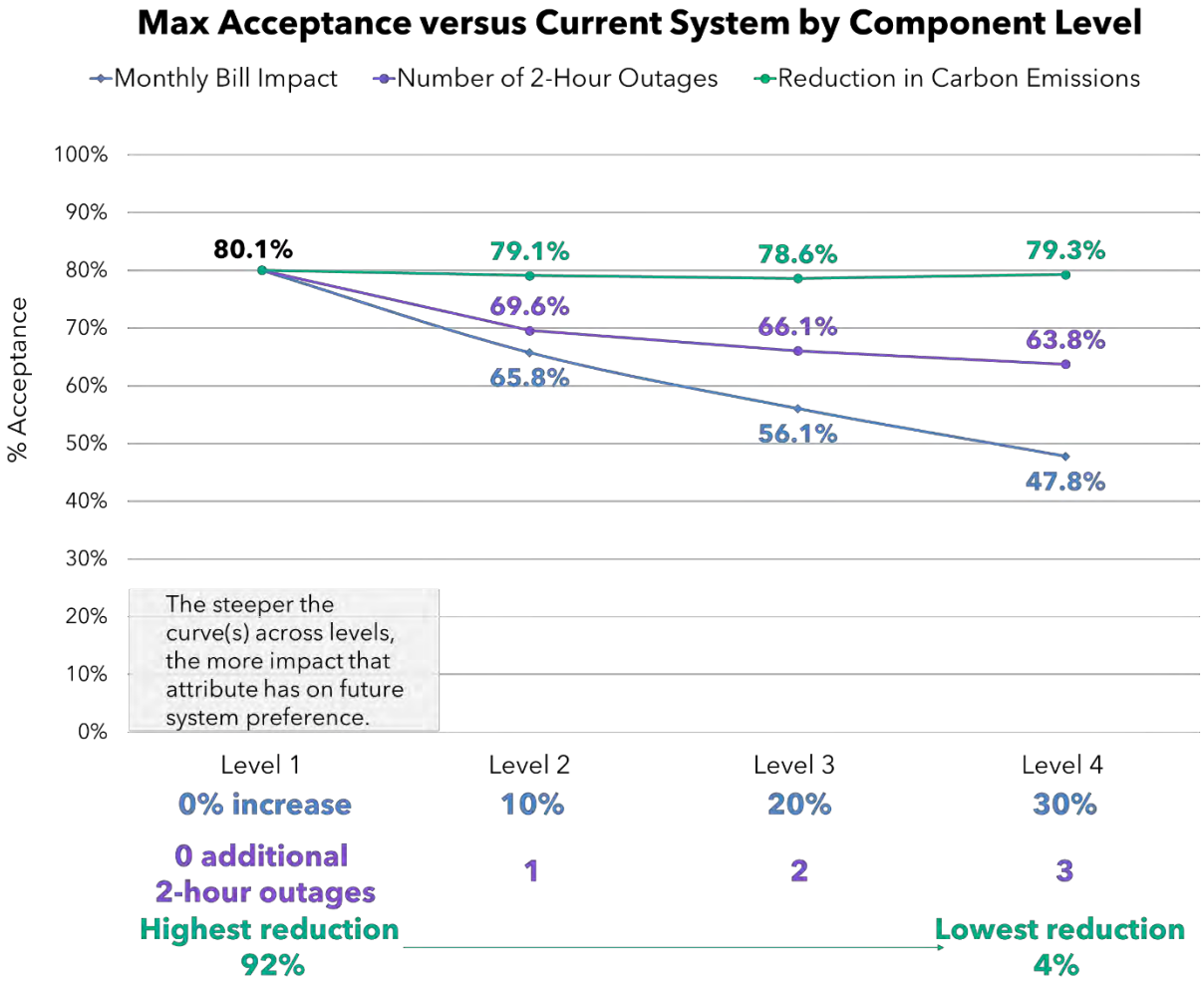
Real-world cost constraints force tradeoffs

While most customers agree that sustainability is important and should be considered by SRP and their customers, there are limitations on how much customers feel they can invest in the “greater good.” Customers expressed that fixed incomes and limited budgets often constrain the degree to which they can support and prioritize sustainability.

Acceptance of future energy systems declines above 0% bill impact

As bill impacts increase, the proportion of customers who accepted an energy system over the current system declined sharply. However, acceptance declines were less steep for the number of 2-hour outages suggesting that customers are less accepting of price increases and more tolerant of minimal additional 2-hour outages.

Furthermore, when tradeoffs are required, carbon reduction has minimal impact with acceptance of energy systems relatively unchanged as the level of reduction in carbon emissions increases.



Customer preferences for a balanced future energy system

While SRP does not know what the future will look like, it will be important to design the future energy system with customer preferences in mind. Findings revealed that from the residential customer's perspective the ideal future energy system should...

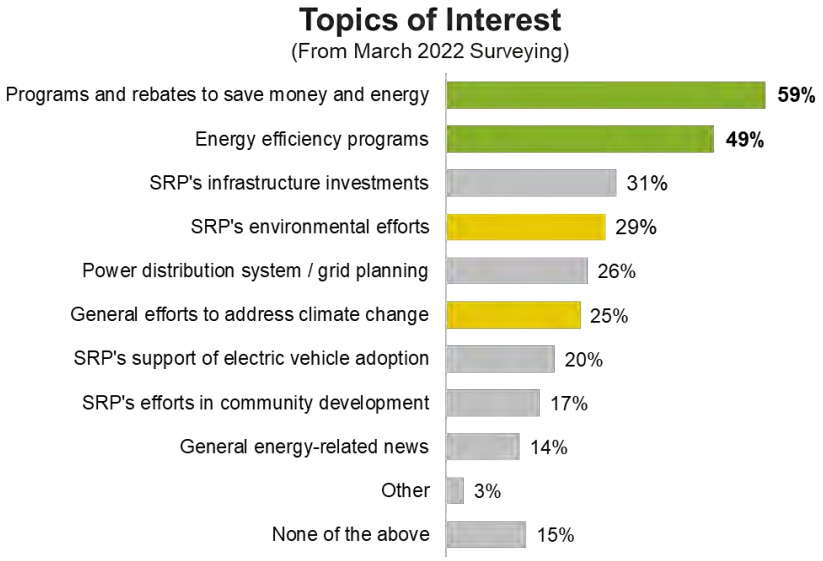
- Manage cost, first and foremost
- Strive to manage monthly bill impacts below a 10% increase
- Include a diverse energy mix to ensure reliability
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase

Topics of Interest

Over half had interest in ways to save

Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their electricity bills.



*Those with a **household income less than $75k** were **more likely** to want to hear about the following:*

- *Programs and rebates to save money and energy*
- *SRP's support for community development*

*Groups more interested in hearing about **SRP's infrastructure investments** included:*

- *Customers **aged 65+***
- *Non-Hispanics*

***Part-time residents** were **more likely** than those living in Phoenix year-round to want to hear about the following**:** energy efficiency programs, SRP's environmental efforts, and general efforts to address climate change*

Appendix

Focus Group Participant Description*

Total	24
Gender	
Female	13
Male	10
Non-binary	1
Ethnicity	
Black	3
Hispanic	2
White	18
Other	1
Homeownership	
Own	18
Rent	6

Age	
25-34	6
35-44	7
45-54	2
55-64	4
65-74	2
75+	3
Income	
<25k	2
25-49k	5
50-74k	8
75-99k	3
100-149k	3
150+	3

** Focus Groups are exploratory in nature and cannot be projected to a larger population. Attendees are not representative of the full SRP customer base or stakeholders*

Survey Respondent Demographics

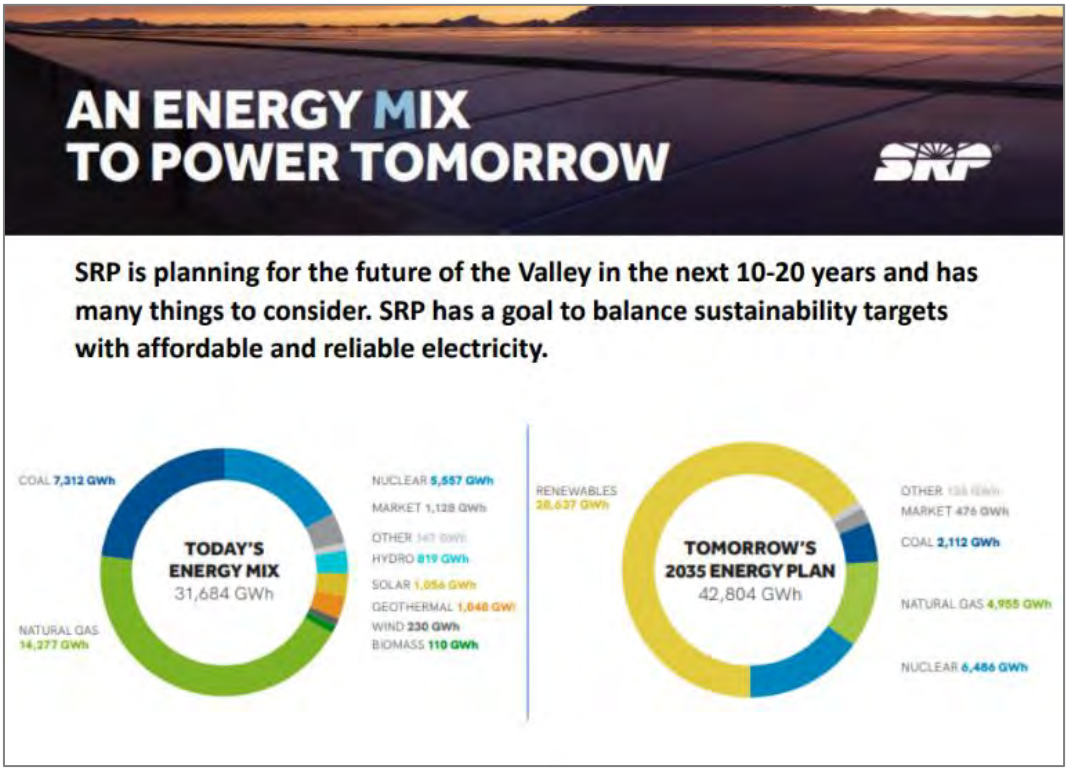
	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
GENDER		
Female	51%	49%
Male	45%	46%
Non-binary	0%	0%
Prefer not to answer	4%	5%
INCOME		
Limited Income 200%	31%	31%
Non-Limited Income 200%	69%	69%
CREDIT RATING		
Preferred	67%	64%
Satisfactory/Slow/ Unsatisfactory	12%	18%
New Customer	21%	18%
Cash Only	-	1%
ETHNICITY (MULTIPLE SELECTIONS)		
White	69%	69%
Black or African American	4%	5%
Other	13%	12%
Prefer not to answer	18%	17%
HISPANIC ORIGIN		
Hispanic	15%	12%
OWN/RENT HOME		
Own	73%	71%
Rent	28%	29%

	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
AGE		
18-44	30%	38%
45-64	37%	37%
65+	34%	25%
EMPLOYMENT		
Ful-time/Part-time	51%	53%
Self-employed	6%	8%
Retired	33%	27%
Unemployed/seeking employment/student	4%	3%
Not working/not seeking	2%	2%
N/A / Prefer not to answer	5%	7%
YEARS IN PHOENIX		
2 or less	7%	8%
3-5	10%	9%
6-20	30%	34%
21-39	30%	29%
40+	15%	20%
USAGE*		
Low (6,000 kWh or less)	19%	12%
Moderate (6,001-12,000 kWh)	33%	32%
Medium (12,001-18,000 kWh)	29%	31%
High (More than 18,000 kWh)	20%	23%

Illustrative Plan Description and Background (Phase I & II)

In addition to the visual depiction of the illustrative plan shown below, respondents were provided the following additional description and background during Phases I & II of this research:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

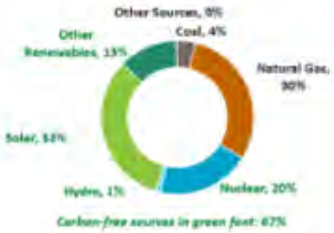


Choice Exercise Example Screen (Phase III)

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a "none of these" option representing the current energy system. An example screen with question wording is shown below.

Which of these hypothetical future energy systems would you prefer SRP implement
Please read through each plan carefully and select the plan you most prefer.

Click here to view a glossary of terms. This will open in a new browser and you can come back to this page to complete the activity.

	2035	2030
Energy Mix:		
SRP will meet its Sustainability Goals by:		
% reduced carbon emissions (equal to number of gas-powered cars on the road each year):	**20% reduction** (about 675,000 gas-powered cars)	**61% reduction** (about 2.0 million gas-powered cars)
% reduced water usage (equal to the amount of water used by the number of 4-person households shown per year):	**16% reduction** (about 9,000 households)	**52% reduction** (about 30,000 households)
Will SRP build new gas power plants to source energy?	**Will** build	**Will not** build
Your monthly bill will:	Increase by **$30**	**Not increase**
Number of 2-hour power outages experienced in one year due to high energy demand (on a hot summer's day):	**Two** 2-hour outages	**Three** 2-hour outages
	Select	Select

None of these, I would stick with the current system at my current monthly bill amount.

Select

Delivering water and power®

982100 03/24

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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

Exhibit 2-101:
Xcel Information Sheet on Colorado Energy Plan

Colorado Energy Plan

Advancing affordable clean energy

The Colorado Energy Plan (CEP) is Xcel Energy's roadmap to develop a significantly cleaner energy mix and reduce carbon emissions in Colorado—all while keeping customer bills low. The Colorado Public Utilities Commission approved the Plan in August 2018. Here's an update on our progress.

About the plan

The Colorado Energy Plan was proposed in 2017 as part of the 2016 Electric Resource Plan. Its benefits:

- Xcel Energy will retire 660 MW of coal-fired generation early and reduce carbon emissions 60% by late 2025 (from 2005 levels).
- We will add 1,100 MW of wind; up to 700 MW of solar and up to 275 MW of storage; and 383 MW of existing natural gas generation to our Colorado fleet.
- The Plan's all-source bid solicitation in late 2017 attracted 400+ bidders and historic low prices for renewable generation.
- By taking advantage of today's low clean energy prices and tax incentives, Xcel Energy will save its customers more than $200 million in the coming years.
- A study by the University of Colorado Boulder predicts the Plan will be a net positive for the state, creating nearly 2,000 jobs and an extra $203.6 million in GDP statewide.

Our 100% carbon-free vision

For more than a decade, Xcel Energy has demonstrated leadership on clean energy and reducing greenhouse gases. Since 2005, we've reduced carbon emissions 41% in Colorado, compared to a 27% reduction in the U.S. power sector as a whole.

We announced ambitious goals in December 2018. We intend by 2030 to reduce carbon emissions 80% from 2005 levels. This can be achieved reliably and affordably with the tools and technologies available today. By 2050, we aspire to serve customers with 100% carbon-free electricity, by increasing renewable energy on our system and taking advantage of technologies that are not yet commercially available.

Our customers and communities, investors and stakeholders have asked us to address the risk of climate change. Xcel Energy has stepped up to do our part.

The Colorado Energy Plan is the latest step in our progress to secure low-cost power for customers, stimulate rural economies, grow the state's renewable and clean energy resources, and reduce carbon emissions.

Project Status – May 2019

Cheyenne Ridge Wind Project – Eastern Colorado

The Colorado Public Utilities Commission recently approved construction of the 500 MW **Cheyenne Ridge Wind Project**, a significant element of the CEP. Cheyenne Ridge will rise on 65,000 acres in Kit Carson and Cheyenne counties. We intend to place the wind project in service by the end of 2020 to take full advantage of federal production tax credits.

- 65 miles of 345 kV transmission line
- 229 Vestas turbines, made in Colorado
- $743 million estimated investment, including transmission and interconnection assets
- Will provide enough energy to power more than 270,000 Colorado homes

To learn more, **visit xcelenergy.com /carbon_free_2050**

Natural gas generation

Two existing gas facilities will become company-owned resources under the CEP at a very favorable price for customers. We are not building any new natural gas generation, reducing the risk of stranded costs. As we continue to make progress on our 100% carbon-free vision, it's important to provide flexible generation on the system to support the integration of more renewables.

- **Manchief**, a 301-MW simple cycle natural gas plant near our Pawnee site in Morgan County
- **Valmont**, an 82-MW simple cycle natural gas plant at our Valmont site in east Boulder County

Purchased wind power agreements

More than half of the total $2.5 billion CEP investment will be made by independent power producers whose wind, solar and storage projects will sell electricity to Xcel Energy. It's a win-win as we continue Colorado's progress to improve air quality, reduce regional haze and shrink our carbon footprint.

- **Bronco Plains Wind Project (300 MW) – Kit Carson County**
- **Mountain Breeze Wind Project (169 MW) – Weld County**
- **Colorado Green Wind Project (162 MW) – Baca County**

  (CGWP, in service since 2003; independent producer plans to repower the project by late 2020.)

Solar energy and solar-plus-storage

Xcel Energy will purchase electricity from two Pueblo area solar-plus-storage projects: **Neptune** (250 MW solar/125 MW storage) and **Thunder Wolf (**200 MW solar/100 MW storage). In Park County, the **Hartsel Solar Project** will supply 72 MW of solar. Other projects are in negotiation.

- Total estimated investment in Pueblo County: more than $600 million, including the proposed Badger Hills substation and transmission lines.
- All solar projects have a target in-service date of 2022.

Two projects in the solar portfolio were not able to reach completion, and are in a rebidding process.

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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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

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

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

[1] Issued 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 portfolio[3] 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)(1).
[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-I[29] 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 commentors 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 reliability[104]—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 analysis[106] 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 commentors 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, pursing 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 prudency 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-I[193] 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 PIM[228] 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 associate 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 proceeding[257]—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 and 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 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 Commission[344] 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,
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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

Exhibit 2-103:
2025 Xcel ERP Annual Progress Report

Colorado PUC E-Filings System

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 PCDAs 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*

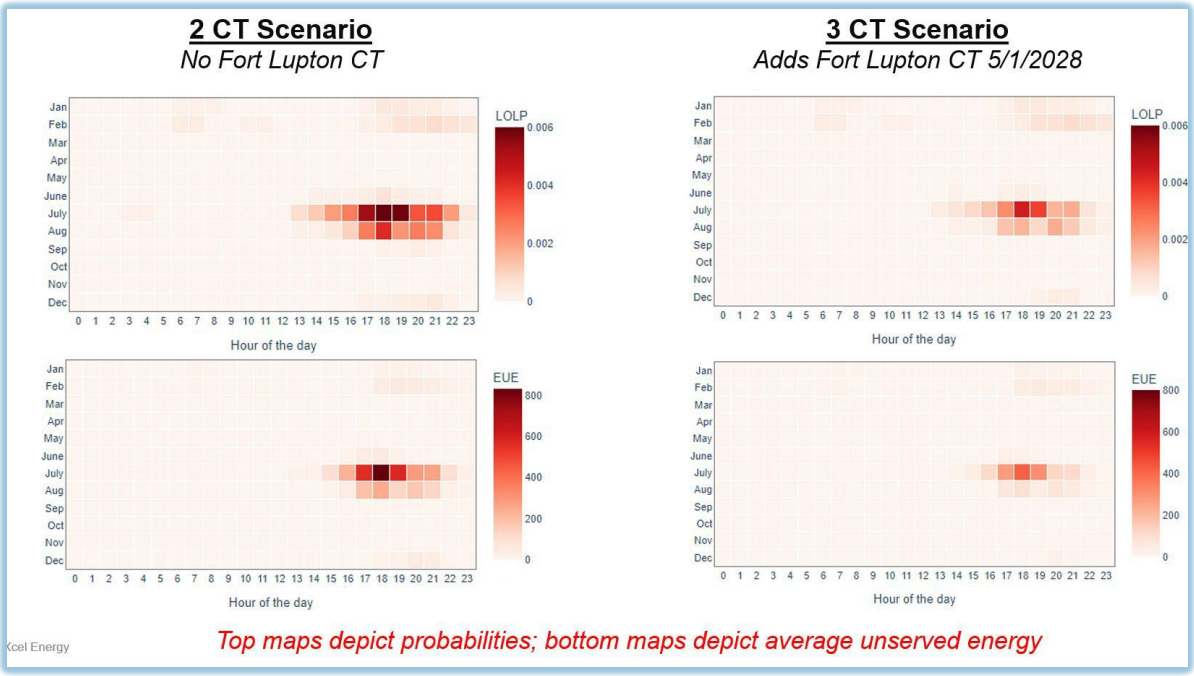
1. Resource Adequacy Update

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.

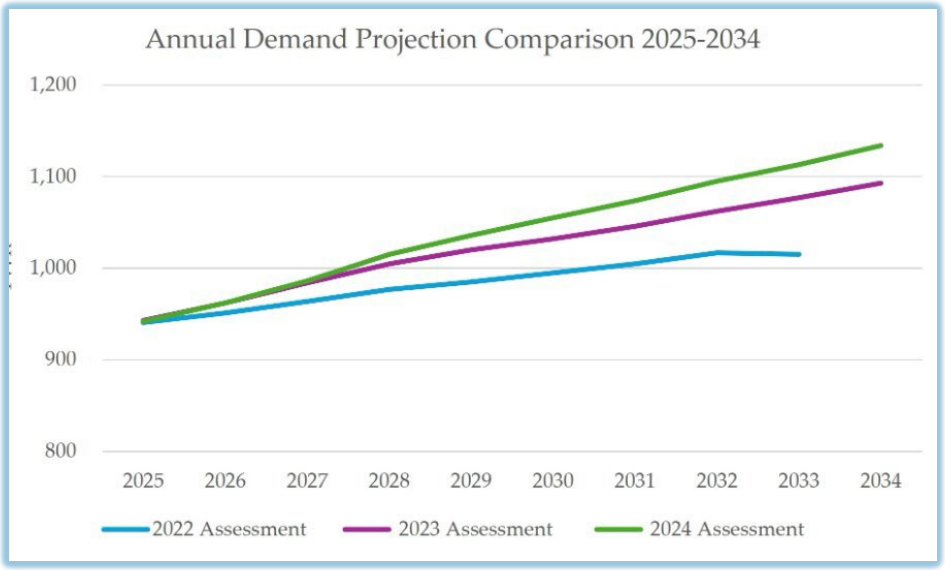
Figure 1 – 2 CT Scenario and 3 CT Scenario Heat Maps



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]

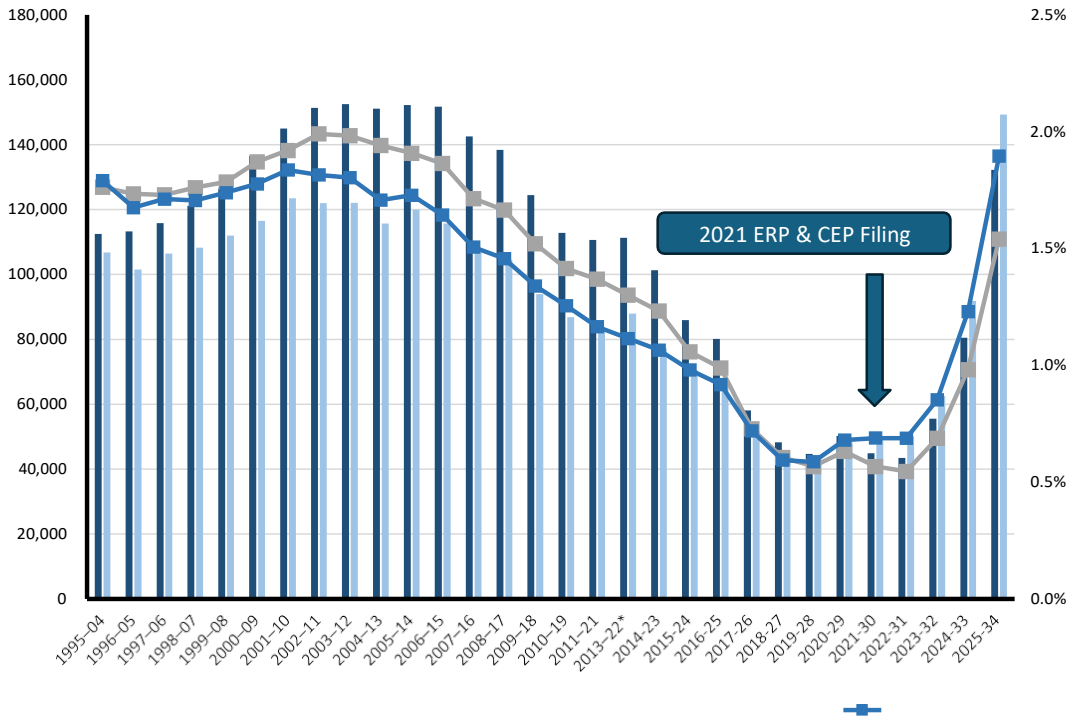
[9] https://feature.wecc.org/wara/.

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	)	Order No. 202-26-21

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

Filed April 28, 2026

Exhibit 2-104:
PacifiCorp 2015 IRP Update

2015 Integrated Resource Plan Update

Let's turn the answers on.

March 31, 2016

PacifiCorp
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*
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EXECUTIVE SUMMARY

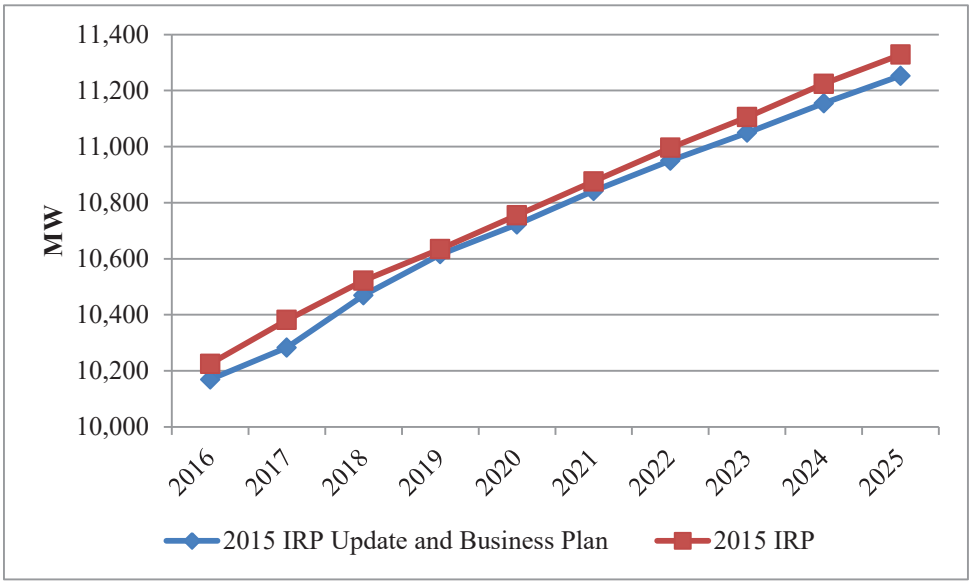
PacifiCorp submitted its 2015 Integrated Resource Plan (2015 IRP) to state regulatory commissions in March 2015. That plan provides a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks for customers. This 2015 IRP Update describes 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:

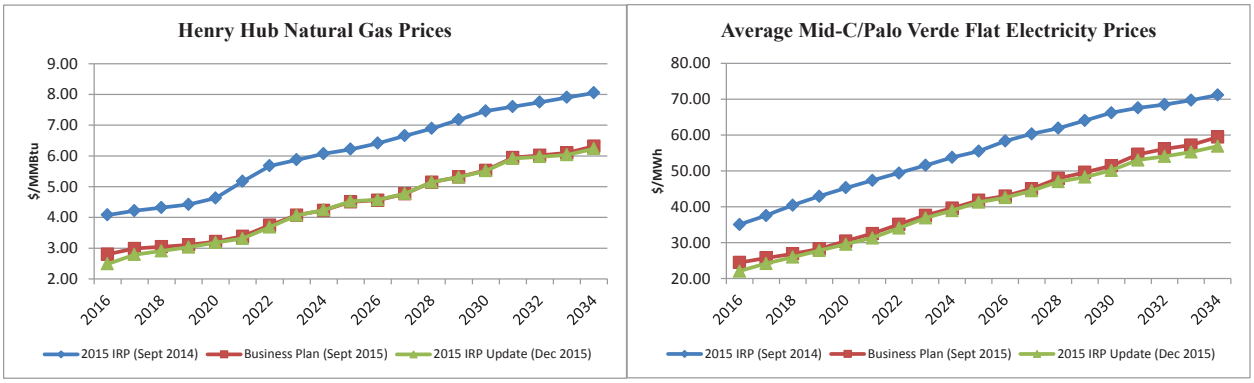
- As shown in Figure ES.1 PacifiCorp's most recent coincident system peak load forecast, used for the Business Plan and the 2015 IRP Update, is down relative to the 2015 IRP. On average, across the front ten years of the planning period, the coincident system peak is down by about 54 MW relative to the 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 SO_2, 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.

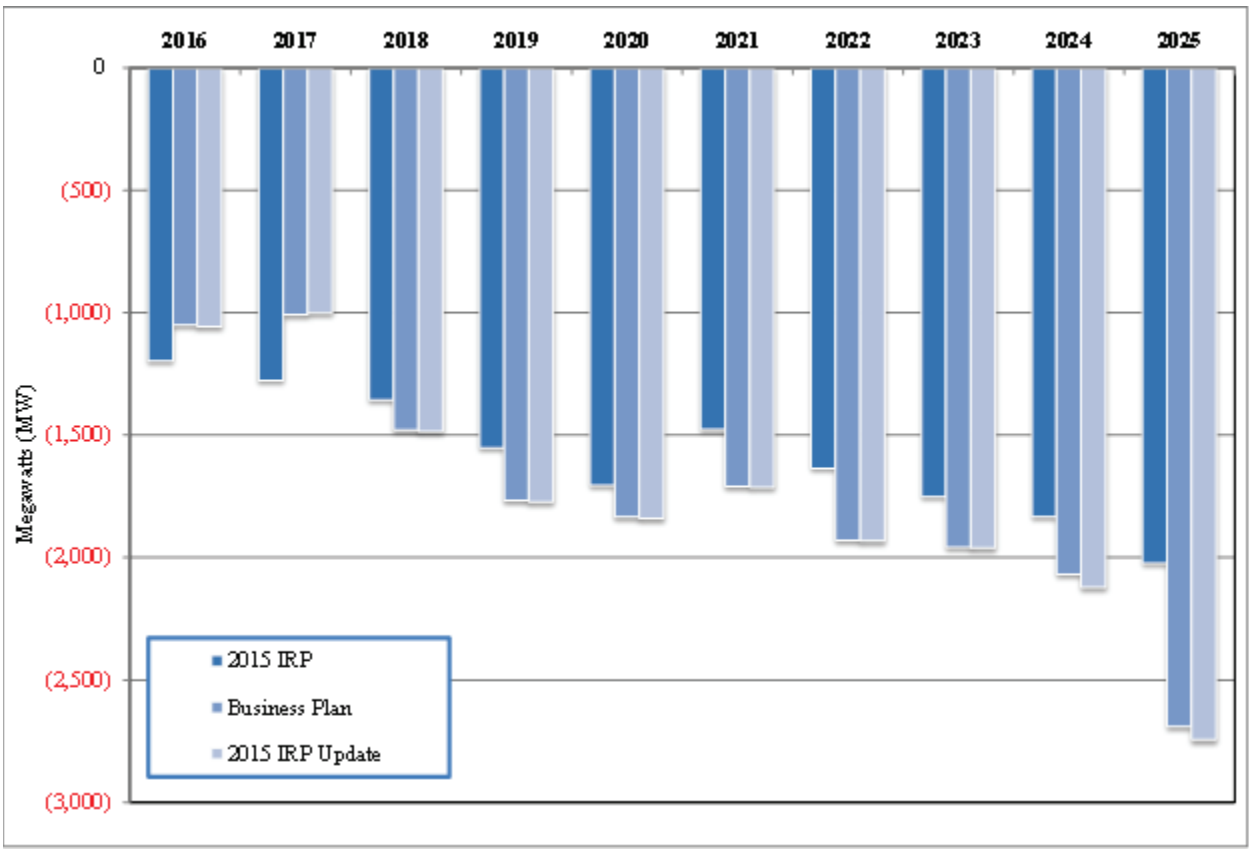
- After PacifiCorp filed its 2015 IRP, EPA issued its final rule for the Clean Power Plan (CPP). On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties 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 CO_2 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

	Capacity (MW)											10- year Total
Resource	**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

	Capacity (MW)											10- year Total
Resource	**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 action items.

Table ES.2 – 2015 IRP Update Action Plan

Action Item	1. Renewable Resource Actions
1a	**Renewable Portfolio Standard Compliance** • 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	**Renewable Energy Credit Optimization** • 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	**Front Office Transactions** – 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

<table>
<tr><td></td><td>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.</td></tr>
<tr><td>Action Item</td><td>3. Demand Side Management (DSM) Actions</td></tr>
<tr><td>3a</td><td><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.</td></tr>
<tr><td>3b</td><td><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.</td></tr>
<tr><td>Action Item</td><td>4. Coal Resource Actions</td></tr>
<tr><td>4a</td><td><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.</td></tr>
<tr><td>4b</td><td><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.</td></tr>
</table>

	• 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	**Wyodak** • 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	**Cholla Unit 4** • 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	**Energy Gateway Permitting** • 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	**Wallula to McNary 230 kilovolt Transmission Line** • 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 (CO_2) per megawatt-hour (MWh). New coal fueled power plants can emit no more than 1,400 pounds of CO_2/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, 3015, 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 CO_2/MWh for coal-fired power plants and 771 lb CO_2/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 (SO_2), ozone (O_3), nitrogen dioxide (NO_2), 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, SO_2, and NO_2.

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, SO_2, 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 SO_2, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_x and PM portions. EPA's approval of the SO_2 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 SO_2, 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 conversation 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.

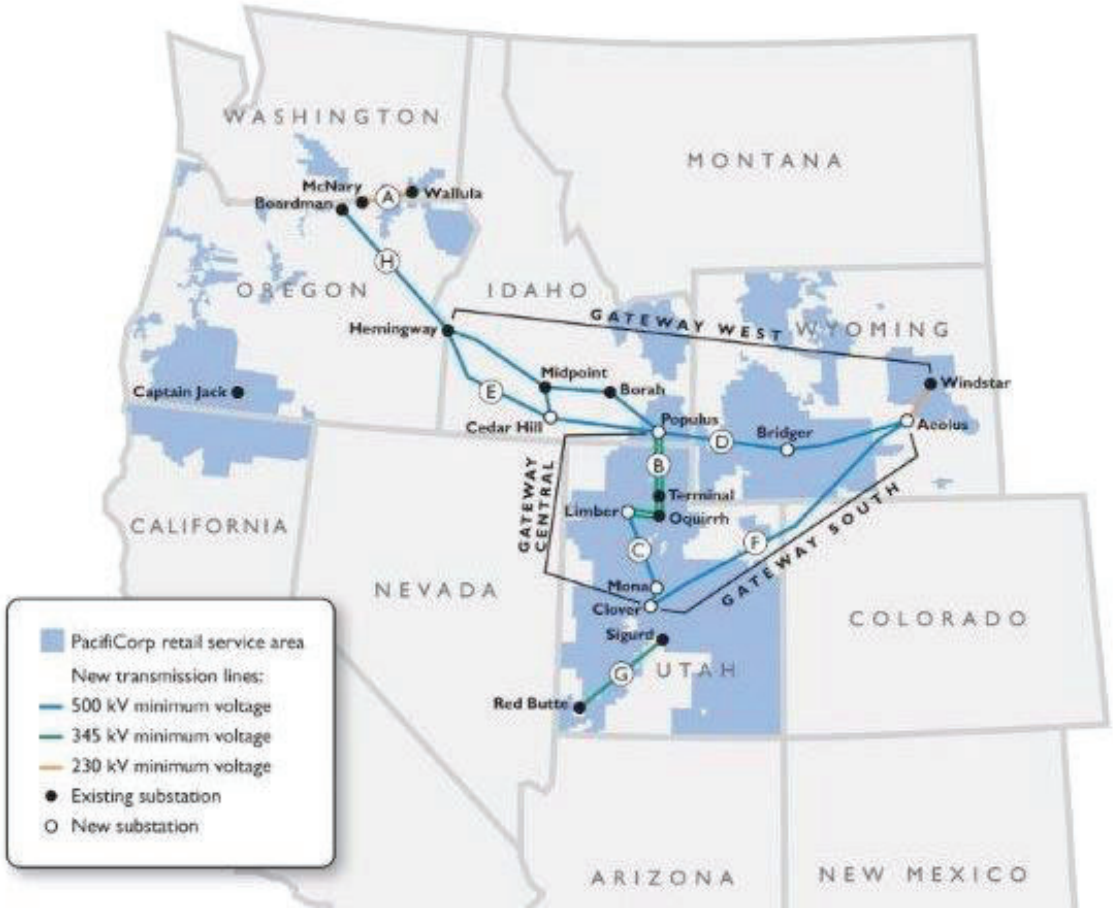
Greenhouse Gas Emission Performance Standards

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 CO_2/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 CO_2/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

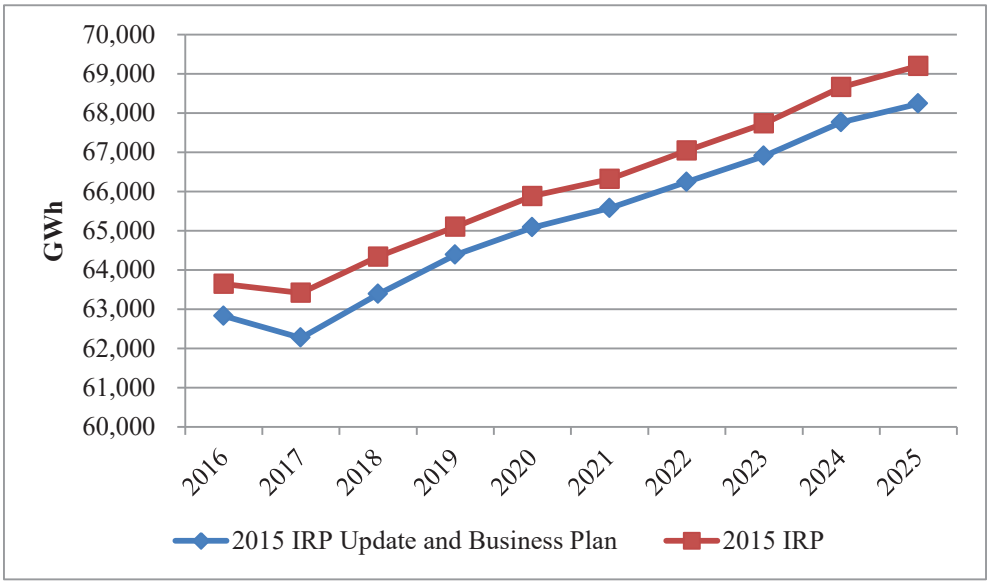
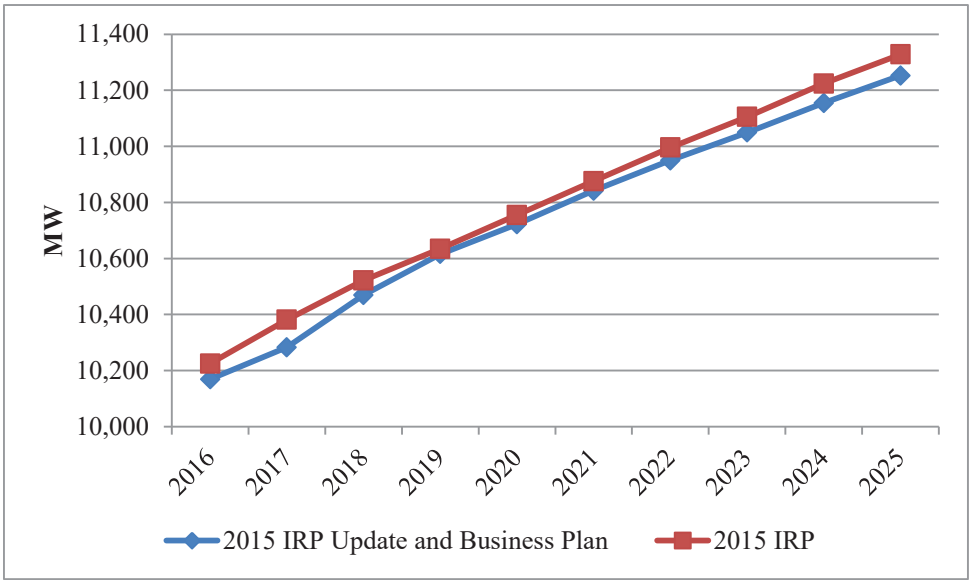


Figure 3.2 – Forecasted Annual Coincident Peak Load



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

		2015 IRP Preferred Portfolio		2015 IRP Update	
Qualifying Facilities	**State**	**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

		2015 IRP Preferred Portfolio		2015 IRP Update	
Qualifying Facilities	**State**	**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

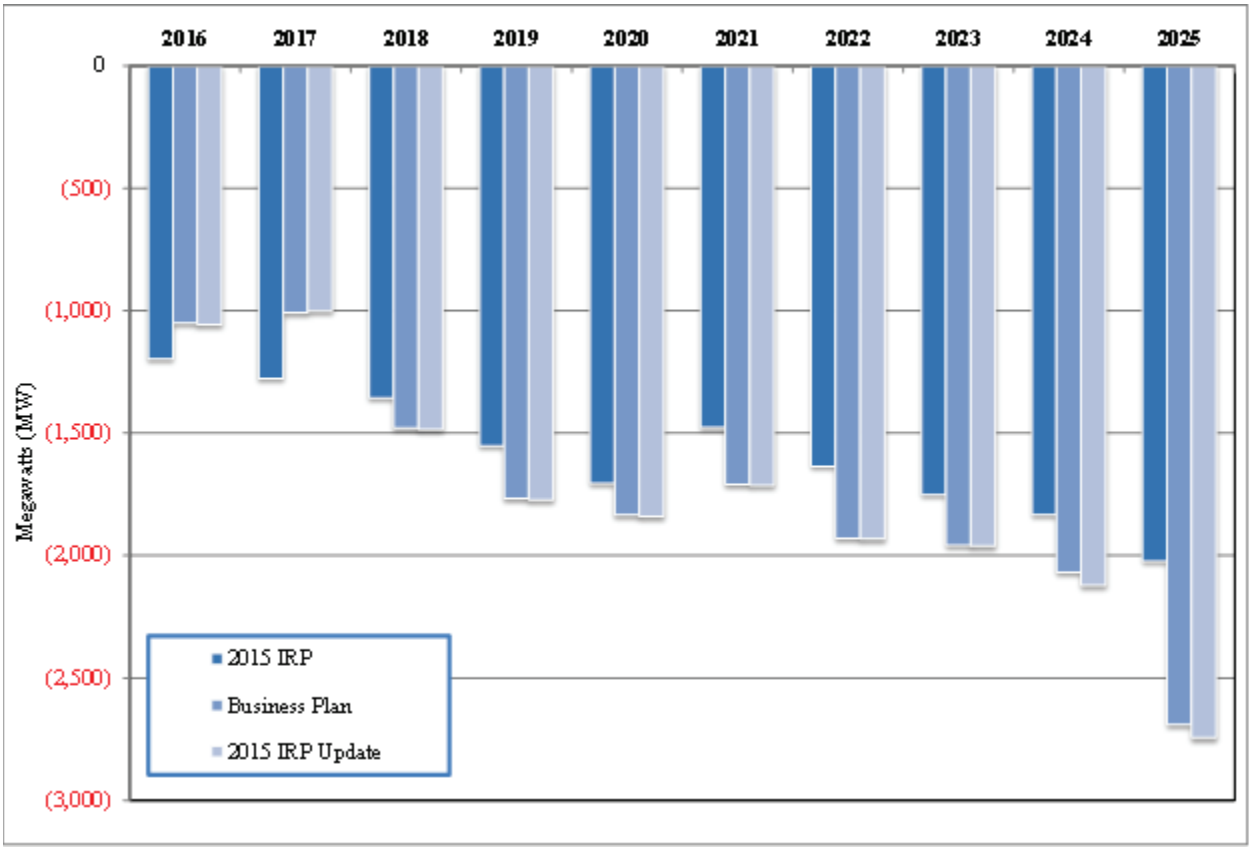
		2015 IRP Preferred Portfolio		2015 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
OR Solar 1, LLC (Sprague River) *	OR			10	4
OR Solar 2, LLC (Agate Bay) *	OR			10	4
OR Solar 3, 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

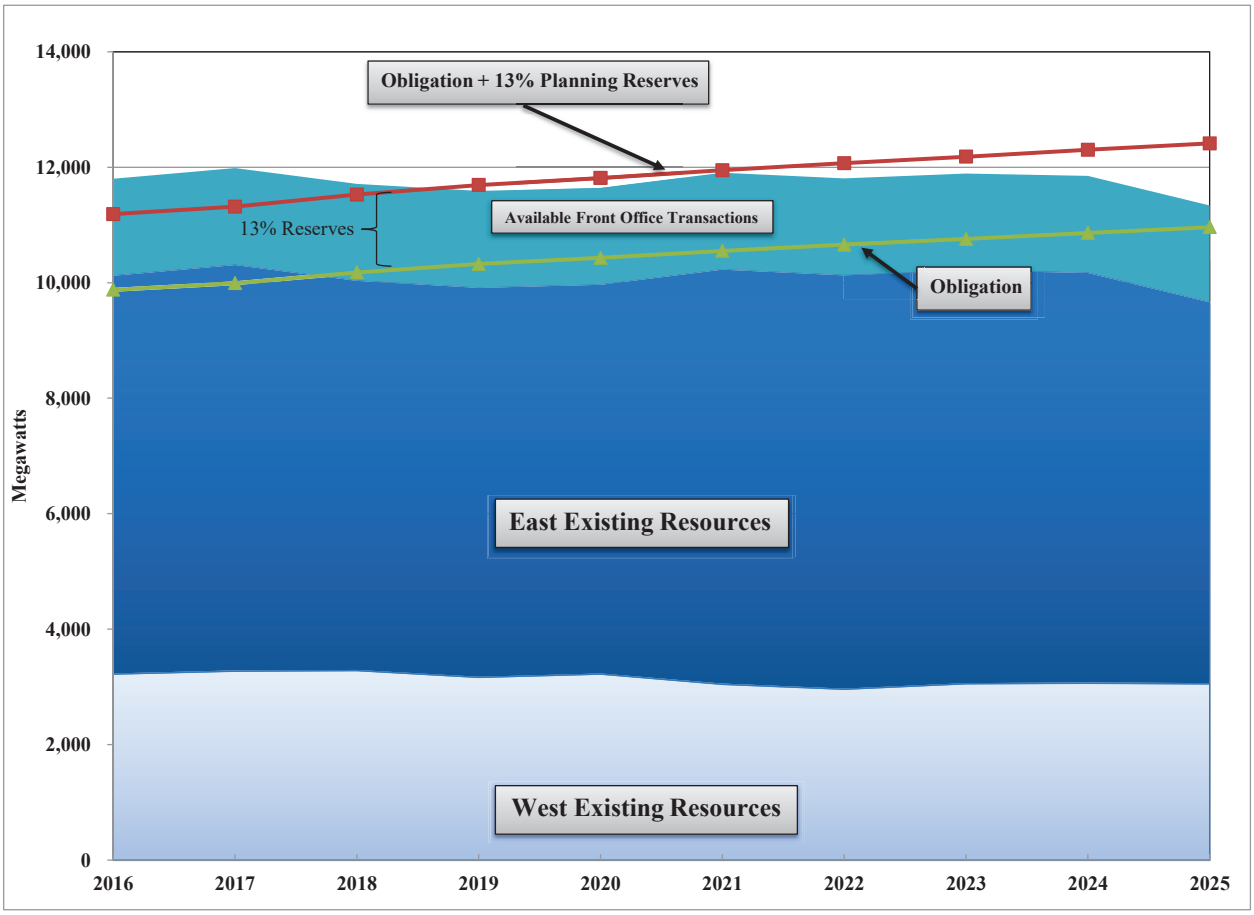


Figure 3.5 – 2015 IRP Update, West Capacity Position Trend

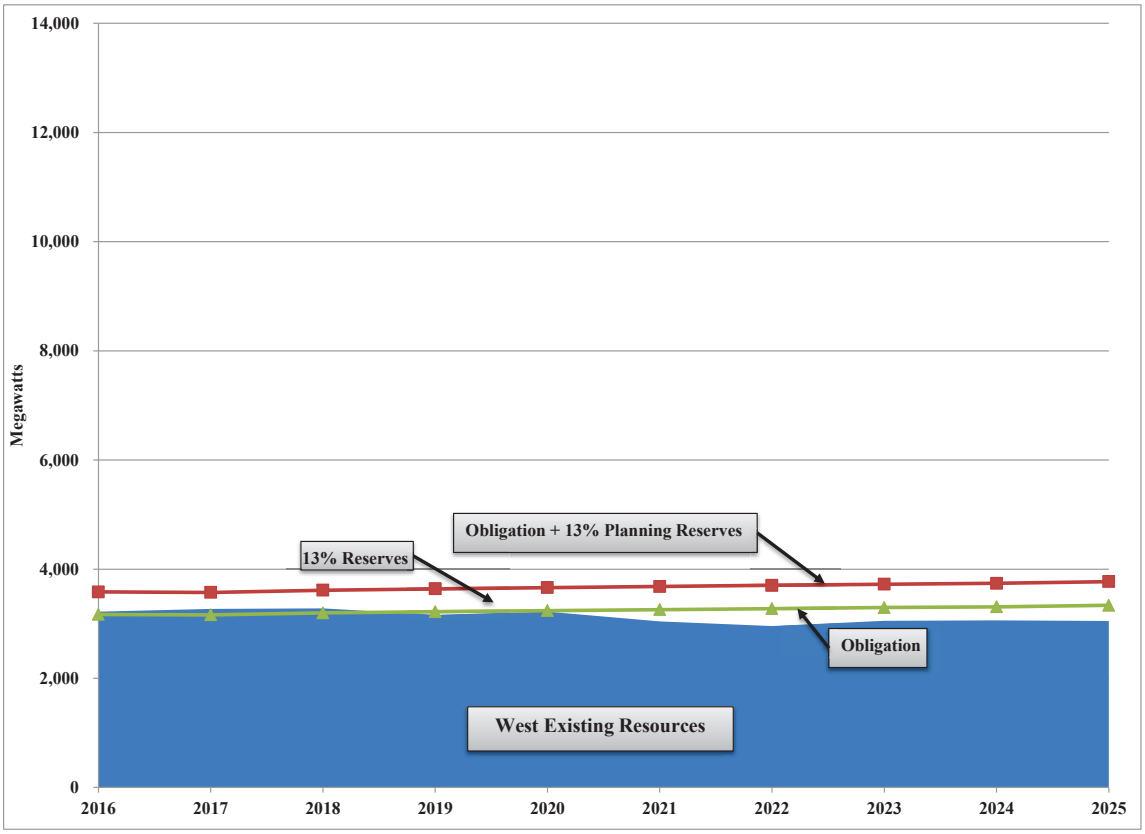
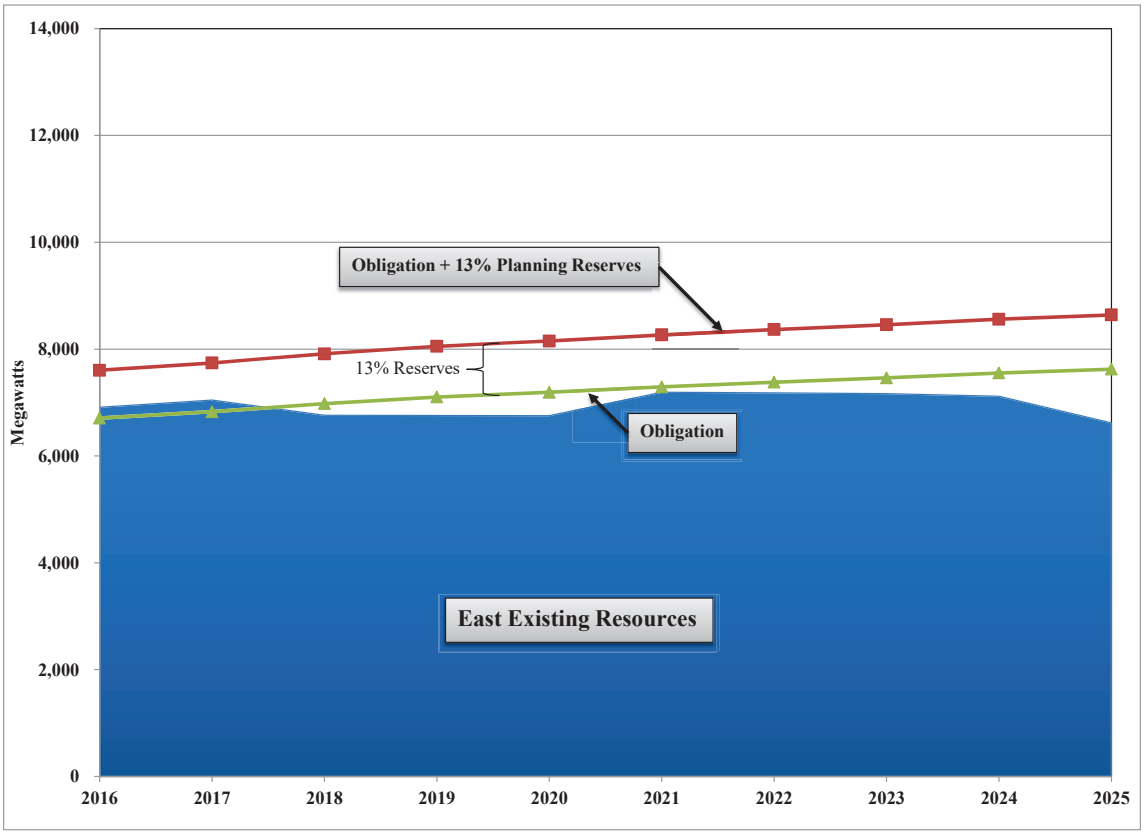


Figure 3.6 – 2015 IRP Update, East Capacity Position Trend



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.

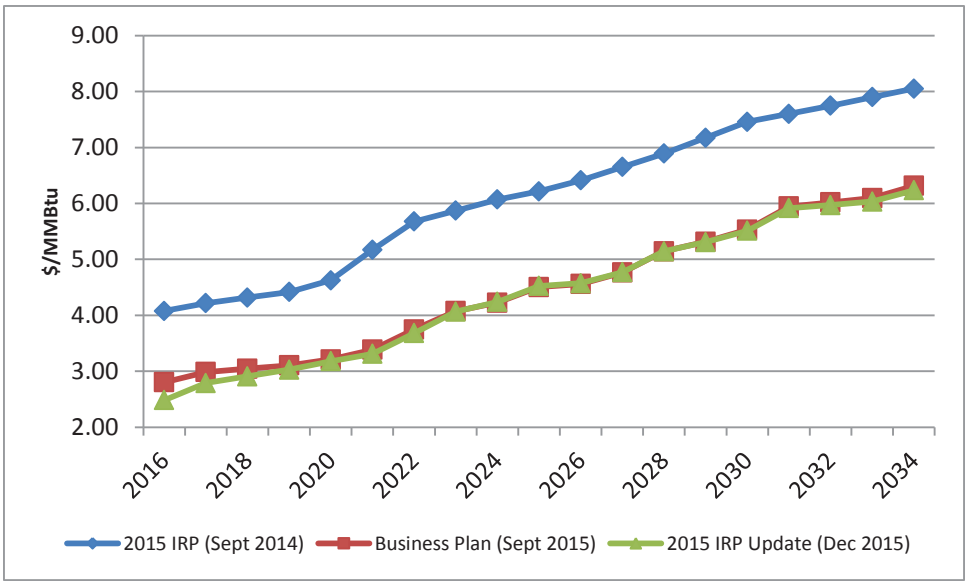
The September 2014 natural gas OFPC, which was used in the 2015 IRP, was based on an expert third-party long-term natural gas price forecast initially issued May 2014 with a front two-year update in August 2014. This price forecast also reflected a considerable portion of domestic natural gas demand 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)

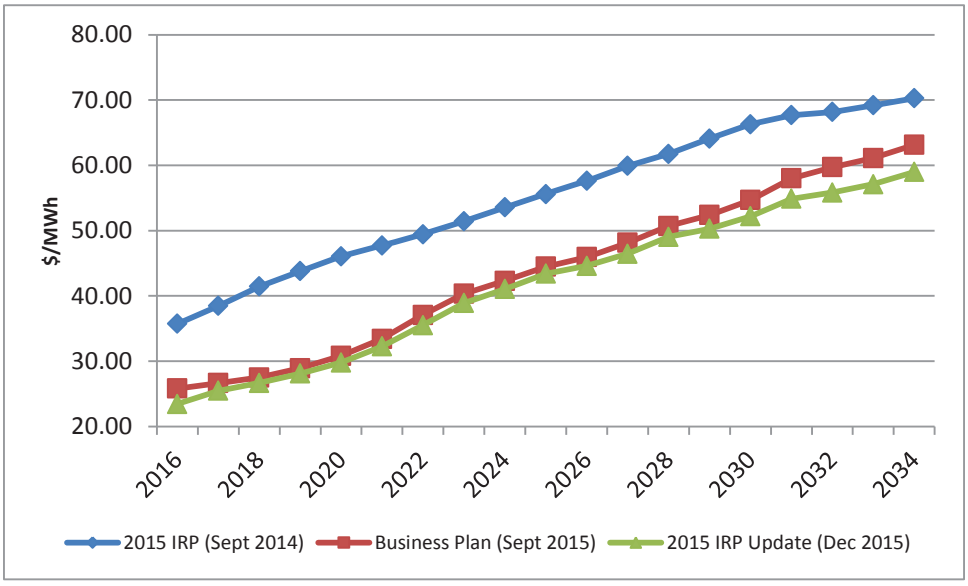


Figure 4.3 – Average Annual Heavy Load Hour Palo Verde Electricity Prices (Nominal)

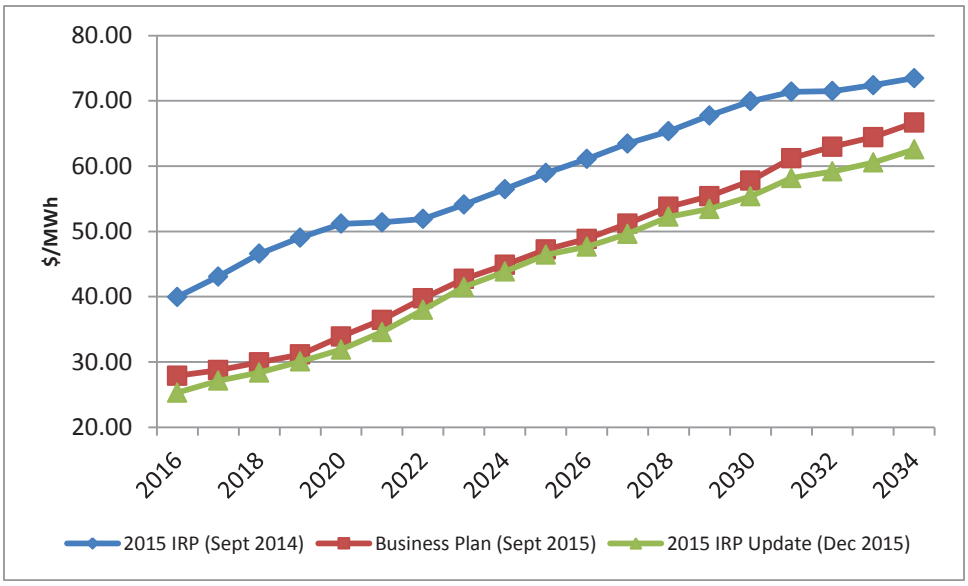


Figure 4.4 – Average Annual Flat Mid-Columbia Electricity Prices (Nominal)

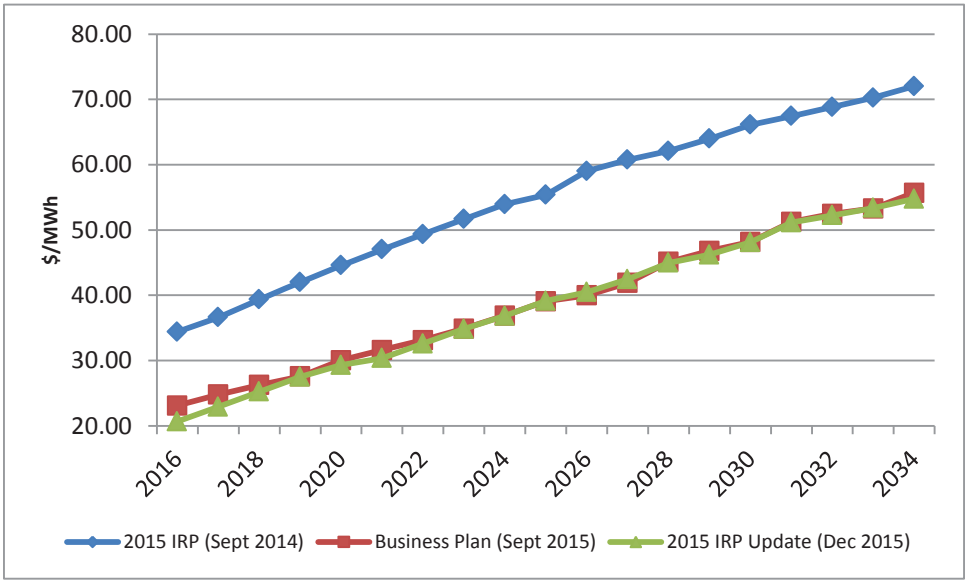
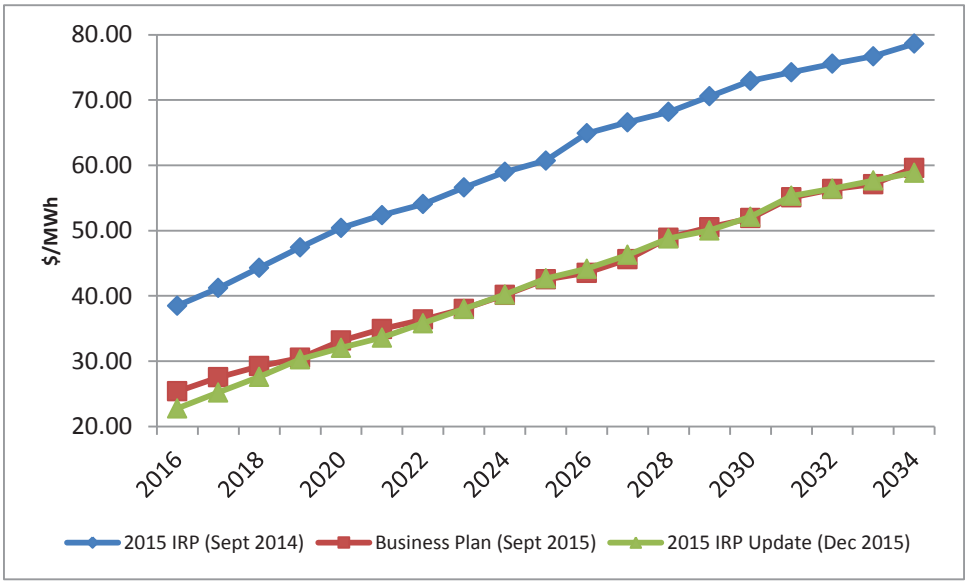


Figure 4.5 – Average Annual Heavy Load Hour Mid-Columbia Electricity Prices (Nominal)



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 CO_2 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$

	2015 IRP Update		2015 IRP	
Location	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	Duration			
Standardized at a 20 year life	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 ($/kW-Yr)					
Resource Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
2.0 MW turbine 29% CF WA_2018	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 35% CF WA_2018	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 29% CF OR_2018	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 35% CF OR_2018	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 31% CF ID_2018	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
2.0 MW turbine 31% CF UT_2018	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 43% CF WY_2018	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
2.0 MW turbine 29% CF WA_2021	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 35% CF WA_2021	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 29% CF OR_2021	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 35% CF OR_2021	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 31% CF ID_2021	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
2.0 MW turbine 31% CF UT_2021	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 43% CF WY_2021	$1,735	7.399%	$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	$2,429	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	$2,429	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 (mills/kWh)					Total Costs and Credits (Mills/kWh)		
				Levelized Fuel									
Resource Description	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	c/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost With PTC / ITC Credits
2.0 MW turbine 29% CF WA_2018	29%	64.69	na	0	0.00	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%	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%	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%	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%	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%	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%	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%	0.00	3.06	0.00	67.75	(7.35)	60.40
2.0 MW turbine 35% CF WA_2021	35%	53.60	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	56.66	(7.35)	49.31
2.0 MW turbine 29% CF OR_2021	29%	63.51	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	66.57	(7.35)	59.22
2.0 MW turbine 35% CF OR_2021	35%	52.62	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	55.68	(7.35)	48.33
2.0 MW turbine 31% CF ID_2021	31%	61.15	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	64.20	(7.35)	56.86
2.0 MW turbine 31% CF UT_2021	31%	59.42	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	62.47	(7.35)	55.12
2.0 MW turbine 43% CF WY_2021	43%	44.08	na	0	0.00	0.67	0.00%	0.00	3.06	0.00	47.81	(7.35)	40.46
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT 2018	32%	79.65	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	80.42	(10.93)	69.49
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR 2018	29%	89.91	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	90.67	(12.39)	78.28
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA 2018	29%	91.39	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	92.15	(12.63)	79.52
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT 2023	32%	79.65	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	80.42	(3.22)	77.19
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR 2023	29%	89.91	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	90.67	(3.66)	87.01
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA 2023	29%	91.39	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	92.15	(3.73)	88.42
Lithium Ion Battery (8 MWh/day)	33%	260.58	91%	474	33.83	0.00	0.00%	0.00	0.00	0.00	294.41	0.00	294.41
Sodium-Sulfur Battery (8 MWh/day)	33%	220.02	75%	474	41.05	0.00	0.00%	0.00	0.00	0.00	261.08	0.00	261.08
Vanadium RedOx Battery (8 MWh/day)	33%	360.74	75%	474	41.05	0.00	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

	Capacity (MW)											10- year Total
Resource	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

	Capacity (MW)											10- year Total
Resource	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

	Capacity (MW)											10- year Total
Resource	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)

		Capacity (MW)																				Resource Totals 1/	
	Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	(33)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(269)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	(450)
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	(220)
	DaveJohnston 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)	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	-	-	-	-	-	635
	CCCT - Utah-N - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423
	CCCT - Utah-S - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	-	-	-	635
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	635	-	-	423	-	-	1,693
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	-	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	-	6.0
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	13.1	24.0	10.7	-	-	-	-	-	15.0	5.0	-	67.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	13.2	-	-	-	-	3.3	-	-	-	2.5	-	19.0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0	-	1.0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	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	88
	DSM, Class 2, UT	71	74	81	89	98	89	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	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 Mona Q3	-	-	-	-	103	60	-	-	-	-	297	297	300	49	80	300	2	126	300	300	16	111
West	**Expansion Resources**																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	454	-	-	-	-	454
	CCCT - WillamValc - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	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	-	-	-	-	-	-	0.6	-	5.1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	36.4	-	-	-	-	-	-	12.9	-	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 COB Q3	-	28	-	219	268	268	95	185	90	118	268	268	268	253	268	268	230	173	268	268	127	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 NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	Existing Plant Retirements/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	(762)	-	(807)	(77)	-	(627)	-		
	Annual Additions, Long Term Resources	143	128	138	146	158	142	149	155	161	162	173	159	186	1,244	130	764	571	118	560	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		
	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	1,292	2,003	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/
	Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	10-year
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

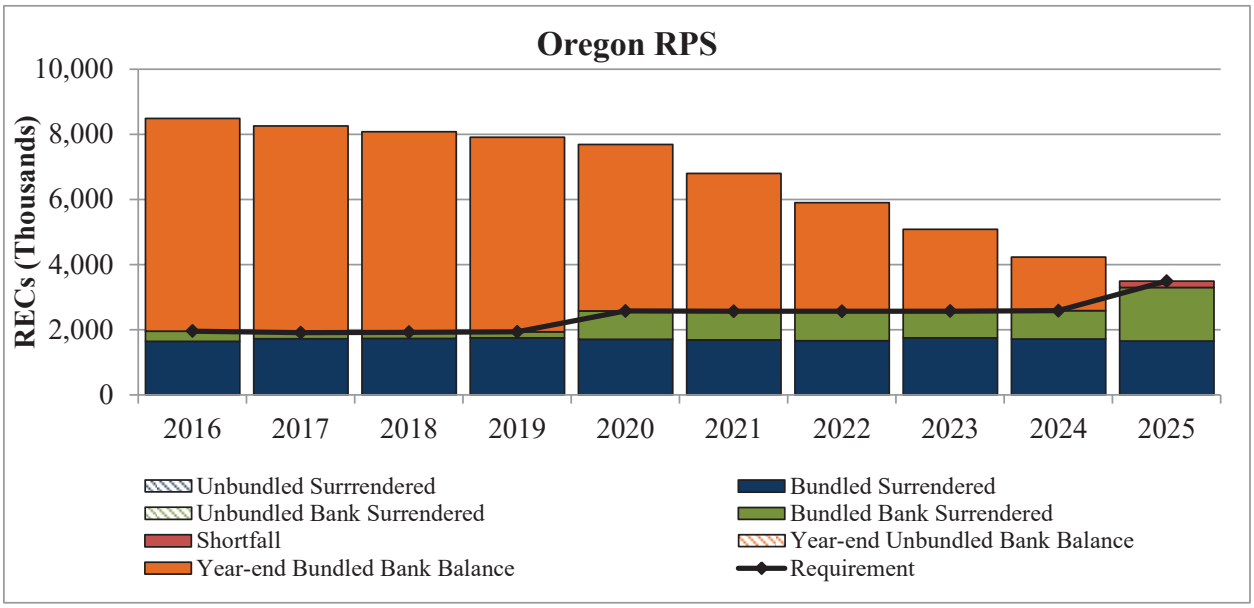
On March 8, 2016, Oregon Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition plan, was signed into law, which doubles the Oregon RPS target to 50% by 2040. Table 5.6 summarizes how the bill affects RPS targets for Oregon relative to those assumed in the 2015 IRP. In addition to 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.

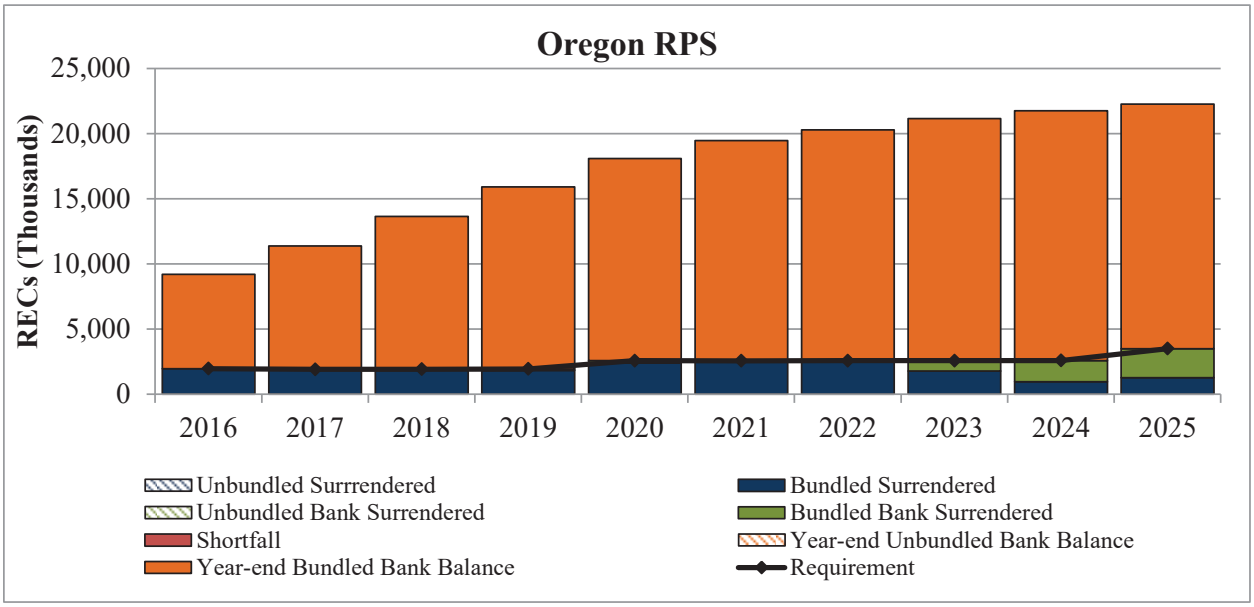
Figure 5.1 – Baseline Oregon RPS Compliance Position



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.

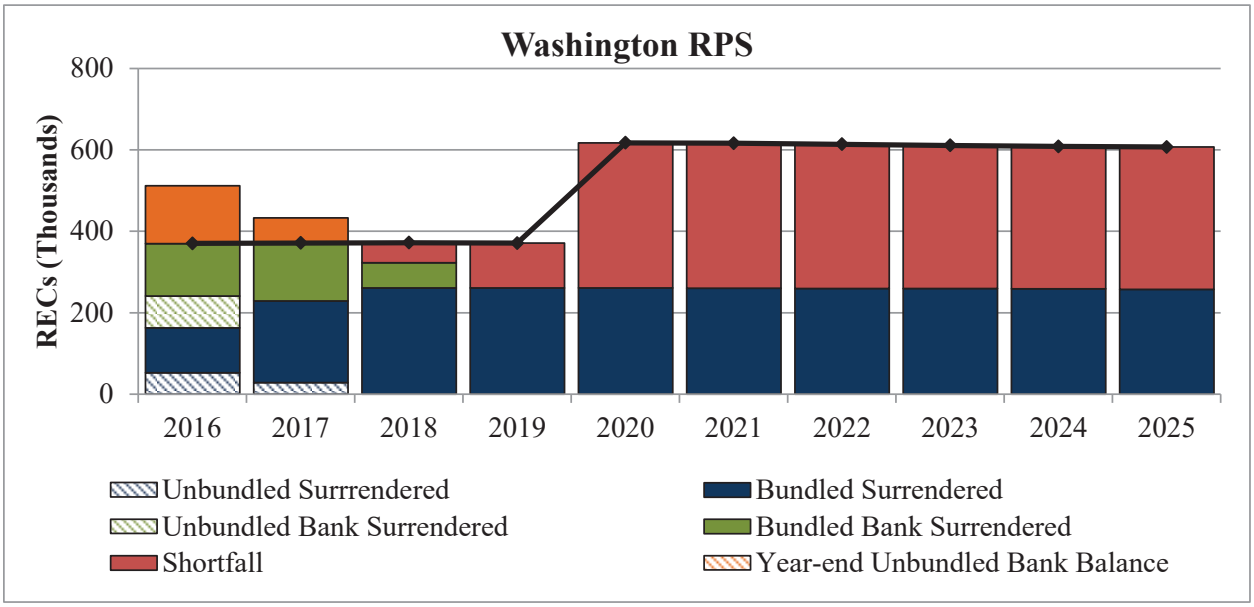
To fully evaluate Oregon RPS compliance alternatives that consider potential near-term, time-sensitive resource procurement opportunities, PacifiCorp intends to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives. Resource proposals will be evaluated concurrent 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

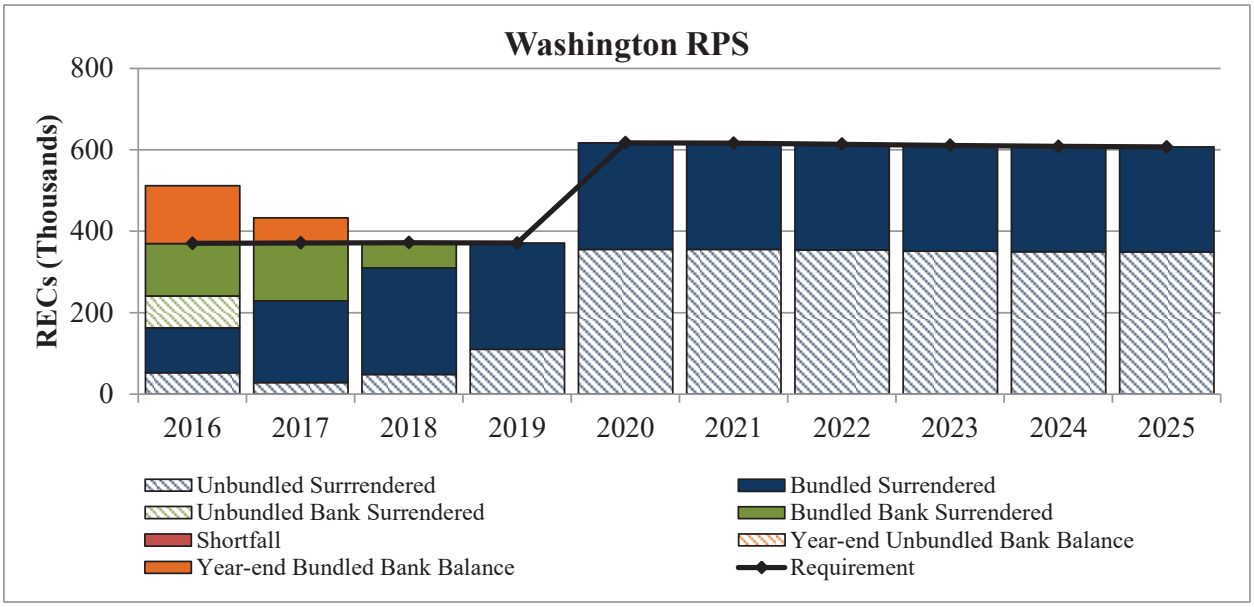
Figure 5.3 shows PacifiCorp's baseline RPS compliance position for Washington for the front ten years of the planning horizon, prior to procuring incremental unbundled RECs. This baseline position incorporates PacifiCorp's most recent procurement of unbundled RECs for Washington's RPS. The baseline position 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

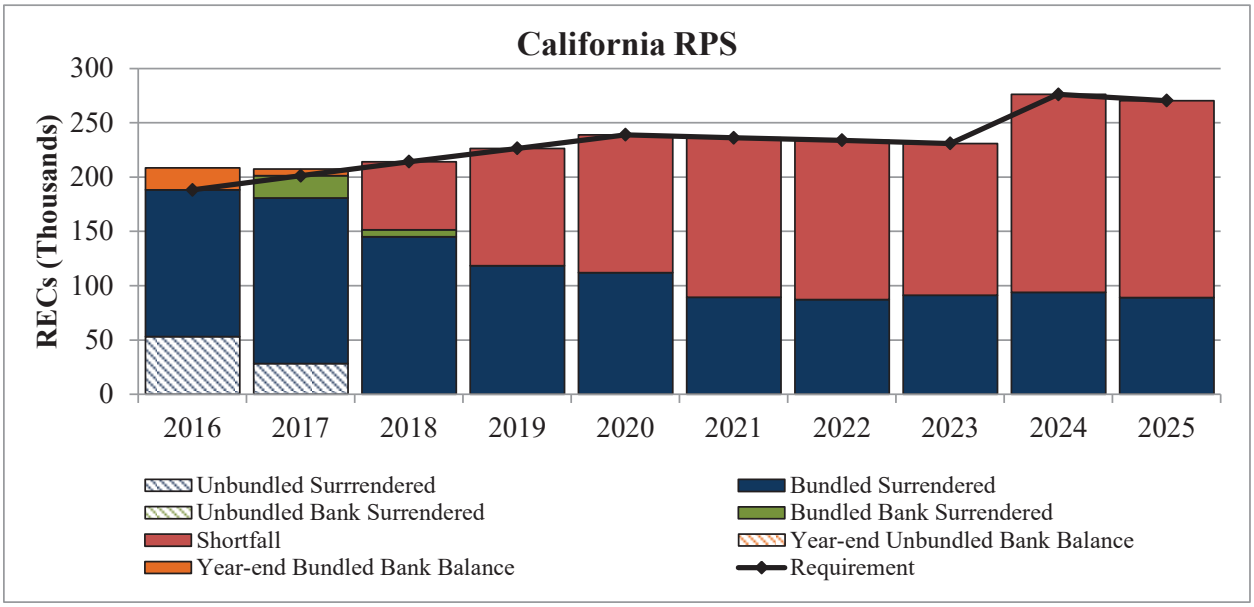
In October 2015, California Senate Bill No. 350 (SB 350) was signed into law, expanding the RPS target to 50% by 2030. Table 5.7 summarizes how the bill affects interim RPS targets for California relative to those assumed in the 2015 IRP.

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

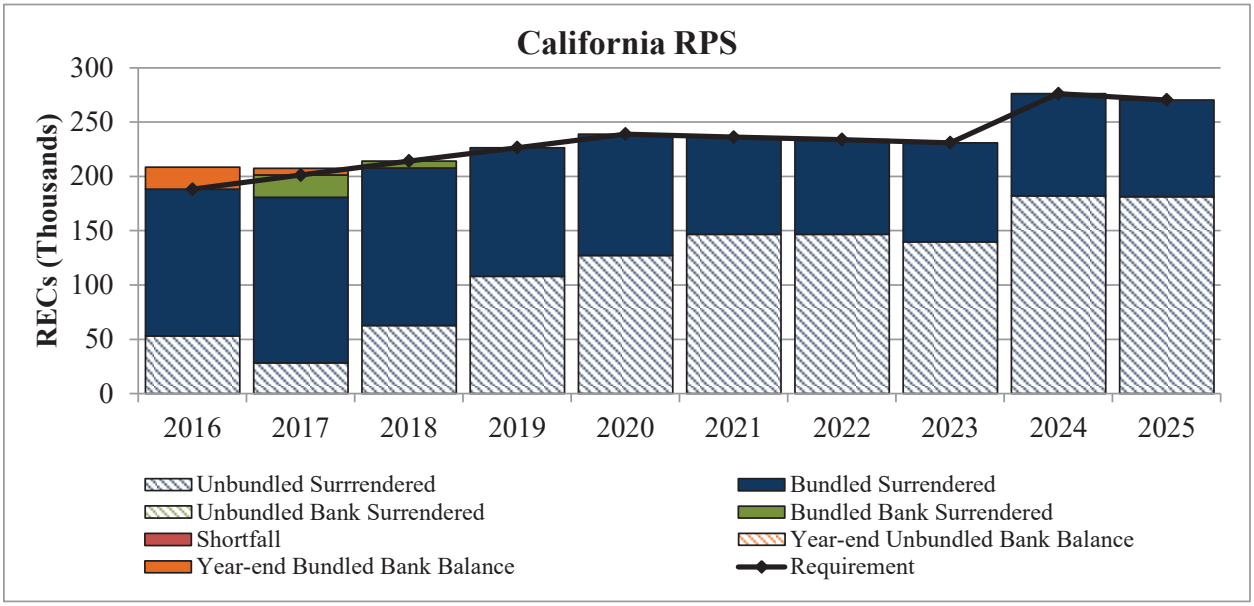


PacifiCorp is not restricted from using unbundled RECs to meet its RPS targets in California, and unbundled REC purchases can be used to achieve compliance through the IRP planning horizon. Figure 5.6 shows PacifiCorp's California RPS compliance position with unbundled REC purchase volumes required to 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 CO_2 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 CO_2 Emissions

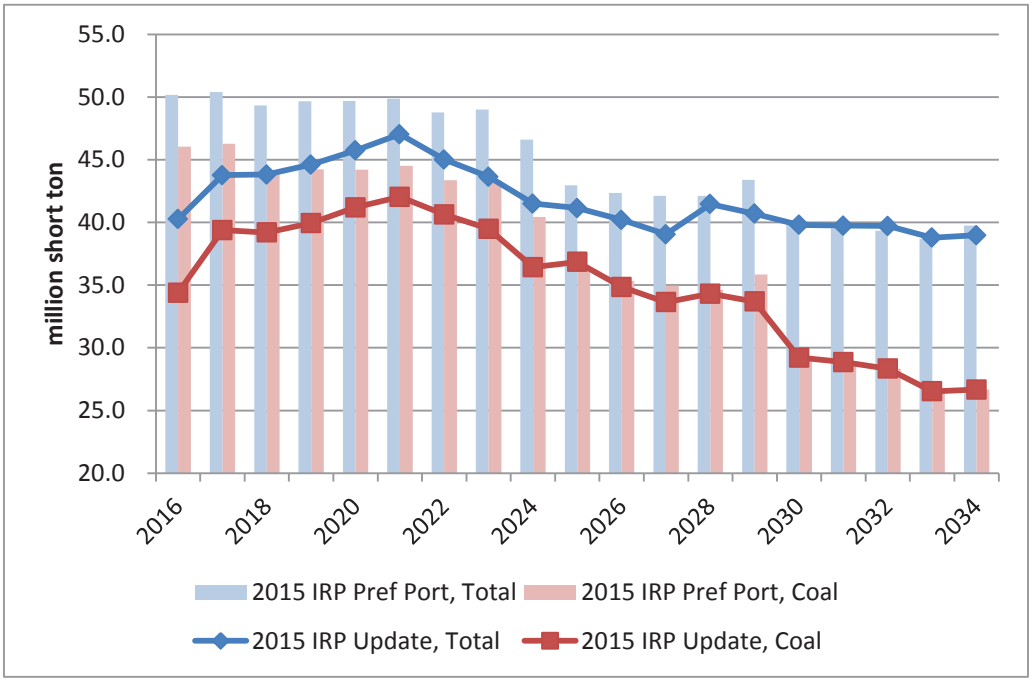


Figure 5.8 – Total Thermal Generation

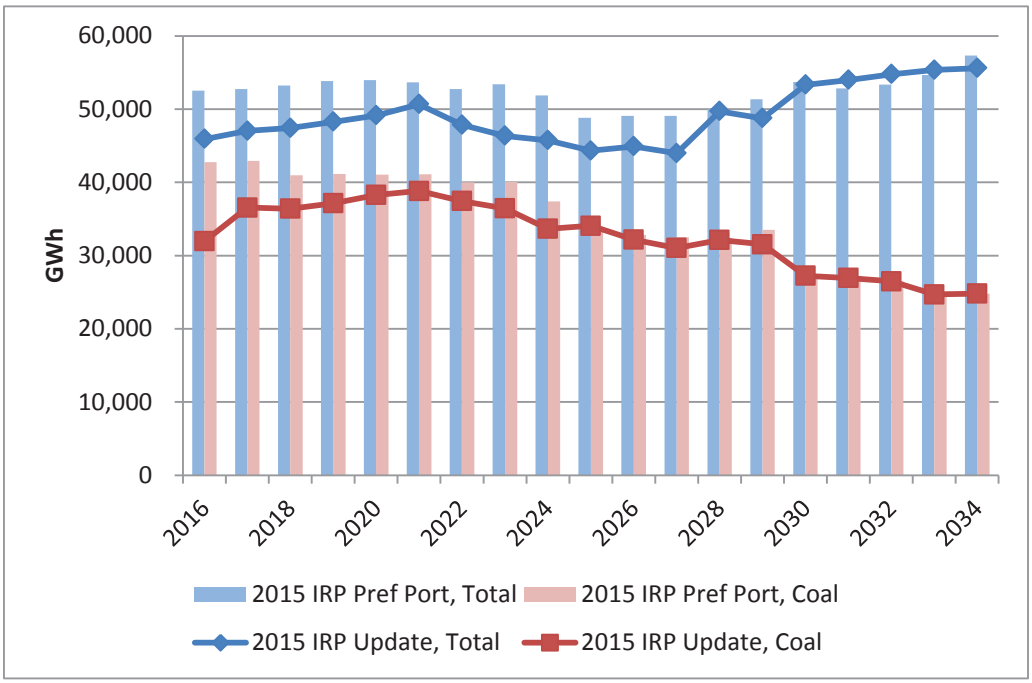
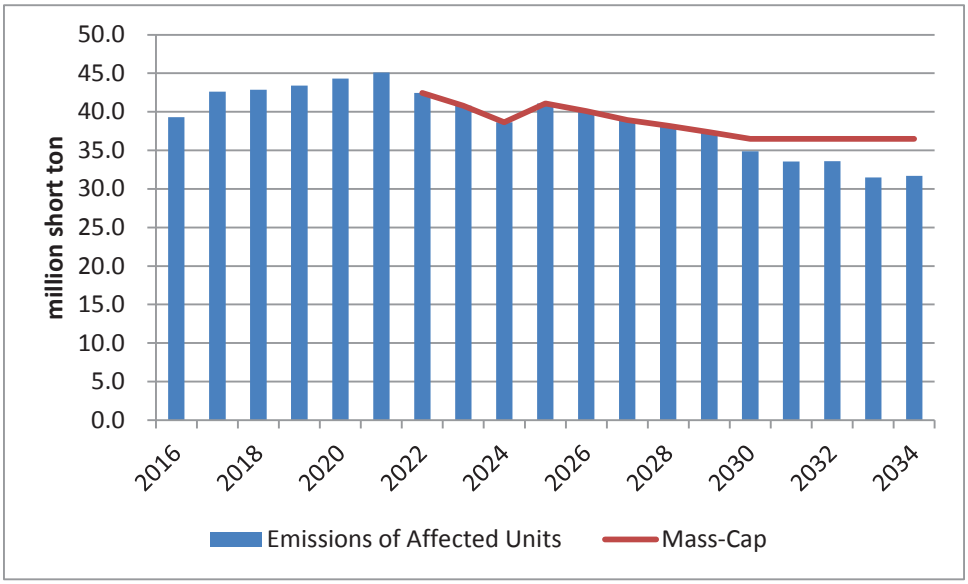
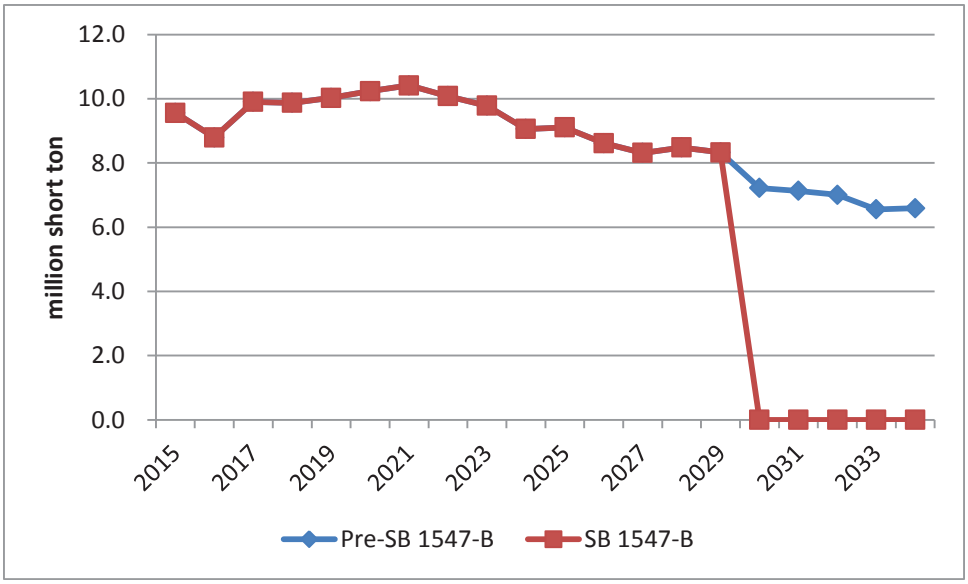


Figure 5.9 – Mass-Cap and Emissions from Affected Units



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 CO_2 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 (PVRR) 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 CO_2 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.

11 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 PacifiCorp's system. The present value revenue requirement (PVRR) 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																					
	Installed Capacity, 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 - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	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																					
	Installed Capacity, 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 - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	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																					
	Installed Capacity, 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 - 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 PacifiCorp'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	**Renewable Portfolio Standard Compliance** • 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	**Renewable Energy Credit Optimization** • 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	**Oregon Solar Capacity Standard** • 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	**Front Office Transactions**
	– 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	**Class 1 DSM** – 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.

<table>
<tr><th>Action Item</th><th>Activity</th><th>Status</th></tr>
<tr><td>3b</td><td><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>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></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.</td><td>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.</td></tr>
<tr><td>4a</td><td><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.</td><td>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</td></tr>
</table>

Action Item	Activity	Status
		updated accordingly as presented in the updated action plan in the Executive Summary.
4b	**Dave Johnston Unit 3** • 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.	PacifiCorp is still awaiting results of appeal of EPA's final regional haze FIP.
4c	**Wyodak** • 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.	PacifiCorp is still awaiting results of appeal of EPA's final regional haze FIP.
4d	**Cholla Unit 4** • 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	**Energy Gateway Permitting** • 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	**Wallula to McNary 230 kilovolt Transmission Line** • 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	)	Order No. 202-26-21

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

Filed April 28, 2026

Exhibit 2-105:
PacifiCorp 2025 IRP

2025
Integrated Resource Plan

Volume I - March 31, 2025

PacifiCorp

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 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:
  - 3,782 megawatts of new wind resources
  - 7,524 megawatts of storage resources, including four-hour, and 100-hour durations
  - 5,912 megawatts of new solar resources, including utility-scale and small-scale
  - 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

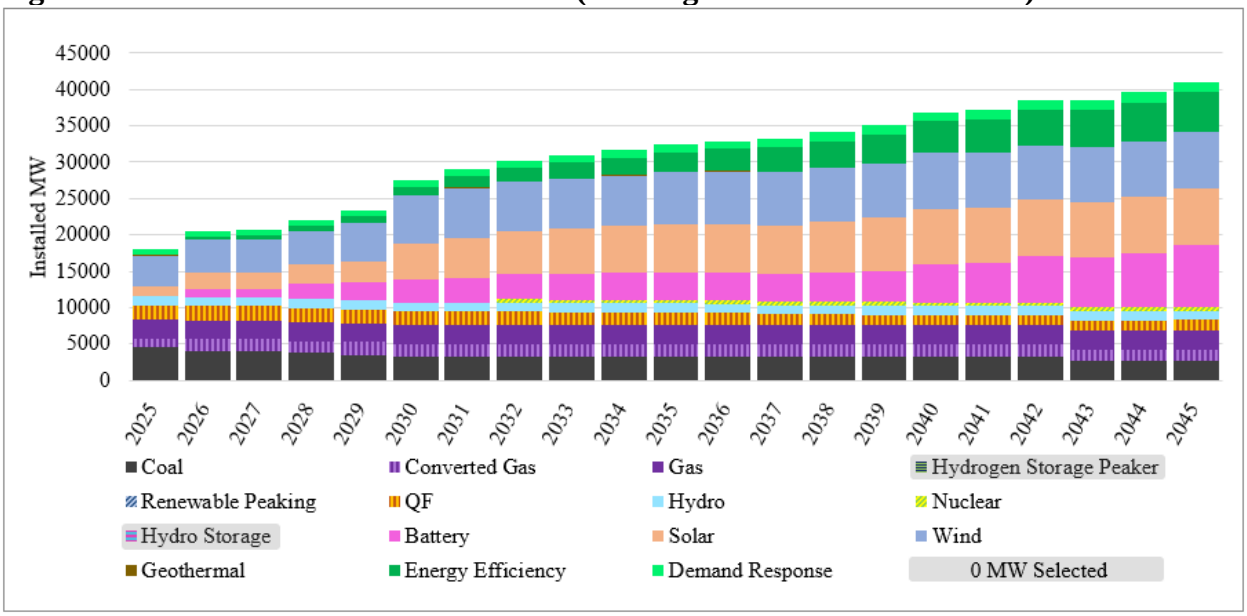
Preferred Portfolio Highlights

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 5,912MW 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 k	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.

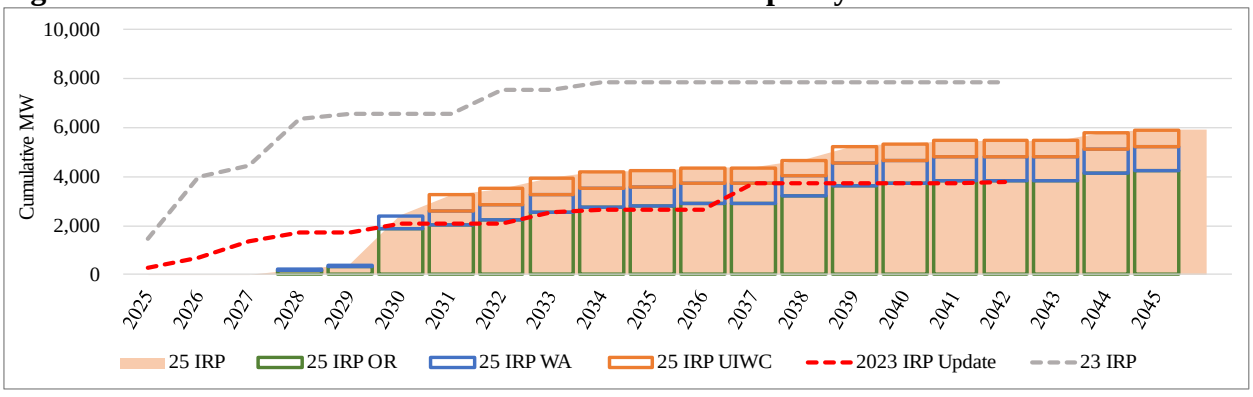
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

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.

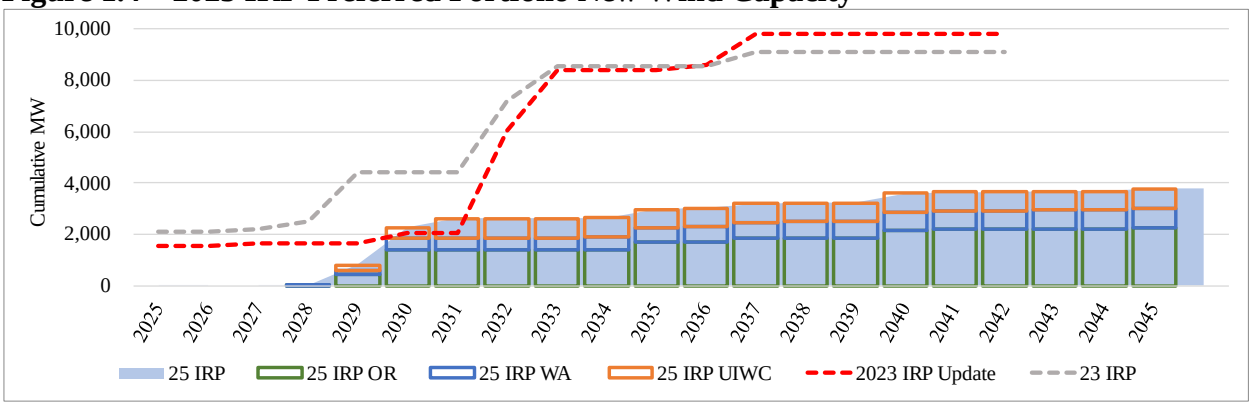
Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity



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.

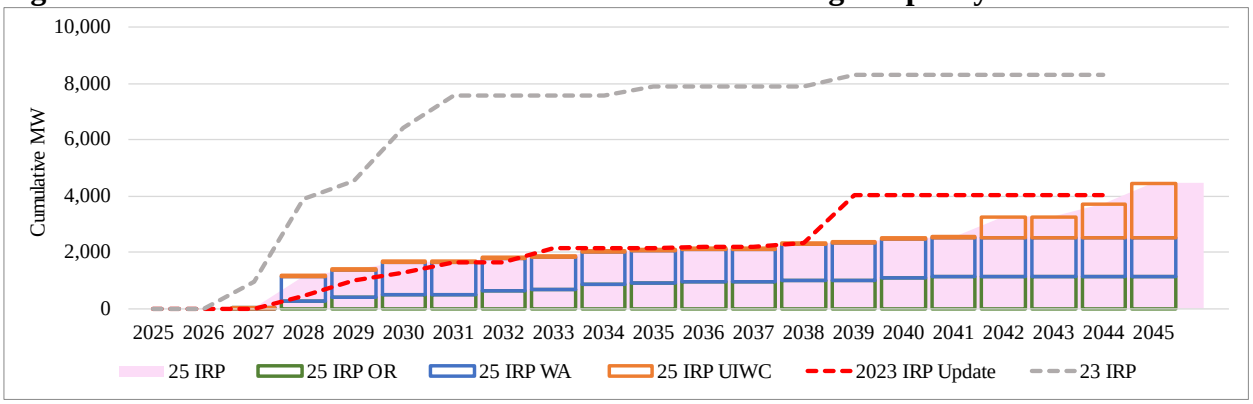
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

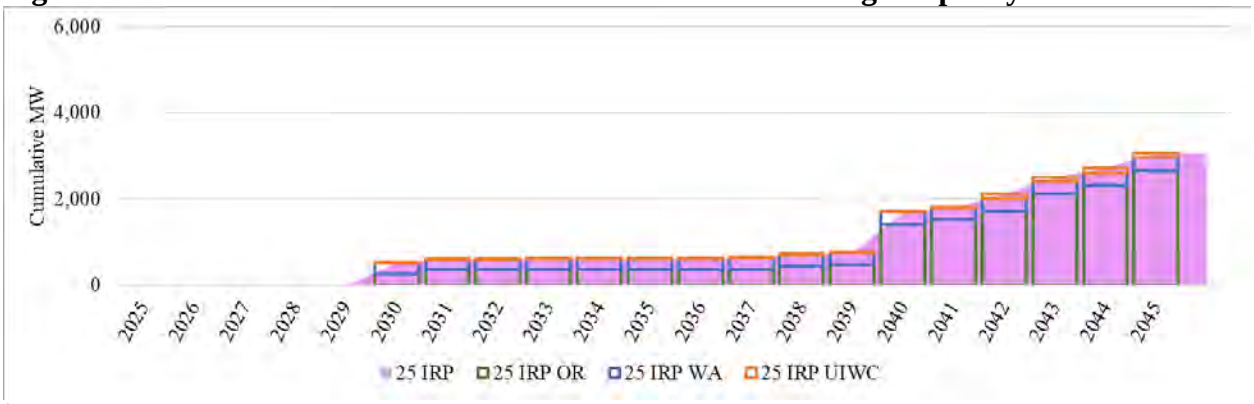
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred 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 Capacity[1]

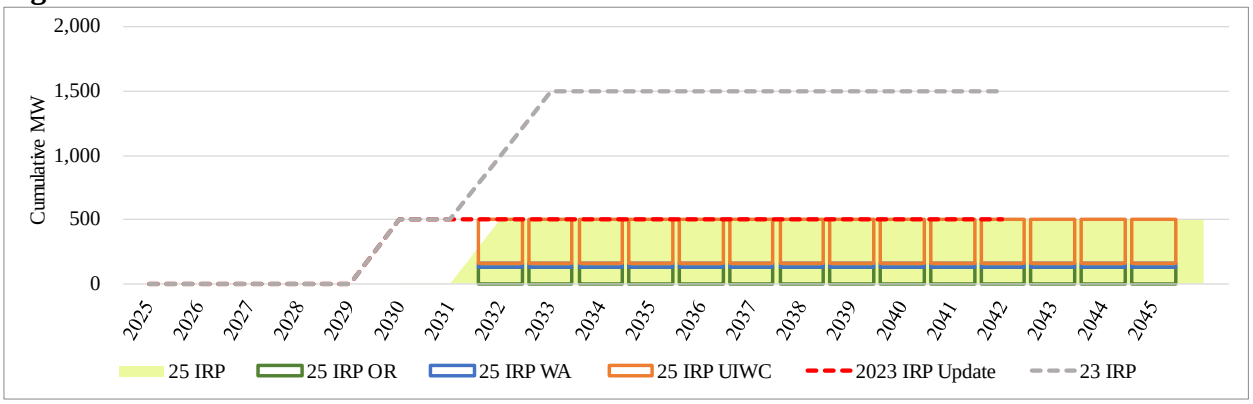


[1]The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

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 Nuclear[1]



[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.

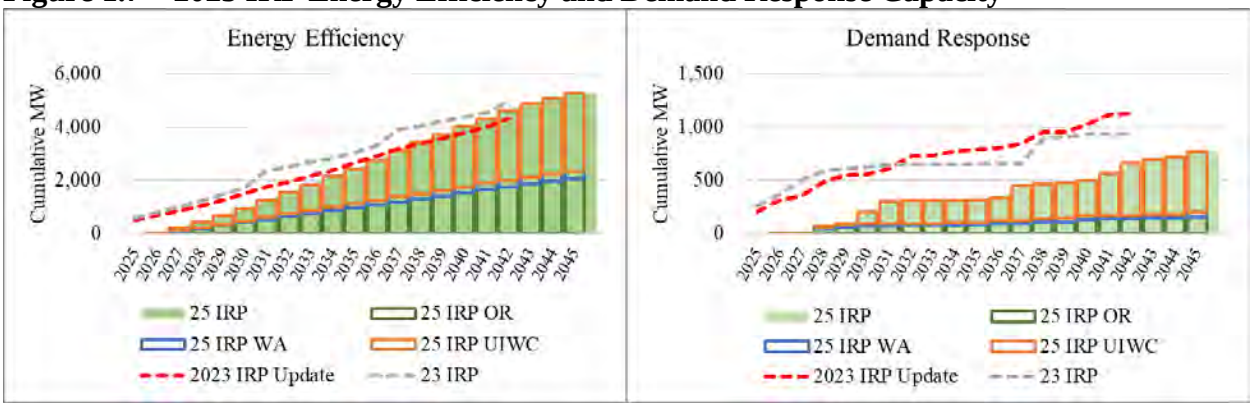
PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 12.3 percent

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

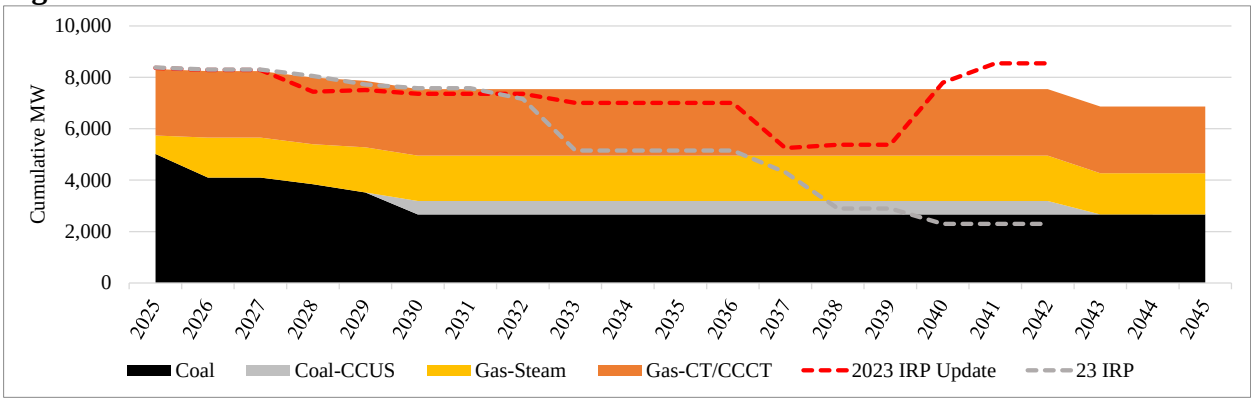


Coal and Gas Exits, Retirements, and Gas Conversions

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)

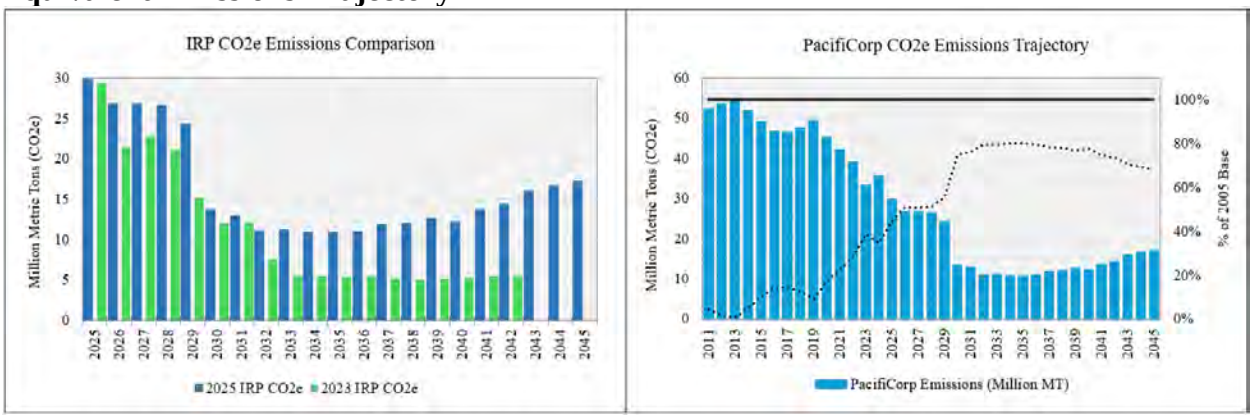
Carbon Dioxide Emissions

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 (CO_2) and CO_2 equivalent (CO_2e) 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 CO_2e 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 CO_2 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 CO_2 Equivalent Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory[1]



[1] PacifiCorp CO_2 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 CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/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	**Colstrip Units 3 and 4:** 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	**Craig Unit 1:** 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	**Naughton Units 1 and 2:** 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	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** 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	**Regional Haze Compliance:** 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	**Natrium™ Demonstration Project:** 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	**Ozone Transport Rule Compliance:** 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	**Natural Gas Emissions Compliance Strategies** 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	**Federal Greenhouse Gas Emission Compliance:** 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	**Dave Johnston Units 1 and 2:** 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	**Customer Preference Request for Proposals:** 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	**2025 All-Source Request for Proposals:** 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	**Local Reinforcement Projects** 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	**Gateway West Support** 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.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

Energy Efficiency & Demand Response Targets:

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.

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]

Year	Annual Incremental Capacity (MW)
2025	18
2026	2
2027	0
2028	63

</td></tr>
</table>

[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	**Market Purchases:** 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	**Renewable Portfolio Standards (RPS):** 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	**Renewable Energy Credit Sales:** 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 markets[3]. 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)
[3] 162 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 114º F in Sacramento, California, 110º F in Burbank, California, and 107º 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 additions[4]. 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 (CO_2) 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 law[6].

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*				

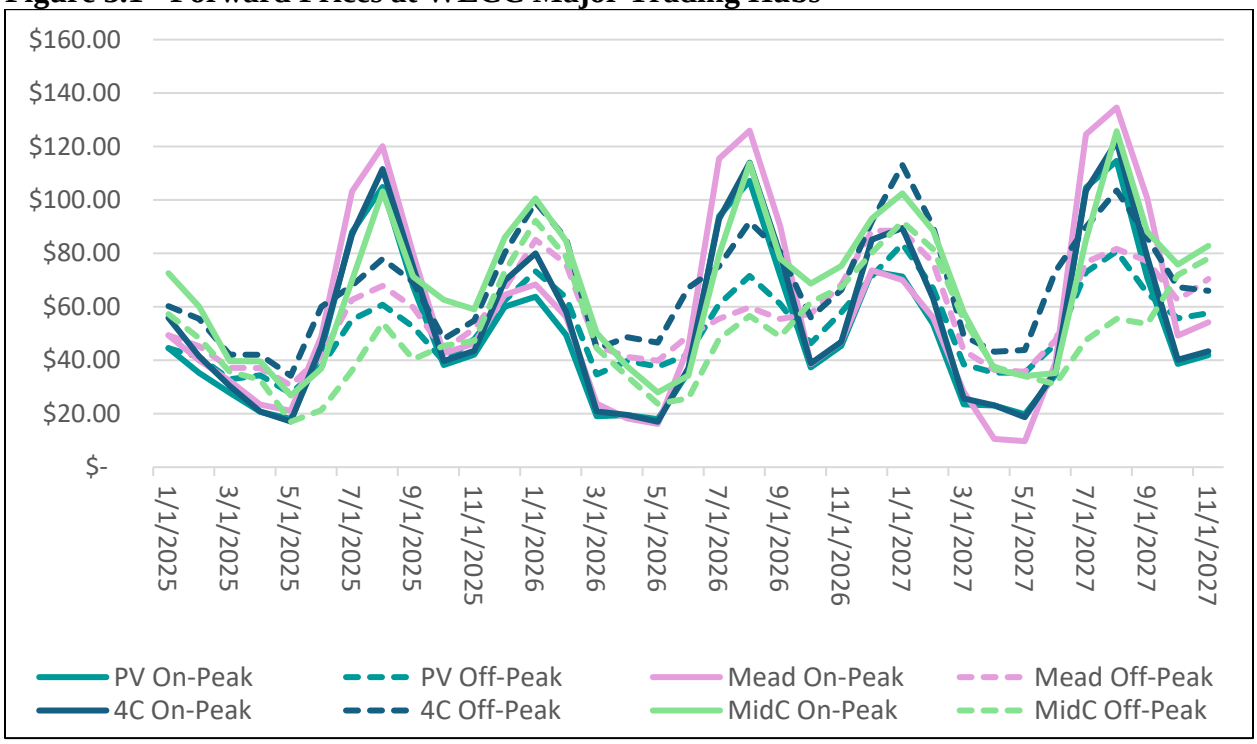
Source: SNL

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

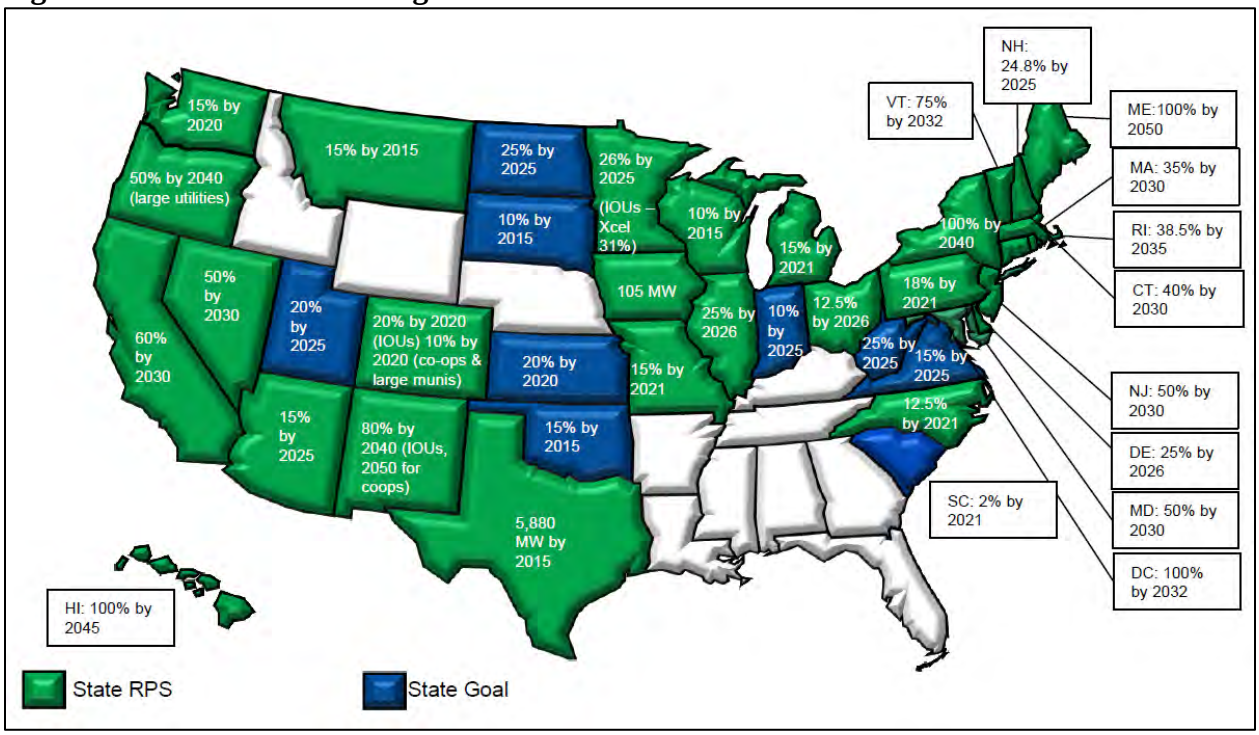
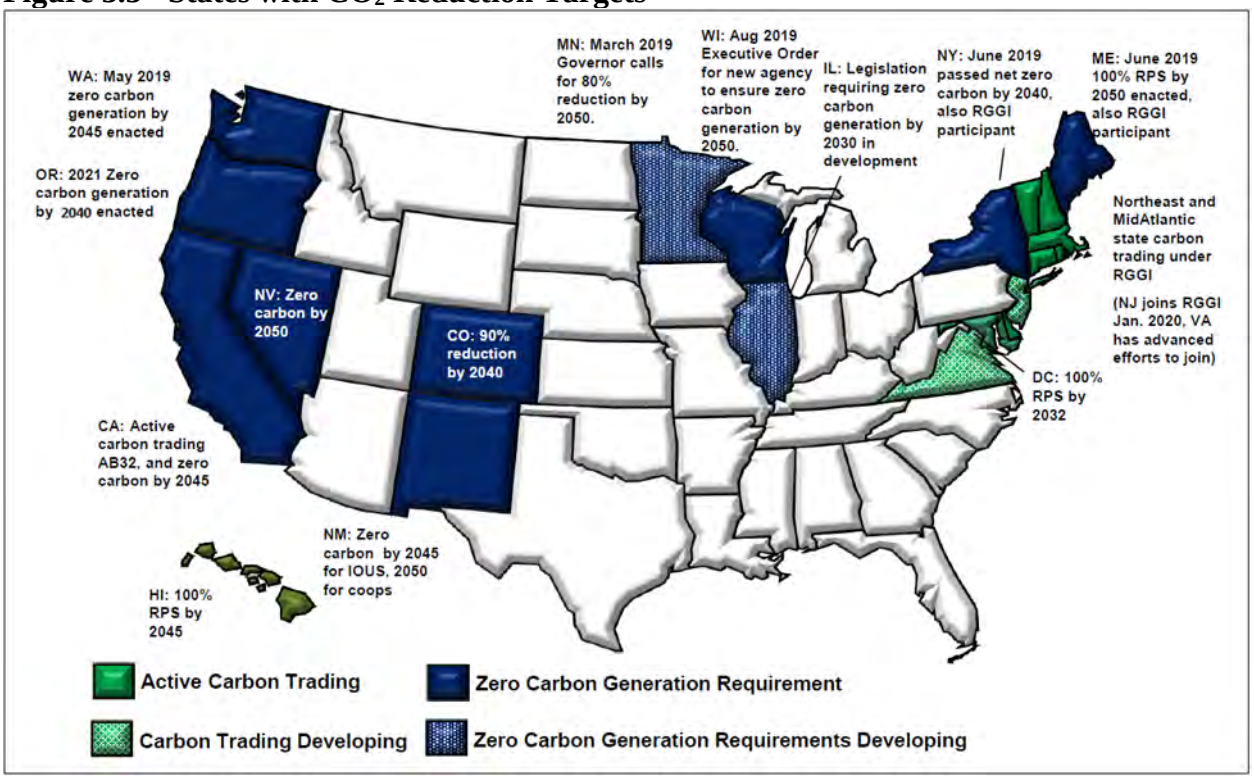
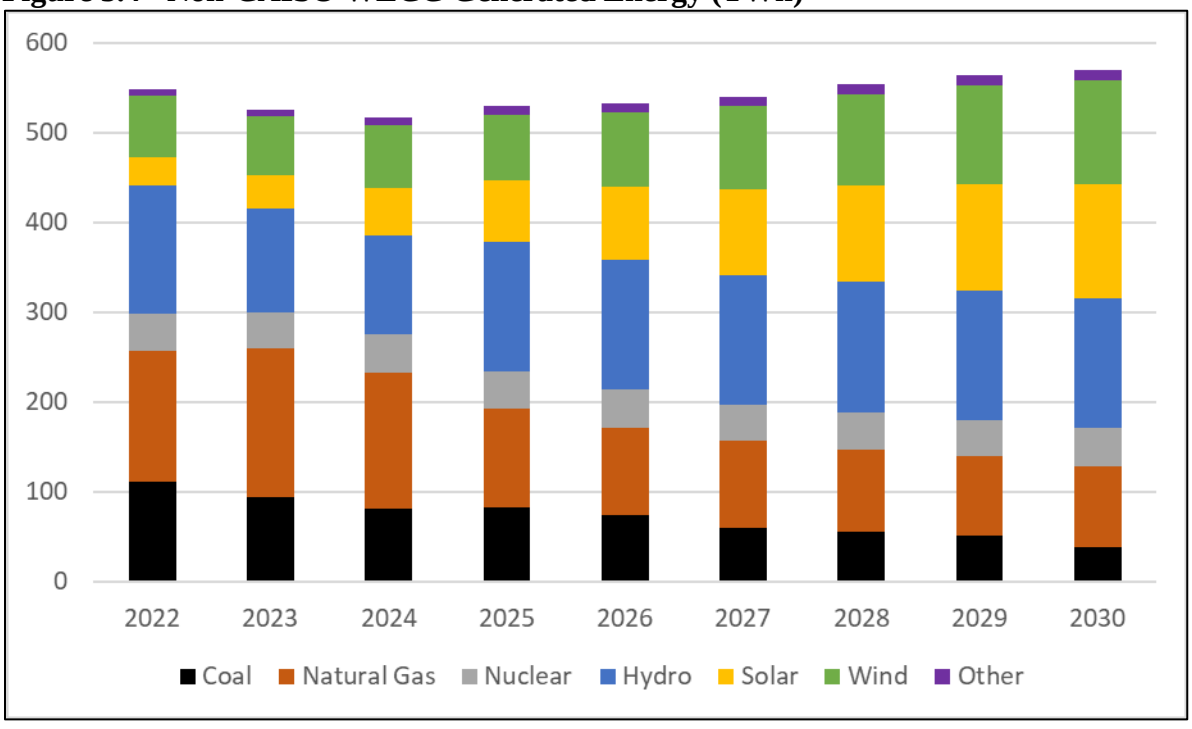


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

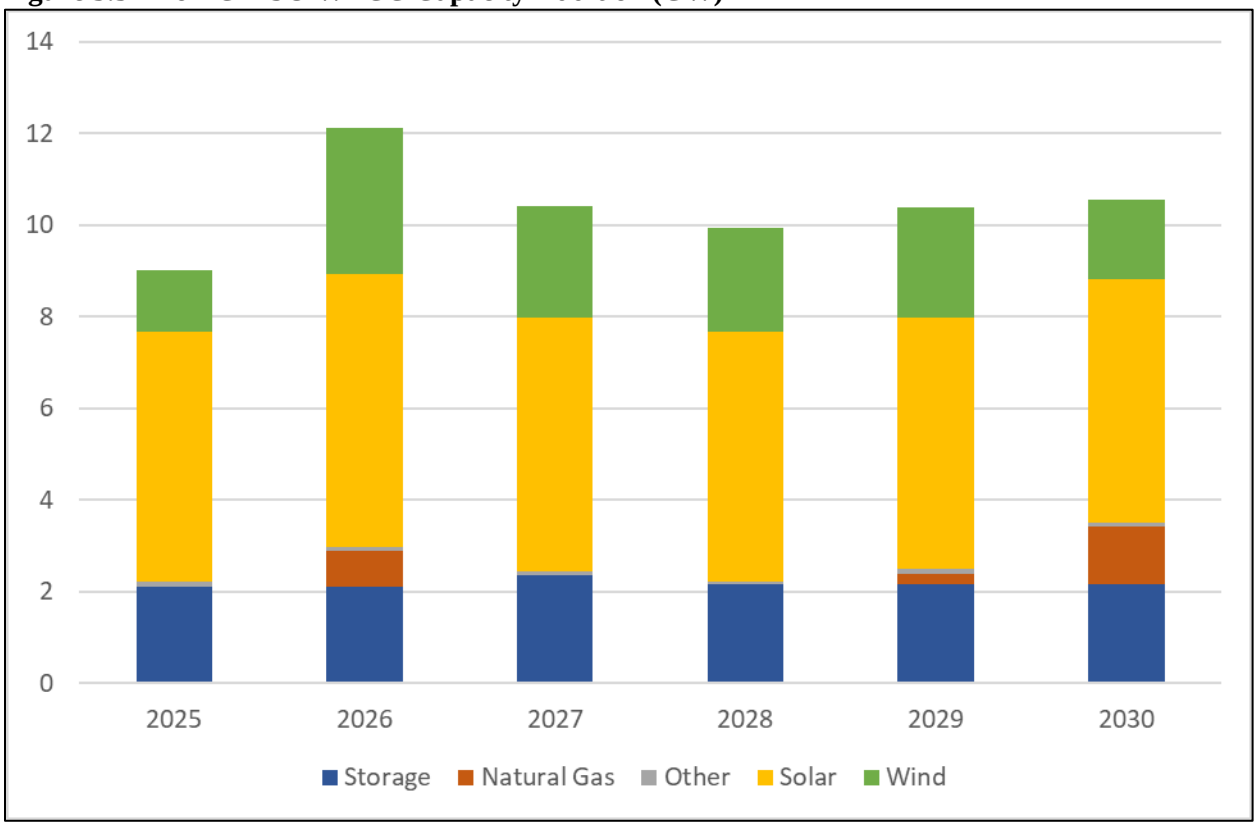
Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)



Source: IHS Markit, SNL, Siemens PTI

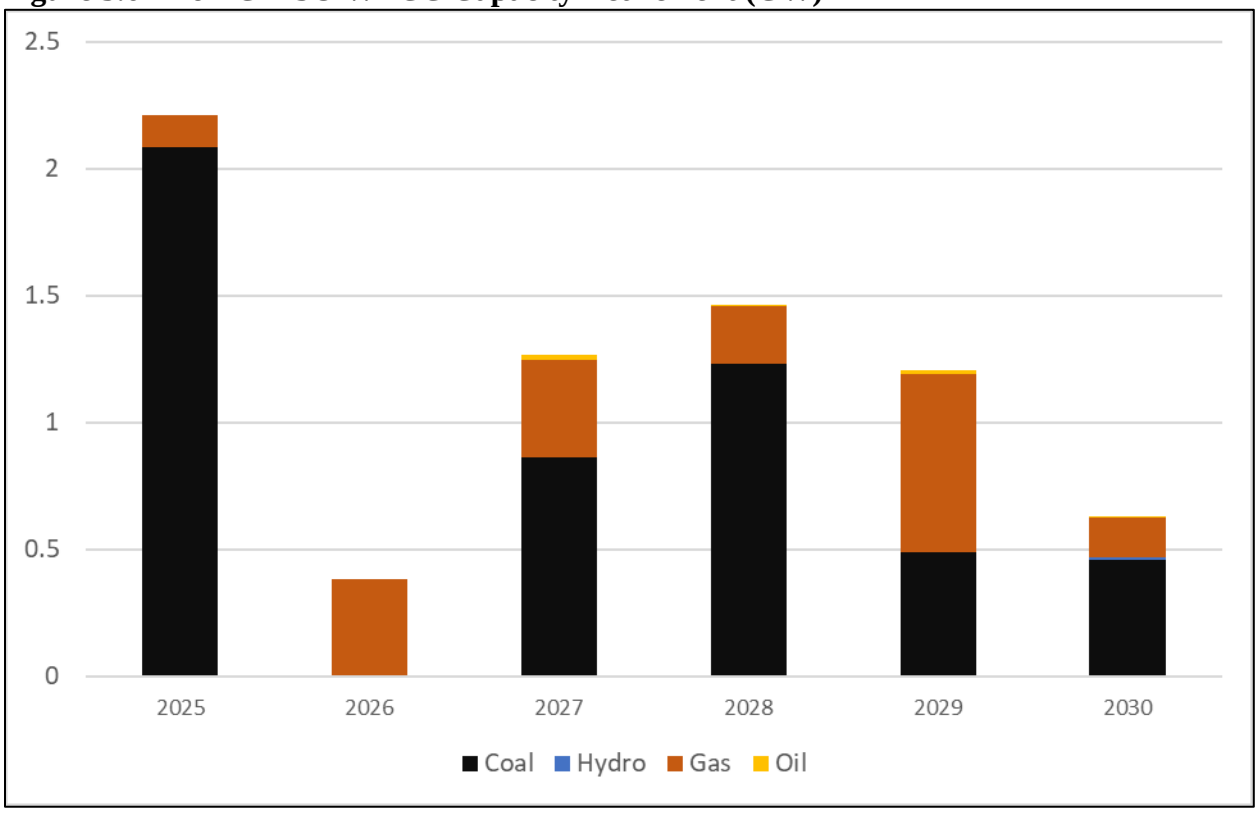
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage 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

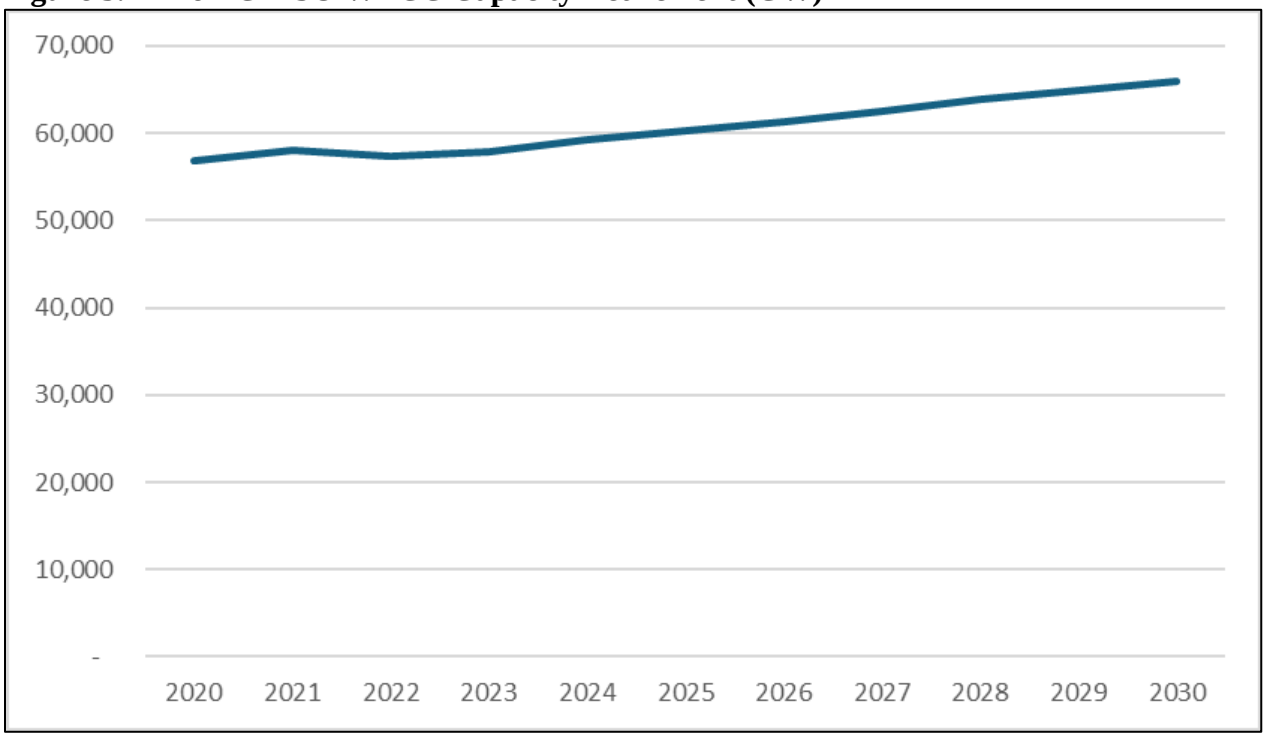
Emissions and Environment

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% NOx 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

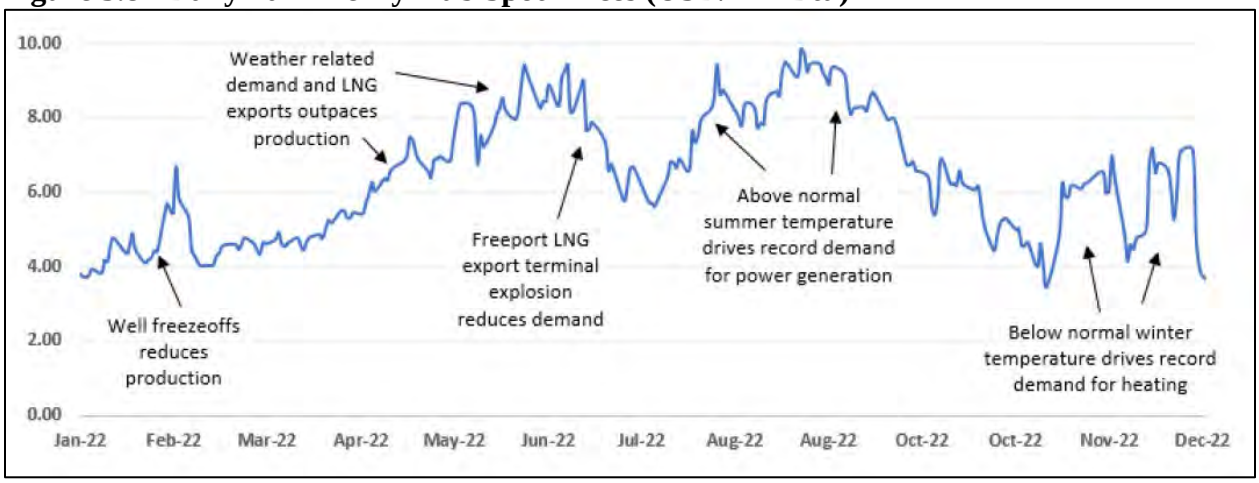
2022 Summary

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. liquified 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.

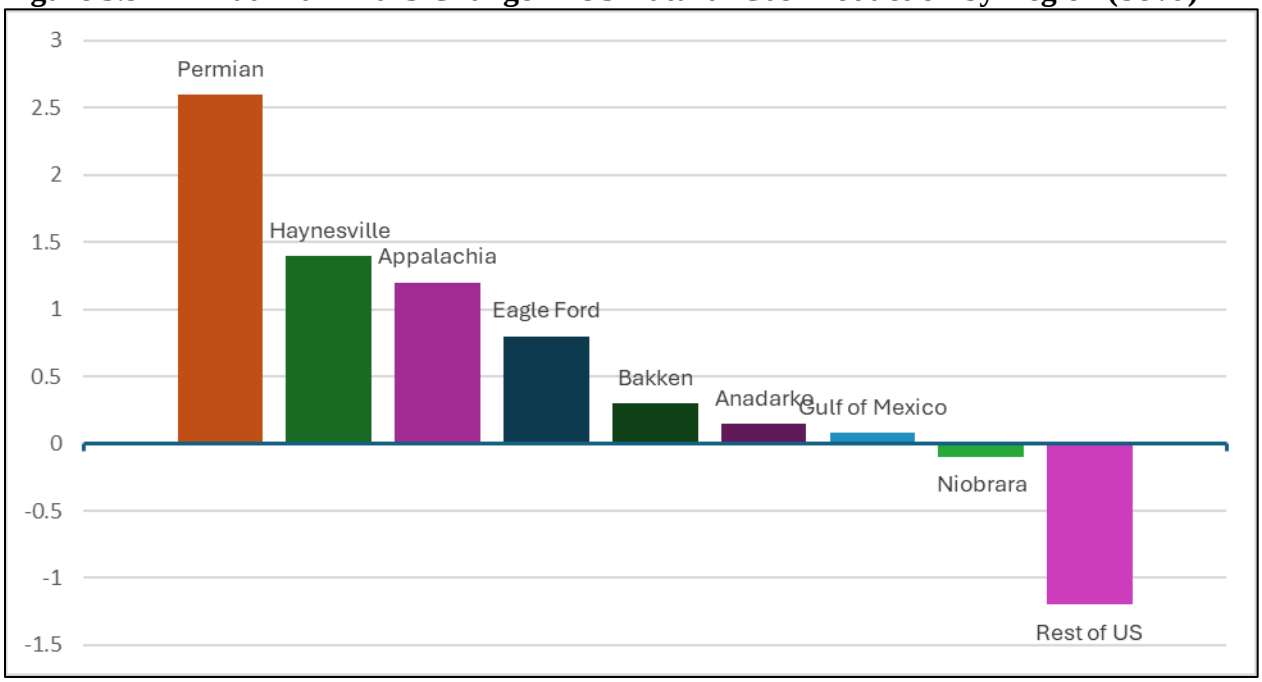
However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased

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.

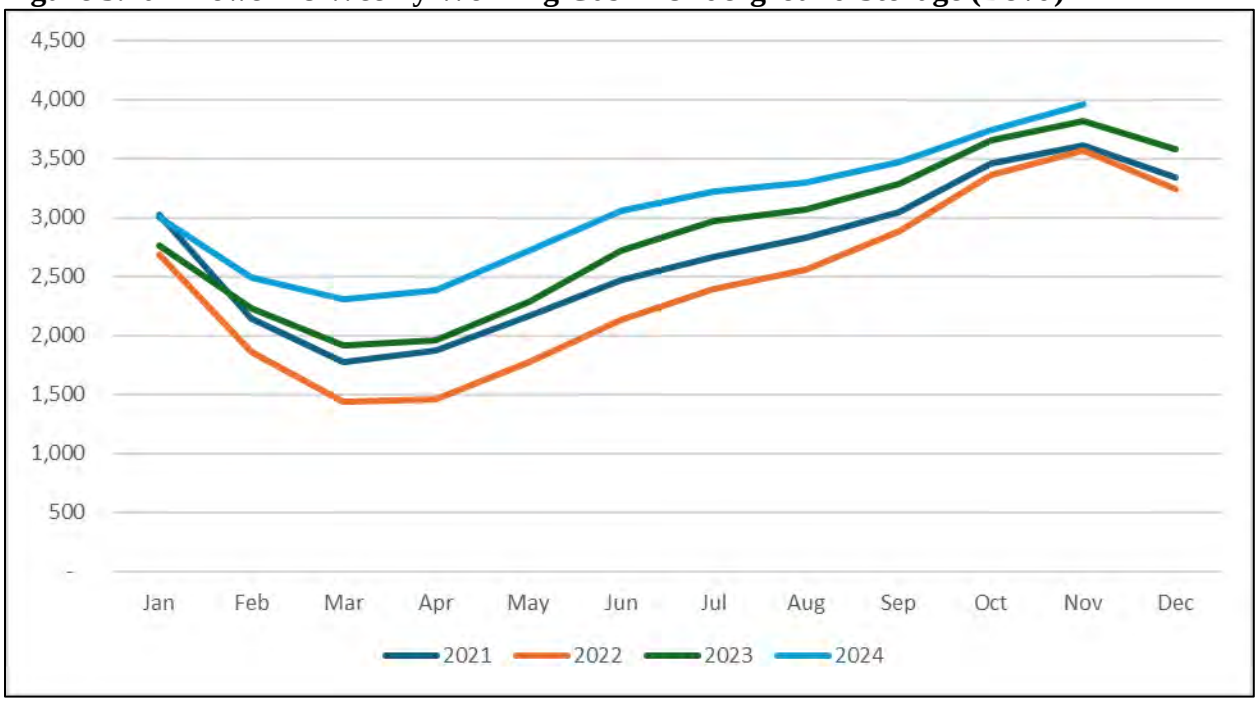
Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



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

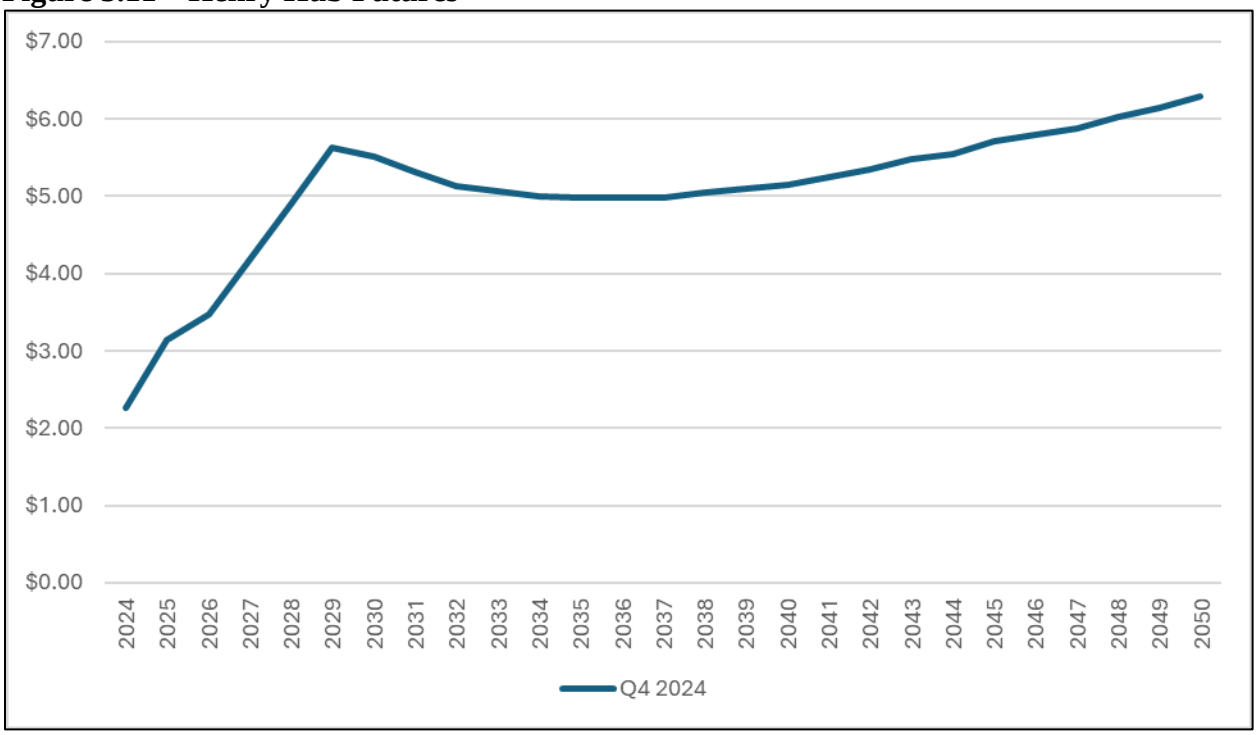
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts 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 polices 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 or 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 CO_2 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 (NOX), particulate matter (PM), and sulfur dioxide (SO_2). 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 CO_2.
[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 NOx emissions from electric generating unit (EGU) sources within the borders of 25 states during the ozone season and to limit ozone season NOx 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 ($\mu g/m^3$) meter to 35 $\mu g/m^3$. 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 PM2.5. 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. Re-designation 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 $\mu g/m^3$ to 9.0 $\mu g/m^3$. 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, NOx, SO_2, 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 SO_2, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NOx and PM portions for Hunter Units 1 and 2 and Huntington Units 1 and 2. EPA's approval of the SO_2 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 NOx 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 NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2 and crediting NOx 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 NOx emission limitations on Hunter Units 1 and 2 and Huntington Units 1 and 2 that are reflective of Selective Catalytic Reduction (SCR) and Low-NOx 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 NOx and SO_2 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 NOx limits. The SIP also concluded that existing SO_2 limits in Hunter and Huntington's title V permits were necessary to make reasonable progress but required no further SO_2 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 NOx 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 NOx 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 NOx 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 NOx BART for Units 1 and 2 was LNB and OFA. While EPA approved Wyoming's NOx 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 NOx 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 NO_X 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 SO_2 emission limits, in addition to an annual combined NOx and SO_2 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 NOx 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 NOx 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 SO_2 BART emission limits on Craig Units 1 and 2 of 0.11 lb/MMBtu (30-day rolling average). Colorado incorporated NOx 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 NOx 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 SO_2 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 NOx, 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 NOx 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 ≥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

Utah[9]

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 CO_2/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 adjusted[10] 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] le.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 Fetvedt 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 States[21]. PacifiCorp states, especially west coast states continue to outpace the US market share percentage, California is number one, with Oregon and Washington close behind[22]. By 2030 EVs (LDV) are expected to reach 7.7 million or 46% of sales[23]. 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)

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.

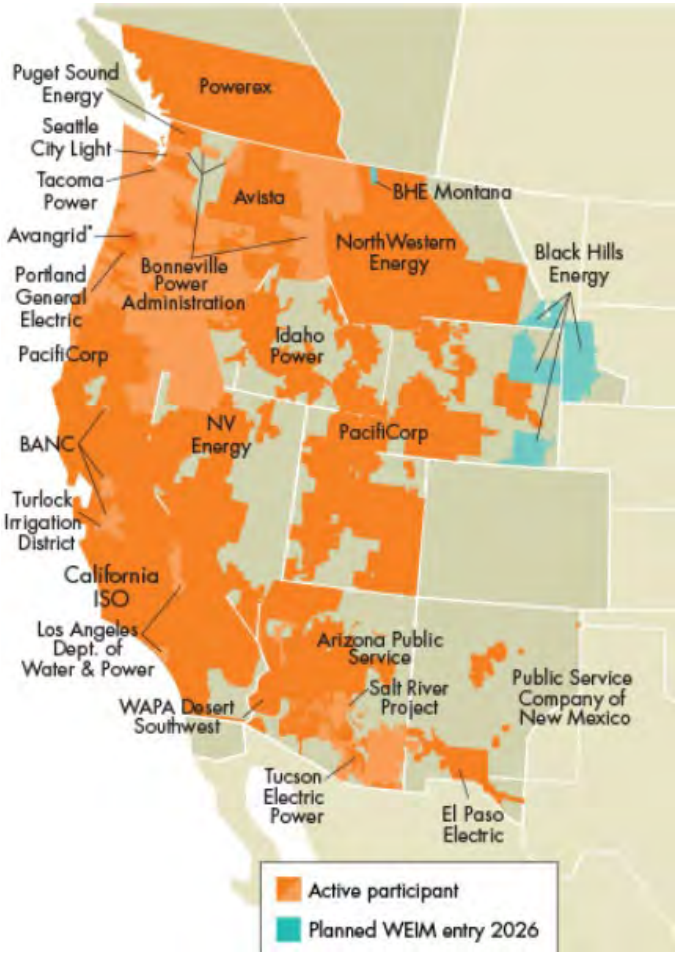
Electricity Market Development Update

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:

Figure 4.1 - Segment D

- 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.

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 Convenance 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.

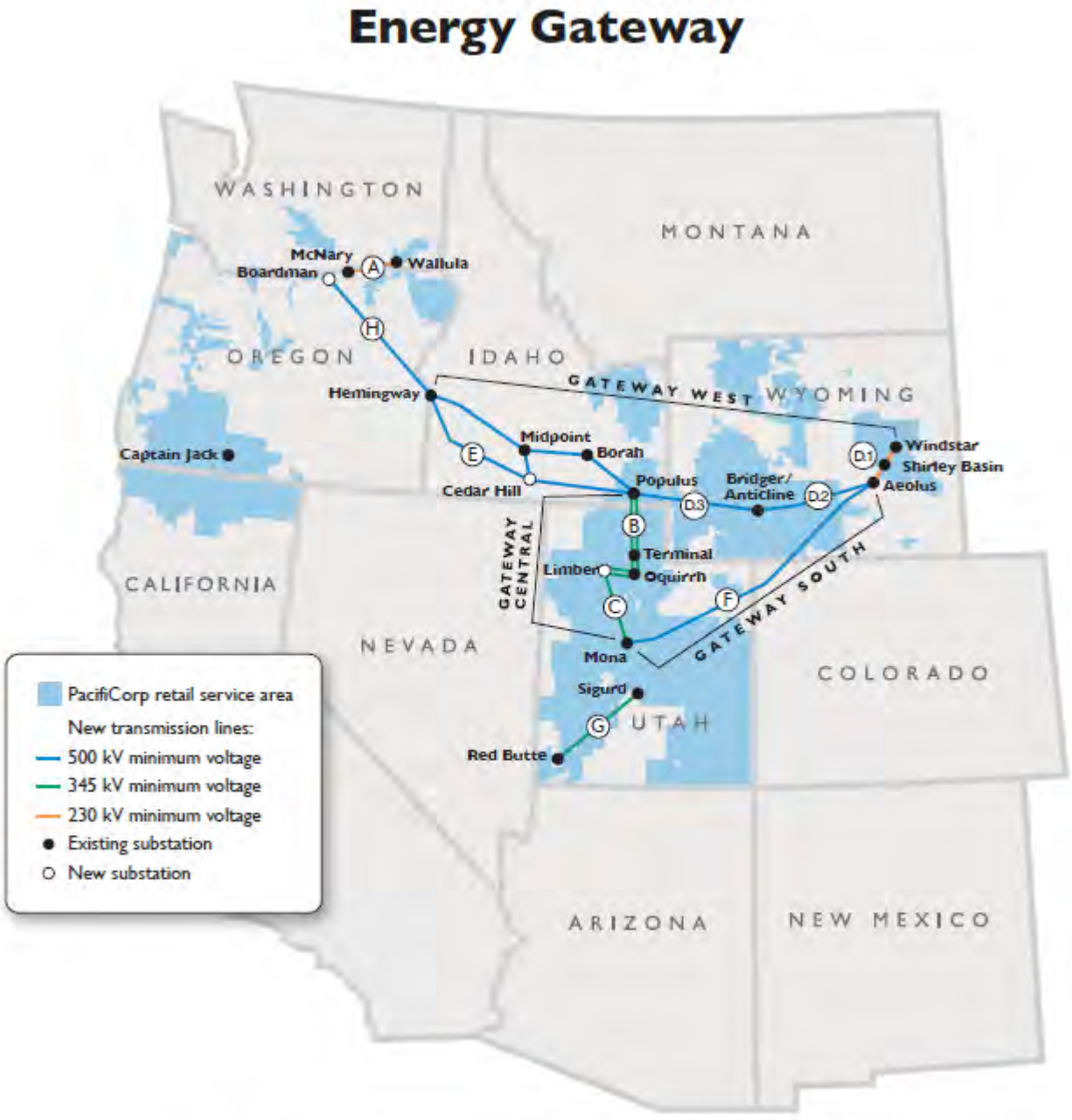
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 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 eliminates 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.

- 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:
     - 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.
     - 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:
     - 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.
     - 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:
     - 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.
     - 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:
     - 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.
     - 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 Summary[2]

	Month											
	55% Resource Additions Scenario											
Region	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	-	-	-
	Month											
	85% Resource Additions Scenario											
Region	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.nwcouncil.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	-
CedarValley	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	-
GranitePeak	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

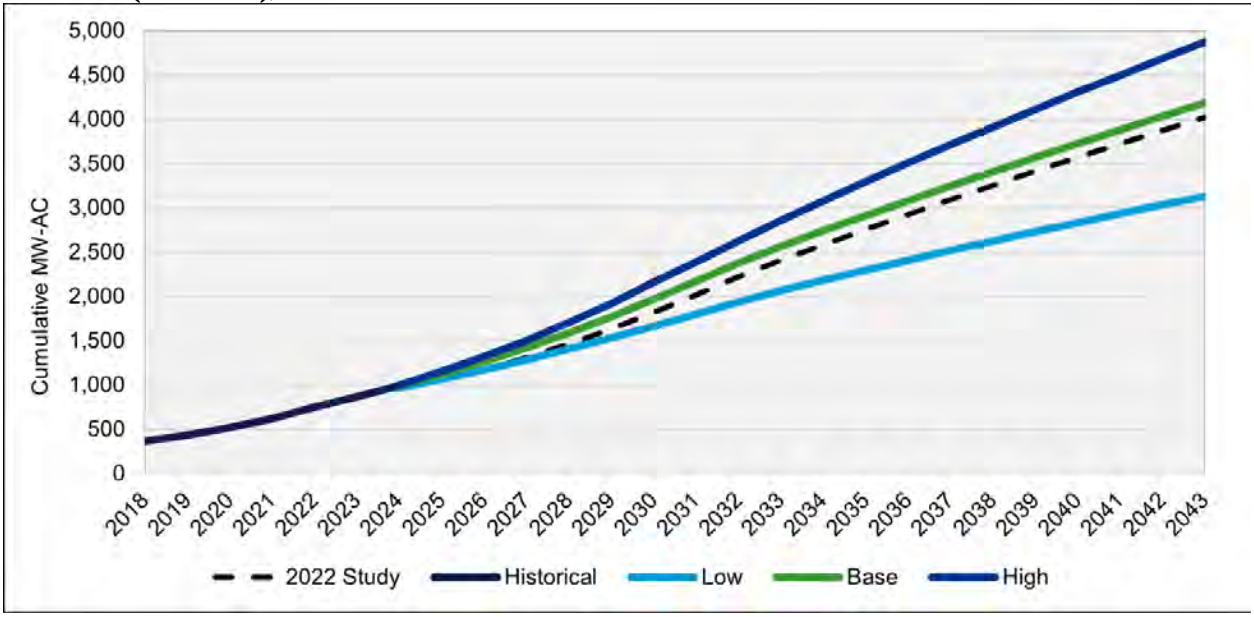
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each 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.

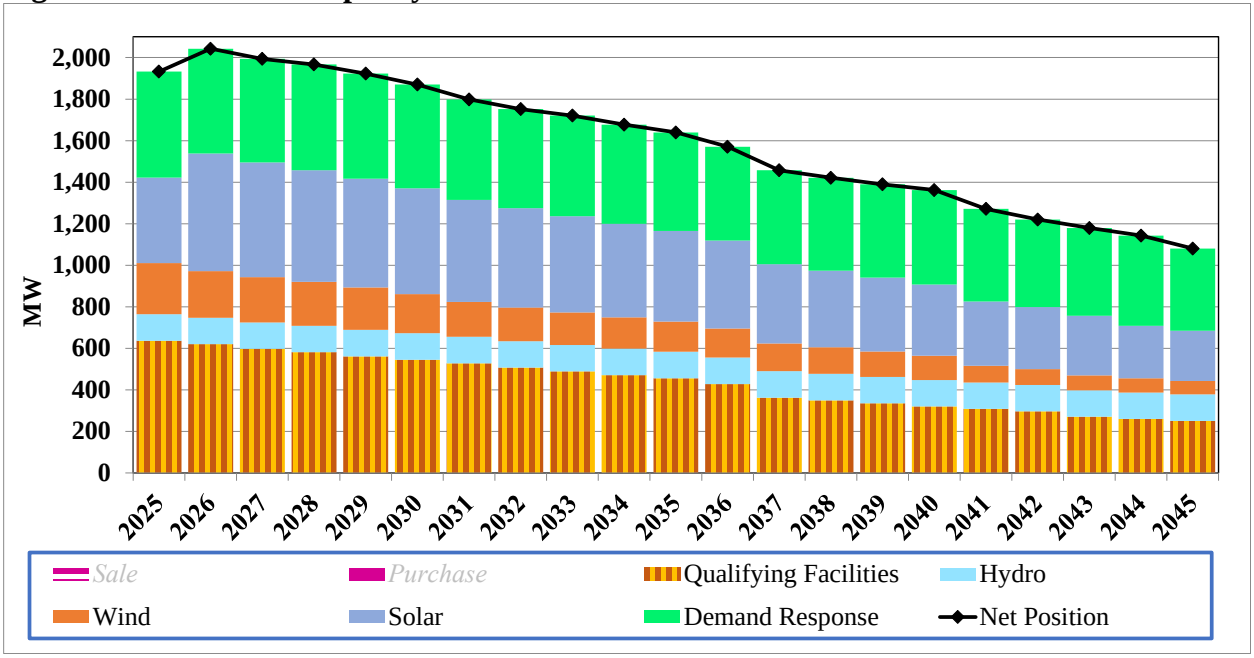
Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



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

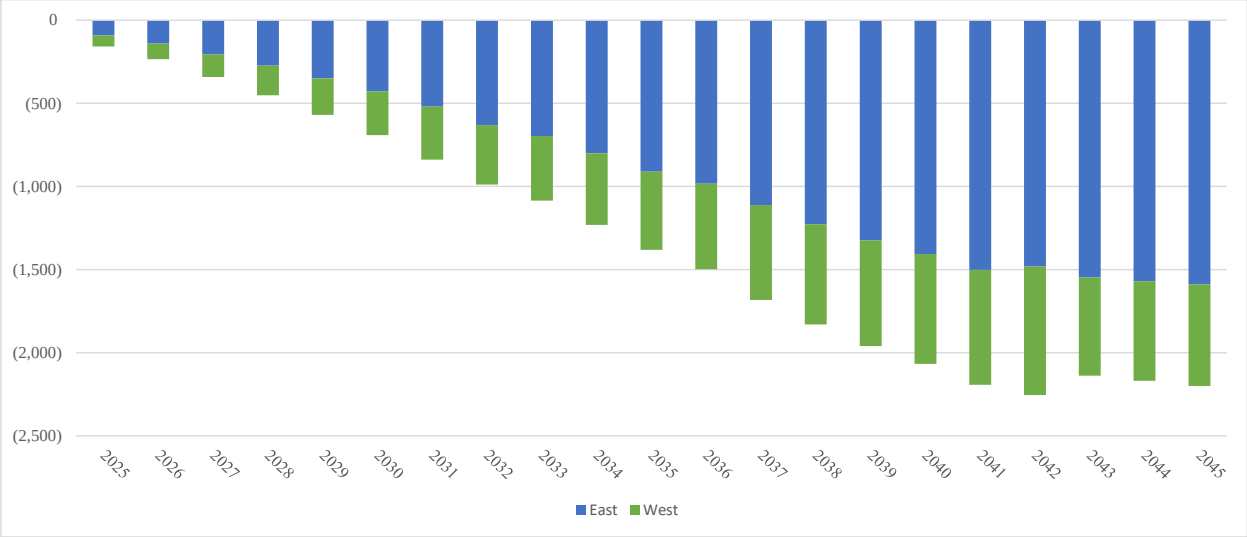
The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system

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:

Existing Resources = Coal + Gas + Hydro + Renewable + Storage + Firm Purchases + Qualifying Facilities + 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:

Obligation = Load – Distributed generation – 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:

Planning Reserves = Obligation x 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:

Capacity Position = (Existing Resources + Available Market purchases) – (Obligation + 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

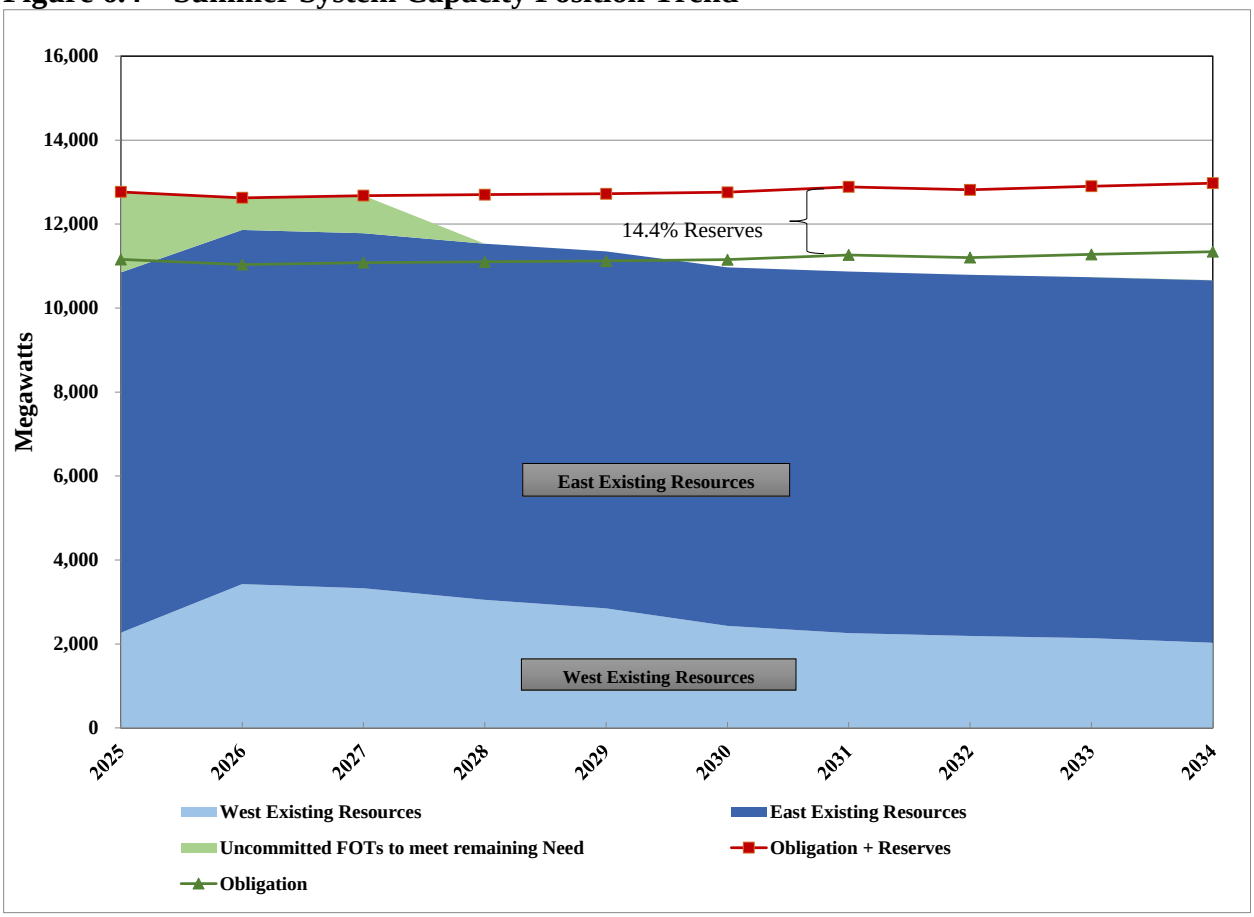


Figure 6.5 – Winter System Capacity Position Trend

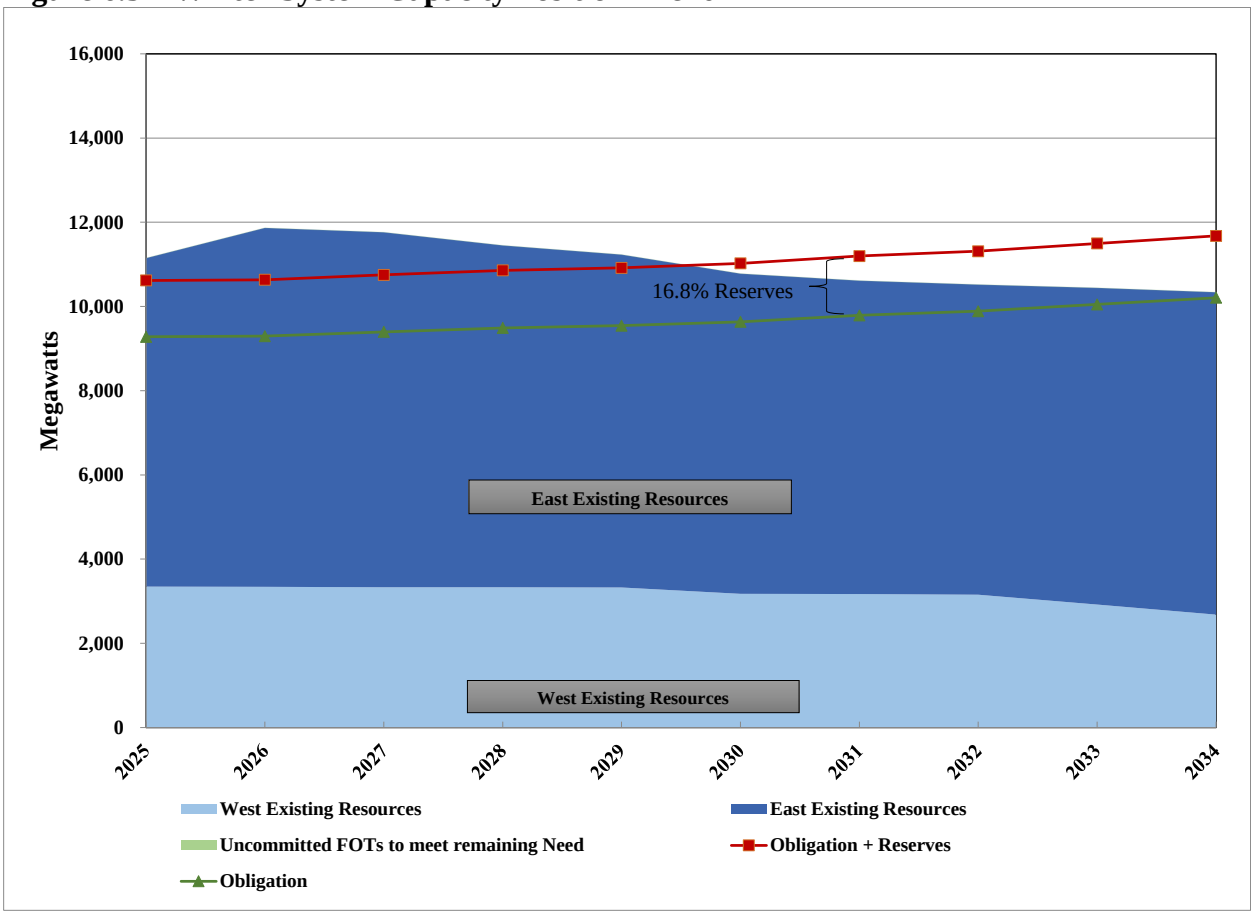


Figure 6.6 – East Summer Capacity Position Trend

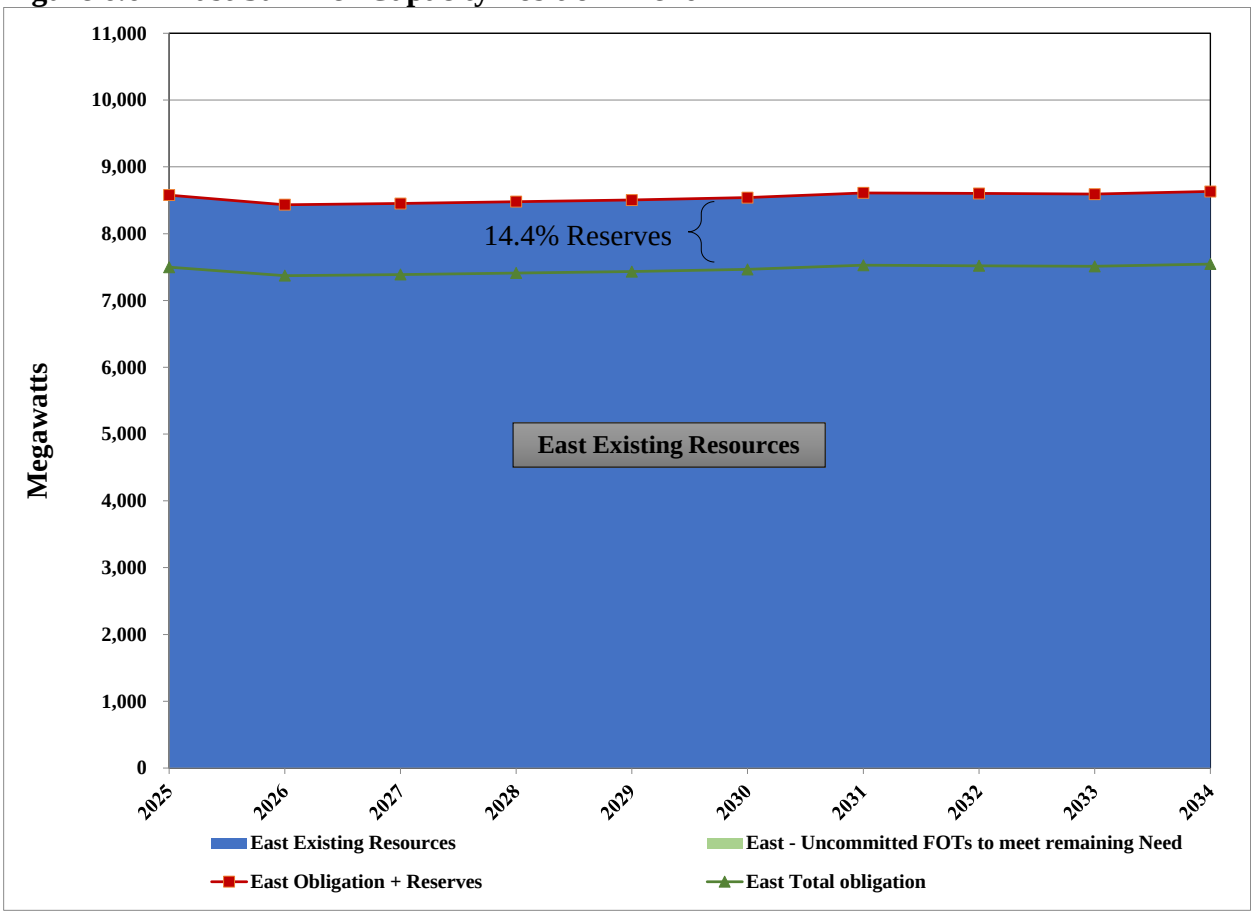
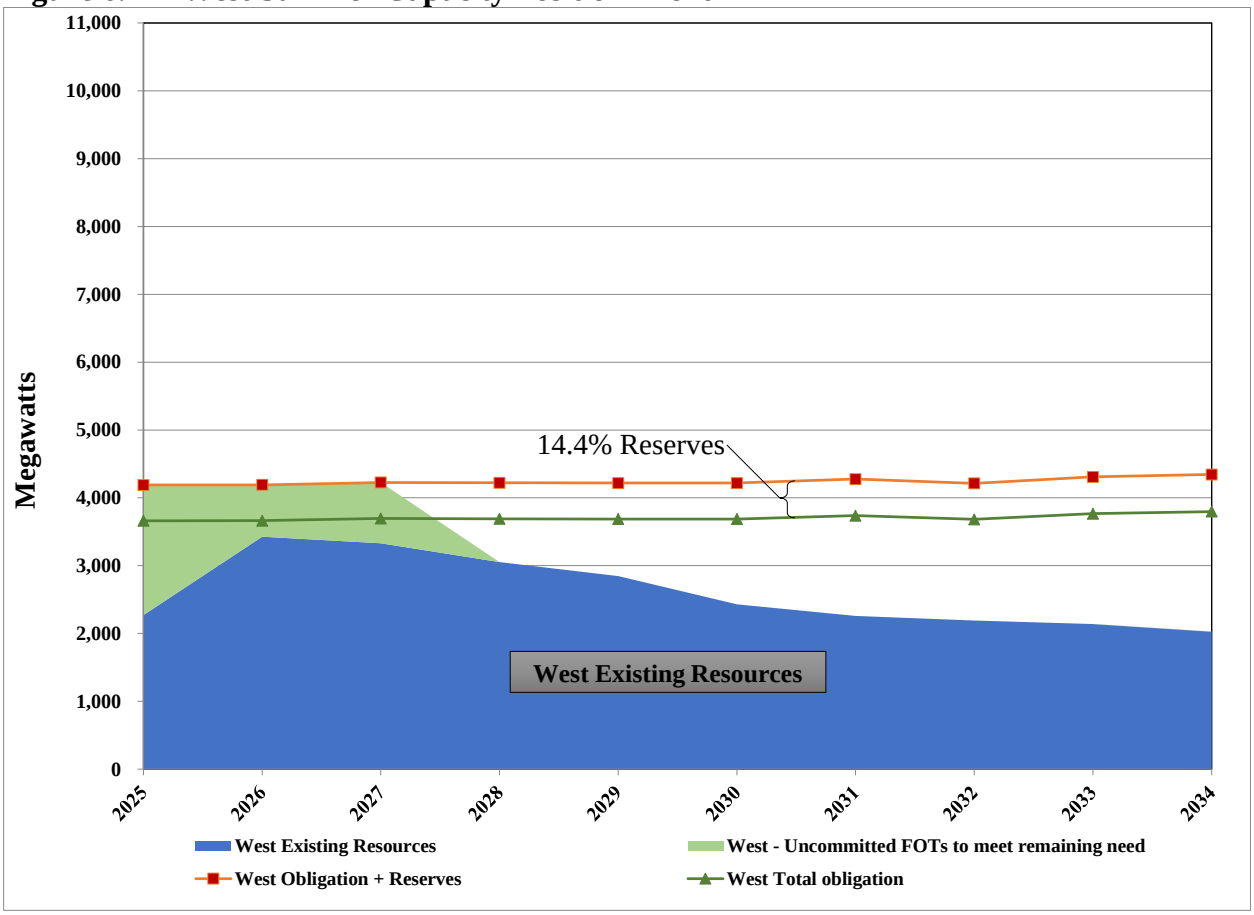


Figure 6.7 – West Summer Capacity Position Trend



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.
- Nuclear[4]
    - 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 2024[6] and 2020[7] 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/electricty/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 dataset[17] and configured in a PV_{syst} model[18] 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 to 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).

Natrium Demonstration Project

PacifiCorp's 2025 IRP includes the Natrium® 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 EIA[20] 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$)

		Characteristics						Costs						
Fuel	Resource Description	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	1085	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	1227	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	1085	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 Jim 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 Enhanhanced 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 Enhanhanced 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]

		Characteristics						Costs						
Fuel	Resource Description	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-located

[23] 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$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	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)
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 Enhanhanced Geothermal System (NF-EGS) Binary	N/A	N/A	10%	10%	510.0	n/a	n/a	n/a	n/a
Geothermal	Near Field Enhanhanced 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$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	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$)

	Additional Attributes							Fixed O&M						
Resource Description	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 ($/kW-Yr)	Gas Trausport ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
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%	$115.38	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	$ 1,553.26	$ 11.89	6.234%	$97.57	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	$ 1,655.10	$ 12.08	6.234%	$103.93	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$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	$ 2,585.93	$ 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	$ 3,038.01	$ 27.08	9.254%	$283.64	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	$238.51	$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	6,429	$ 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%	$193.83	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 Wyodak (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%	$353.80	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 Enhanhanced Geothermal System (NF-EGS) Binary	Yes	N/A	$ 7,593.06	$ 125.09	6.262%	$483.31	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$679.00	$96.89
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	$ 7,593.06	$ 125.09	6.262%	$483.31	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$679.00	$96.89

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics 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$)

	Additional Attributes							Fixed O&M					
Resource Description	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)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
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	$47.92
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$)

	Additional Attributes								Fixed O&M					
Resource Description	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)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
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	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	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

[1]Assumed 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
CCCT Dry "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
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 34.37	$2.62	14.39%	$0.38	$57.42	-	$57.42	$136.97
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 Enhanhanced 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 characterisitics 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.
SO2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NOx) (expressed as NO2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO2 (lbs/MMBtu)	Pounds of carbon dioxide (CO2) 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 scenario[24], 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 CO_2 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 m^3). There are at least two salt domes under development within PacifiCorp'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 Plan[33] 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. "H_2 gas is compressed at ambient temperature to 300 – 700 bar. Storage capacity is limited due to the low volumetric density of H_2 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 Record[36] 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 report[39] ("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

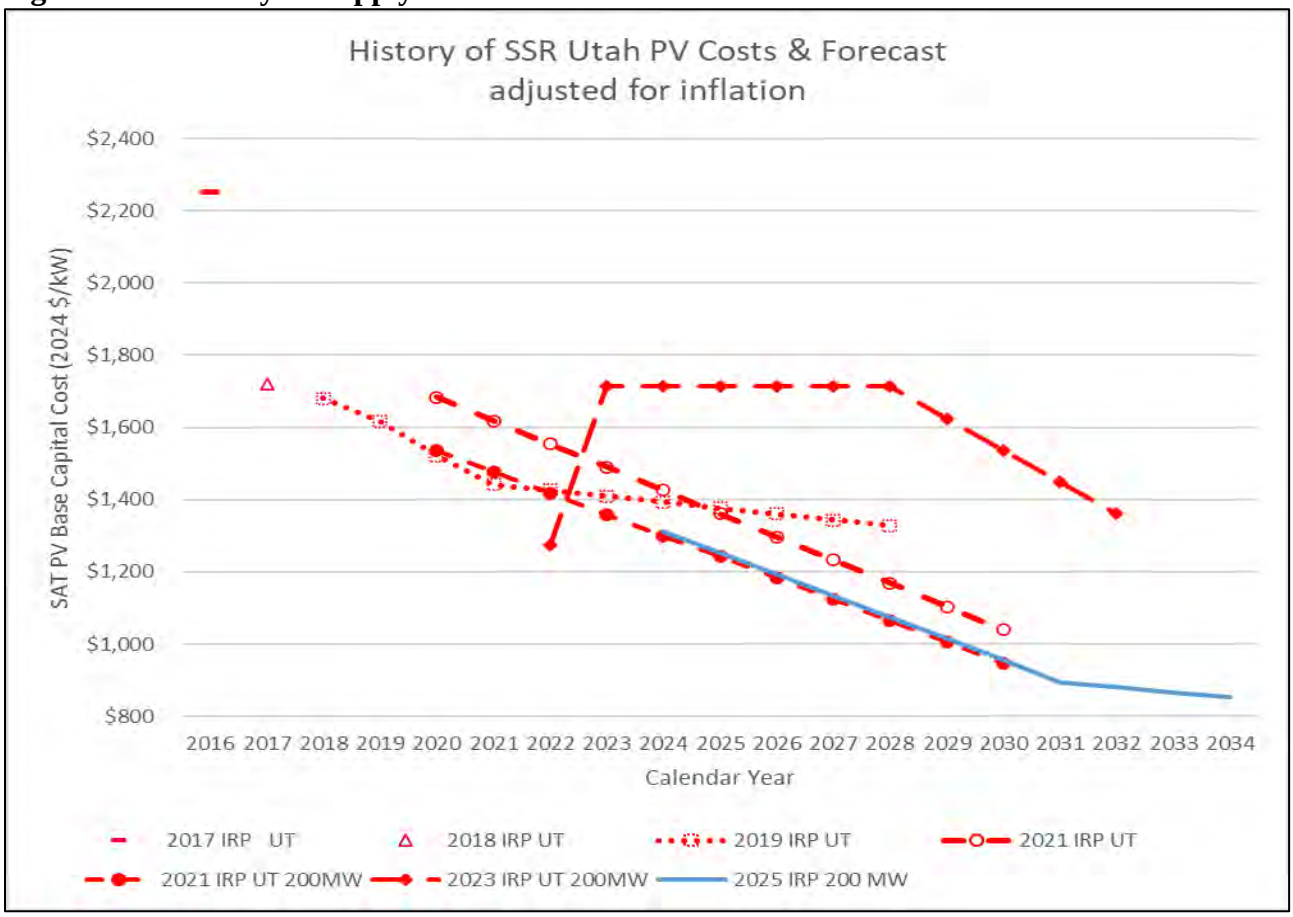
Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options 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).

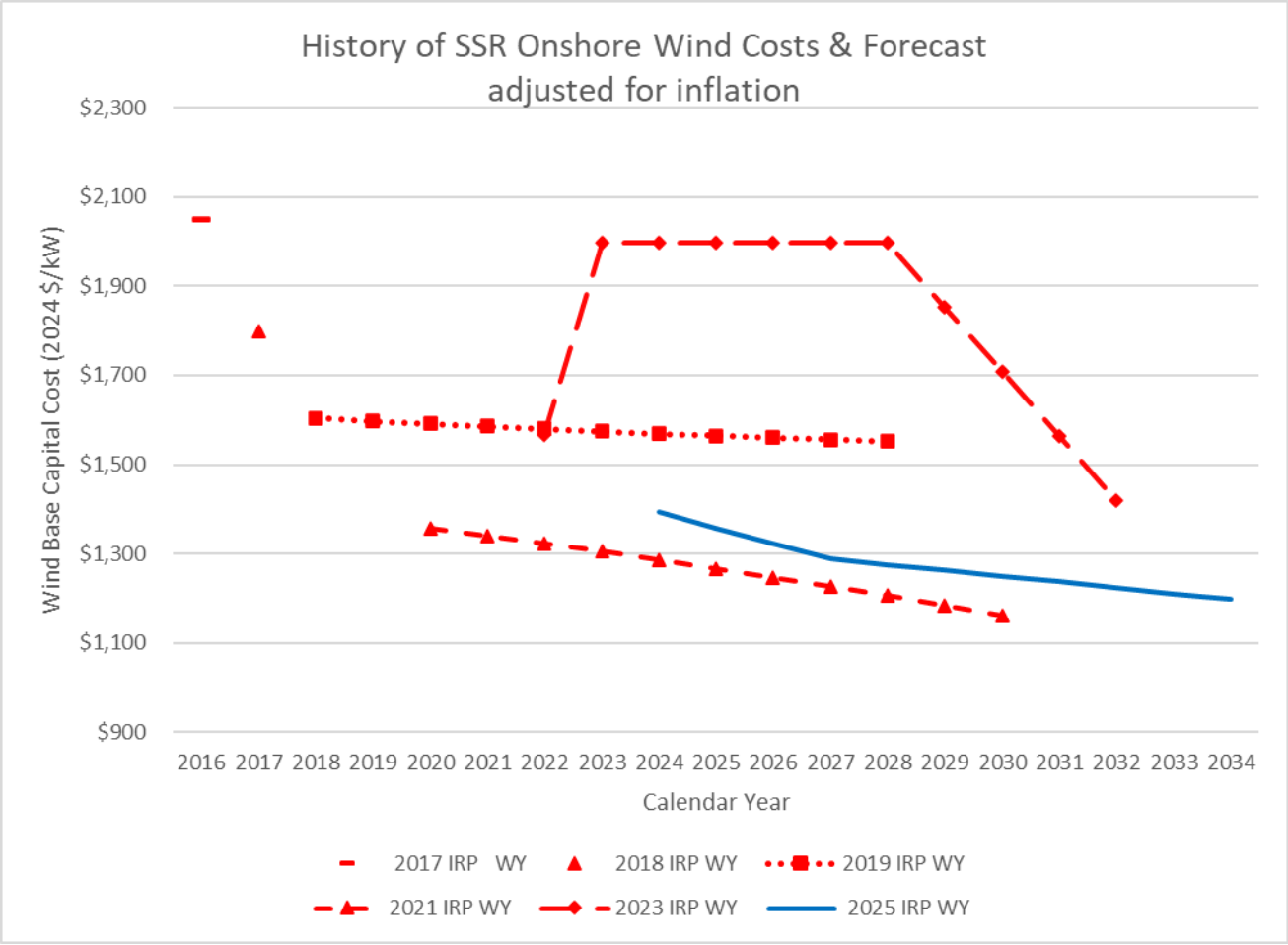
Figure 7.1 – History of Supply-side Resource PV Cost & Forecast



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.

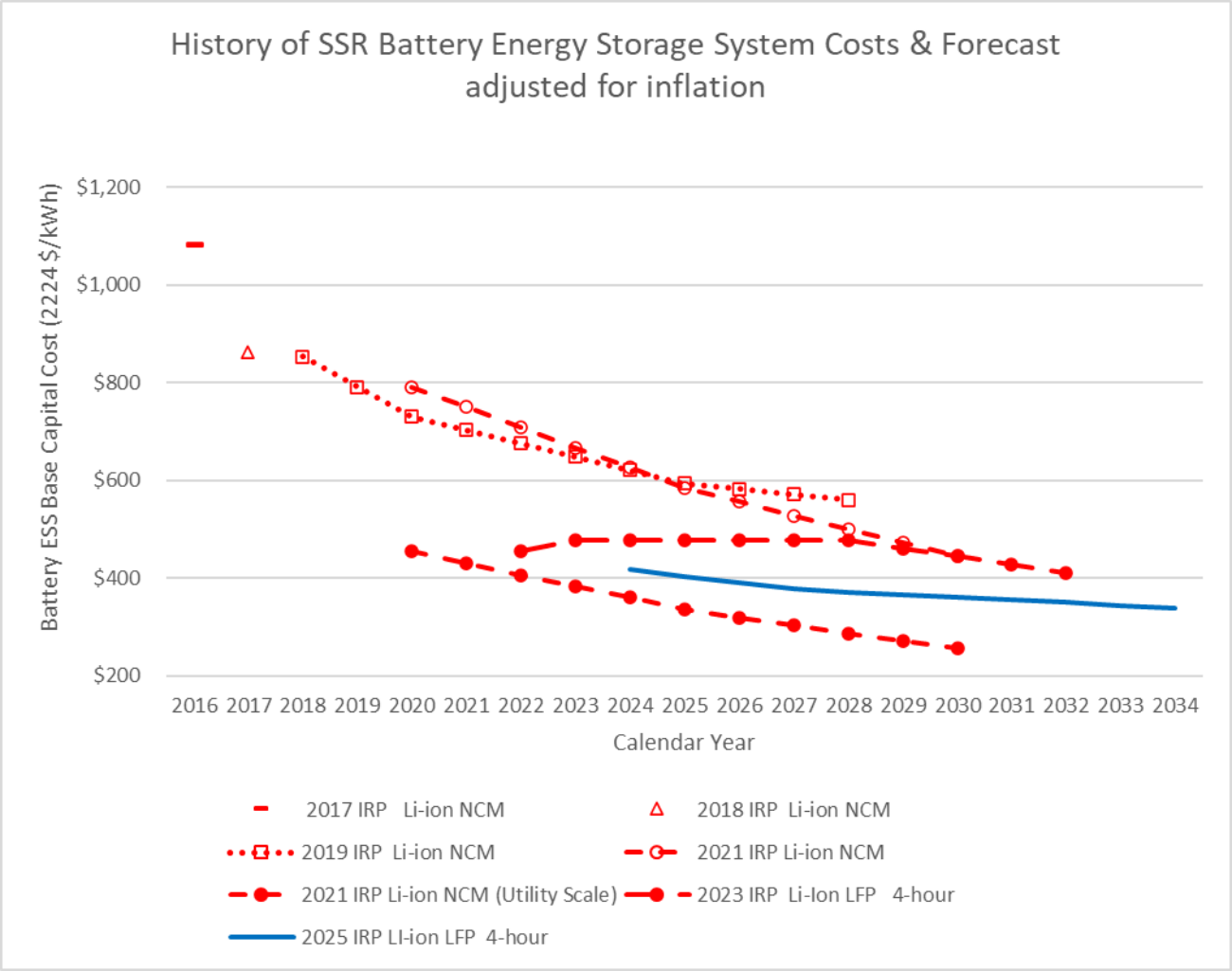
Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast



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 ATB[42]

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.

<u>Demand Response: DSM Capacity Supply Curves</u>

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, Wyoming[48]
- **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 (CO_2) policy scenarios (zero compliance requirements, a high price on CO_2 emissions, and compliance with current Environmental Protection Agency (EPA) CO_2 regulations). An additional CO_2 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 CO_2, high gas and coal/high CO_2, low gas/zero CO_2, 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, CO_2 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 CO_2 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.

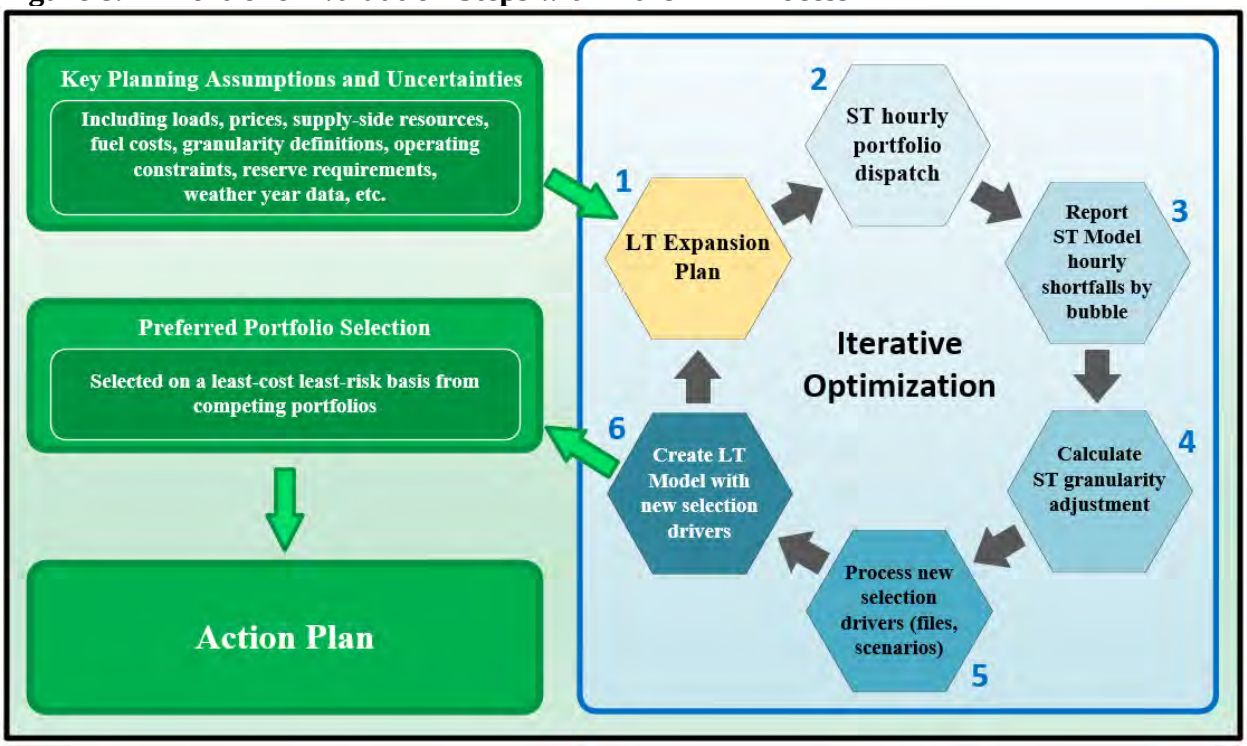
Modeling and Evaluation Steps

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 tools[5], 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.

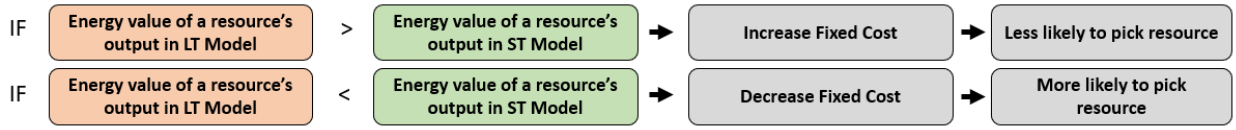
This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

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 CO_2 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, CO_2 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 CO_2), 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.

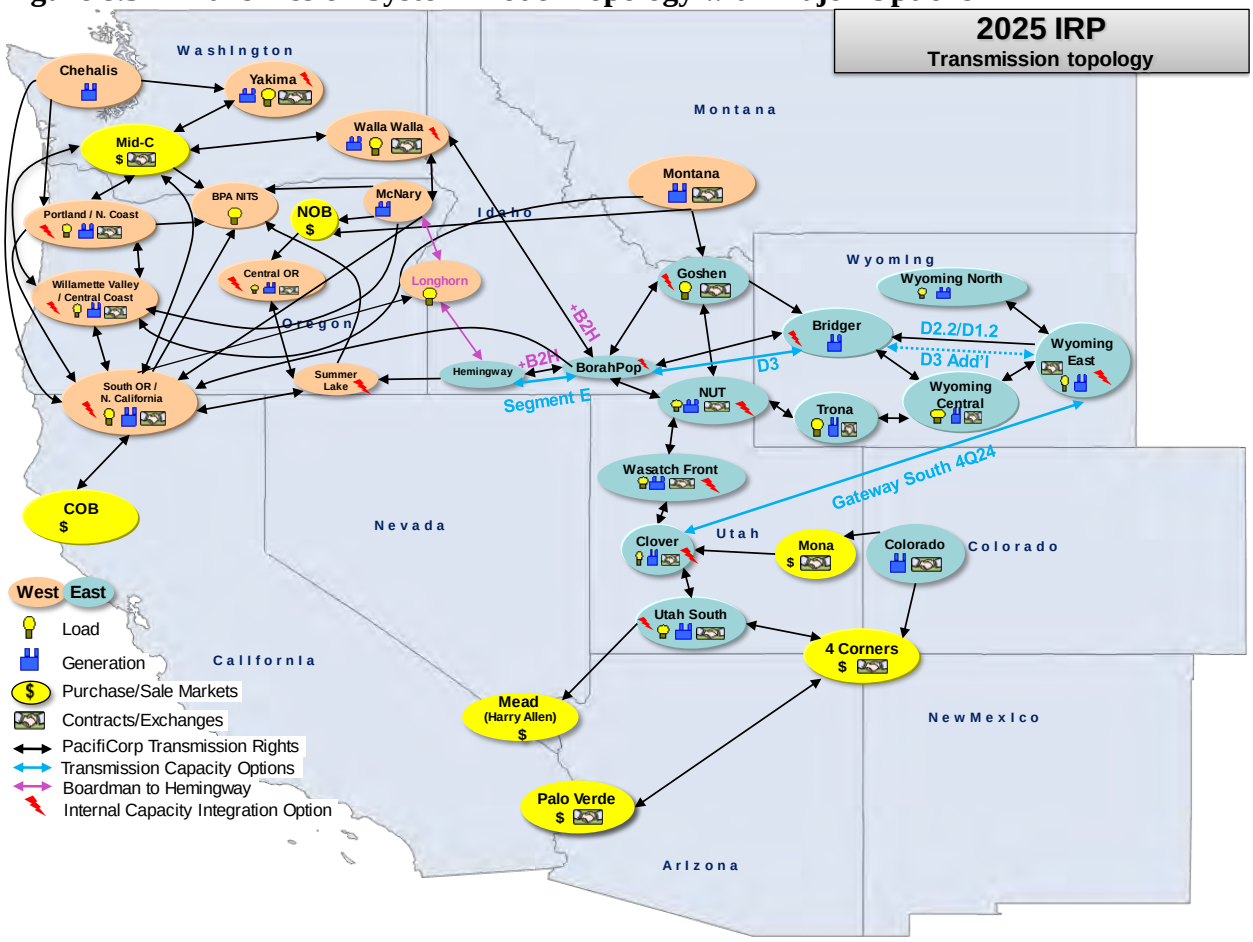
Key modeling elements and inputs for the LT capacity expansion model include the following:

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, it's 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		PAC share moves to Unit 4																			
Colstrip 4	*Includes Unit 3 share*																				
Craig 1																					
Craig 2																					
Hayden 1																					
Hayden 2																					

Key: Default/current operation; Assumed retired

Table 8.3 - Natural Gas Generator Resource Options[14]

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		Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-CO_2-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 CO_2 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.

CO_2 Price Scenarios

PacifiCorp used three different CO_2 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).

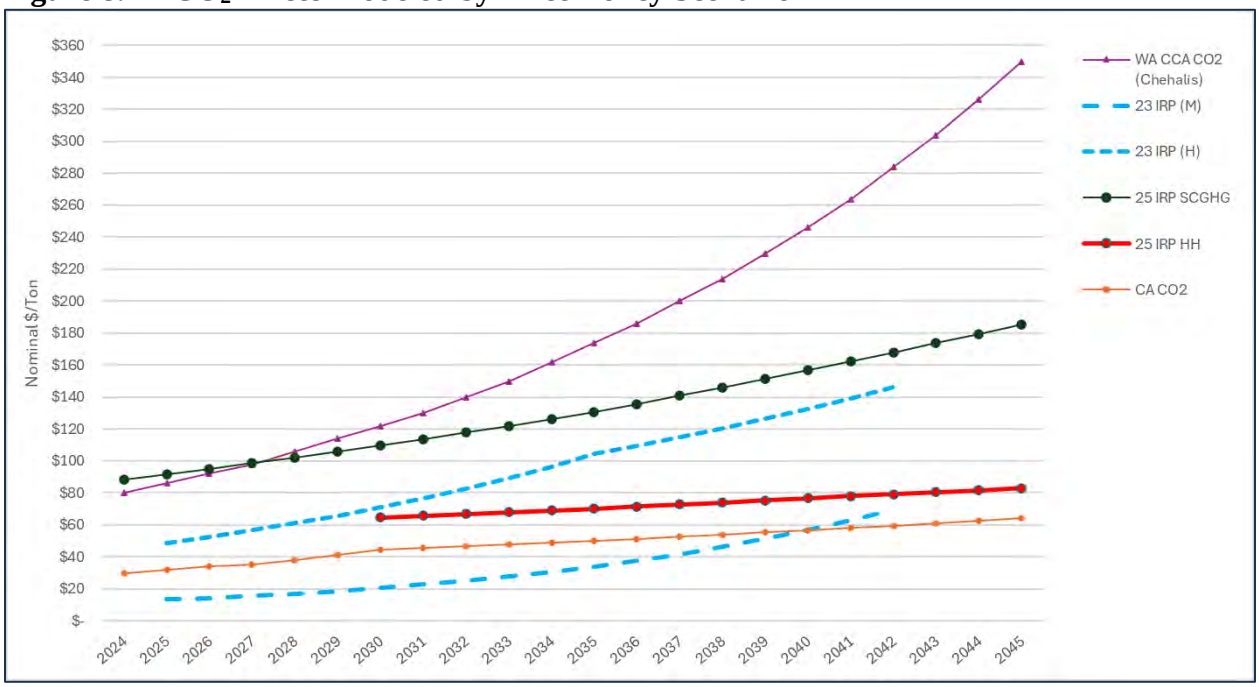
In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.[17] This is in addition to the assumed federal CO_2 policy represented in the 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 – CO_2 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 AURORAxmp[20] (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

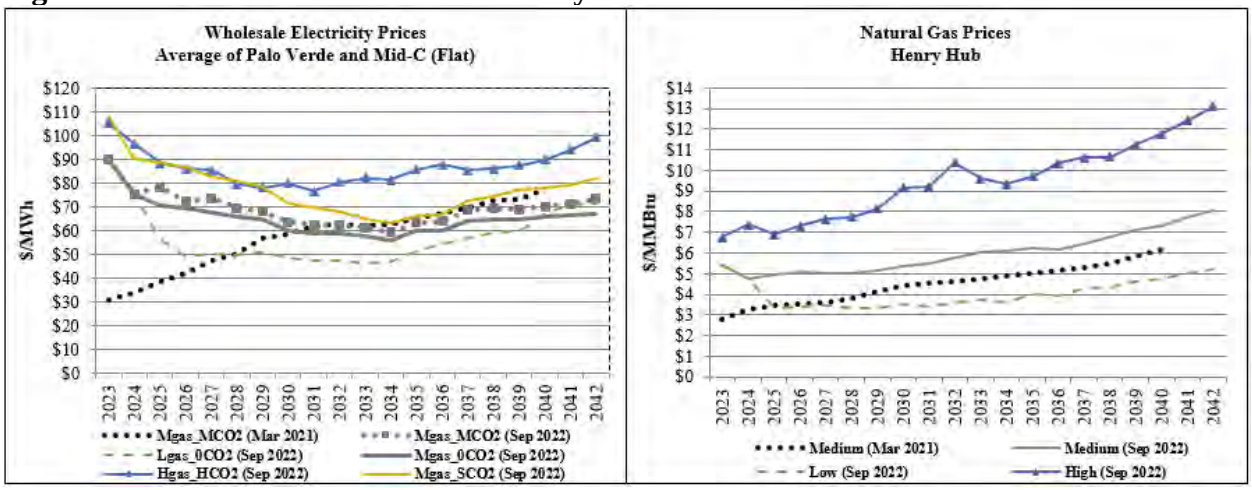
[19] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[20] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

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 CO_2 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
- 5^{th}, 90^{th} and 95^{th} 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 CO_2 emission costs for any scenarios that include a CO_2 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 CO_2 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 PVRRs) 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 PVRR 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, CO_2 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 CO_2 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 CO_2 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 CO_2-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 CO_2regulations
- MR: Medium natural gas/current federal CO_2 regulations under Section 111 of the Clean Air Act.
- LN: Low natural gas/No federal CO_2 regulations.
- HH: High natural gas/High CO_2 cost applied to all generators (updated CO_2 forecast, starting 2030) with no other federal CO_2 regulations.
- SC: Medium natural gas/Social cost of greenhouse gases (starting immediately) from Washington docket U-190730 with no other federal CO_2 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 CO_2 cost included in each price-policy scenario. Where applicable, the price-policy scenarios above represent CO_2 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 CO_2 (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 CO_2 regulations. For the 2025 IRP the MR price-policy scenario, which was not included in the 2023 IRP, encompasses federal CO_2 regulations. This

price-policy scenario was added in response to the final CO_2 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 interest[23], 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

Jurisidiction	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 Othe 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.

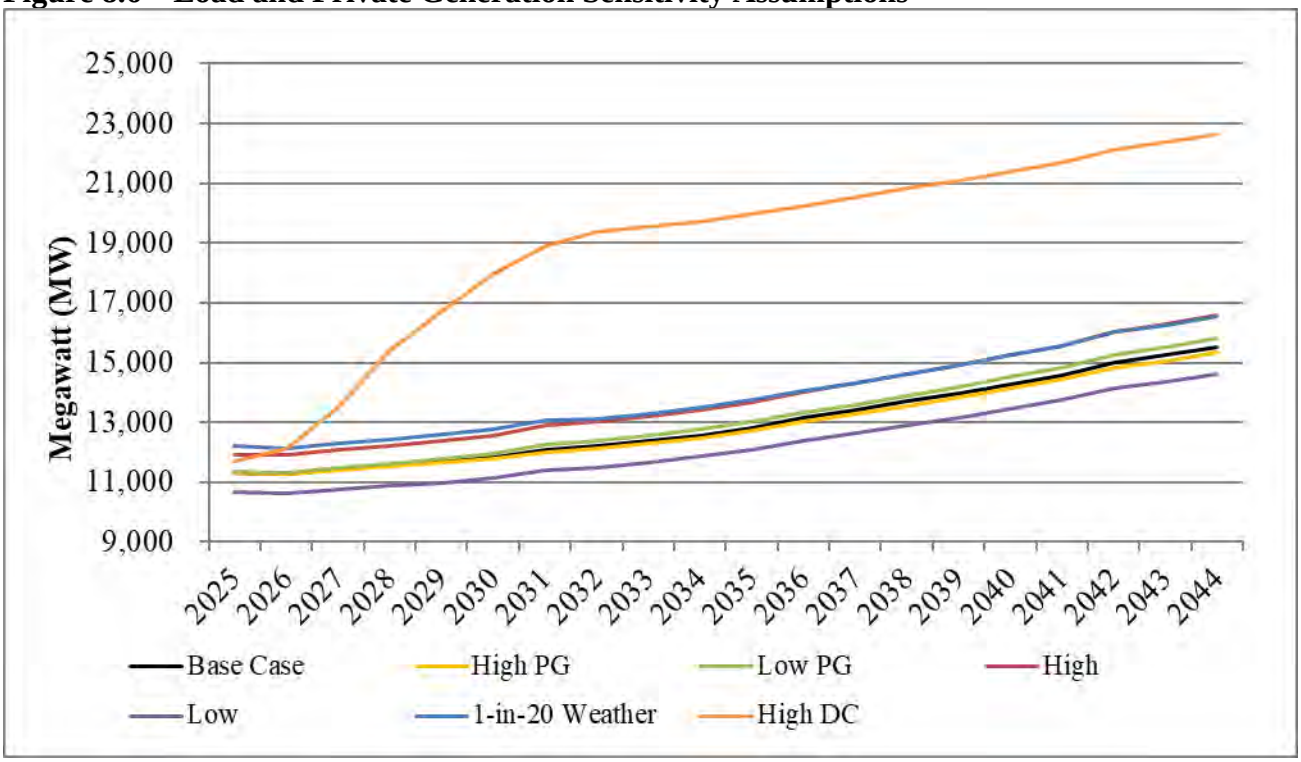
Table 8.7 – Sensitivity Case Definitions

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 Usual[25] (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

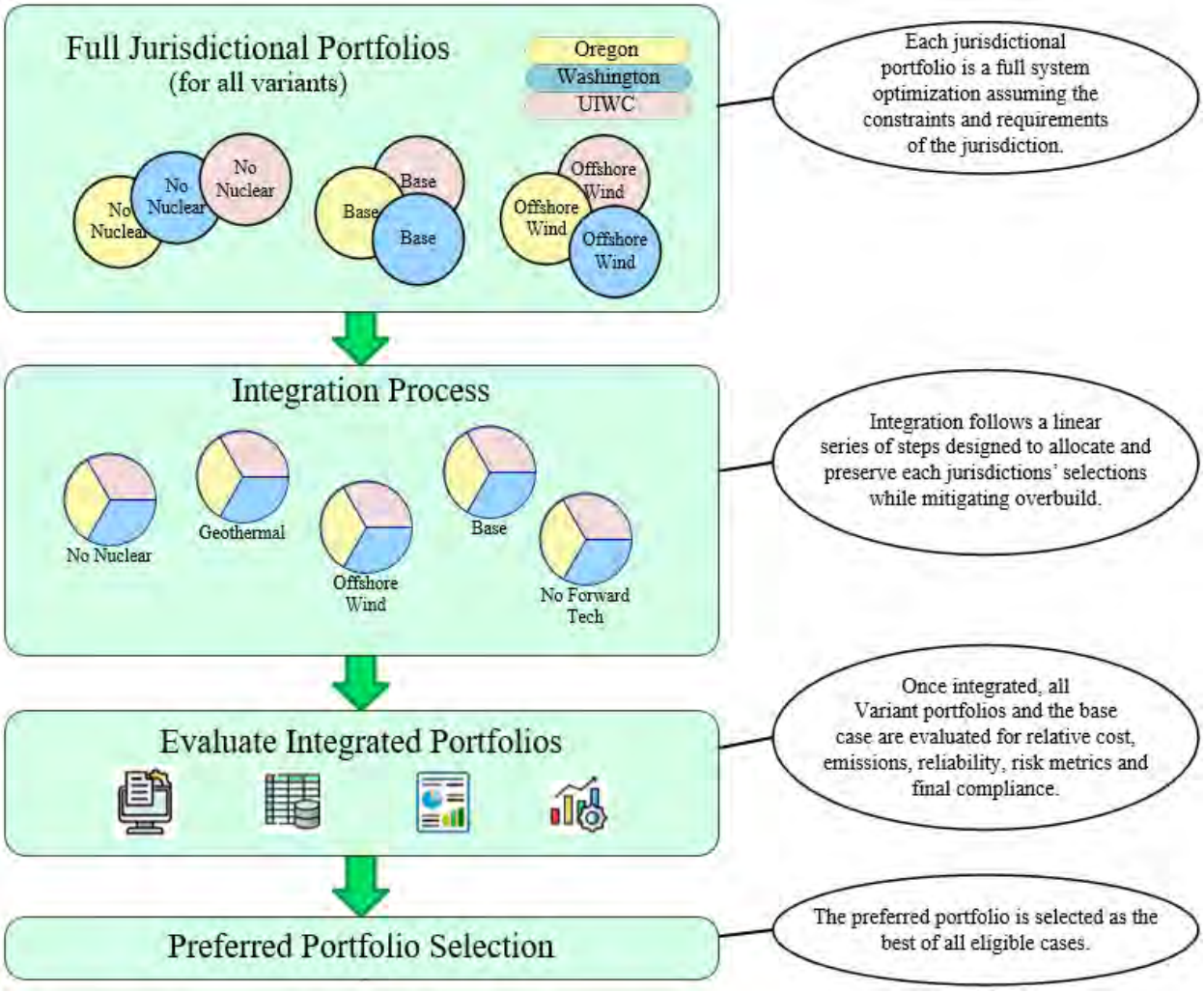
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis 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^{TM} 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 CO_2 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 CO_2 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 CO_2 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																						
	Installed Capacity, MW																					
Resource	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 Acceleration[2]				***794***		***(794)***																

Table 9.3 – Washington Share[4]

WA Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	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 Acceleration[4]				***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																						
	Installed Capacity, MW																					
Resource	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																						
	Installed Capacity, MW																					
Resource	**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																						
	Installed Capacity, MW																					
Resource	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

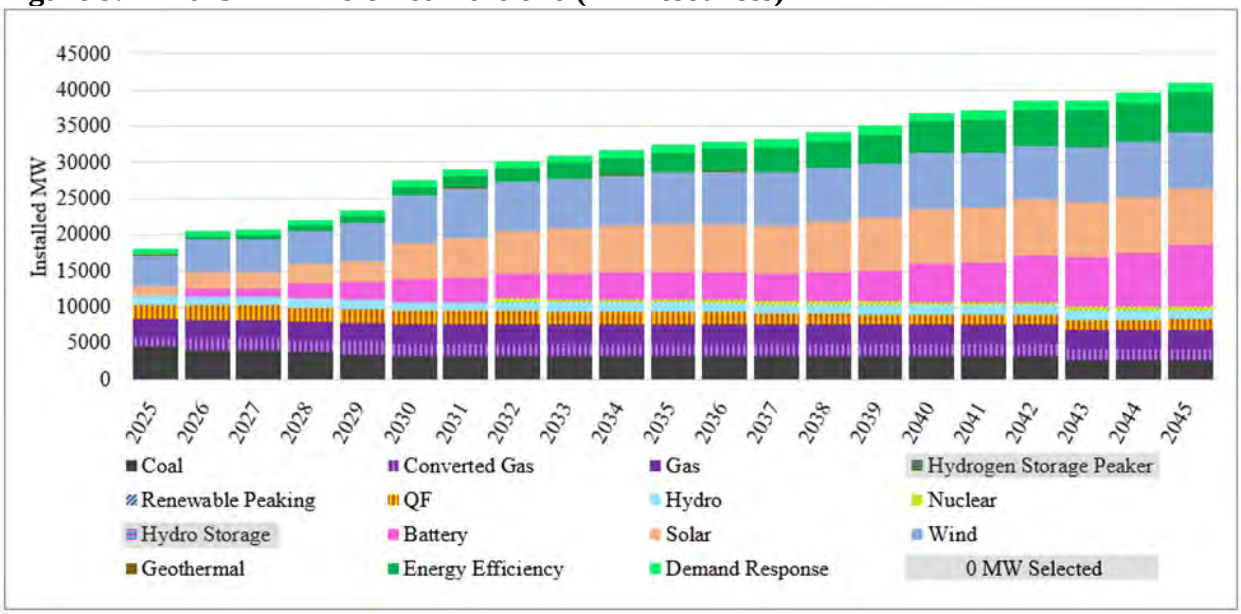
Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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**			

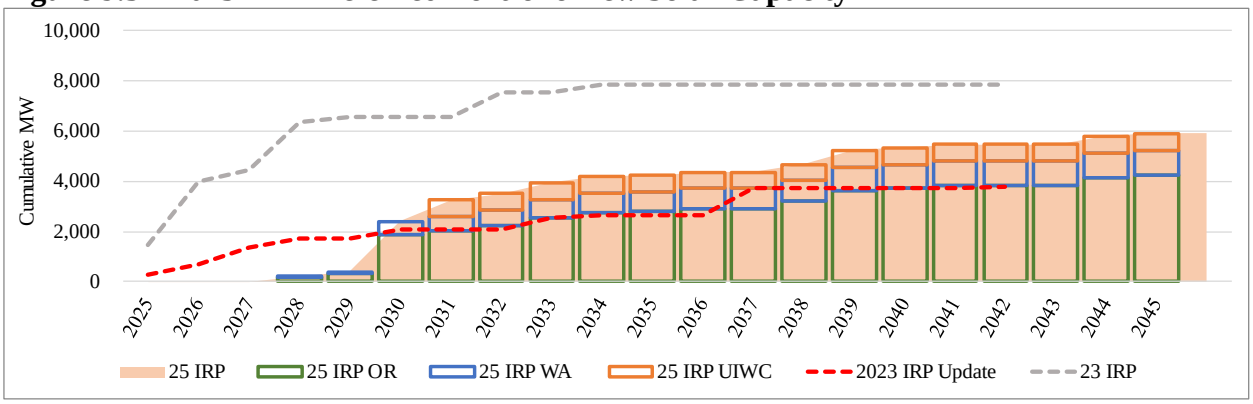
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource 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.

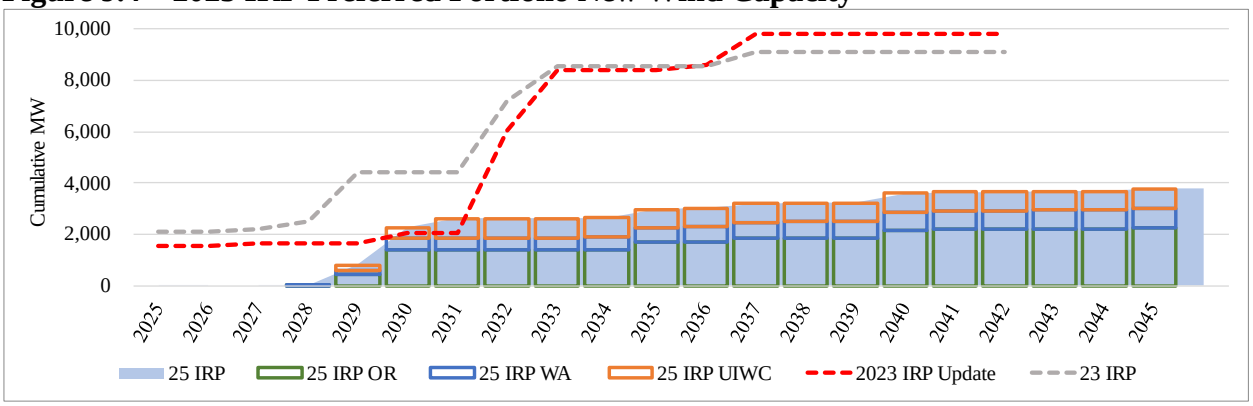
Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity



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.

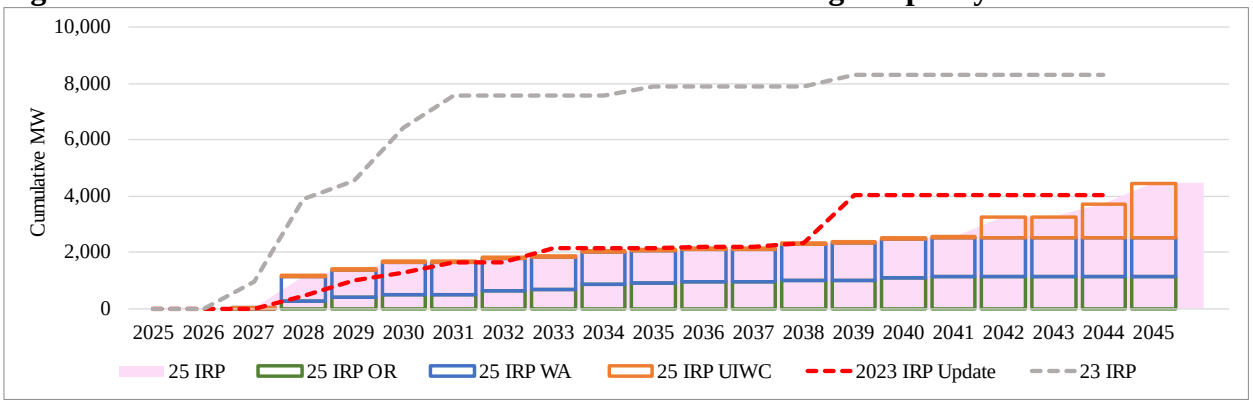
Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

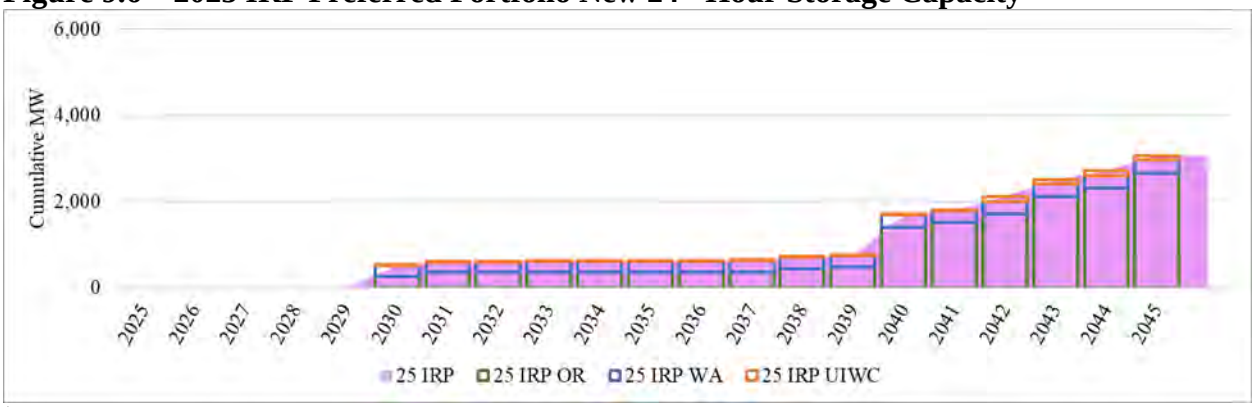
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 9.5 and 9.X. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio 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 Capacity[1]

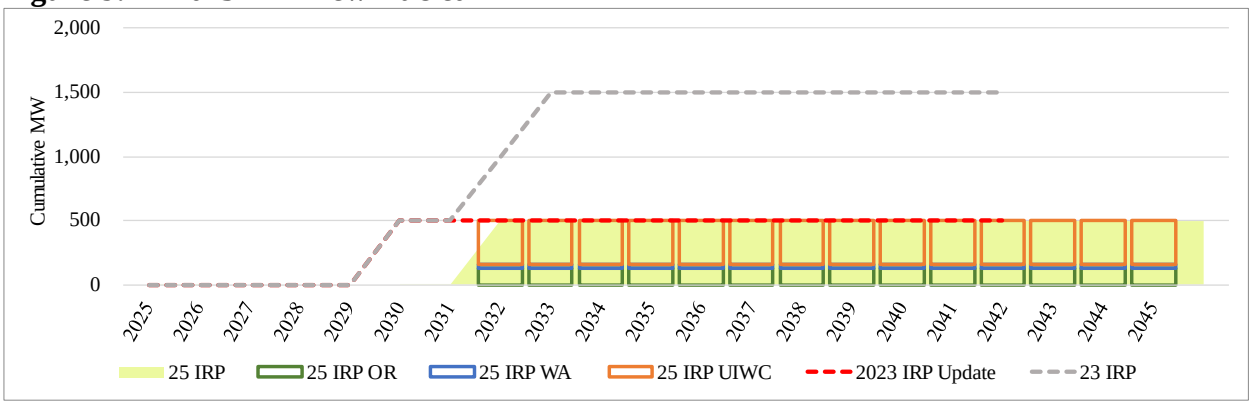


[1]The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

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 Nuclear[1]



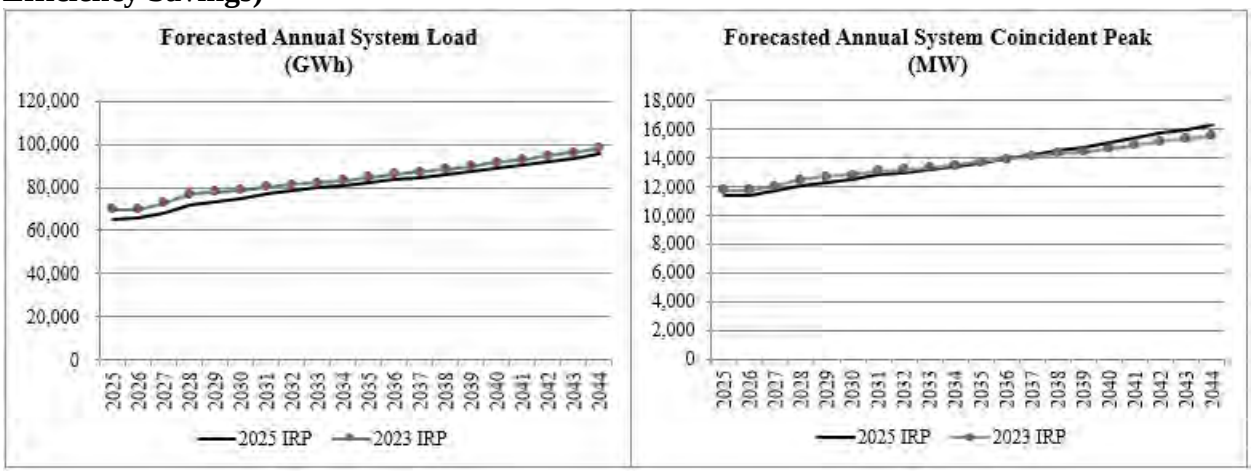
[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

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)

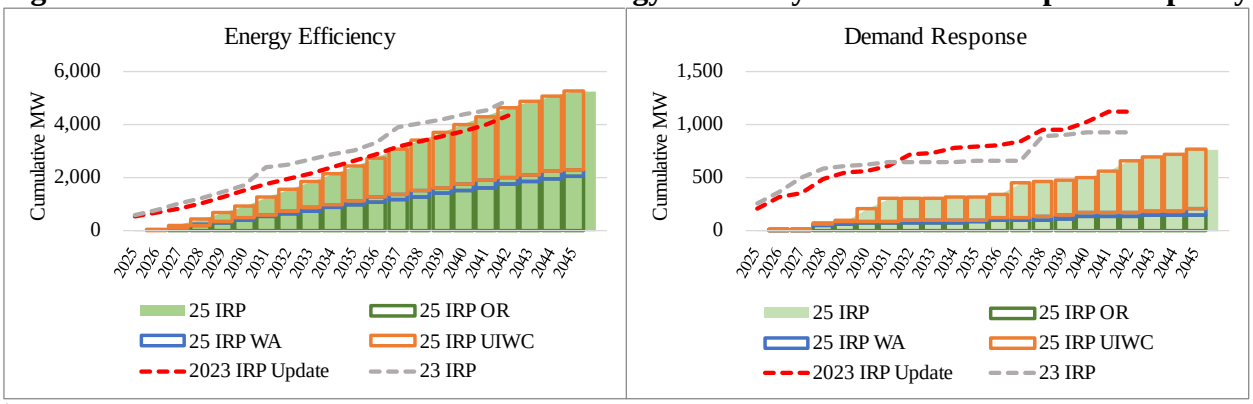


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 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

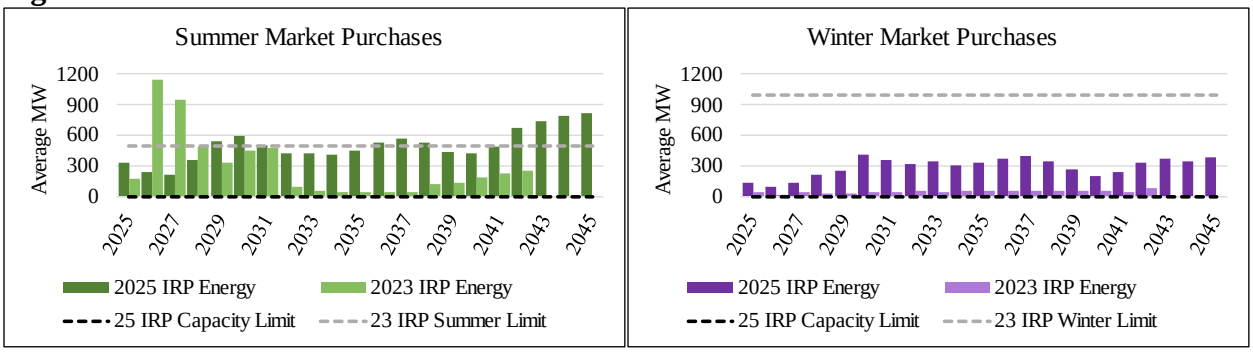
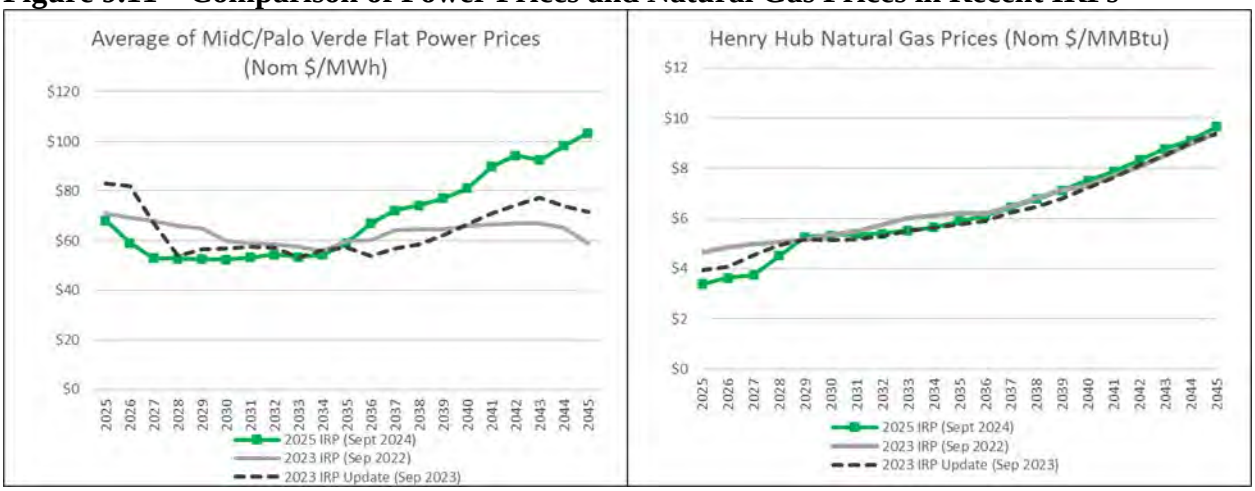


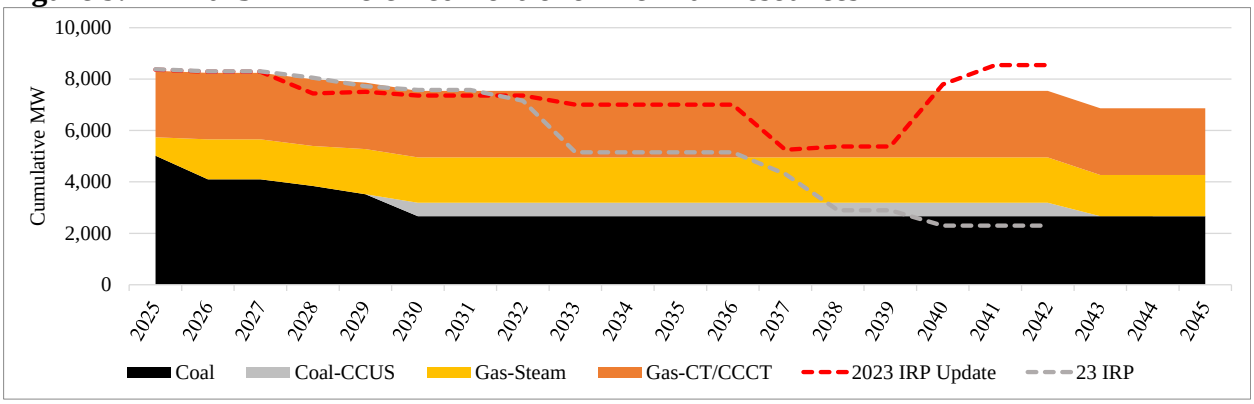
Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



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 (CO_2e) 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 CO_2e 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-

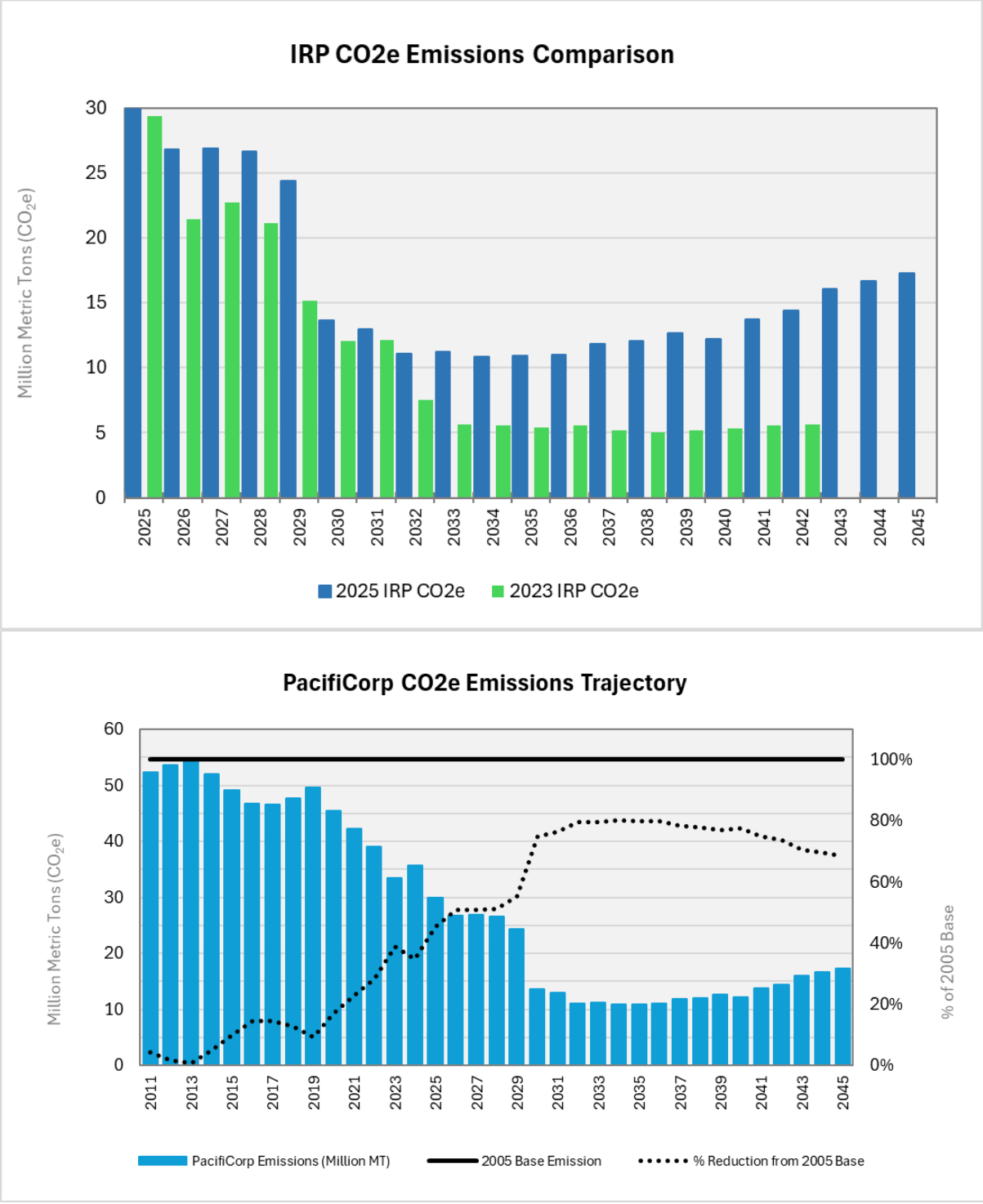
[6] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

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 CO_2 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 Trajectory[1]



[1] PacifiCorp CO_2 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 CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed.

Renewable Portfolio Standards

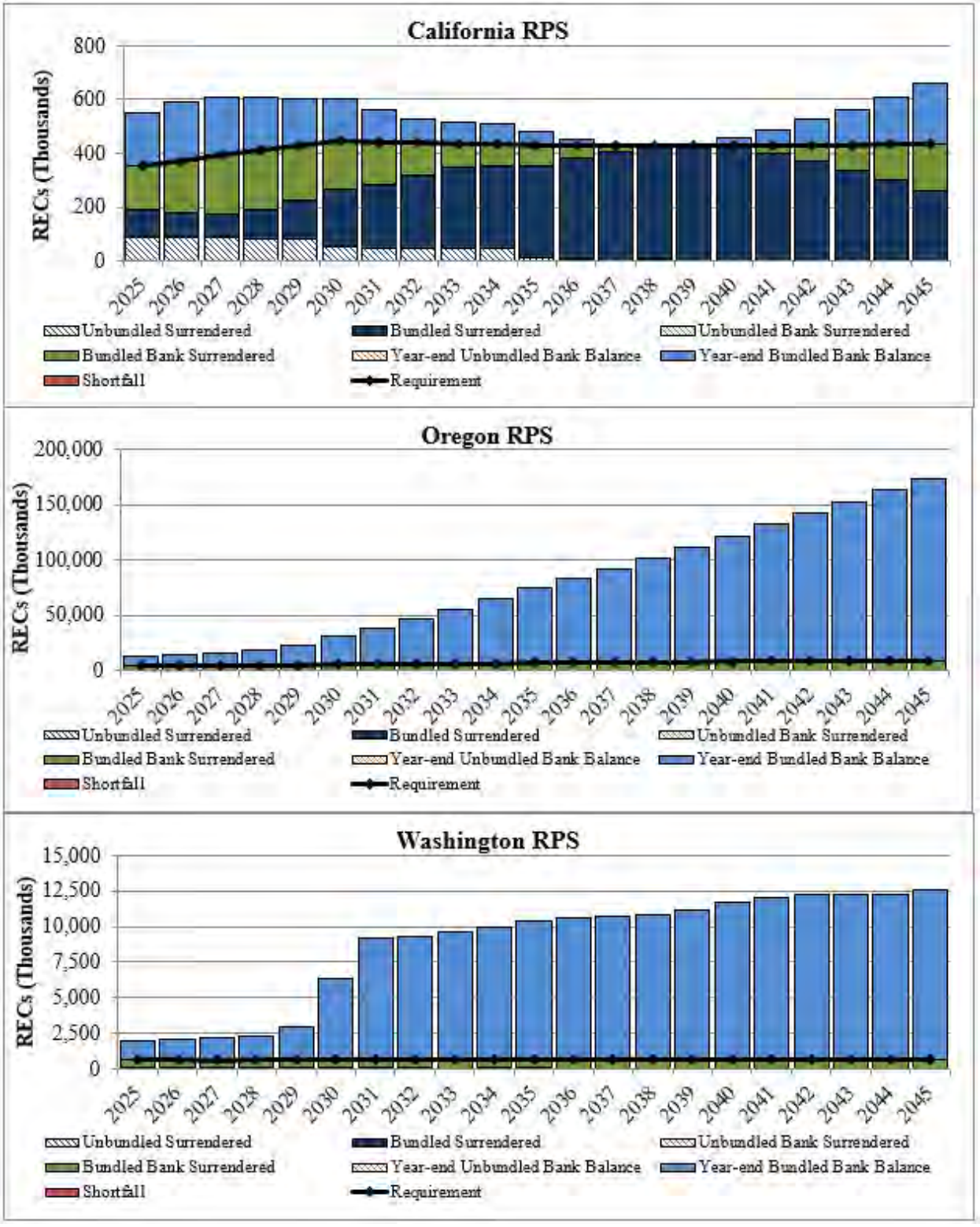
Figure 9.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective 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 (CO_2e) to 1.79 MMT CO_2e by 2030, 0.89 MMT CO_2e 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.

[7]The projected PacifiCorpIRP 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'sIRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.15 – Projected Energy Mix with Preferred Portfolio Resources

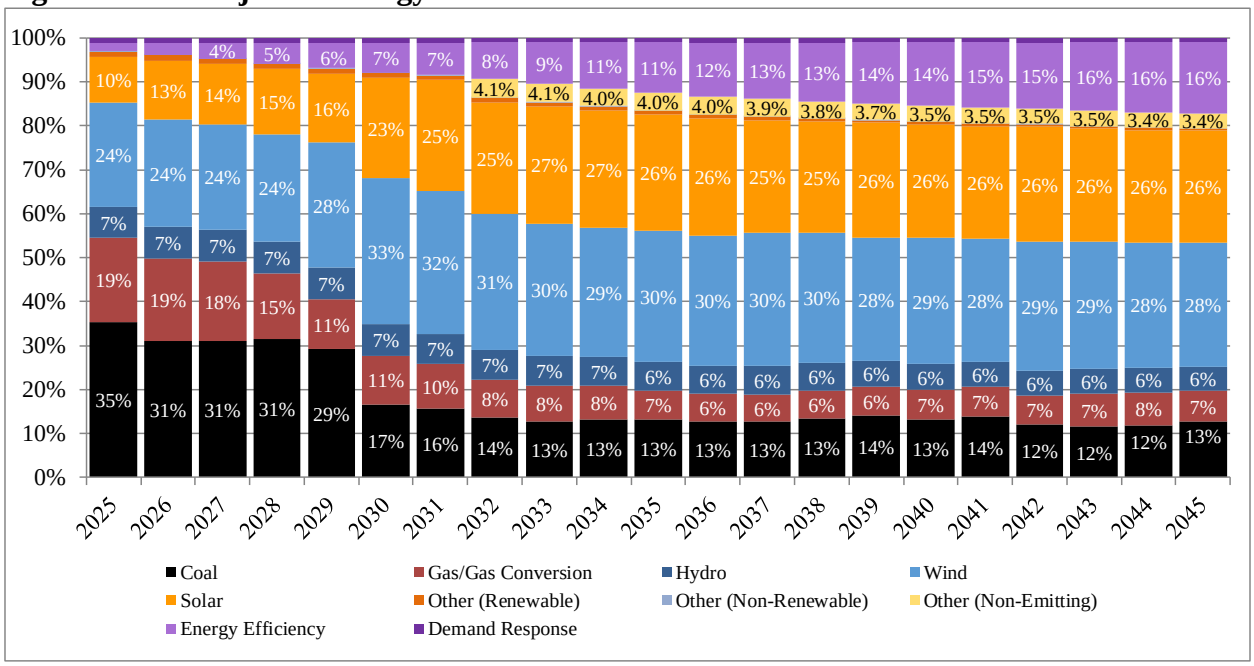
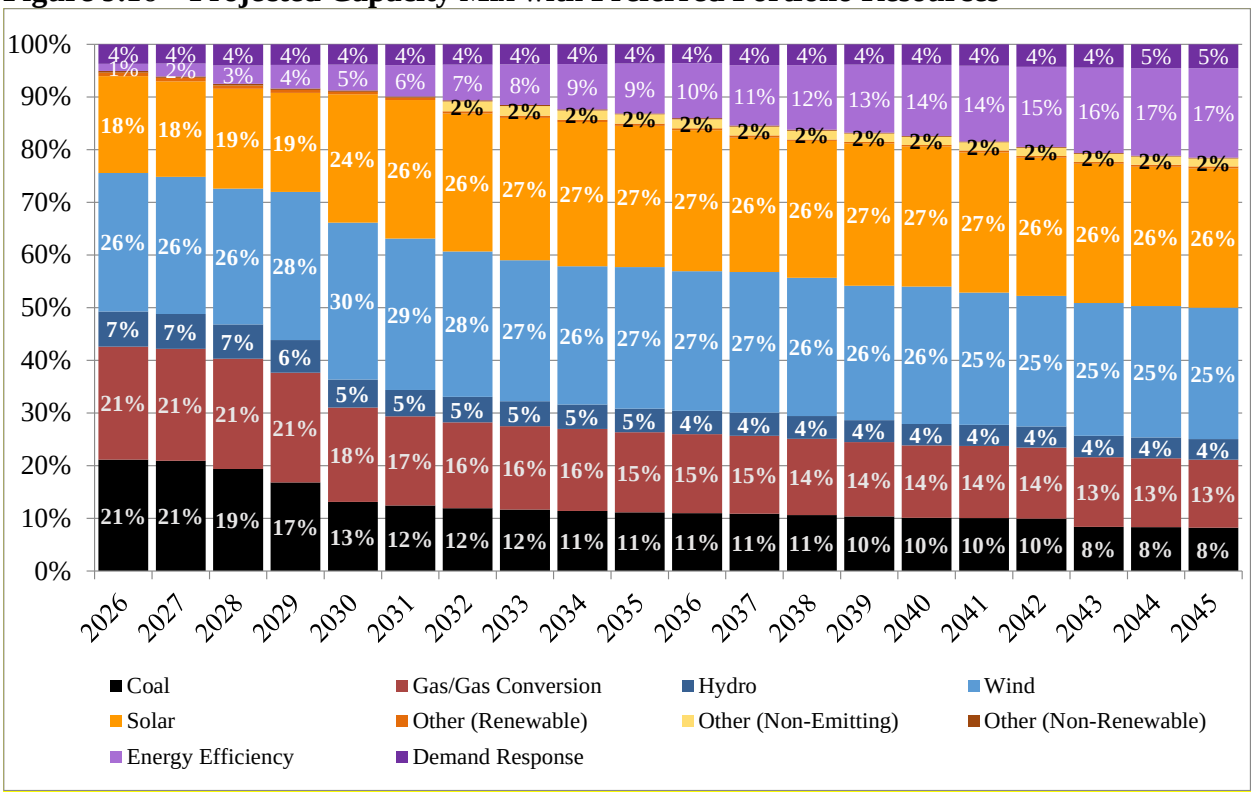


Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources



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																						
	Installed Capacity, MW																					
Resource	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	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,436
DSM - Demand Response	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	789
Renewable - Wind	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
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
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
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	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
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**	**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

	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
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 Purchas	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 Purchas	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 Purchas	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 Purchas	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 Gas[1]

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 - Nuclear[1]

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 Peaking[1]

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 Wind[1]

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 Wind[1]

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 Solar[1]

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 Solar[1]

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 hour [1]

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 hour[1]

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+ hour [1]

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 Retirements[1]

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 Retirements[1]

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)

[1]Only 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 CO_2) 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 CO_2

	ST Value			Risk Adjusted			With End Effects			CO2 Emissions		
Case - MN	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 CO_2) price-policy scenario.

Table 9.35 –Integrated Portfolios Under Low Gas/ Zero CO_2

	ST Value			CO2 Emissions		
Case - LN	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 CO_2) price-policy scenario.

Table 9.36 – Integrated Portfolios Under High Gas and Coal/ High CO_2

	ST Value			CO2 Emissions		
Case - HH	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 CO_2

	ST Value			CO2 Emissions		
Case - SC	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

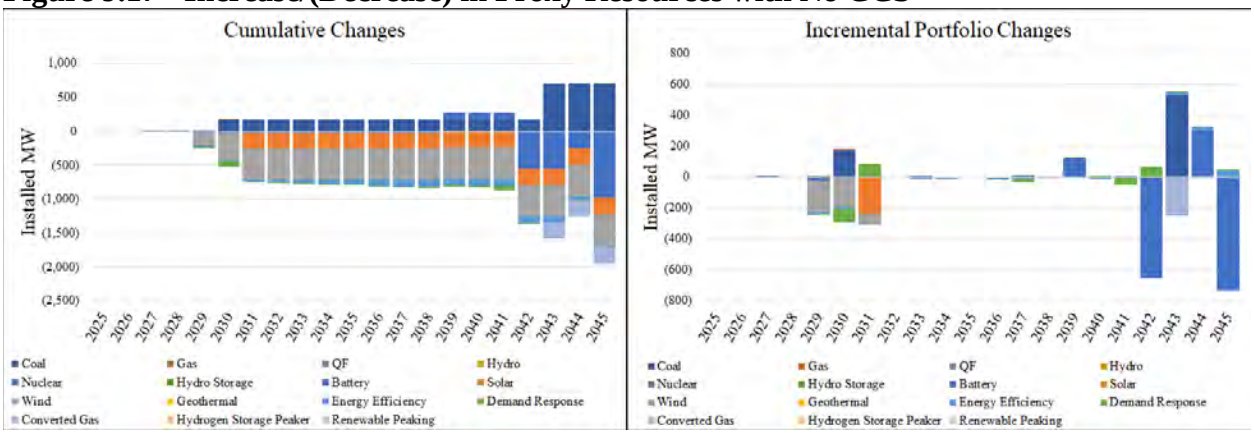
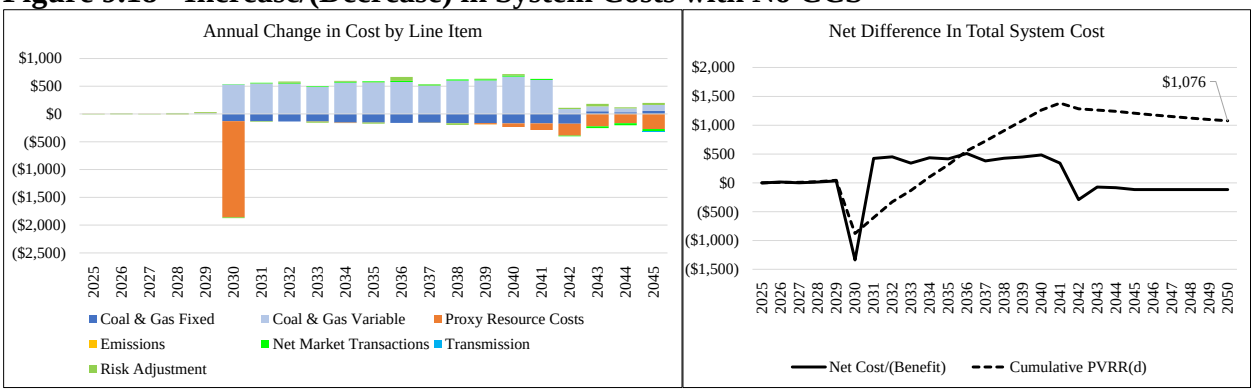


Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

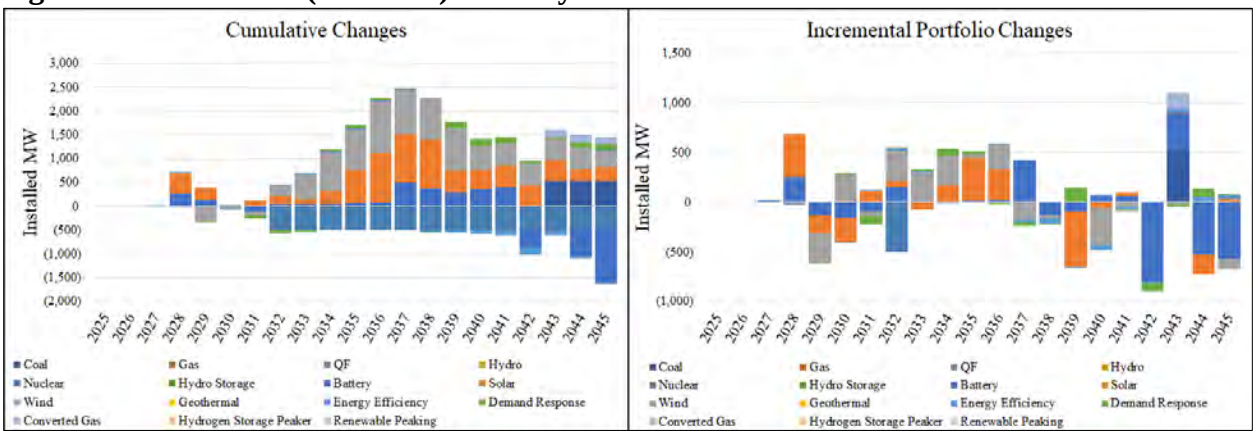
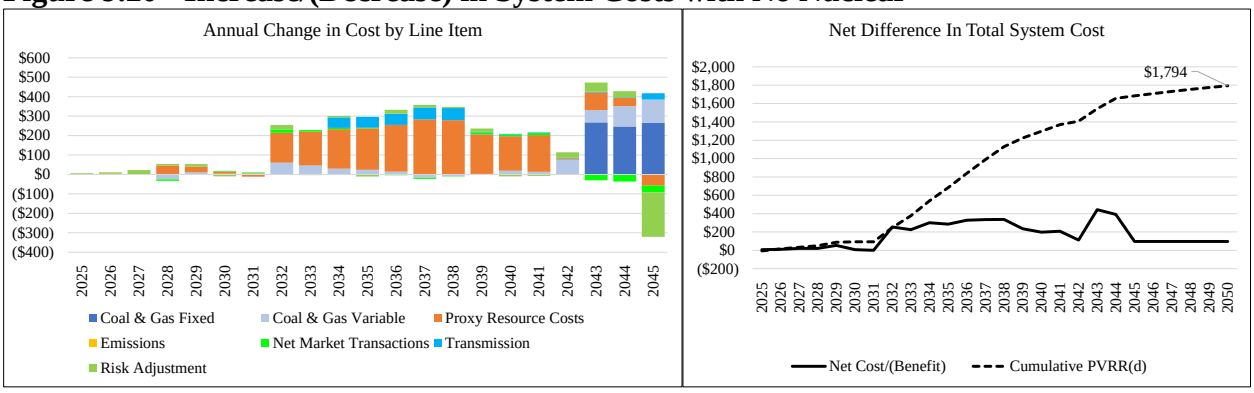


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid 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

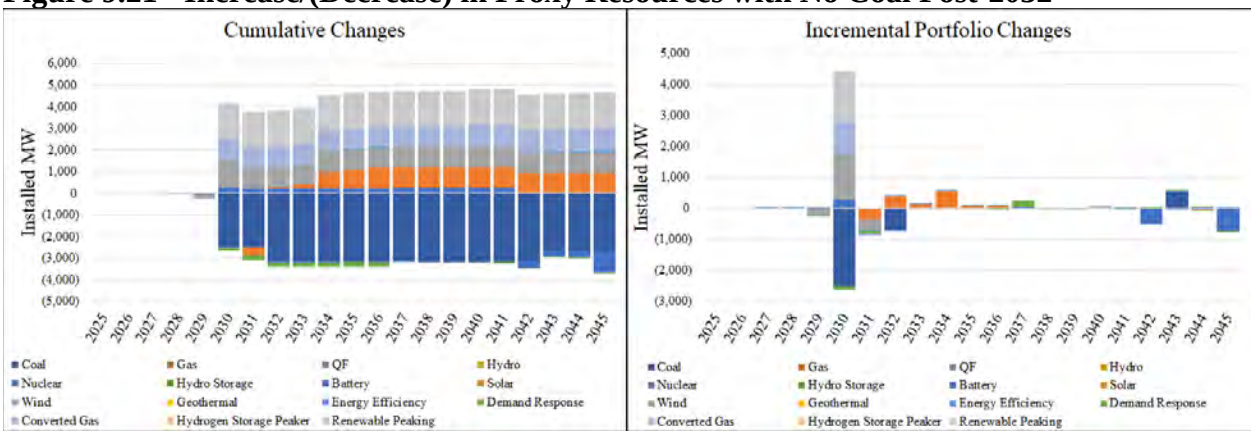
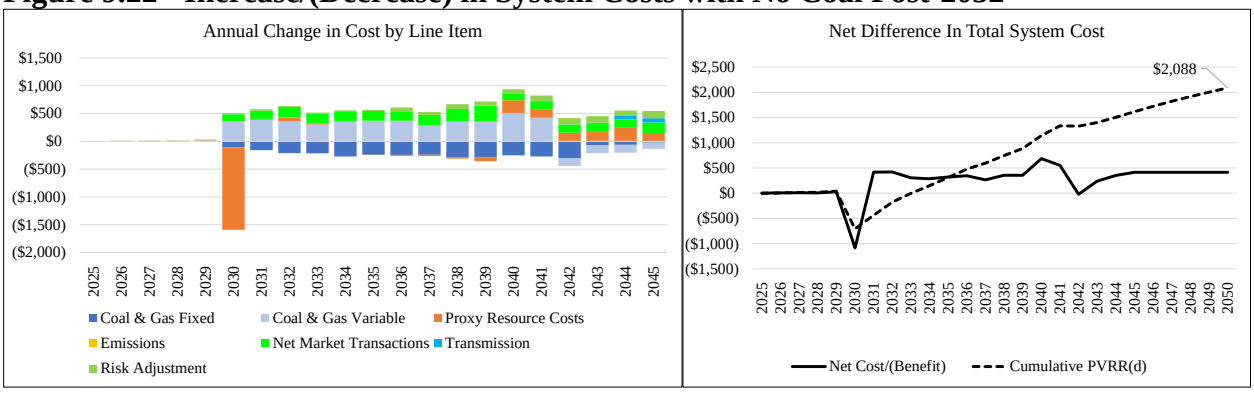


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the 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

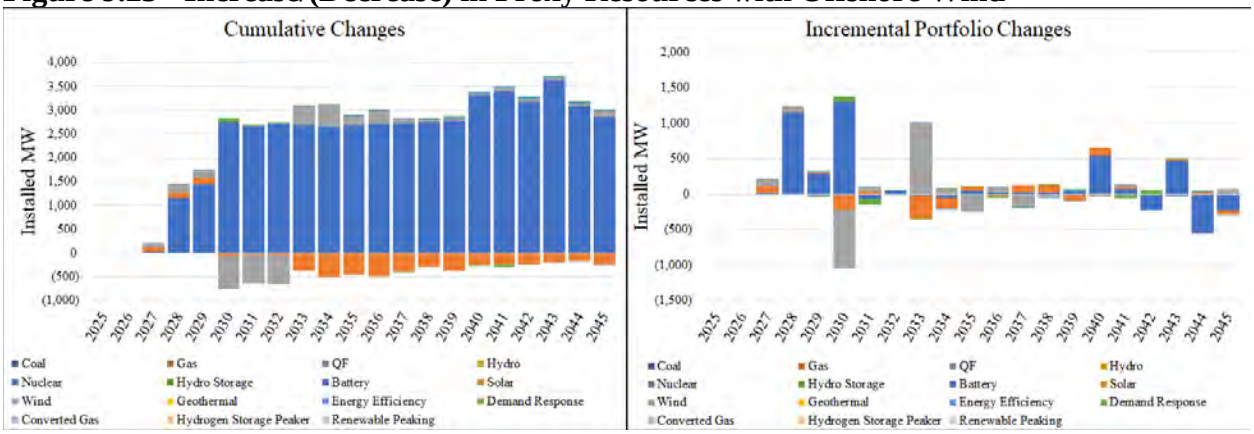
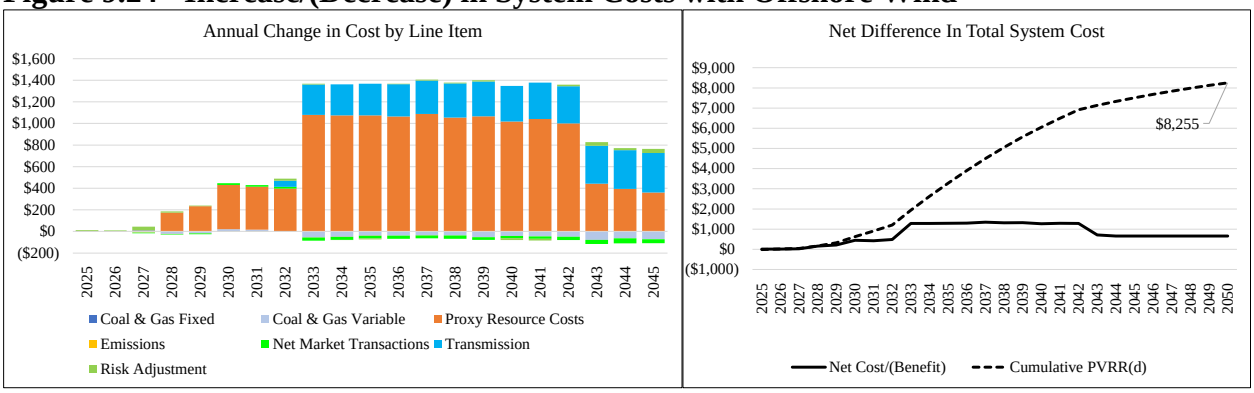


Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total 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

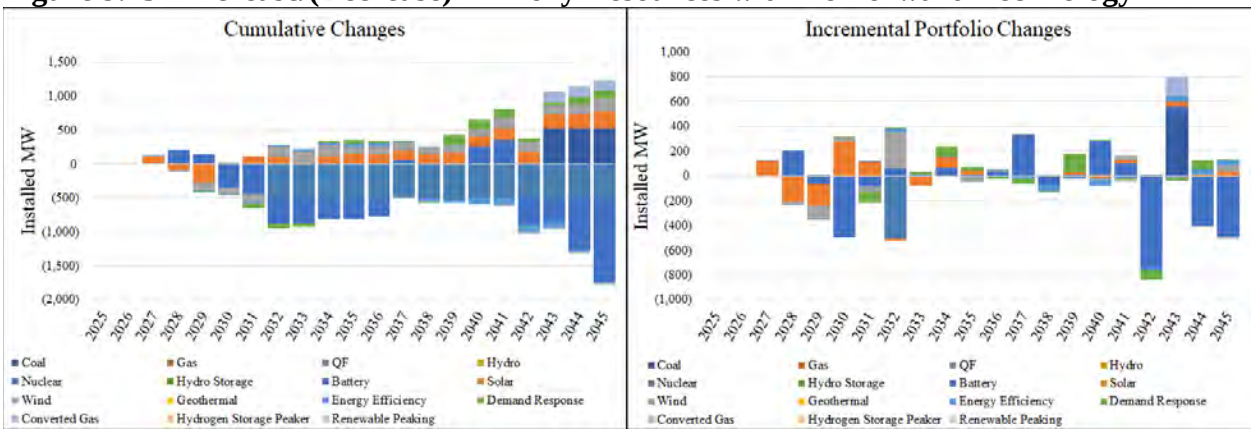
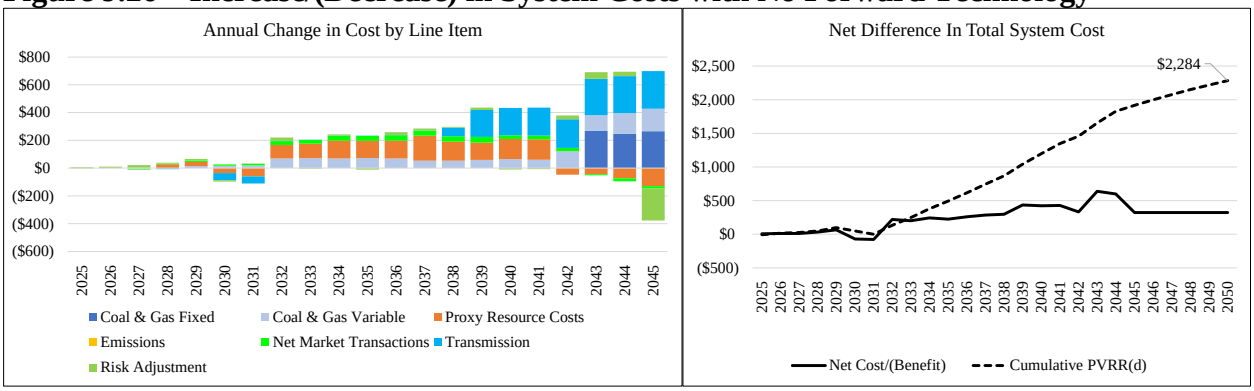


Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the 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

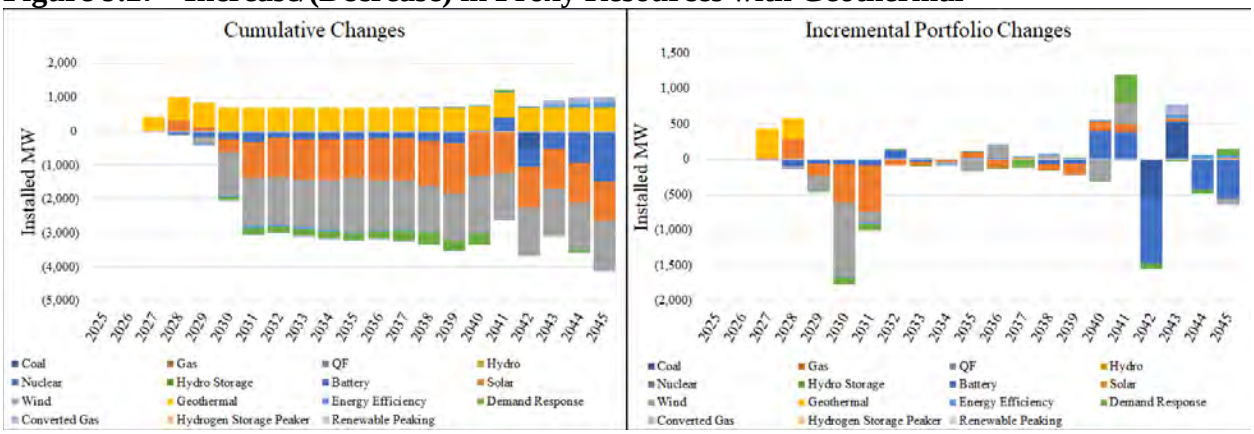
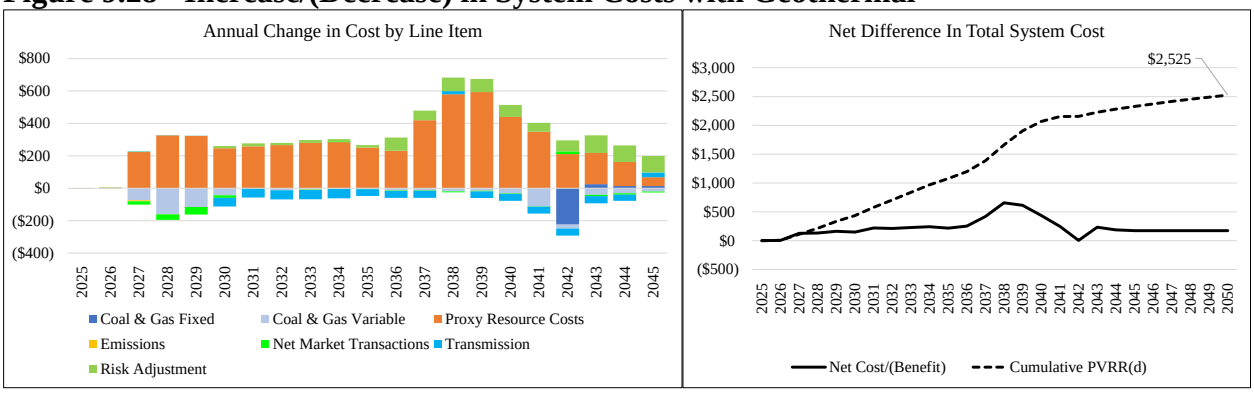


Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total 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

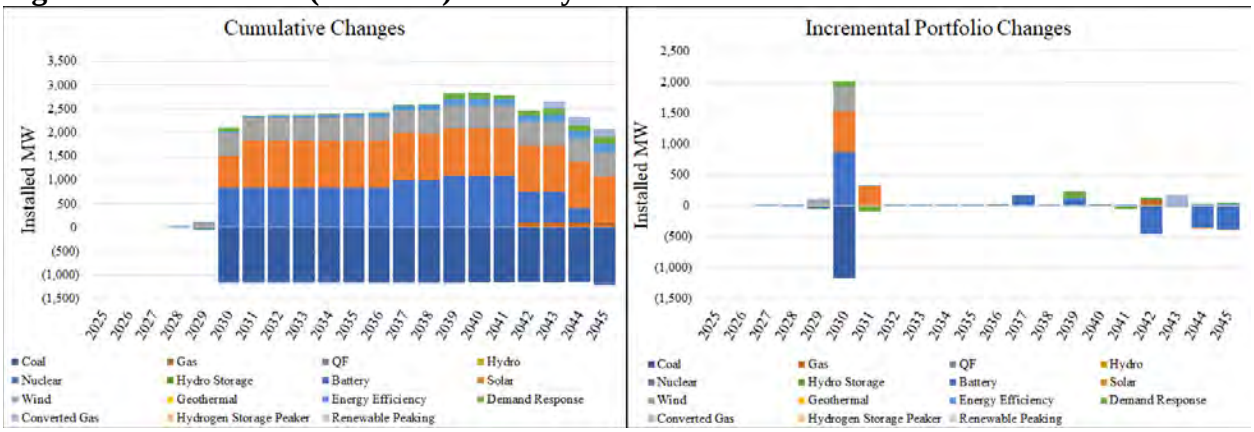
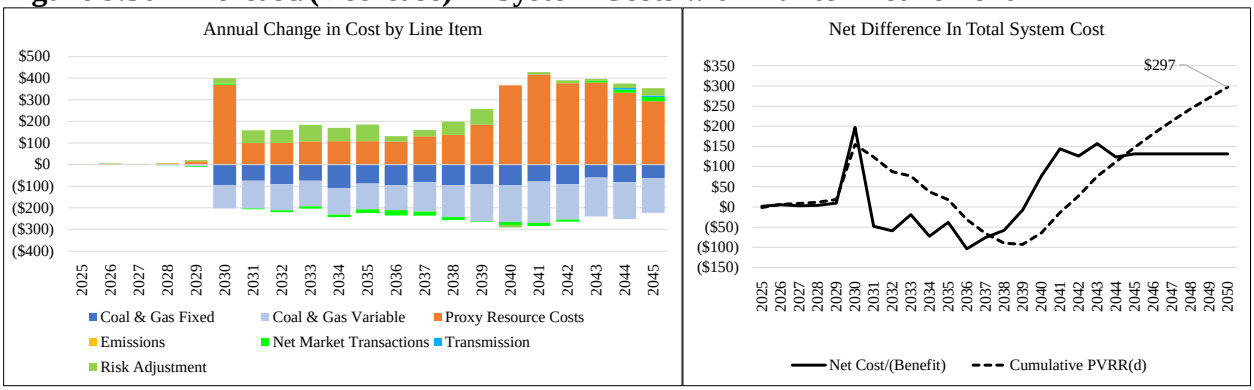


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

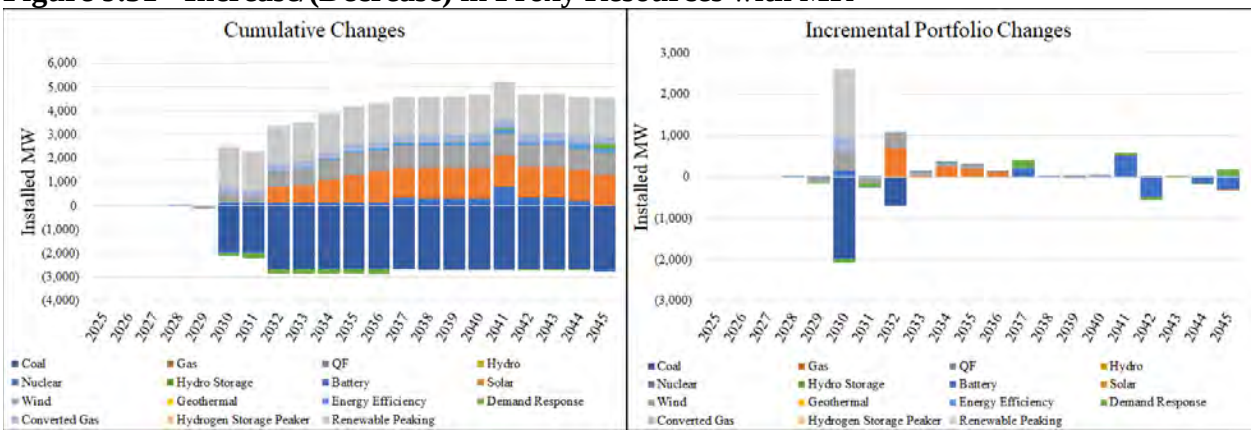
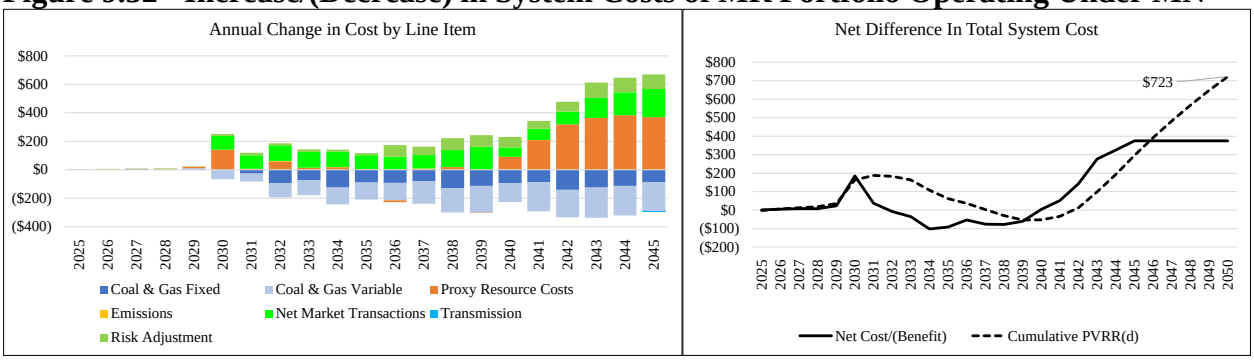


Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

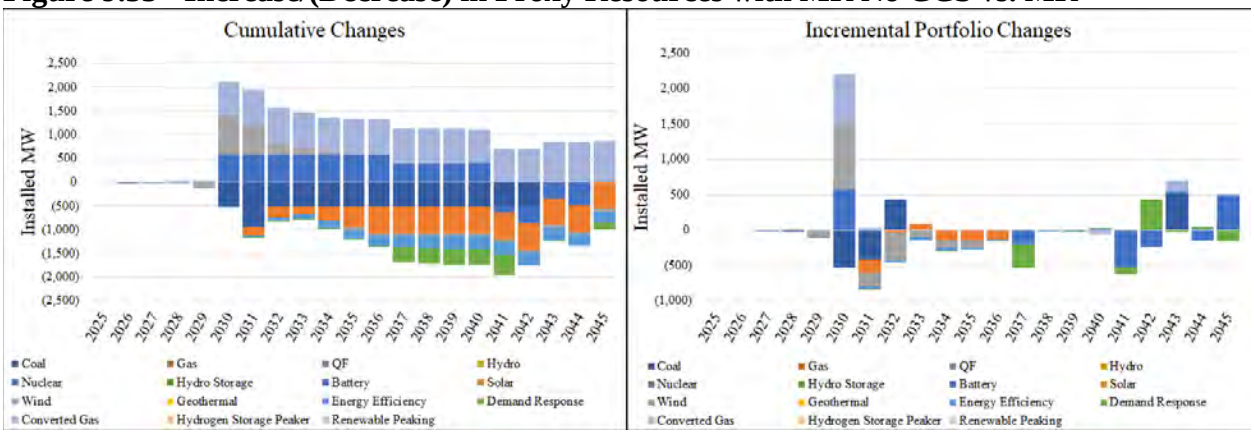
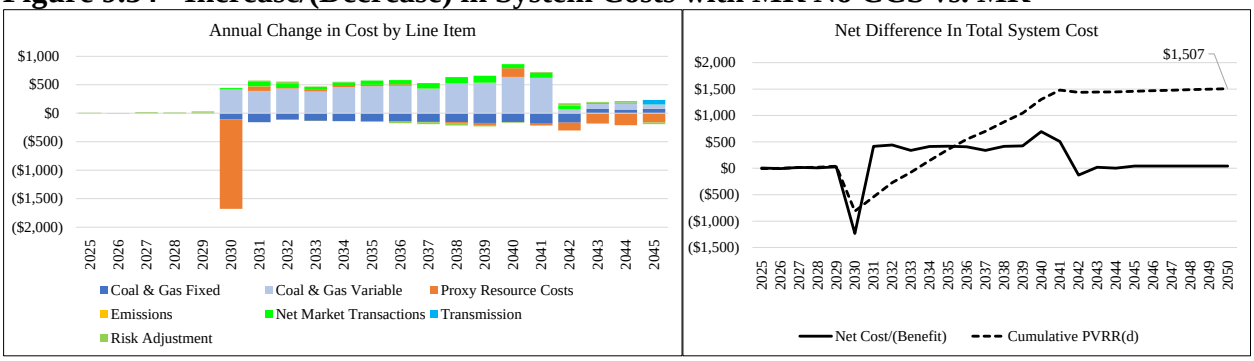


Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

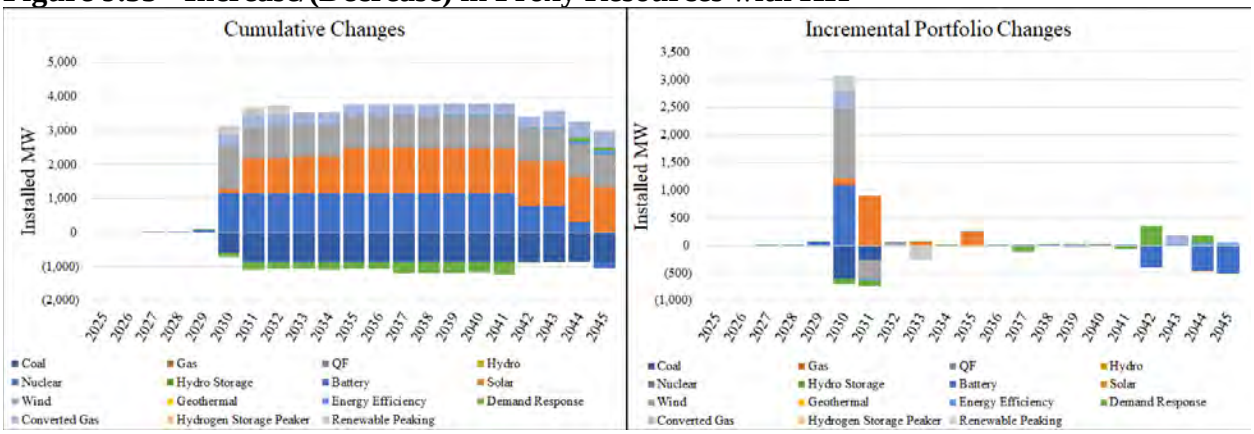
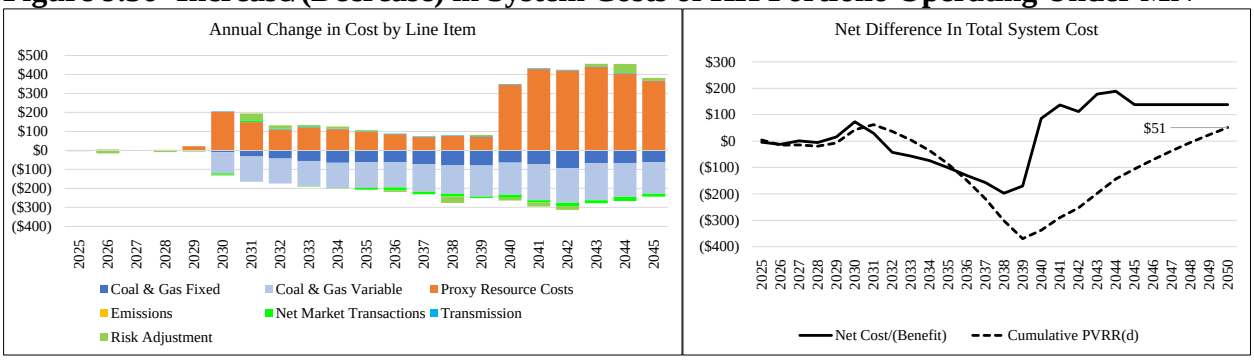


Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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 CO_2 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

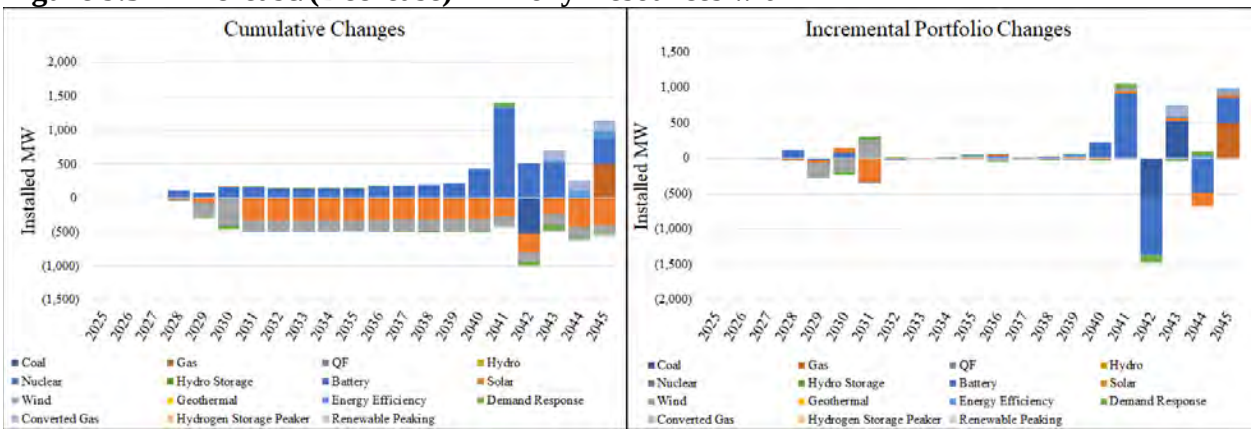
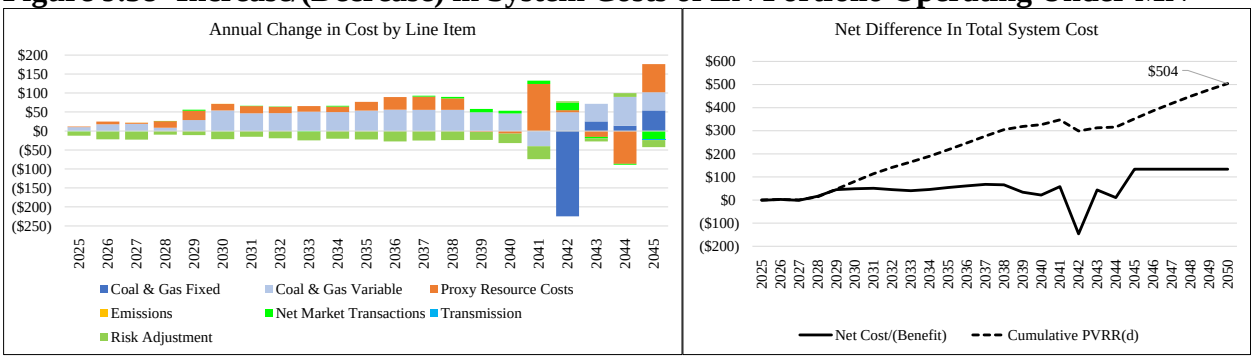


Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

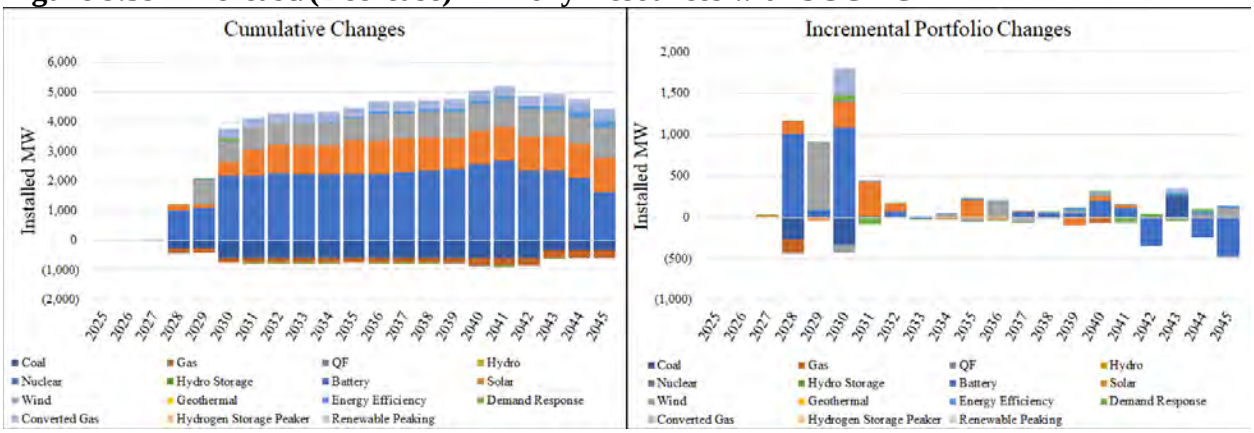
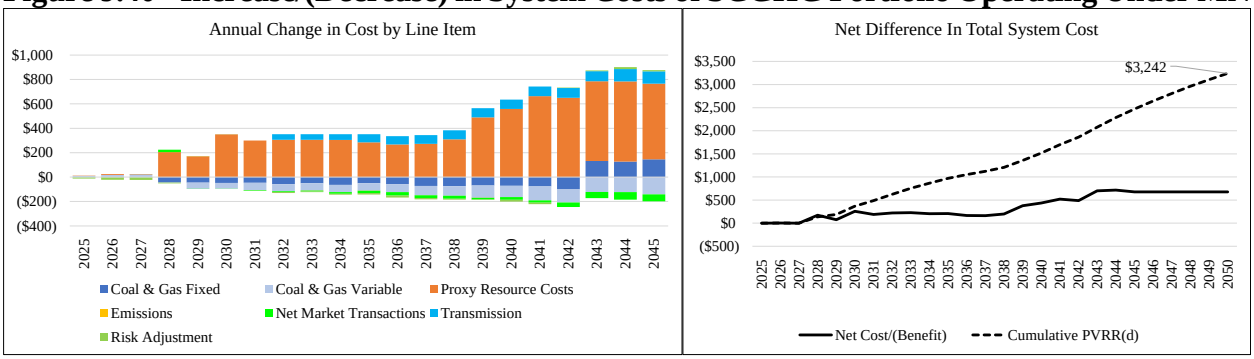


Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

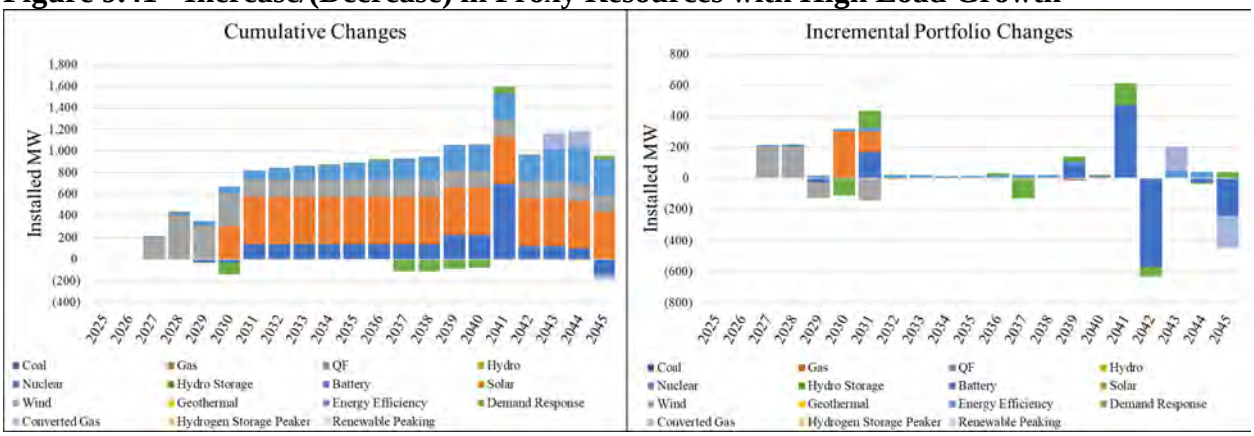
High Load Growth

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

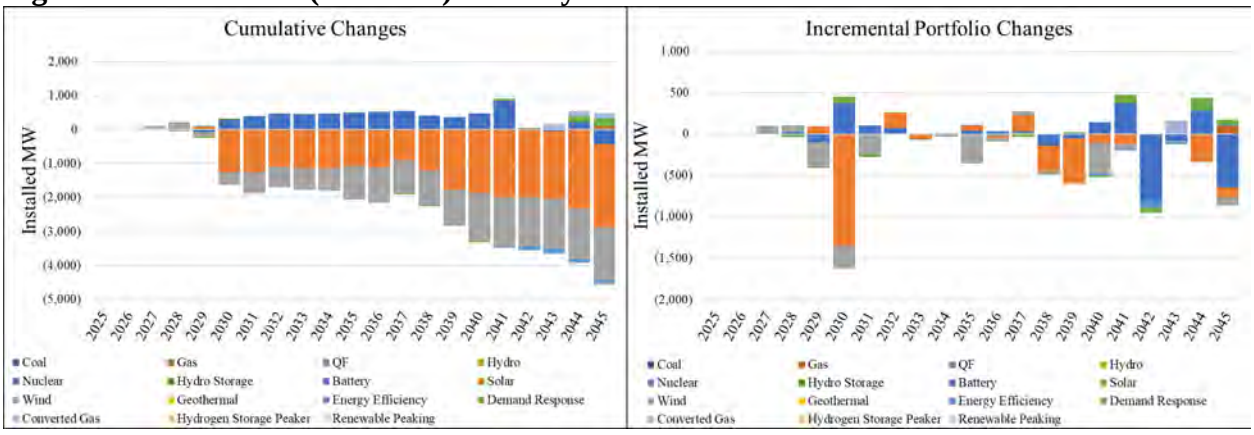


Low Load Growth

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



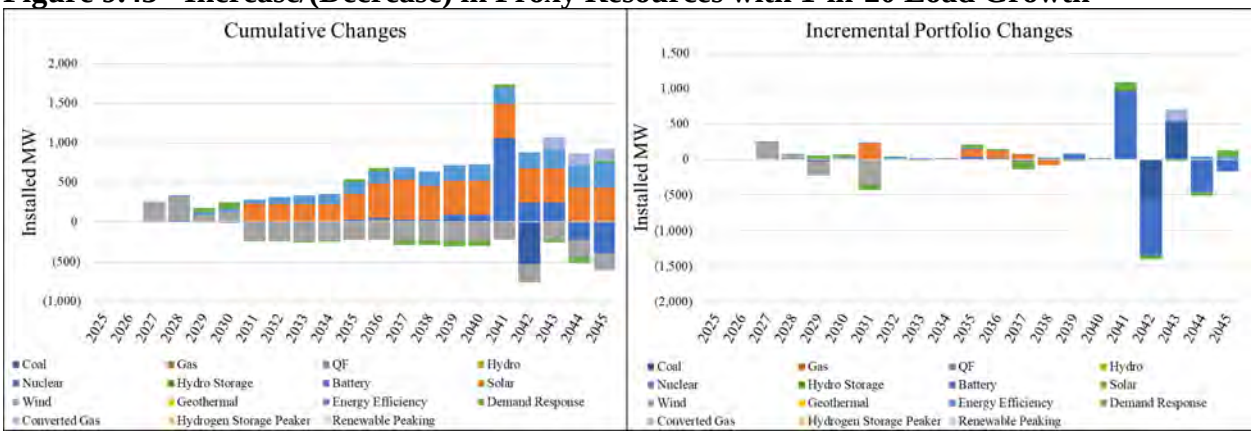
1-in-20 Peak Load Growth

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

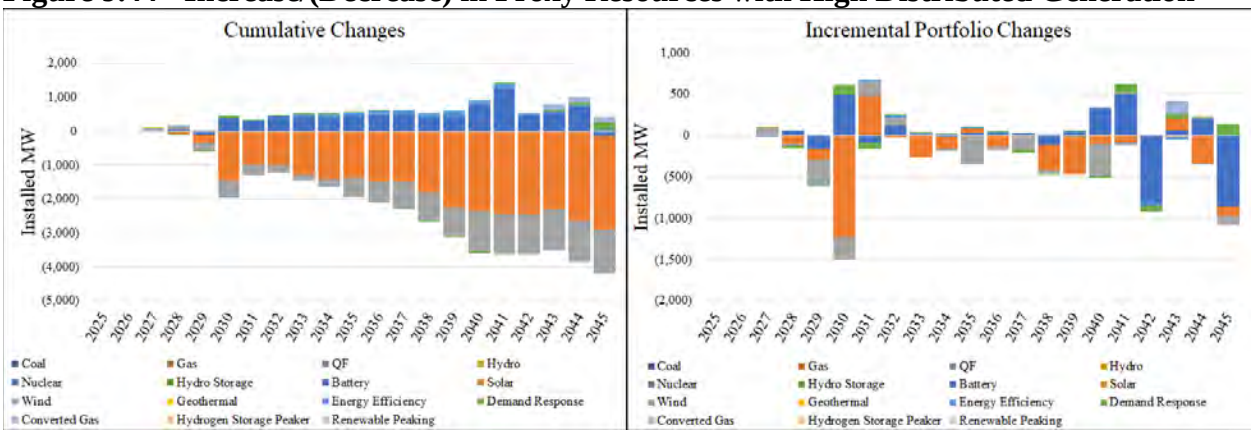


High Distributed Generation Growth

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

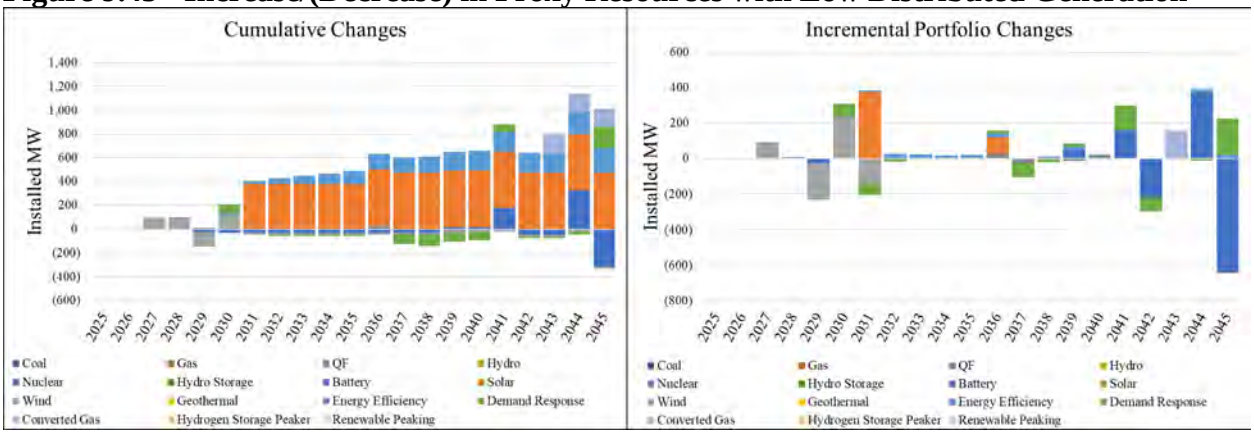


Low Distributed Generation Growth

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

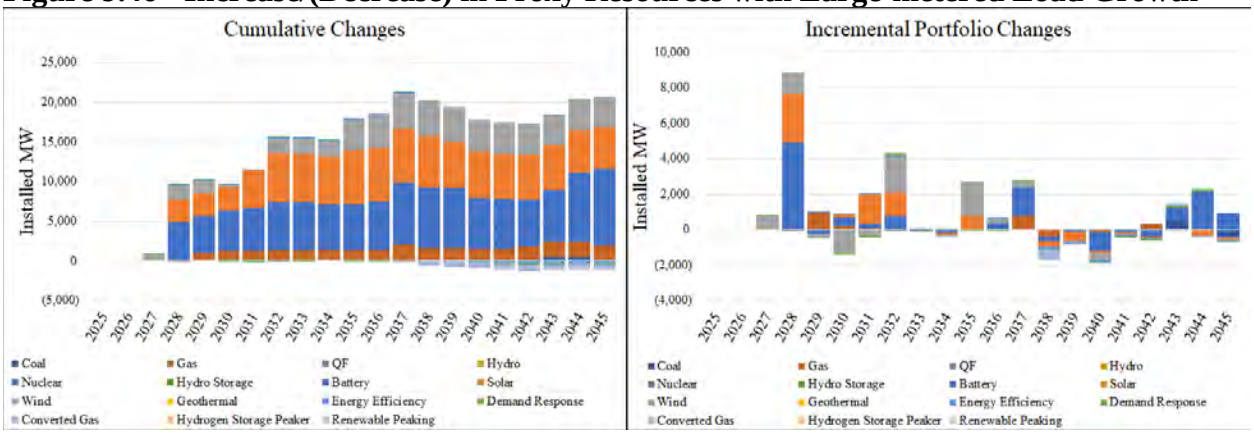
The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the 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



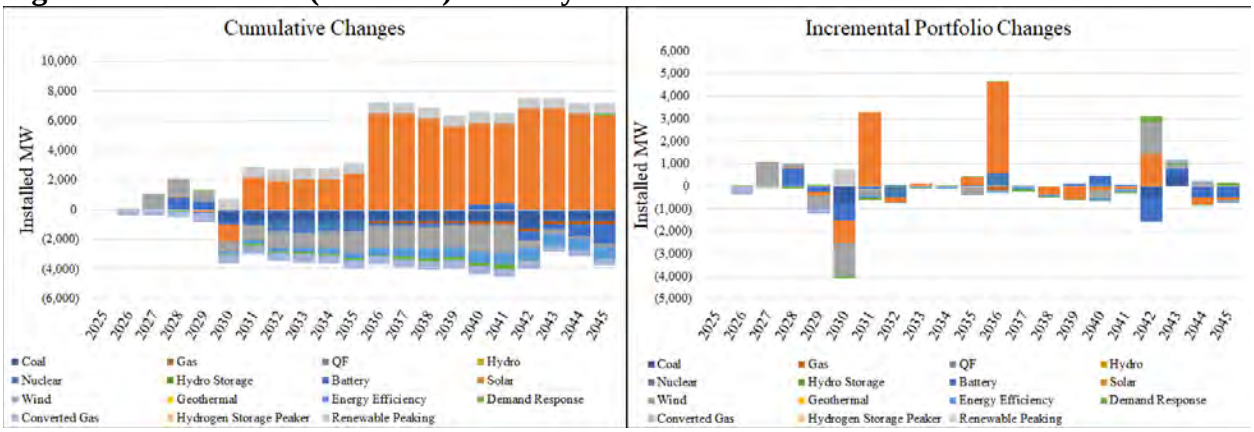
Low-Cost Renewables

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

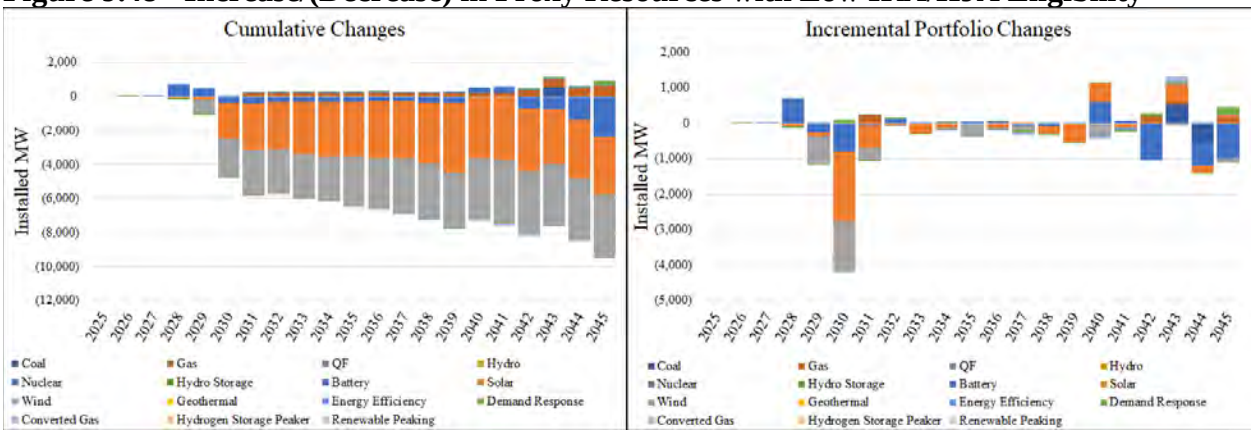


Low IRA/IIJA Eligibility

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

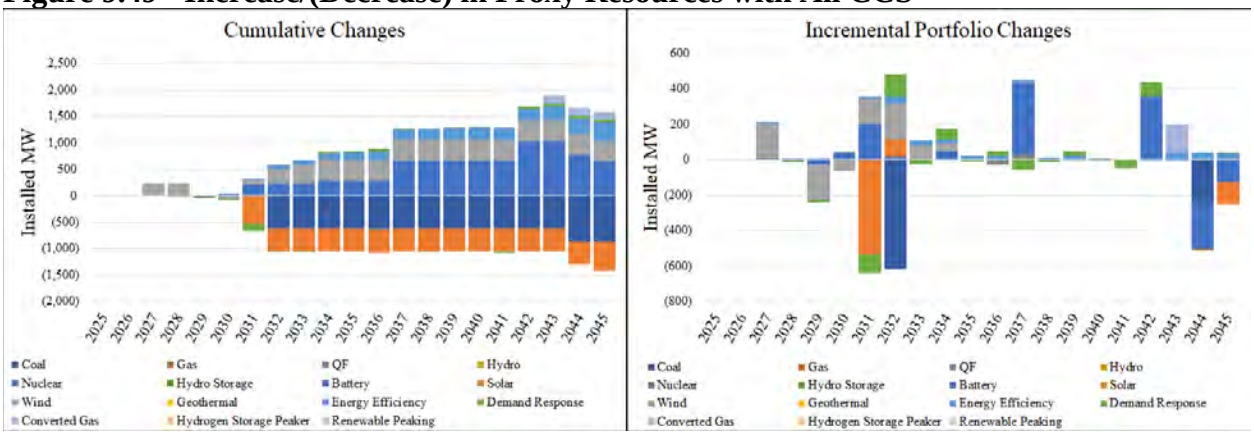


All CCS

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

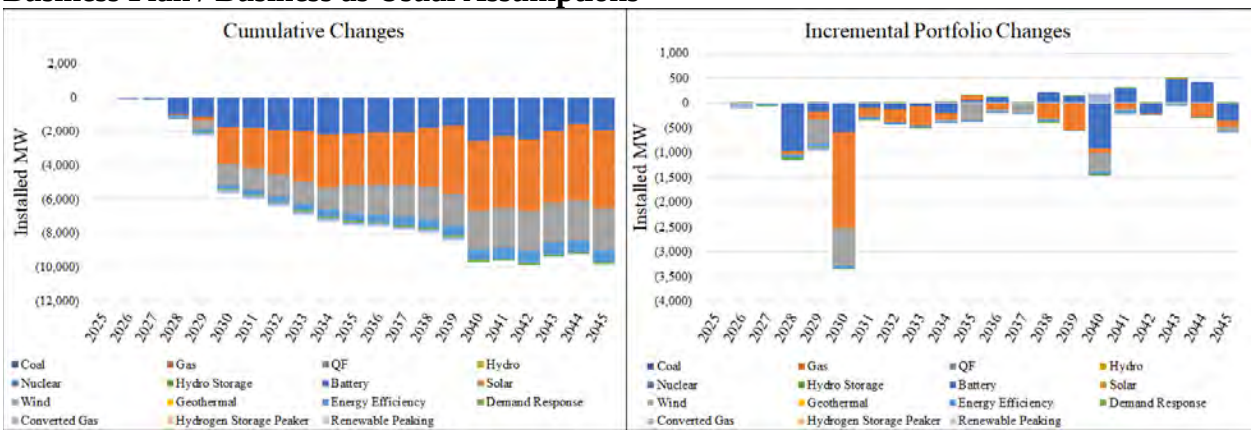


Business as Usual/Business Plan

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 be 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 Change[9]

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 (CO_2) emission polices.
- 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	**Colstrip Units 3 and 4:** • 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	**Craig Unit 1:** • 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	**Naughton Units 1 and 2:** • 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	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** • 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	**Regional Haze Compliance:** • 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	**Natrium™ Demonstration Project:** • 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	**Ozone Transport Rule Compliance:** • 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	**Natural Gas Emissions Compliance Strategies** • 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	**Federal Greenhouse Gas Emission Compliance:** • 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	**Dave Johnston Units 1 and 2:** • 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	**Customer Preference Request for Proposals:** • 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	**2025 All-Source Request for Proposals:** • 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.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

Energy Efficiency & Demand Response Targets:

- 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>

- 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>

</td></tr>
</table>

[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	**Market Purchases:** • 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: o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. o 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. o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

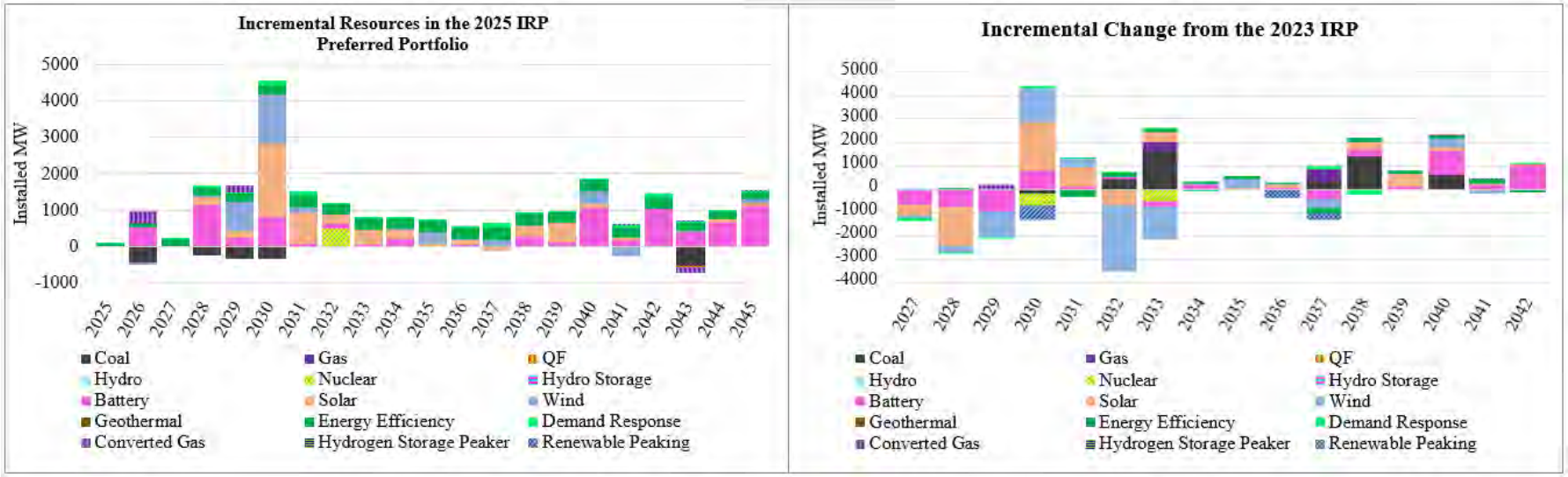
Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** • 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	**Colstrip Units 3 and 4:** • 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	**Craig Unit 1:** • 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	**Naughton Units 1 and 2 Gas Conversion:** • 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	**Jim Bridger Units 1 and 2 Gas Conversion:** • 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	**Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:** • 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	**Regional Haze Compliance:** • 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	**Natrium™ Demonstration Project:**	• 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	**Customer Preference Request for Proposals:** • 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	**2025 All-Source Request for Proposals:** • 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	**Energy Efficiency Targets:** • 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.	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

<table>
<tr><td></td><td>

- 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.

Year	Annual Incremental Capacity (MW)
2023	72
2024	39
2025	152
2026	109

</td><td></td></tr>
<tr><th>Action Item</th><th>5. Market Purchases</th><th>Status</th></tr>
<tr><td>5a</td><td>

<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.

</td><td>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.</td></tr>
</table>

Action Item	6. **Renewable Energy Credit (REC) Actions**	Status

6a	**Renewable Portfolio Standards (RPS):** • 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	**Renewable Energy Credit Sales:** • 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 polices. 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 and 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 Management[9]

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

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 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 CO_2 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 CO_2 capture with sequestration. As mentioned above, plant CO_2 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 CO_2 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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

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.

Independent Statistics & Analysis
www.eia.gov
U.S. Department of Energy
Washington, DC 20585

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Chapter 1

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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 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, tire-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

(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 Conven-tional	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

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 Conven-tional	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

	For Electricity Generation				For Useful Thermal Output			
Year	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

	Total			
Year	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

	Electric Power Sector Year End Stocks		Annual Receipts at All Electricty Generators			Average Cost of Fuel at All Electricty 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)

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

	Savings		Incremental Costs		Life Cycle Savings		Life Cycle Costs	
Year	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

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, commerical 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.

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	169,867	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.
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 2.9. 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.
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 2.10. 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	10.80	10.85	9.66	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.
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, 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	2,933,914	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)

	Canada		Mexico		U.S. Total	
Year	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)

	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small 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 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	1,126,635	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	953	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	18,830
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	56,365	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)

	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													
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
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	1,286	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. 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.
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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 3.2.A. Net Generation by Energy Source: Electric Utilities, 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	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	998,385	10,386	8,278	619,003	199	416,680	229,640	1,494	35,992	-4,105	558	2,316,508
2016	922,399	9,069	8,881	655,744	154	424,400	247,787	1,995	40,666	-5,629	421	2,305,887
2017	893,639	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	6,817	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	428,953	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	66,631	678	388	95,306	0	38,888	23,132	1,811	5,104	-623	40	231,355
August	64,386	661	421	93,582	0	38,921	19,778	1,717	4,893	-495	36	223,900
September	49,704	680	480	75,975	0	35,914	15,593	1,489	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	-498	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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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 3.2.B. Net Generation from Renewable Sources: Electric Utilities, 2014 - 2024
(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													
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	86	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. 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 3.3.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	258,962	-1,047	6,439	1,603,086
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
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	8,956	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)

	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													
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	340,780	139,513	2,847	7,637	6,646	2,858	828	15,586	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	885	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.
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 3.4.A. Net Generation by Energy Source: Commercial Sector, 2014 - 2024
(Thousand Megawatthours)

	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small 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 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.
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 3.4.B. Net Generation from Renewable Sources: Commercial Sector, 2014 - 2024
(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													
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	168	586	0	91	657	832	565	449	214	3,561	12,859	13,445	13,445
2021	168	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)

	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small 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 Generation at Utility Scale Facilities	Estimated Solar Photovoltaic	Estimated Total Solar Photovoltaic	Estimated Total Solar
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	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
2020	5,451	398	510	96,381	8,644	0	1,001	101	26,348	0	4,231	143,064	3,484	3,586	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	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	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	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	5,265
Year 2022															
January	445	51	31	8,683	713	0	77	13	2,137	0	359	12,508	230	243	243
February	409	NM	36	7,440	635	0	83	15	1,944	0	319	10,921	244	259	259
March	459	41	30	7,931	683	0	111	21	2,051	0	347	11,673	348	369	369
April	402	42	28	7,350	630	0	102	24	1,986	0	308	10,871	377	401	401
May	461	40	35	7,790	671	0	84	28	2,045	0	332	11,485	413	441	441
June	450	45	29	7,964	706	0	63	32	2,053	0	319	11,661	413	446	446
July	453	48	28	8,667	741	0	53	31	2,152	0	336	12,510	426	458	458
August	453	38	31	8,759	731	0	61	30	2,091	0	303	12,498	411	441	441
September	404	47	29	7,842	680	0	60	26	1,919	0	265	11,272	368	395	395
October	396	43	33	7,903	692	0	51	24	1,828	0	260	11,230	333	357	357
November	372	43	38	8,144	675	0	62	18	1,998	0	287	11,635	256	273	273
December	425	137	31	8,075	714	0	92	13	2,023	0	270	11,779	229	242	242
Year 2023															
January	414	59	32	8,052	660	0	85	16	1,989	0	290	11,597	244	260	260
February	354	50	25	7,582	654	0	86	18	1,753	0	281	10,803	259	277	277
March	343	48	31	8,127	748	0	104	24	1,916	0	276	11,616	370	395	395
April	334	39	17	7,021	665	0	87	34	1,725	0	252	10,176	408	442	442
May	359	32	20	7,791	703	0	84	35	1,882	0	273	11,180	447	481	481
June	362	38	18	8,433	701	0	69	35	1,751	0	253	11,660	446	481	481
July	387	38	27	8,854	741	0	69	37	1,813	0	292	12,255	461	497	497
August	366	38	23	8,930	755	0	57	34	1,918	0	290	12,410	444	478	478
September	358	36	19	8,511	694	0	46	30	1,789	0	276	11,760	400	429	429
October	340	36	20	8,171	675	0	40	26	1,747	0	304	11,358	363	389	389
November	340	38	21	8,293	697	0	45	21	1,875	0	293	11,622	286	307	307
December	370	41	20	8,699	746	0	72	17	1,971	0	290	12,226	254	271	271
Year 2024															
January	383	42	27	8,925	782	0	88	23	1,936	0	273	12,477	268	290	290
February	346	39	28	7,860	687	0	89	32	1,849	0	250	11,181	296	329	329
March	380	29	30	7,853	655	0	89	43	1,935	0	249	11,263	406	449	449
April	293	32	24	7,687	657	0	89	52	1,849	0	242	10,925	440	492	492
May	341	27	22	7,834	680	0	85	62	1,904	0	268	11,224	478	540	540
June	348	29	23	7,795	649	0	58	62	1,866	0	291	11,122	476	539	539
July	388	30	32	8,475	684	0	48	61	1,939	0	302	11,960	490	551	551
August	371	28	23	8,914	687	0	51	59	1,958	0	264	12,354	473	532	532
September	346	27	19	8,027	572	0	36	52	1,835	0	240	11,154	433	485	485
October	344	30	22	7,330	555	0	62	44	1,736	0	217	10,338	390	433	433
November	352	28	23	7,595	583	0	51	31	1,922	0	267	10,852	303	334	334
December	385	32	29	8,476	681	0	63	25	1,946	0	263	11,900	267	292	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.
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 3.5.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	
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													
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 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 - 2024
(Thousand Megawatthours)

	Small Scale Generation
Period	**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

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, 2024 and 2023 (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 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	91,059	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)

	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 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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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)

	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 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)

	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 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

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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 3.11. Utility Scale Facility Net Generation from Natural Gas by State, by Sector, 2024 and 2023 (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 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

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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 3.12. Utility Scale Facility Net Generation from Other Fossil Gas by State, by Sector, 2024 and 2023 (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 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)

	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 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)

	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 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	2,852	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	23,556	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

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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 3.15. Utility Scale Facility Net Generation from Renewable Sources Excluding Hydroelectric by State, by Sector, 2024 and 2023 (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 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	5,959	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	5,198	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)

	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 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

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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 3.17. Utility Scale Facility Net Generation from Other Energy Sources by State, by Sector, 2024 and 2023 (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 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

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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, 2024 and 2023 (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 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	2,819	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

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, 2024 and 2023 (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 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)

	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 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)

	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		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		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	
Census Division and State	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
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	3,848	4,280	3,913	143	146	4,137	3,768	315	324	21	22	295	302	4,460	4,094
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	656	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	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	298	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	1,114	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	468	459
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	5	3
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	7,849	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	141
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	8,680	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	233	253	4,084	2,688	130	109	5	5	124	104	12	11	5	6	7	5	174	139
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	86	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	5,035	636	370	43,738	28,914	749	689	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	501	241	1,807	535	188	167	17	19	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	34	16	14	4,236	3,756
Colorado	6,974	5,319	31.1%	4,939	3,616	2,035	1,704	18	13	4,887	3,588	415	381	6	8	409	373	88	40	27	6	61	34	1,566	1,296
Idaho	1,294	1,092	18.5%	1,018	854	276	238	258	268	757	583	16	14	0	0	16	14	33	31	3	3	30	29	230	195
Montana	473	316	49.6%	366	240	107	76	0	0	363	240	19	16	0	0	19	16	4	0	4	0	0	0	88	60
Nevada	14,252	11,209	27.1%	12,210	9,525	2,042	1,685	418	177	11,734	9,288	181	173	47	47	133	127	81	82	10	12	71	69	1,838	1,489
New Mexico	5,087	3,314	53.5%	4,287	2,613	800	701	451	451	3,836	2,162	156	143	0	0	156	143	1	1	0	0	1	1	643	557
Utah	6,306	4,835	30.4%	5,311	3,929	995	906	33	7	5,271	3,922	153	140	0	0	153	140	21	13	7	0	14	13	827	753
Wyoming	456	202	125.3%	423	174	33	29	0	0	423	174	3	3	0	0	3	3	1	1	0	0	1	1	28	25
Pacific Contiguous	81,797	70,376	16.2%	48,821	41,365	32,977	29,011	318	342	48,021	40,613	6,853	6,191	165	197	6,688	5,993	3,617	3,279	317	212	3,300	3,067	22,989	19,951
California	78,107	67,077	16.4%	46,382	39,100	31,724	27,977	306	330	45,595	38,360	6,617	5,988	165	197	6,452	5,791	3,591	3,257	317	212	3,274	3,044	21,998	19,142
Oregon	2,620	2,416	8.4%	2,001	1,901	618	515	5	5	1,996	1,896	149	133	0	0	149	133	24	21	0	0	24	21	445	361
Washington	1,071	883	21.3%	437	364	634	518	7	7	430	357	87	69	0	0	87	69	2	1	0	0	2	1	546	448
Pacific Noncontiguous	2,306	2,059	12.0%	713	653	1,594	1,406	77	79	632	568	524	507	4	6	520	501	4	4	0	0	4	4	1,070	901
Alaska	28	18	52.6%	8	0	20	18	0	0	8	0	6	6	0	0	6	6	0	0	0	0	0	0	14	12
Hawaii	2,278	2,040	11.7%	705	653	1,573	1,387	77	79	624	568	518	501	4	6	514	495	4	4	0	0	4	4	1,056	888
U.S. Total	300,634	236,090	27.3%	216,715	162,683	83,918	73,406	30,347	22,230	185,257	139,513	22,218	20,366	566	615	21,652	19,751	5,265	4,708	546	326	4,719	4,382	57,547	49,273

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.
Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report;
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 3.22. Utility Scale Facility Net Generation from Solar Thermal by State, by Sector, 2024 and 2023 (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 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	104,868	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
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.
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 seperating 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, 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.
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 seperating 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 3.25. 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.
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 seperating 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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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 3.26. 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)

	Generation at Utility Scale Facilities									
	Gross Generation					Net Generation				
Period	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

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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: 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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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	19,666.8	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	24,505.3	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 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.
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

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)

	Generator Additions		Generator Retirements		Net Capacity Additions	
Energy Source	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)

	Generator Additions				Generator Retirements			
Energy Source	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

	Other Changes to Existing Capacity			
Energy Source		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 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, 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	8,054.9	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	
	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
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
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
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
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
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
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
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
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
New York	2,869.7	2,746.3	2,668.6	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
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	3,787.8	3,594.8	984.0	811.8	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
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
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
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
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
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
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
Iowa	12,865.5	12,803.8	676.1	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
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
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
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
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
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	2.2	2.2	2.2	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
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
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
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
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
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
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
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
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
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
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
East South Central	186.6	29.1	2,910.3	1,692.5	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	1,869.7	3,114.7	1,869.7
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	616.9	680.5	616.9
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
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
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
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
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
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
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
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
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	24,567.0	19,137.4
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	7,947.1	6,326.1
Colorado	5,336.7	5,336.7	2,366.7	2,173.4	0.0	0.0	693.2	689.7	28.7	28.7	0.0	0.0	8,425.3	8,228.5	1,201.2	1,089.0	3,567.9	3,262.4	3,567.9	3,262.4
Idaho	1,128.3	968.3	501.6	402.0	0.0	0.0	2,653.8	2,630.8	87.6	84.4	10.0	10.0	4,381.3	4,095.5	177.6	156.0	679.2	558.0	679.2	558.0
Montana	1,889.6	1,581.7	179.0	177.0	0.0	0.0	2,834.1	2,825.0	6.2	6.2	0.0	0.0	4,908.9	4,589.9	81.8	59.0	260.8	236.0	260.8	236.0
Nevada	150.0	150.0	5,028.4	3,854.3	178.5	178.5	1,051.7	1,051.7	9.8	9.8	662.5	659.0	7,080.9	5,903.3	1,124.3	952.5	6,152.7	4,806.8	6,331.2	4,985.3
New Mexico	3,997.0	4,409.0	2,321.9	1,131.9	0.0	0.0	82.7	82.7	6.4	3.2	8.6	8.6	6,416.6	5,635.4	411.6	375.3	2,733.5	1,507.2	2,733.5	1,507.2
Utah	389.7	389.7	2,197.1	1,630.8	0.1	0.1	259.7	259.7	12.8	16.0	70.7	70.7	2,930.1	2,367.0	586.3	522.1	2,783.4	2,152.9	2,783.5	2,153.0
Wyoming	3,603.9	3,106.0	242.0	92.0	0.0	0.0	307.1	307.1	0.0	0.0	0.0	0.0	4,153.0	3,505.1	21.7	17.4	263.7	109.4	263.7	109.4
Pacific Contiguous	13,802.1	13,635.6	22,685.2	19,968.3	917.8	1,005.8	39,991.1	40,101.0	1,544.1	1,688.9	1,900.7	1,904.5	80,841.0	78,304.1	19,189.6	17,444.1	41,874.8	37,412.4	42,792.6	38,418.2
California	6,456.8	6,284.2	21,365.2	18,769.3	917.8	1,005.8	10,213.6	10,225.9	979.4	1,118.8	1,881.2	1,885.0	41,814.0	39,289.0	18,209.2	16,615.2	39,574.4	35,384.5	40,492.2	36,390.3
Oregon	3,970.4	3,976.5	1,051.7	1,010.7	0.0	0.0	8,264.2	8,363.2	294.9	294.9	19.5	19.5	13,600.7	13,664.8	476.8	398.1	1,528.5	1,408.8	1,528.5	1,408.8
Washington	3,374.9	3,374.9	268.3	188.3	0.0	0.0	21,513.3	21,511.9	269.8	275.2	0.0	0.0	25,426.3	25,350.3	503.6	430.7	771.9	619.0	771.9	619.0
Pacific Noncontiguous	292.2	292.2	473.2	399.9	0.0	0.0	508.7	508.6	160.9	160.9	43.0	43.0	1,478.0	1,404.6	937.4	852.9	1,410.6	1,252.8	1,410.6	1,252.8
Alaska	59.0	59.0	7.7	7.7	0.0	0.0	476.3	476.2	7.0	7.0	0.0	0.0	550.0	549.9	19.2	19.2	26.9	26.9	26.9	26.9
Hawaii	233.2	233.2	465.5	392.2	0.0	0.0	32.4	32.4	153.9	153.9	43.0	43.0	928.0	854.7	918.1	833.8	1,383.6	1,226.0	1,383.6	1,226.0
U.S. Total	152,097.3	147,444.7	122,060.1	90,527.7	1,392.0	1,480.0	79,896.9	79,985.3	11,411.8	11,826.3	2,695.5	2,695.8	369,553.6	333,959.8	53,228.1	47,774.7	175,288.2	138,302.4	176,680.2	139,782.4

NM = Not meaningful due to large relative standard error.
Values are final.

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.'
Estimated small scale solar photovoltaic capacity is based on data from Form EIA-861M, Form EIA-861, and from estimation methods described in the technical notes.

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	5,382.6	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	11,223.8	11,509.1
New York	9,927.1	9,908.2	2,398.1	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	25,811.9
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	251.1	251.1	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	1,889.2	1,892.5	3,323.9	3,200.8	333.1	392.8	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	363.6	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	410.0	410.0	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	8,898.8	4,212.0	4,245.9	590.8	581.8	1,530.1	1,530.1	0.0	0.0	741.6	737.2	0.0	0.0	15,984.6	15,993.8
West Virginia	0.0	0.0	1,088.3	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	702.8	703.3	824.0	4,729.6	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	6,679.2	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	4,078.0	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	2,751.6	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

	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Fossil Gas		Solar				Wind		Wood	
Year/Month											Photovoltaic		Thermal					
	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%	79,698.8	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%
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

	Battery		Pumped Storage	
Year/Month	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%	22,939.6	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	7,469.9	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	14,197.9	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	23,981.5	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

Year	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
Photovoltaic						
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	594.977	188.874	--	126.793	1,199.688
2019	437.911	688.600	202.899	--	131.391	1,460.800
2020	655.125	872.946	211.173	--	138.251	1,877.496
2021	981.281	1,035.068	214.531	--	148.136	2,379.018
2022	1,334.849	1,106.717	188.956	--	150.016	2,780.539
2023	1,613.746	1,114.113	221.723	--	156.700	3,106.283
2024	2,023.152	1,064.818	233.024	--	157.265	3,478.259
Battery						
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
2020	26.048	136.448	16.876	--	17.245	196.617
2021	108.876	166.042	16.733	--	20.719	312.370
2022	171.343	221.150	16.594	--	20.535	429.622
2023	239.419	242.722	16.699	--	3.110	501.950
2024	343.048	267.814	18.780	--	3.330	632.972
Battery Energy (MWh)						
2014	--	--	--	--	--	--
2015	--	--	--	--	--	--
2016	--	--	--	--	--	--
2017	--	--	--	--	--	--
2018	--	--	--	--	--	--
2019	--	--	--	--	--	--
2020	--	--	--	--	--	--
2021	--	--	--	--	--	--
2022	--	--	--	--	--	--
2023	607.049	563.367	0.086	--	22.134	1,192.636
2024	423.115	628.692	2.086	--	4.019	1,057.912
Wind						
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
2020	2.104	13.947	1.249	--	9.523	26.823
2021	2.000	15.108	1.153	--	9.571	27.832
2022	1.884	13.303	1.171	--	9.572	25.930
2023	1.861	15.547	0.771	--	9.572	27.751
2024	2.425	15.109	1.909	--	10.452	29.895
Hydroelectric						
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	--	113.916	164.713
2020	2.822	39.539	2.793	--	104.293	149.447
2021	2.529	43.226	6.053	--	102.912	154.720
2022	2.529	45.892	4.893	--	99.542	152.856
2023	2.529	44.890	4.493	--	108.164	160.076
2024	2.524	44.224	2.430	--	97.972	147.150
Fuel Cell						
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
2020	1.133	18.599	4.599	--	0.625	24.956
2021	0.133	20.608	5.564	--	0.625	26.930
2022	0.134	23.207	5.310	--	0.625	29.276
2023	0.134	23.353	5.310	--	0.625	29.422
2024	0.117	26.600	3.285	--	0.645	30.647
Internal Combustion						
2014	--	--	--	--	--	813.847
2015	--	--	--	--	--	797.585
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
2020	56.878	862.233	299.805	--	81.835	1,300.751
2021	70.081	906.179	345.146	--	78.941	1,400.347
2022	85.208	944.560	326.954	--	77.522	1,434.244
2023	78.968	1,040.781	321.369	--	79.488	1,520.606
2024	78.272	1,095.666	300.771	--	59.399	1,534.108
Gas Turbine						
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
2020	0.077	94.906	21.828	--	3.488	120.299
2021	0.197	102.084	22.333	--	1.253	125.867
2022	0.213	109.087	21.598	--	1.253	132.151
2023	0.213	96.431	37.178	--	1.253	135.075
2024	0.588	90.309	19.287	--	1.013	111.197
Steam Turbine						
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
2020	--	7.464	0.539	--	2.581	10.584
2021	--	7.589	0.539	--	2.581	10.709
2022	--	9.256	0.019	--	2.581	11.856
2023	--	7.779	0.019	--	2.581	10.379
2024	--	7.779	0.674	--	2.581	11.034
Other						
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
2020	0.117	38.842	16.249	--	2.979	58.187
2021	0.841	46.050	15.564	--	2.019	64.474
2022	0.901	48.004	15.084	--	2.019	66.008
2023	1.233	47.196	7.134	--	1.169	56.732
2024	1.582	37.898	9.789	--	1.119	50.388
Total						
2014	--	--	--	--	--	1,855.455
2015	--	--	--	--	--	1,994.564
2016	137.524	1,261.901	413.648	--	302.783	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
2020	744.304	2,084.924	575.111	--	360.820	3,765.160
2021	1,165.938	2,341.954	627.616	--	366.757	4,502.267
2022	1,597.061	2,521.175	580.579	--	363.665	5,062.472
2023	1,938.103	2,632.812	614.696	--	362.662	5,548.274
2024	2,451.708	2,650.217	589.949	--	333.776	6,025.650
Total Number of Generators						
2014	--	--	--	--	--	203,099
2015	--	--	--	--	--	215,825
2016	--	--	--	--	--	195,703
2017	--	--	--	--	--	215,889
2018	--	--	--	--	--	231,220
2019	--	--	--	--	--	251,357
2020	--	--	--	--	--	279,730
2021	--	--	--	--	--	323,085
2022	--	--	--	--	--	389,197
2023	--	--	--	--	--	433,096
2024	--	--	--	--	--	451,159

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 2018, 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 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, 2014 through 2024

	Capacity (MW)					Customers				
Year	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)

		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	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)

		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	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)

		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.
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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.E. Coal: 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	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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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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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

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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 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 5.2.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.
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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.
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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.
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Table 5.2.D. Petroleum Liquids: 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	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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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.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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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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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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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.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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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.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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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.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

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Totals may not equal sum of components because of independent rounding.
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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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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.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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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 5.4.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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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.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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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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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.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

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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

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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

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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

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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.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

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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

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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

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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.B. Landfill 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	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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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.
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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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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 5.6.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

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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.
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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.
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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.
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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 5.7.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
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
2020	114,814	2,284	95,941	16,511	77
2021	113,173	2,029	92,144	18,944	56
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

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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

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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

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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

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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

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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

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Table 5.9. Consumption of Coal for Electricity Generation by State by Sector, 2024 and 2023 (Thousand Tons)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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 5.10. Consumption of Petroleum Liquids for Electricity Generation by State, by Sector,. 2024 and 2023 (Thousand Barrels)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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.
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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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.
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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, 2014 - 2024

	Electric Power Sector			Electric Utilities			Independent Power Producers		
Period	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

	Electric Power Sector			Electric Utilities		Independent Power Producers	
Census Division	**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)

	Electric Power Sector			
Period	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

	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)
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.

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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 7.2. Receipts and Quality of Coal Delivered for the Electric Power Industry, 2014 through 2024

	Bituminous			Subbituminous			Lignite		
Period	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

* = 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, 2014 through 2024

	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
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

* = 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 7.4. 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

* = 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 - 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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- 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 7.5. Receipts, Average Cost, and Quality of Fossil Fuels: Electric Utilities, 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	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.
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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Table 7.6. 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
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	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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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 7.7 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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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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- 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 7.8. 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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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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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 7.9. Receipts, Average Cost, and Quality 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	--	--	--	--

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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 7.10. Receipts, Average Cost, and Quality of Fossil Fuels: Commerical 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

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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 7.11. Receipts, Average Cost, and Quality of Fossil Fuels: Industrial 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	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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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 7.12. 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

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Table 7.13. Receipts of Coal Delivered for Electricity Generation by State, 2024 and 2023
(Thousand Tons)

Census Division and State	All Sectors			Electric Power Sector							
				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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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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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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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	All Sectors			Electric Power Sector							
				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

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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 7.16. Receipts of Natural Gas Delivered for Electricity Generation by State, 2024 and 2023
(Million Cubic Feet)

Census Division and State	All Sectors			Electric Power Sector							
				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	968,555	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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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	--	--

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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, 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

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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.
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 Utilties 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.
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, 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)

	Operation				Maintenance			
Year	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

	Fuel				Total			
Year	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

	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)
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	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

	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		
Year	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

			All Events (With Major Event Days)						Without Major Event Days						Loss of Supply Removed					
	Percent of Customers 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)		SAIDI (minutes per year)		SAIFI (times per year)		CAIDI (minutes per interruption)	
Census Division and State	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	108.9	119.9	1.0	0.9	108.7	130.4
Wyoming	71.3%	65.9%	137.8	121.4	1.0	0.9	138.0	129.8	116.0	102.6	0.9	0.8	125.4	124.3	128.6	106.4	1.0	0.9	126.4	116.3
Pacific Contiguous	93.0%	92.8%	371.7	299.1	1.4	1.3	261.7	230.9	159.6	147.8	1.1	1.0	140.9	142.8	380.0	287.3	1.4	1.2	269.6	236.5
California	94.4%	94.6%	285.0	352.5	1.4	1.4	210.7	250.2	164.4	157.1	1.2	1.1	139.2	143.2	306.3	351.5	1.4	1.4	214.3	252.4
Oregon	87.5%	87.5%	579.3	122.9	1.3	0.8	437.6	152.1	124.1	103.5	0.8	0.7	150.6	140.4	547.0	115.9	1.2	0.8	457.0	153.9
Washington	90.0%	88.0%	643.5	153.8	1.8	1.1	362.8	146.5	157.3	129.8	1.1	0.9	144.9	141.9	587.2	113.4	1.4	0.7	406.3	156.4
Pacific Noncontiguous	36.9%	23.7%	329.8	456.2	2.6	3.4	129.3	135.2	195.4	325.7	1.9	2.4	101.7	137.6	307.3	472.5	1.5	2.5	201.7	188.8
Alaska	79.5%	47.7%	323.2	499.4	2.3	3.3	139.3	153.2	192.4	325.7	1.9	2.4	103.3	137.6	371.0	472.5	1.8	2.5	201.7	188.8
Hawaii	6.9%	6.9%	382.6	248.8	4.4	3.9	87.2	63.4	219.3		2.4		91.8		0.0		0.0			
U.S. Total	79.3%	78.4%	662.6	366.6	1.5	1.3	432.7	271.8	131.6	123.9	1.1	1.0	123.6	121.3	646.1	357.7	1.4	1.2	451.6	288.0

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.
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.
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 11.3 Reliability Metrics Using Any Method of U.S. Distribution System by State, 2024 and 2023

			All Events (With Major Events)						Without Major Events					
	Percent of Customers 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)	
Census Division and State	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 11.4 SAIDI Values (Minutes Per Year) of U.S. Distribution System by State, 2014 - 2024

Census Division and State	IEEE										Any Method									
	All Events (With Major Event Days)										Without Major Event Days									
	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
New England	389.8	489.3	309.3	382.1	1,272.8	351.5	723.6	778.5	231.2	145.7	306.7	101.4	103.4	98.2	104.1	101.9	95.0	119.1	107.9	126.3
Connecticut	152.8	193.4	187.4	170.9	3,033.8	246.6	761.6	348.9	201.1	112.5	93.7	73.6	77.7	73.7	76.7	70.2	67.5	80.9	78.1	103.2
Maine	1,748.6	1,863.0	863.6	325.2	1,726.0	908.1	665.3	2,492.6	535.4	213.6	1,049.3	274.0	247.4	216.7	223.5	244.8	213.7	273.0	238.5	264.4
Massachusetts	103.7	265.3	165.8	527.8	224.1	244.3	865.3	178.7	148.6	86.4	126.8	77.0	83.5	84.4	88.1	63.6	67.5	81.3	72.7	91.6
New Hampshire	735.5	590.6	495.5	176.5	408.5	219.6	450.8	915.4	192.5	117.3	815.3	84.2	89.3	78.2	98.3	99.0	84.9	122.0	120.5	135.3
Rhode Island	104.3	104.6	81.9	448.8	548.4	238.5	594.8	728.1	168.9	341.8	54.2	60.8	52.2	63.2	68.8	69.1	68.2	85.1	59.1	69.1
Vermont	895.8	486.3	914.6	215.2	158.4	334.0	929.8	1,792.4	198.8	193.4	240.0	231.8	204.3	178.5	215.3	158.4	170.4	357.7	186.2	198.8
Middle Atlantic	309.1	196.8	184.7	190.8	588.9	262.5	516.4	172.6	150.0	193.6	283.1	121.5	112.2	111.7	110.9	105.0	115.1	113.2	98.2	110.1
New Jersey	173.3	108.2	89.6	139.2	943.3	249.7	505.5	85.6	137.5	263.6	111.7	98.8	89.0	78.7	84.3	85.1	86.4	87.4	71.0	85.0
New York	477.3	204.8	347.7	218.8	447.4	323.7	396.5	344.5	208.1	146.4	198.0	142.8	130.1	150.0	131.5	142.1	136.9	145.2	132.1	160.2
Pennsylvania	353.1	265.1	207.5	222.6	355.4	252.5	564.0	184.5	132.3	166.2	438.3	131.5	125.9	125.4	125.2	107.5	130.5	122.8	108.4	105.1
East North Central	357.8	499.5	319.7	377.0	311.1	315.5	254.0	332.1	189.9	219.4	285.4	114.3	108.8	121.4	120.8	113.8	135.4	128.1	122.9	124.4
Illinois	158.0	210.4	90.8	127.2	335.8	116.3	143.8	120.0	136.1	170.9	197.6	59.1	56.2	59.1	63.6	57.1	73.8	72.5	72.8	80.7
Indiana	310.0	467.4	276.5	302.7	294.3	266.6	302.4	223.5	254.2	257.4	236.5	123.3	111.3	139.9	137.4	127.6	147.5	146.1	135.4	129.4
Michigan	481.7	1,127.7	520.7	890.0	418.7	570.2	450.2	802.2	268.4	374.5	592.5	161.3	164.8	166.8	178.6	198.7	213.9	186.4	180.1	194.2
Ohio	511.0	366.6	413.6	244.9	283.6	303.6	240.3	249.8	169.5	167.5	185.5	133.3	127.1	144.1	136.0	129.2	145.2	150.1	141.8	127.1
Wisconsin	266.2	203.8	307.9	361.2	119.6	383.5	117.0	219.2	147.2	107.8	154.1	97.5	76.8	104.7	88.0	89.1	90.0	76.4	69.1	76.3
West North Central	255.3	222.7	202.8	236.4	229.8	195.2	140.2	223.0	220.1	179.0	133.1	93.9	84.8	95.1	88.8	87.0	95.4	91.1	90.3	95.1
Iowa	209.3	83.9	95.0	137.8	1,066.5	126.0	115.4	128.1	136.5	96.0	151.2	84.1	60.7	78.2	89.7	85.7	83.7	92.9	103.8	96.0
Kansas	269.4	287.1	179.3	346.0	106.4	241.2	153.1	388.6	169.1	360.5	153.4	104.0	101.8	108.1	113.9	91.9	117.2	105.6	130.9	132.3
Minnesota	222.4	127.1	275.2	121.0	129.0	148.2	129.8	308.9	350.8	123.1	91.5	72.8	71.6	83.7	84.7	79.8	87.8	71.7	88.6	79.4
Missouri	212.8	379.0	149.5	267.9	154.1	261.0	151.2	307.2	215.4	164.9	134.3	106.6	104.4	97.0	97.8	98.7	113.6	91.8	90.8	86.6
Nebraska	897.8	69.4	73.0	556.8	115.4	78.6	189.7	160.7	63.1	67.6	98.3	69.8	55.6	56.2	59.9	67.4	59.2	76.8	72.9	49.2
North Dakota	159.7	262.3	677.6	101.6	123.3	132.6	111.2	91.2	152.3	113.6	102.5	87.6	93.9	102.8	88.4	86.8	77.1	96.0	76.4	110.4
South Dakota	85.6	78.1	338.3	101.3	97.4	311.4	93.1	101.7	255.8	135.0	120.6	61.5	63.9	126.3	61.9	71.5	108.2	73.0	80.3	84.4
South Atlantic	1,405.8	240.4	615.9	191.2	321.4	206.0	639.0	1,241.6	576.5	195.4	309.4	133.1	119.7	127.9	113.0	122.6	124.2	135.3	122.4	129.3
Delaware	117.9	109.7	79.8	64.3	271.9	102.0	136.2	154.8	148.7	191.4	169.8	66.8	61.2	66.4	64.3	84.0	74.2	73.8	83.3	102.3
District of Columbia	32.6	71.9	33.7	52.0	44.0	77.0	109.2	57.5	115.0	112.4	96.0	26.4	33.3	26.3	42.0	39.0	55.0	52.9	57.5	115.0
Florida	1,467.4	172.3	1,011.3	82.9	200.4	88.9	305.5	2,693.2	388.2	86.1	89.4	66.7	69.4	69.8	65.3	72.5	74.0	79.6	76.7	82.7
Georgia	1,269.1	342.7	212.4	140.5	521.7	149.8	230.7	1,030.8	424.0	248.2	252.3	211.4	133.4	129.3	123.8	130.5	125.8	118.8	115.2	120.6
Maryland	118.1	166.2	260.0	127.8	113.8	143.8	330.4	103.1	120.7	117.2	255.9	75.1	66.8	84.2	89.2	76.2	89.0	93.6	81.5	104.5
North Carolina	1,519.1	262.5	486.0	215.2	437.4	287.5	1,877.9	282.2	857.3	220.8	519.0	143.9	156.4	150.7	125.9	146.0	147.0	168.0	151.1	152.1
South Carolina	3,155.0	169.8	302.4	122.9	332.6	338.2	488.6	388.9	1,698.8	234.3	787.0	115.9	126.5	114.8	101.3	121.3	106.3	138.8	119.4	122.1
Virginia	962.1	292.8	1,108.2	798.2	337.7	478.0	1,133.7	279.2	317.8	249.0	287.1	245.1	239.8	342.3	262.7	250.8	285.4	307.8	218.0	219.7
West Virginia	1,165.5	751.5	1,003.2	1,117.2	924.2	755.2	739.7	690.8	743.4	814.6	662.8	486.1	385.7	543.6	451.8	467.9	471.3	513.1	451.8	439.1
East South Central	423.7	864.3	392.5	573.8	825.2	269.4	314.9	427.7	216.0	272.4	263.9	176.3	186.5	187.8	152.6	147.8	160.3	158.3	144.4	147.9
Alabama	197.7	400.2	231.1	175.7	3,320.4	183.7	457.8	242.4	174.2	274.7	282.9	120.8	189.5	198.4	110.9	144.8	166.8	136.8	130.8	140.1
Kentucky	537.7	861.5	345.1	698.2	284.7	204.2	407.5	183.3	194.2	245.8	249.5	145.7	140.6	151.5	130.3	125.3	148.9	146.7	120.0	139.0
Mississippi	607.3	877.8	455.9	1,189.8	1,611.7	466.1	271.6	580.2	276.7	363.3	279.4	279.0	266.6	243.3	224.5	203.9	214.3	209.7	205.5	179.9
Tennessee	289.3	926.9	428.3	316.8	618.4	252.9	217.5	621.5	212.9	257.5	277.7	169.9	192.7	194.1	151.7	144.3	160.4	145.6	141.7	141.6
West South Central	1,268.9	685.0	242.8	1,893.7	1,018.2	309.0	265.4	218.6	204.8	164.2	163.0	178.3	188.8	152.5	162.3	150.3	144.8	145.8	155.3	138.0
Arkansas	527.8	915.3	437.5	308.4	771.6	451.3	330.9	405.8	400.5	326.2	238.5	201.9	230.7	279.6	199.4	210.8	228.0	214.1	176.0	213.7
Louisiana	630.6	663.2	323.8	5,868.8	4,331.9	521.2	285.7	423.5	442.6	411.9	499.1	215.9	199.3	252.2	265.0	217.9	223.5	214.2	196.9	190.1
Oklahoma	220.7	1,239.4	165.6	165.9	585.1	186.2	154.7	194.0	326.2	597.0	115.9	164.2	163.0	178.3	186.8	152.5	162.3	150.3	144.8	145.8
Texas	1,614.3	583.1	204.6	1,496.4	419.4	254.8	170.4	488.8	216.8	279.8	198.8	153.4	150.3	153.7	174.1	132.7	141.4	130.2	135.1	132.7
Mountain	176.3	117.9	153.2	166.3	178.8	131.1	119.0	131.7	131.3	131.7	107.3	102.4	90.4	95.4	99.5	87.3	91.2	88.6	95.6	90.6
Arizona	83.6	103.8	136.9	101.9	70.6	83.3	111.6	89.5	86.8	89.6	86.9	69.8	66.0	69.1	69.2	63.0	64.0	57.6	50.8	67.9
Colorado	257.0	100.2	143.7	185.4	136.4	184.5	99.6	132.7	154.5	107.9	86.7	118.9	89.2	96.9	104.6	83.4	84.3	86.5	80.2	83.5
Idaho	204.4	134.4	167.4	438.0	286.5	155.4	169.9	253.9	183.0	238.1	168.4	152.5	121.8	144.5	137.5	158.1	132.3	140.8	222.9	157.6
Montana	340.7	224.1	251.7	275.3	165.8	135.4	216.4	295.4	144.9	132.3	113.8	169.6	147.2	136.8	121.7	118.3	160.8	118.8	119.6	161.5
Nevada	158.9	138.7	195.1	102.4	73.3	87.0	126.2	114.4	95.7	107.0	75.7	63.8	81.2	77.0	69.7	66.3	77.5	76.7	87.7	73.7
New Mexico	272.6	156.0	175.2	204.3	140.1	158.2	132.9	121.2	130.4	108.8	74.5	152.0	123.7	125.4	120.0	113.6	121.5	123.9	114.5	102.2
Utah	115.4	127.7	108.7	113.4	133.8	144.4	115.5	142.1	150.3	203.2	193.5	109.0	108.1	99.6	106.5	109.5	118.4	115.5	114.3	130.1
Wyoming	137.8	121.4	159.0	167.9	293.4	166.8	125.4	200.4	180.2	181.3	201.9	118.0	102.6	116.1	115.6	105.1	134.0	107.1	171.9	135.8
Pacific Contiguous	371.7	299.1	246.2	483.8	282.8	528.9	200.9	258.5	147.8	188.1	160.6	159.6	147.8	152.8	149.5	119.4	106.1	101.0	108.8	103.5
California	285.0	252.5	202.4	335.2	280.7	610.7	199.4	243.2	119.0	120.4	113.0	164.4	157.7	156.5	148.0	107.6	106.7	99.5	104.5	100.0
Oregon	579.1	122.9	325.2	1,588.3	325.0	290.4	111.4	314.5	233.5	225.9	259.9	124.1	103.5	121.0	113.9	103.4	101.6	90.3	111.6	106.1
Washington	643.5	153.8	403.6	554.5	268.6	310.9	265.3	311.3	258.0	620.9	412.6	157.3	129.8	153.5	151.1	126.9	105.8	115.5	135.8	121.3
Pacific Noncontiguous	329.8	456.2	891.3	537.3	374.0	218.0	250.2	215.4	149.1	332.4	312.0	195.4	325.7	334.9	230.9	140.8	134.1	163.9	119.3	116.8
Alaska	323.2	499.4	891.3	537.3	256.9	279.0	339.3	149.2	198.6	657.8	312.0	192.4	325.7	334.9	230.9	140.8	134.1	163.9	136.9	176.9
Hawaii	382.6	248.8			123.8	182.1	198.0	254.3	109.3	152.0		210.3				97.3	113.4	151.9	112.0	83.2
U.S. Total	682.4	686.6	333.0	475.8	456.1	293.5	349.2	585.9	268.4	209.0	236.2	131.8	123.9	131.1	125.7	116.0	122.2	121.4	117.0	119.8

Census Division and State	Loss of Supply Removed										Any Method									
	All Events (With Major Event Days)										Without Major Event Days									
	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
New England	387.1	481.2	349.9	357.7	1,284.0	351.7	721.4	780.4	229.4	140.0	303.4	419.6	480.5	333.0	364.0	1,067.1	335.8	715.4	682.4	211.1
Connecticut	152.8	193.4	187.4	170.9	3,033.8	246.6	761.6	348.9	201.1	112.5	93.7	73.6	77.7	73.7	76.7	70.2	67.5	80.9	78.1	103.2
Maine	1,748.6	1,863.0	863.6	325.2	1,726.0	908.1	665.3	2,492.6	535.4	213.6	1,049.3	274.0	247.4	216.7	223.5	244.8	213.7	273.0	238.5	264.4
Massachusetts	103.7	265.3	165.8	527.8	224.1	244.3	865.3	178.7	148.6	86.4	126.8	77.0	83.5	84.4	88.1	63.6	67.5	81.3	72.7	91.6
New Hampshire	735.5	590.6	495.5	176.5	408.5	219.6	450.8	915.4	192.5	117.3	815.3	84.2	89.3	78.2	98.3	99.0	84.9	122.0	120.5	135.3
Rhode Island	104.3	104.6	81.9	448.8	548.4	238.5	594.8	728.1	168.9	341.8	54.2	60.8	52.2	63.2	68.8	69.1	68.2	85.1	59.1	69.1
Vermont	895.8	486.3	914.6	215.2	158.4	334.0	929.8	1,792.4	198.8	193.4	240.0	231.8	204.3	178.5	215.3	158.4	170.4	357.7	186.2	198.8
Middle Atlantic	309.1	196.8	184.7	190.8	588.9	262.5	516.4	172.6	150.0	193.6	283.1	121.5	112.2	111.7	110.9	105.0	115.1	113.2	98.2	110.1
New Jersey	173.3	108.2	89.6	139.2	943.3	249.7	505.5	85.6	137.5	263.6	111.7	98.8	89.0	78.7	84.3	85.1	86.4	87.4	71.0	85.0
New York	477.3	204.8	347.7	218.8	447.4	323.7	396.5	344.5	208.1	146.4	198.0	142.8	130.1	150.0	131.5	142.1	136.9	145.2	132.1	160.2
Pennsylvania	353.1	265.1	207.5	222.6	355.4	252.5	564.0	184.5	132.3	166.2	438.3	131.5	125.9	125.4	125.2	107.5	130.5	122.8	108.4	105.1
East North Central	357.8	499.5	319.7	377.0	311.1	315.5	254.0	332.1	189.9	219.4	285.4	114.3	108.8	121.4	120.8	113.8	135.4	128.1	122.9	124.4
Illinois	158.0	210.4	90.8	127.2	335.8	116.3	143.8	120.0	136.1	170.9	197.6	59.1	56.2	59.1	63.6	57.1	73.8	72.5	72.8	80.7
Indiana	310.0	467.4	276.5	302.7	294.3	266.6	302.4	223.5	254.2	257.4	236.5	123.3	111.3	139.9	137.4	127.6	147.5	146.1	135.4	129.4
Michigan	481.7	1,127.7	520.7	890.0	418.7	570.2	450.2	802.2	268.4	374.5	592.5	161.3	164.8	166.8	178.6	198.7	213.9	186.4	180.1	194.2
Ohio	511.0	366.6	413.6	244.9	283.6	303.6	240.3	249.8	169.5	167.5	185.5	133.3	127.1	144.1	136.0	129.2	145.2	150.1	141.8	127.1
Wisconsin	266.2	203.8	307.9	361.2	119.6	383.5	117.0	219.2	147.2	107.8	154.1	97.5	76.8	104.7	88.0	89.1	90.0	76.4	69.1	76.3
West North Central	255.3	222.7	202.8	236.4	229.8	195.2	140.2	223.0	220.1	179.0	133.1	93.9	84.8	95.1	88.8	87.0	95.4	91.1	90.3	95.1
Iowa	209.3	83.9	95.0	137.8	1,066.5	126.0	115.4	128.1	136.5	96.0	151.2	84.1	60.7	78.2	89.7	85.7	83.7	92.9	103.8	96.0
Kansas	269.4	287.1	179.3	346.0	106.4	241.2	153.1	388.6	169.1	360.5	153.4	104.0	101.8	108.1	113.9	91.9	117.2	105.6	130.9	132.3
Minnesota	222.4	127.1	275.2	121.0	129.0	148.2	129.8	308.9	350.8	123.1	91.5	72.8	71.6	83.7	84.7	79.8	87.8	71.7	88.6	79.4
Missouri	212.8	379.0	149.5	267.9	154.1	261.0	151.2	307.2	215.4	164.9	134.3	106.6	104.4	97.0	97.8	98.7	113.6	91.8	90.8	86.6
Nebraska	897.8	69.4	73.0	556.8	115.4	78.6	189.7	160.7	63.1	67.6	98.3	69.8	55.6	56.2	59.9	67.4	59.2	76.8	72.9	49.2
North Dakota	159.7	262.3	677.6	101.6	123.3	132.6	111.2	91.2	152.3	113.6	102.5	87.6	93.9	102.8	88.4	86.8	77.1	96.0	76.4	110.4
South Dakota	85.6	78.1	338.3	101.3	97.4	311.4	93.1	101.7	255.8	135.0	120.6	61.5	63.9	126.3	61.9	71.5	108.2	73.0	80.3	84.4
South Atlantic	1,405.8	240.4	615.9	191.2	321.4	206.0	639.0	1,241.6	576.5	195.4	309.4	133.1	119.7	127.9	113.0	122.6	124.2	135.3	122.4	129.3
Delaware	117.9	109.7	79.8	64.3	271.9	102.0	136.2	154.8	148.7	191.4	169.8	66.8	61.2	66.4	64.3	84.0	74.2	73.8	83.3	102.3
District of Columbia	32.6	71.9	33.7	52.0	44.0	77.0	109.2	57.5	115.0	112.4	96.0	26.4	33.3	26.3	42.0	39.0	55.0	52.9	57.5	115.0
Florida	1,467.4	172.3	1,011.3	82.9	200.4	88.9	305.5	2,693.2	388.2	86.1	89.4	66.7	69.4	69.8	65.3	72.5	74.0	79.6	76.7	82.7
Georgia	1,269.1	342.7	212.4	140.5	521.7	149.8	230.7	1,030.8	424.0	248.2	252.3	211.4	133.4	129.3	123.8	130.5	125.8	118.8	115.2	120.6
Maryland	118.1	166.2	260.0	127.8	113.8	143.8	330.4	103.1	120.7	117.2	255.9	75.1	66.8	84.2	89.2	76.2	89.0	93.6	81.5	104.5
North Carolina	1,519.1	262.5	486.0	215.2	437.4	287.5	1,877.9	282.2	857.3	220.8	519.0	143.9	156.4	150.7	125.9	146.0	147.0	168.0	151.1	152.1
South Carolina	3,155.0	169.8	302.4	122.9	332.6	338.2	488.6	388.9	1,698.8	234.3	787.0	115.9	126.5	114.8	101.3	121.3	106.3	138.8	119.4	122.1
Virginia	962.1	292.8	1,108.2	798.2	337.7	478.0	1,133.7	279.2	317.8	249.0	287.1	245.1	239.8	342.3	262.7	250.8	285.4	307.8	218.0	219.7
West Virginia	1,165.5	751.5	1,003.2	1,117.2	924.2	755.2	739.7	690.8	743.4	814.6	662.8	486.1	385.7	543.6	451.8	467.9	471.3	513.1	451.8	439.1
East South Central	423.7	864.3	392.5	573.8	825.2	269.4	314.9	427.7	216.0	272.4	263.9	176.3	186.5	187.8	152.6	147.8	160.3	158.3	144.4	147.9
Alabama	197.7	400.2	231.1	175.7	3,320.4	183.7	457.8	242.4	174.2	274.7	282.9	120.8	189.5	198.4	110.9	144.8	166.8	136.8	130.8	140.1
Kentucky	537.7	861.5	345.1	698.2	284.7	204.2	407.5	183.3	194.2	245.8	249.5	145.7	140.6	151.5	130.3	125.3	148.9	146.7	120.0	139.0
Mississippi	607.3	877.8	455.9	1,189.8	1,611.7	466.1	271.6	580.2	276.7	363.3	279.4	279.0	266.6	243.3	224.5	203.9	214.3	209.7	205.5	179.9
Tennessee	289.3	926.9	428.3	316.8	618.4	252.9	217.5	621.5	212.9	257.5	277.7	169.9	192.7	194.1	151.7	144.3	160.4	145.6	141.7	141.6
West South Central	1,268.9	685.0	242.8	1,893.7	1,018.2	309.0	265.4	218.6	204.8	164.2	163.0	178.3	188.8	152.5	162.3	150.3	144.8	145.8	155.3	138.0
Arkansas	527.8	915.3	437.5	308.4	771.6	451.3	330.9	405.8	400.5	326.2	238.5	201.9	230.7	279.6	199.4	210.8	228.0	214.1	176.0	213.7
Louisiana	630.6	663.2	323.8	5,868.8	4,331.9	521.2	285.7	423.5	442.6	411.9	499.1	215.9	199.3	252.2	265.0	217.9	223.5	214.2	196.9	190.1
Oklahoma	220.7	1,239.4	165.6	165.9	585.1	186.2	154.7	194.0	326.2	597.0	115.9	164.2	163.0	178.3	186.8	152.5	162.3	150.3	144.8	145.8
Texas	1,614.3	583.1	204.6	1,496.4	419.4	254.8	170.4	488.8	216.8	279.8	198.8	153.4	150.3	153.7	174.1	132.7	141.4	130.2	135.1	132.7
Mountain	176.3	117.9	153.2	166.3	178.8	131.1	119.0	131.7	131.3	131.7	107.3	102.4	90.4	95.4	99.5	87.3	91.2	88.6	95.6	90.6
Arizona	83.6	103.8	136.9	101.9	70.6	83.3	111.6	89.5	86.8	89.6	86.9	69.8	66.0	69.1	69.2	63.0	64.0	57.6	50.8	67.9
Colorado	257.0	100.2	143.7	185.4	136.4	184.5	99.6	132.7	154.5	107.9	86.7	118.9	89.2	96.9	104.6	83.4	84.3	86.5	80.2	83.5
Idaho	204.4	134.4	167.4	438.0	286.5	155.4	169.9	253.9	183.0	238.1	168.4	152.5	121.8	144.5	137.5	158.1	132.3	140.8	222.9	157.6
Montana	340.7	224.1	251.7	275.3	165.8	135.4	216.4	295.4	144.9	132.3	113.8	169.6	147.2	136.8	121.7	118.3	160.8	118.8	119.6	161.5
Nevada	158.9	138.7	195.1	102.4	73.3	87.0	126.2	114.4	95.7	107.0	75.7	63.8	81.2	77.0	69.7	66.3	77.5	76.7	87.7	73.7
New Mexico	272.6	156.0	175.2	204.3	140.1	158.2	132.9	121.2	130.4	108.8	74.5	152.0	123.7	125.4	120.0	113.6	121.5	123.9	114.5	102.2
Utah	115.4	127.7	108.7	113.4	133.8	144.4	115.5	142.1	150.3	203.2	193.5	109.0	108.1	99.6	106.5	109.5	118.4	115.5	114.3	130.1
Wyoming	137.8	121.4	159.0	167.9	293.4	166.8	125.4	200.4	180.2	181.3	201.9	118.0	102.6	116.1	115.6	105.1	134.0	107.1	171.9	135.8
Pacific Contiguous	371.7	299.1	246.2	483.8	282.8	528.9	200.9	258.5	147.8	188.1	160.6	159.6	147.8	152.8	149.5	119.4	106.1	101.0	108.8	103.5
California	285.0	252.5	202.4	335.2	280.7	610.7	199.4	243.2	119.0	120.4	113.0	164.4	157.7	156.5	148.0	107.6	106.7	99.5	104.5	100.0
Oregon	579.1	122.9	325.2	1,588.3	325.0	290.4	111.4	314.5	233.5	225.9	259.9	124.1	103.5	121.0	113.9	103.4	101.6	90.3	111.6	106.1
Washington	643.5	153.8	403.6	554.5	268.6	310.9	265.3	311.3	258.0	620.9	412.6	157.3	129.8	153.5	151.1	126.9	105.8	115.5	135.8	121.3
Pacific Noncontiguous	329.8	456.2	891.3

Table 11.5 SAIFI Values (Times Per Year) of U.S. Distribution System by State, 2014 - 2024

Census Division and State	IEEE																						Any Method																	
	All Events (With Major Event Days)										Without Major Event Days										Loss of Supply Removed										All Events (With Major Event Days)										Without Major Event Days					
	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
New England	1.3	1.4	1.3	1.4	2.0	1.4	1.8	1.5	1.4	1.1	1.6	0.9	0.9	1.0	1.0	1.0	0.9	1.1	0.9	1.2	1.0	1.0	1.2	1.3	1.3	1.3	1.9	1.3	1.7	1.4	1.3	1.0	1.5	1.4	1.4	1.4	1.4	1.9	1.4	1.7	1.5	1.3	1.0	1.6	1.0	0.9	1.0	1.0	1.1	0.9	1.1	0.9	1.1	1.0	1.1
Connecticut	0.9	0.9	0.9	1.0	2.0	1.0	1.3	1.0	1.2	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	1.0	0.7	0.8	0.9	0.9	0.9	1.0	2.0	1.0	1.3	1.0	1.2	0.7	0.8	0.9	0.9	0.9	1.1	2.0	1.1	1.3	1.0	1.2	0.7	0.7	0.8	0.6	0.7	0.6	0.8	0.6	0.7	0.7	0.8	0.6	0.7
Maine	3.6	3.3	3.0	2.5	3.9	2.5	2.8	2.6	2.7	1.9	5.1	2.1	2.0	2.0	2.1	2.1	1.7	2.0	1.9	2.2	1.8	2.0	3.3	3.0	2.8	2.2	3.8	2.3	2.8	2.6	2.6	1.7	5.1	3.6	3.3	3.0	2.5	3.8	2.5	2.8	2.8	2.7	1.8	5.1	2.1	2.0	2.0	2.1	2.1	1.7	2.0	1.8	2.2	1.8	2.0
Massachusetts	0.9	1.1	1.1	1.2	1.2	1.1	1.7	1.0	1.0	0.8	1.0	0.7	0.8	0.9	0.9	0.8	0.8	0.9	0.3	0.9	0.7	0.8	0.8	1.0	1.0	1.1	1.2	1.1	1.6	1.0	0.9	0.8	1.0	0.8	1.1	1.1	1.2	1.3	1.2	1.6	1.1	1.0	0.8	1.0	0.7	0.8	0.9	0.9	1.0	0.8	0.9	0.6	0.9	0.7	0.8
New Hampshire	1.6	1.5	1.4	1.1	1.5	1.2	1.9	2.0	1.5	1.1	2.0	0.8	0.8	0.8	0.7	0.9	0.9	0.8	1.1	1.1	1.4	1.1	1.6	1.5	1.4	1.0	1.5	1.2	1.9	2.0	1.5	1.1	1.8	2.0	1.8	1.8	1.4	1.8	1.4	2.2	2.3	1.5	1.4	2.3	1.0	1.0	0.9	1.1	1.1	0.9	1.2	1.3	1.3	1.4	1.6
Rhode Island	0.9	0.8	1.0	1.4	2.0	1.4	1.8	1.2	1.2	1.2	0.8	0.8	0.7	0.8	0.8	0.9	0.9	1.0	1.0	0.8	1.0	0.8	0.9	0.7	0.9	1.4	1.4	1.2	1.8	1.1	1.0	1.2	0.8	0.9	0.8	1.0	1.4	2.0	1.4	1.6	1.2	1.2	1.2	0.8	0.8	0.7	0.8	0.8	0.9	0.9	1.0	1.0	0.8	1.0	0.8
Vermont	3.3	2.3	2.4	1.9	1.8	2.0	3.4	2.6	1.8	1.8	2.5	1.4	1.4	2.0	1.9	1.6	1.5	2.3	1.6	1.8	1.8	1.4	2.1	2.0	2.3	1.8	1.8	1.9	2.9	2.5	1.4	1.5	2.3	2.5	2.4	2.6	2.1	1.9	2.0	2.6	2.4	1.9	1.7	2.2	1.7	1.6	2.0	2.1	1.9	1.5	1.9	1.8	1.8	1.7	1.5
Middle Atlantic	1.2	1.0	1.1	1.2	1.5	1.3	1.5	1.1	1.2	1.0	1.1	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.8	0.9	1.2	1.0	1.0	1.1	1.3	1.2	1.4	1.0	1.1	1.0	1.1	1.1	1.0	1.0	1.2	1.1	1.2	1.2	1.0	1.0	0.8	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
New Jersey	1.1	0.9	0.9	1.0	1.8	1.0	1.4	0.9	1.2	1.0	1.0	0.8	0.8	0.8	0.8	0.9	0.9	1.0	0.9	1.0	0.8	0.9	1.0	0.8	0.8	0.9	1.4	1.1	1.3	0.9	1.0	1.0	0.9	1.1	0.9	0.9	1.0	1.8	1.2	1.4	0.9	1.2	1.0	1.0	0.9	0.8	0.8	0.8	0.9	0.9	1.0	0.9	1.0	0.8	0.9
New York	1.7	1.1	1.5	1.3	1.5	1.5	1.5	1.4	1.3	1.2	1.2	1.1	1.0	1.2	1.1	1.1	1.0	1.1	1.0	1.2	1.1	1.0	1.7	1.1	1.5	1.3	1.5	1.5	1.5	1.4	1.2	1.1	1.2	0.9	0.7	0.9	0.9	1.0	0.9	1.0	0.8	0.8	0.7	0.8	0.8	0.6	0.8	0.8	0.6	0.7	0.7	0.6	0.8	0.6	0.6
Pennsylvania	1.4	1.1	1.2	1.2	1.3	1.3	1.5	1.1	1.1	1.0	1.3	1.0	0.9	1.0	1.0	0.9	1.0	1.0	0.9	1.0	0.8	1.0	1.3	1.0	1.1	1.1	1.2	1.2	1.4	1.0	1.0	0.9	1.1	1.4	1.1	1.1	1.2	1.3	1.3	1.4	1.1	1.1	1.0	1.2	1.0	0.9	1.0	1.0	0.9	1.0	1.0	0.9	1.0	0.9	0.9
East North Central	1.2	1.2	1.2	1.3	1.3	1.3	1.2	1.2	1.1	1.2	1.2	0.8	0.8	0.8	0.8	0.8	0.8	1.0	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.2	1.1	1.2	1.0	1.0	1.0	1.1	1.2	1.2	1.2	1.2	1.3	1.2	1.3	1.2	1.2	1.1	1.2	1.1	0.8	0.8	0.8	0.8	0.8	0.9	0.9	1.0	0.8	0.9
Illinois	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.1	1.1	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.7	0.8	0.8	1.0	0.8	0.8	0.7	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.1	0.9	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.1	1.1	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.9	1.0
Indiana	1.3	1.4	1.4	1.4	1.3	1.5	1.5	1.3	1.3	1.3	1.3	1.0	0.9	1.1	1.1	1.0	1.2	1.2	1.0	1.1	1.0	1.0	1.1	1.3	1.2	1.1	1.0	1.2	1.2	1.1	1.2	1.1	1.1	1.3	1.4	1.4	1.4	1.4	1.3	1.5	1.5	1.3	1.3	1.3	1.3	1.0	0.9	1.1	1.1	1.0	1.2	1.1	1.0	1.0	1.0
Michigan	1.4	1.5	1.3	1.6	1.4	1.5	1.4	1.4	1.1	1.2	1.2	1.0	0.9	1.0	1.0	1.0	1.1	1.2	1.1	1.0	1.0	1.0	1.3	1.5	1.3	1.6	1.3	1.5	1.3	1.4	1.1	1.1	1.2	1.4	1.5	1.3	1.7	1.4	1.5	1.4	1.4	1.1	1.1	1.2	1.0	0.9	1.0	1.0	1.1	1.2	1.1	1.0	1.0	1.0	0.9
Ohio	1.3	1.3	1.5	1.3	1.4	1.5	1.4	1.4	1.2	1.2	1.2	1.0	0.9	1.1	1.1	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.1	1.2	1.2	1.2	1.1	1.0	1.0	1.3	1.3	1.5	1.3	1.4	1.5	1.4	1.4	1.2	1.2	1.2	1.0	0.9	1.1	1.1	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Wisconsin	1.2	0.9	1.1	1.1	0.8	1.1	0.8	0.9	0.9	1.5	0.8	0.7	0.6	0.6	0.7	0.7	0.7	0.6	0.6	0.7	1.2	0.7	1.0	0.9	1.1	1.1	0.8	1.1	0.7	0.8	0.8	0.8	1.0	0.9	1.0	1.0	0.8	1.1	0.8	0.9	0.8	1.3	0.8	0.7	0.8	0.7	0.7	0.8	0.7	0.6	0.7	1.1	0.7
West North Central	1.2	1.1	1.1	1.2	1.0	1.2	1.0	1.1	1.2	1.1	1.1	0.9	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.9	0.9	0.9	0.8	0.9	0.9	1.0
Iowa	1.2	0.9	1.0	1.0	1.5	1.1	1.0	1.1	1.2	1.0	1.2	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	0.7	0.8	0.8	1.3	1.0	0.9	0.9	0.9	0.8	1.1	1.2	0.9	0.9	0.9	1.5	1.1	1.0	1.0	1.0	1.0	1.2	0.9	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0
Kansas	1.5	1.3	1.3	1.5	0.9	1.4	1.2	1.5	1.4	1.6	1.4	1.0	1.0	1.1	1.1	0.9	1.0	1.0	1.1	1.3	1.3	1.2	1.4	1.2	1.1	1.3	0.9	1.3	1.0	1.2	1.3	1.2	1.5	1.2	1.3	1.5	0.9	1.4	1.2	1.5	1.4	1.6	1.3	1.0	1.1	1.1	1.1	0.9	1.0	1.0	1.1	1.2	1.3	1.2
Minnesota	1.3	1.0	1.2	1.0	1.0	1.0	1.0	1.2	1.0	1.0	0.9	0.8	0.8	0.8	0.9	0.9	0.8	0.9	0.8	0.9	0.8	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.3	1.0	1.0	1.2	1.0	1.0	1.0	1.0	0.8	0.8	0.9	0.9	0.9	0.8	0.8	0.8	0.9	0.9	0.9	0.8	0.9	0.8	0.8
Missouri	1.2	1.3	1.1	1.3	1.0	1.3	1.0	1.2	1.0	1.0	1.1	0.9	0.9	0.9	0.8	0.9	1.0	0.8	0.8	0.8	0.8	0.9	1.0	1.1	1.3	1.0	1.1	1.0	1.0	1.1	1.0	1.0	1.3	1.2	1.3	1.1	1.2	1.0	1.1	1.0	1.3	1.0	1.0	1.2	1.1	1.1	1.1	0.9	0.9	0.9	0.8	0.9	1.0	0.8	0.8
Nebraska	1.2	0.8	0.8	1.0	0.8	0.7	1.1	0.9	0.7	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.5	0.7	0.7	0.6	0.6	0.6	0.7	0.5	0.6	1.1	0.9	0.7	0.7	0.7	0.6	0.6	0.5	1.2	0.9	0.8	1.2	0.8	0.7	1.1	0.9	0.7	0.7	0.9	0.6	0.5	0.5	0.5	0.6	0.5	0.7	0.7	0.6	0.6	0.7
North Dakota	0.9	1.2	1.4	1.0	1.2	1.0	1.0	2.1	2.4	1.8	0.9	0.8	0.8	1.1	1.0	1.0	0.8	0.9	0.9	1.9	2.3	1.7	0.7	0.8	1.1	0.6	0.8	0.8	0.7	0.7	1.0	0.7	1.0	0.9	1.1	1.3	0.9	0.8	1.0	0.8	0.9	0.8	1.0	1.0	1.6	2.1	1.4	0.9	0.9	0.8	1.0	1.0	2.3	1.7
South Dakota	0.8	1.0	1.2	1.0	1.1	1.6	1.1	1.2	1.4	1.1	1.0	0.7	0.9	0.8	0.7	0.9	1.1	0.9	1.1	1.0	0.9	1.0	0.8	0.7	0.9	0.7	0.7	1.1	0.7	0.9	0.9	0.9	0.7	0.8	1.0	1.2	1.0	1.1	1.6	1.1	1.2	1.4	1.1	1.0	0.7	0.9	0.8	0.7	0.9	1.1	0.9	1.0	1.0	0.9	0.9
South Atlantic	1.8	1.3	1.7	1.2	1.5	1.3	1.8	1.8	1.6	1.3	1.4	1.0	1.1	1.1	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.7	1.2	1.5	1.3	1.3	1.2	1.5	1.6	1.5	1.2	1.4	1.8	1.3	1.7	1.2	1.5	1.3	1.6	1.7	1.6	1.3	1.4	1.0	1.1	1.1	1.2	1.1	1.2	1.2	1.2	1.2
Delaware	0.9	0.8	0.9	1.0	1.5	1.0	1.3	1.5	1.4	0.7	0.7	0.8	0.8	1.0	0.9	0.9	0.9	1.0	1.1	1.3	1.2	0.9	0.9	0.9	1.0	1.5	1.0	1.0	1.3	1.4	1.3	0.8	0.8	0.9	1.0	1.2	1.4	1.5	1.4	0.7	0.7	0.8	1.0	1.0	0.9	0.9	1.0	1.2	1.3	1.2	1.3	1.2	1.2
District of Columbia	0.3	0.4	0.3	0.5	0.4	0.6	0.6	0.8	0.8	0.7	0.7	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.8	0.7	0.6	0.3	0.4	0.3	0.5	0.4	0.6	0.6	0.6	0.8	0.7	0.7	0.3	0.4	0.3	0.5	0.4	0.6	0.6	0.6	0.8	0.7	0.6	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.8	0.7	0.6
Florida	1.8	1.0	1.5	0.9	1.1	1.0	1.1	2.1	1.4	1.1	1.1	0.7	0.8	0.8	0.8	0.9	0.9	1.0	1.0	1.1	1.0	1.1	1.7	0.9	1.4	0.9	1.1	0.9	1.1	2.0	1.3	1.0	1.5	1.8	1.0	1.5	0.9	1.2	1.0	1.1	2.0	1.4	1.1	1.1	0.8	0.8	0.9	0.8	1.0	0.9	1.0	1.0	1.1	1.1	1.1
Georgia	2.1	1.9	1.7	1.3	2.0	1.4	1.5	2.2	1.5	1.6	1.5	1.2	1.3	1.3	1.2	1.3	1.2	1.2	1.2	1.3	1.3	1.2	1.9	1.5	1.1	1.7	1.2	1.4	2.1	1.2	1.4	1.3	2.0	1.4	1.6	2.4	1.5	1.5	1.9	1.7	1.3	2.0	1.4	1.6	1.3	1.3	1.4	1.2	1.3	1.3	1.2	1.3	1.3	1.2	1.2
Maryland	0.8	0.9	1.2	1.0	0.9	1.0	1.2	0.9	1.1	1.0	1.3	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.8	1.0	1.0	1.0	0.8	0.9	1.1	0.9	0.9	1.0	1.2	0.9	1.1	1.0	1.2	0.8	0.9	1.2	1.0	1.0	1.0	1.3	1.0	1.1	1.1	1.3	0.7	0.7	0.8	0.8	0.8	0.9	1.0	0.9	1.0	1.0	1.0
North Carolina	1.8	1.5	2.0	1.2	1.7	1.4	2.3	1.4	1.9	1.4	1.5	1.2	1.3	1.2	1.1	1.2	1.1	1.2	1.1	1.1	1.0	1.1	1.7	1.4	1.8	1.2	1.5	1.3	2.0	1.2	1.3	1.2	1.7	1.8	1.5	1.9	1.2	1.7	1.4	2.2	1.3	1.8	1.3	1.5	1.2	1.3	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0
South Carolina	2.4	1.5	1.9	1.2	1.5	1.5	1.8	1.6	2.4	1.5	1.9	1.2	1.3	1.2	1.0	1.1	1.0	1.2	1.1	1.2	1.2	1.1	2.1	1.2	1.6	1.0	1.3	1.3	1.5	1.5	2.2	1.2	1.6	2.4	1.5	1.9	1.2	1.5	1.5	1.7	1.6	2.4	1.5	1.8	1.2	1.3	1.2	1.0	1.1	1.0	1.2	1.1	1.2	1.2	1.3
Virginia	2.2	1.7	2.5	2.0	1.8	2.1	2.6	1.6	1.7	1.5	1.6	1.6	1.5	1.8	1.6	1.6	1.7	1.7	1.4	1.5	1.4	1.4	2.0	1.6	2.4	1.9	1.7	1.9	2.4	1.5	1.3	1.4	1.4	1.6	1.5	1.9	1.6	1.6	1.7	1.8	1.4	1.5	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.4	1.2	1.3	1.2	1.2
West Virginia	2.6	2.4	2.7	2.4	2.8	2.6	2.3	2.4	2.4	2.4	2.3	1.8	2.2	2.1	2.2	2.4	2.4	2.1	2.2	2.1	2.2	2.1	2.5	2.3	2.1	2.3	2.5	2.4	2.0	2.1	2.2	2.1	2.6	2.4	2.7	2.4	2.8	2.6	2.3	2.4	2.4	2.3	1.9	2.2	2.1	2.2	2.4	2.4	2.1	2.2	2.1	2.2	2.1
East South Central	2.0	2.4	2.5	1.8	2.0	1.9	1.9	1.7	1.7	1.8	1.8	1.6	1.6	1.7	1.4	1.4	1.5	1.5	1.3	1.5	1.5	1.4	1.9	2.3	2.3	1.7	1.8	1.8	1.7	1.6	1.5	1.6	1.8	2.0	2.3	2.3	1.8	2.0	1.8	1.8	1.8	1.7	1.7	1.7	1.5	1.5	1.6	1.4	1.3	1.5	1.4	1.3	1.4	1.4	1.3
Alabama	1.7	2.3	2.3	1.4	3.5	1.6	2.0	1.9	1.8	2.0	2.0	1.3	1.5	2.0	1.2	1.4	1.4	1.5	1.5	1.4	1.5	1.6	1.7	1.7	2.0	2.2	1.6	3.4	1.5	1.7	1.6	1.5	1.8	2.0	1.9	1.6	1.4	1.4	2.4	1.4	1.5	2.0	1.6	1.7	1.5	1.0	1.0	1.2	1.1	1.1	1.1	1.2	1.1	1.2	1.2	1.1
Kentucky	1.8	1.3	1.7	1.2	1.5	1.3	1.8	1.8	1.6	1.3	1.4	1.0	1.1	1.1	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.7	1.2	1.5	1.3	1.3	1.2	1.5	1.6	1.5	1.2	1.4	1.8	1.3	1.7	1.2	1.5	1.3	1.6	1.7	1.6	1.3	1.4	1.0	1.1	1.1	1.2	1.1	1.2	1.2	1.2	1.2
Mississippi	2.5	2.6	2.2	2.3	2.4	2.0	1.7	2.1	1.9	2.1	2.0	1.9	2.1	1.7	1.5	1.4	1.6	1.6	1.5	1.6	1.8	1.4	2.7	2.9	2.3	2.5	2.4	2.2	1.9	2.3	1.9	1.9	1.8	2.6	2.7	2.4	2.4	2.5	2.1	1.8	2.2	1.9	2.0	1.7	2.0	2.1	2.0	1.8	1.5	1.6	1.6	1.8	1.7	1.6	1.2
Tennessee	1.9	2.8	3.3	2.0	2.1	2.1	2.0	1.9	1.8	1.8	1.8	1.8	1.9	2.0	1.7	1.5	1.8	1.7	1.5	1.6	1.5	1.5	1.9	2.8	3.1	1.8	2.0	2.1	1.9	1.8	1.7	1.7	1.7	2.0	2.8	3.2	2.0	2.1	2.2	1.9	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.7	1.6	1.8	1.7	1.5	1.6	1.5	1.6
West South Central	2.2	1.9	1.8	3.0	1.8	1.8	1.8	1.8	1.5	1.6	1.7	1.2	1.3	1.3	1.4	1.4	1.4	1.4	1.3	1.4	1.4	1.3	2.1	1.8	1.7	3.0	1.8	1.6	1.5	1.6	1.8	1.5	1.7	2.1	1.8	1.7	2.7	2.3	1.7	1.9	1.5	1.7	1.8	1.7	1.5	1.3	1.4	1.1	1.2	1.3	1.3	1.5	1.2	1.2	1.2
Arkansas	2.1	2.1	2.2	1.7	1.9	1.9	1.7	2.1	2.1	2.1	1.8	1.6	1.6	1.8	1.4	1.4	1.5	1.5	1.5	1.7	1.8	1.6	1.8	1.9	1.9	1.4	1.7	1.7	1.8	1.9	1.9	1.8	2.2	2.1	2.1	2.1	1.7	1.8	1.9	1.8	2.0	2.0	2.0	1.8	1.8	1.5	1.8	1.4	1.4	1.5	1.5	1.5	1.7	1.8	1.6
Louisiana	2.4	1.9	2.0	3.4	3.3	2.1	2.0	2.3	2.1	2.3	3.0	1.7	1.5	1.9	1.8	1.8	1.6	1.8	1.7	1.7	1.8	1.5	2.2	1.8	1.9	3.1	3.1	2.0	1.8	2.0	1.9	2.0	1.6	2.7	2.1	2.1	3.3	3.2	2.2	2.1	2.3	2.1	2.3	2.4	1.8	1.6	1.9	1.8	1.7	1.6	1.8	1.7	1.8	1.8	1.5
Oklahoma	1.6	2.1	1.5	1.5	1.8	1.6	1.4	1.5	1.7	1.9	1.5	1.4	1.5	1.4	1.3	1.4	1.4	1.3	1.2	1.3	1.2	1.2	1.4	1.2	1.7	3.0	1.8	1.6	1.5	1.6	1.8	1.5	1.7	1.7	1.2	1.4	1.4	2.1	1.5	1.3	1.5	1.7	1.8	1.5	1.3	1.3	1.4	1.1	1.2	1.5	1.3	1.3	1.4	1.2	1.0
Texas	2.3	1.9	1.7	3.3	1.8	1.7	1.4	1.7	1.6	1.8	1.5	1.4	1.4	1.4	1.4	1.2	1.3	1.2	1.3	1.3	1.3	1.2	2.3	1.8	1.7	3.5	1.5	1.5	1.3	1.5	1.5	1.7	1.5	2.1	1.8	1.7	2.9	2.2	1.7	1.4	1.7	1.6	1.8	1.4	1.2	1.2	1.2	1.2	1.5	1.1	1.1	1.3	1.3	1.3	1.2
Mountain	1.2	1.0	1.0	1.1	1.0	1.0	1.0	1.1	1.1	1.0	1.0	1.0	0.8	0.9	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	1.1	0.9	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	0.9	1.2	1.0	1.1	1.2	1.0	1.0	1.0	1.1	1.1	1.1	1.0	1.0	0.8	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9
Arizona	1.0	1.0

Table 11.6 CAIDI Values (Minutes Per Interruption) of U.S. Distribution System by State, 2014 - 2024

Census Division and State	IEEE																						Any Method																	
	All Events (With Major Event Days)										Without Major Event Days										Loss of Supply Removed										All Events (With Major Event Days)										Without Major Event Days					
	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
New England	299.6	357.7	230.7	282.2	643.0	258.6	405.4	521.7	163.9	137.9	195.7	111.9	112.5	101.0	102.8	99.0	103.0	110.8	125.8	105.1	100.3	105.7	311.8	370.7	262.4	280.1	677.0	270.7	423.1	542.0	177.7	138.2	196.3	303.6	343.7	240.9	267.3	575.0	242.2	410.3	470.8	161.4	133.5	203.8	118.0	114.2	104.5	105.1	131.2	111.5	114.5	125.6	114.9	103.2	108.4
Connecticut	174.2	212.4	207.0	172.8	1,531.0	247.1	592.4	333.8	173.4	148.6	120.6	113.3	114.0	109.4	111.1	101.7	102.6	110.7	102.9	103.9	111.8	120.6	177.4	214.9	208.5	173.8	1,545.5	248.1	604.1	336.7	173.5	149.4	120.5	175.5	188.8	191.8	162.2	1,446.4	243.3	522.5	307.7	163.8	147.6	116.3	113.4	107.3	106.4	107.3	98.1	98.2	107.4	100.1	101.5	108.4	116.3
Maine	480.8	582.2	321.1	130.5	446.5	358.6	237.5	885.7	198.8	114.2	204.8	128.1	125.0	110.8	107.8	115.7	127.3	134.0	123.8	122.0	109.3	115.3	511.5	580.0	334.1	140.4	458.2	364.8	246.1	927.6	215.4	102.2	205.1	480.9	582.2	321.1	130.5	446.5	358.6	237.5	885.7	198.8	114.2	204.8	128.1	125.0	110.8	107.8	115.7	127.3	134.0	123.8	122.0	109.3	115.3
Massachusetts	121.8	248.2	151.7	428.8	184.4	219.1	521.1	174.2	144.7	110.6	130.9	102.9	105.7	94.0	99.1	79.3	87.7	95.3	286.4	100.6	95.4	100.5	125.3	262.0	186.9	542.0	199.3	235.0	562.7	188.5	174.9	112.1	134.2	120.9	245.4	151.0	426.3	244.9	204.4	524.1	253.4	146.3	115.8	130.2	102.3	105.4	93.6	99.0	166.5	114.1	107.8	159.8	122.5	101.3	100.3
New Hampshire	455.2	397.7	349.6	161.2	269.7	188.0	238.6	456.7	125.5	103.9	414.2	108.5	116.8	111.8	114.5	108.4	110.9	112.8	105.1	99.5	95.7	100.2	459.0	397.2	352.5	173.1	271.2	188.0	240.4	461.7	128.1	111.1	452.6	456.6	368.5	345.9	171.3	274.3	204.3	234.2	484.7	124.9	107.9	381.1	134.3	126.1	115.6	117.8	112.3	120.8	119.7	116.7	102.1	102.1	109.1
Rhode Island	116.4	133.7	85.4	313.8	278.9	168.3	378.8	614.6	140.0	277.7	71.1	79.8	78.3	78.2	72.6	73.1	68.6	85.0	76.3	71.0	68.8	71.1	114.9	136.8	87.0	312.7	314.1	179.5	385.5	649.8	158.0	277.7	71.3	116.4	133.7	85.4	313.8	278.9	168.3	378.8	614.6	140.0	277.7	71.1	79.8	78.3	78.2	72.6	73.1	68.6	85.0	76.3	71.0	68.8	71.1
Vermont	268.2	216.1	374.8	112.7	97.2	170.4	274.3	687.1	128.1	109.6	95.2	165.8	148.1	91.5	112.7	97.2	114.4	152.8	114.1	128.1	109.6	129.7	429.4	235.3	388.3	120.1	96.8	173.4	256.0	715.5	136.6	117.2	103.0	276.9	316.5	367.8	151.0	134.7	224.0	342.8	362.1	193.1	122.3	339.1	165.5	140.0	136.0	127.5	132.7	116.2	137.4	130.4	151.8	117.6	145.1
Middle Atlantic	230.7	189.0	187.7	165.1	406.2	203.0	352.2	157.2	129.1	184.9	247.8	123.3	126.1	117.3	115.7	109.3	115.2	111.4	106.0	107.7	104.5	104.6	243.2	195.5	173.3	171.9	427.3	212.5	373.9	160.9	123.2	193.8	260.9	224.0	180.7	183.6	165.8	420.5	196.5	376.3	188.2	125.3	175.1	221.1	120.9	122.2	116.5	118.5	110.3	116.0	111.9	107.2	105.6	105.8	105.9
New Jersey	155.3	122.9	102.2	139.0	596.4	209.2	357.2	81.1	118.7	265.1	117.2	104.2	106.0	94.0	95.2	92.1	91.7	90.9	81.0	86.6	76.8	90.3	168.0	126.6	104.9	146.4	633.9	222.2	382.1	91.3	108.5	271.7	119.4	155.7	123.0	102.4	138.8	609.8	208.1	359.6	81.8	118.9	262.8	117.5	105.2	106.5	94.3	95.7	92.8	92.1	90.9	81.7	87.5	77.5	90.7
New York	286.1	181.7	237.2	166.8	302.4	219.5	261.2	249.6	157.0	124.8	172.2	134.4	135.1	129.1	118.5	131.9	131.2	137.4	129.5	134.7	121.2	120.8	291.1	182.0	237.7	168.7	304.0	220.2	262.8	247.9	149.9	125.7	172.2	241.7	165.8	232.7	166.3	418.1	195.2	403.4	269.3	137.0	128.9	145.9	117.8	119.4	118.5	117.1	116.9	124.2	122.2	116.0	118.5	118.8	114.9
Pennsylvania	253.5	232.0	178.3	181.4	266.1	192.6	378.8	163.8	121.2	162.9	341.8	133.0	137.7	128.6	129.5	114.5	126.9	117.6	115.9	107.9	112.3	109.4	266.7	242.3	184.2	188.8	282.8	202.4	408.3	169.4	120.7	175.0	373.7	248.3	228.0	175.9	181.5	257.8	190.4	362.0	159.3	118.2	157.7	326.0	134.9	135.8	130.4	135.2	116.1	124.6	116.7	115.9	105.6	110.8	108.5
East North Central	309.6	412.3	263.8	298.2	263.9	241.3	213.8	278.3	171.7	182.6	248.2	131.5	134.8	130.4	129.7	125.2	135.4	131.4	133.1	132.5	121.2	131.1	323.7	434.5	264.8	307.2	274.8	254.8	220.7	292.7	174.7	201.7	254.5	302.2	401.8	260.3	292.7	258.6	238.3	269.6	273.4	171.2	180.4	242.7	130.0	133.3	129.8	129.0	124.3	134.8	130.7	133.0	132.4	120.7	129.4
Illinois	186.3	252.4	120.2	141.2	362.7	126.1	157.7	130.2	134.0	153.7	175.8	92.7	93.0	91.9	90.4	87.5	96.8	93.3	97.3	97.2	94.3	96.8	189.9	258.4	119.8	143.3	369.8	121.7	158.5	130.2	133.2	156.7	178.5	184.0	249.2	118.9	140.1	358.4	125.5	156.0	129.3	132.0	152.4	173.9	92.3	92.9	91.4	90.4	87.3	96.8	93.3	97.2	97.2	94.4	96.8
Indiana	242.9	330.6	193.7	217.8	224.7	174.9	202.6	170.2	188.7	198.9	188.0	122.4	118.0	123.2	127.5	127.0	125.9	126.7	129.6	121.6	115.0	114.8	221.4	357.6	177.0	197.5	202.9	174.2	213.5	173.9	202.1	213.7	197.6	243.5	314.8	195.3	210.5	217.3	173.4	196.3	167.3	189.1	193.3	187.5	121.8	118.6	122.4	125.5	125.3	125.0	125.4	129.8	121.8	117.8	114.9
Michigan	353.0	730.9	388.7	540.8	303.1	369.7	327.6	597.2	237.5	325.4	481.0	164.0	177.1	164.2	175.6	157.5	184.1	176.8	183.0	193.5	187.2	204.2	364.5	738.0	391.9	546.2	309.5	375.8	332.7	574.9	237.7	324.9	491.4	346.8	723.5	383.2	527.5	296.8	363.5	322.6	550.9	233.6	318.5	473.8	162.4	176.7	163.6	172.6	154.6	181.7	175.4	180.8	184.8	203.5
Ohio	393.7	292.7	272.4	184.1	209.1	206.1	170.7	182.7	143.5	140.4	155.0	133.4	138.4	128.5	121.4	120.5	127.8	127.9	125.0	120.2	123.6	118.7	445.1	312.6	284.8	174.5	224.0	226.7	181.3	195.9	143.7	146.8	141.3	393.4	292.5	272.4	184.1	209.0	207.1	171.6	183.6	147.1	142.8	155.4	133.4	138.4	128.4	121.2	120.4	128.5	128.6	126.1	121.0	123.6	118.5
Wisconsin	265.2	223.3	279.9	334.6	144.0	341.6	152.3	236.2	171.2	74.1	184.7	134.3	121.4	137.5	126.6	126.4	124.5	112.7	118.9	114.2	58.6	115.0	288.8	228.0	288.9	340.7	147.3	359.4	147.6	243.2	176.0	136.3	188.4	360.8	208.8	262.3	308.0	141.3	326.3	151.3	224.0	162.3	79.6	172.8	129.2	114.7	132.7	124.9	122.8	123.1	113.3	126.1	115.4	64.0	109.5
West North Central	207.8	203.8	183.2	201.0	217.1	169.7	135.2	198.4	194.5	157.6	117.8	106.8	104.3	103.9	105.5	102.5	105.7	103.8	105.0	101.1	95.7	92.3	228.9	221.5	195.7	219.9	253.2	183.3	137.2	219.8	188.0	165.7	134.1	202.9	198.1	179.8	195.3	350.8	165.4	139.2	191.0	176.0	151.2	122.0	108.8	105.9	104.6	104.5	103.6	105.0	103.2	105.5	104.4	104.5	100.8	95.1	93.0
Iowa	165.1	97.7	97.2	143.8	716.5	111.7	112.9	119.4	117.1	96.2	123.6	103.6	94.1	93.5	99.4	99.1	89.4	99.5	107.2	97.0	91.5	91.9	179.5	101.9	105.4	148.3	785.4	115.5	120.7	129.0	136.6	101.0	128.6	145.0	115.7	96.8	144.1	1,183.1	113.7	125.0	118.8	112.1	100.4	137.2	101.3	99.3	93.3	98.8	103.5	94.9	98.7	104.9	98.2	92.5	94.2
Kansas	192.3	218.3	134.9	225.1	112.8	172.2	130.1	247.7	118.8	215.2	113.3	103.5	101.4	99.5	107.1	103.2	114.0	107.1	114.3	106.8	100.7	95.2	205.5	234.5	138.2	143.6	110.7	198.3	139.1	288.1	118.2	174.2	113.7	189.7	214.9	136.4	222.7	113.1	176.4	132.6	246.3	119.1	213.3	113.6	103.1	101.9	99.5	106.8	104.2	113.4	102.3	114.4	107.1	99.6	96.0
Minnesota	176.3	130.6	228.0	116.5	123.5	150.9	124.1	136.2	253.7	165.4	121.1	101.5	93.6	95.8	94.2	94.1	100.7	98.8	93.1	102.9	95.8	83.5	194.3	143.9	245.5	123.1	129.2	156.6	132.5	147.2	278.2	177.1	134.2	175.6	129.9	226.3	116.2	123.1	153.0	124.9	120.1	102.3	93.5	98.0	94.2	95.0	100.9	98.9	94.8	102.6	93.7	89.8
Missouri	180.8	286.1	141.5	211.8	153.8	200.6	155.3	264.7	206.8	161.3	124.5	115.4	118.8	110.5	117.2	112.1	111.5	110.5	116.0	111.6	105.9	104.6	192.5	309.8	146.3	231.6	164.9	239.5	157.2	342.3	155.6	195.3	129.4	188.6	282.9	141.0	208.8	153.1	198.9	153.8	254.6	195.9	161.7	126.7	115.3	121.7	110.7	117.5	111.6	110.9	112.5	113.4	108.5	103.3	103.6
Nebraska	560.8	125.7	123.8	47.8	145.7	119.7	168.5	176.5	89.9	102.6	142.4	116.3	116.2	109.2	116.1	122.1	107.7	105.2	107.1	85.1	87.8	83.0	564.0	121.8	124.0	485.6	104.9	83.8	147.6	164.2	80.5	93.6	151.8	520.8	130.2	134.8	447.0	143.6	128.4	173.4	175.6	124.0	117.8	141.5	123.8	118.3	115.1	118.0	123.8	114.1	105.0	103.4	93.8	93.8	99.5
North Dakota	109.0	227.9	475.5	101.3	107.2	131.8	116.8	87.8	74.0	47.7	57.8	98.7	99.7	96.6	93.5	86.9	92.6	109.8	74.7	57.1	43.8	53.3	109.7	307.2	701.2	131.8	129.3	137.6	135.8	121.2	140.6	112.4	80.2	108.4	197.3	431.4	97.2	104.0	123.6	103.4	88.9	76.7	54.9	61.3	98.3	99.1	89.7	86.6	90.7	107.2	75.2	58.5	42.7	50.5
South Dakota	105.0	76.8	281.1	103.4	89.0	191.5	84.1	88.0	187.8	120.4	115.1	85.4	71.4	159.4	91.2	79.9	98.3	78.6	75.4	84.5	114.6	111.9	116.0	90.1	274.9	113.5	116.3	225.0	108.9	97.5	135.3	112.8	134.1	104.0	76.2	264.9	104.6	88.8	187.2	84.9	87.3	180.2	117.7	114.9	86.2	78.8	155.8	92.3	81.8	97.5	80.9	77.4	84.6	114.9	111.9
South Atlantic	768.2	178.4	370.5	165.8	219.5	159.0	403.4	702.1	360.4	146.4	217.9	129.0	111.9	116.6	113.0	111.0	114.5	117.8	110.1	108.2	105.0	104.1	809.3	180.0	416.1	175.8	223.0	167.6	429.4	771.5	382.0	150.5	268.7	698.7	189.3	401.0	163.2	208.3	155.0	394.6	642.2	332.2	141.1	203.1	124.0	108.6	113.6	108.3	107.4	112.4	114.4	107.5	107.2	102.3	100.3
Delaware	138.0	130.4	93.5	66.8	180.0	104.0	131.3	136.8	110.7	125.1	120.1	91.9	87.2	86.5	66.8	89.3	85.9	85.9	84.9	89.2	89.0	96.9	138.7	130.8	93.4	68.0	184.0	104.0	138.0	140.4	110.4	113.0	131.5	122.2	137.8	130.3	93.5	66.8	180.0	104.0	131.3	136.5	110.4	124.8	119.4	91.9	87.3	86.5	66.8	89.3	86.0	85.5	83.9	89.3	88.8	96.4
District of Columbia	120.2	194.2	111.5	115.8	110.0	130.5	169.9	104.0	140.2	163.9	139.1	107.2	104.6	95.1	102.4	105.4	112.2	98.3	104.0	140.2	163.9	128.1	120.2	194.2	111.5	115.6	110.0	130.5	169.9	104.0	140.2	163.9	139.1	107.2	104.6	95.1	102.4	105.4	112.2	98.3	104.0	140.2	163.9	139.1	107.2	104.6	95.1	102.4	105.4	112.2	98.3	104.0	140.2	163.9	139.1
Florida	833.9	175.5	691.2	92.0	175.9	90.3	274.7	1,302.1	262.0	78.6	78.9	90.0	89.0	83.8	82.0	81.2	81.8	83.5	76.8	78.7	76.2	78.4	865.9	172.3	719.3	89.9	184.2	90.5	276.5	1,337.8	302.9	79.1	81.6	746.6	157.2	774.5	87.0	161.2	87.9	268.2	1,241.6	259.4	78.3	80.2	87.2	84.1	80.4	77.7	76.7	79.1	79.7	75.5	76.3	73.6	75.2
Georgia	574.3	184.5	127.3	108.9	267.2	110.1	149.7	465.8	278.1	158.9	165.0	170.6	99.8	100.2	99.8	98.3	103.0	95.2	96.9	90.1	84.8	83.0	403.2	170.1	119.9	106.9	291.9	94.9	167.9	439.1	343.2	253.0	163.3	579.2	185.2	155.9	110.7	298.7	123.4	239.7	428.3	278.1	158.4	163.3	169.0	100.8	102.3	102.0	98.0	102.9	97.5	101.6	100.2	86.2	84.8
Maryland	144.5	180.7	224.2	132.1	123.8	137.1	264.8	114.8	109.8	114.6	199.3	109.6	95.1	100.2	101.5	98.9	103.0	99.7	99.8	102.2	103.2	92.7	145.6	176.9	213.0	132.3	123.8	136.8	267.1	116.8	109.5	116.2	200.5	144.5	180.7	224.1	132.1	125.9	134.7	260.1	120.1	110.2	114.2	193.5	109.6	95.1	100.2	101.5	100.5	103.1	98.5	99.1	103.1	104.4	92.3
North Carolina	851.3	172.1	246.7	172.3	254.6	198.4	822.2	204.4	461.9	159.7	343.3	122.4	121.9	121.6	119.2	120.7	132.0	143.8	130.1	132.4	115.0	116.9	879.2	178.6	236.6	179.9	271.8	208.3	818.6	209.6	464.7	163.5	361.7	795.0	167.4	236.8	165.4	246.3	200.1	812.7	197.9	460.8	157.8	327.5	120.6	120.5	120.2	116.0	119.2	131.9	141.5	128.7	130.5	114.8	116.1
South Carolina	1,332.3	112.3	161.7	106.2	224.4	226.0	276.1	240.5	694.7	157.3	424.7	96.7	98.1	99.4	98.6	107.5	105.7	112.1	106.1	99.5	103.2	90.1	1,447.2	117.3	174.7	111.7	251.3	248.9	309.9	253.0	764.9	164.1	479.4	1,326.3	110.9	161.0	104.1	219.8	220.2	269.4	235.2	680.7	154.1	440.3	97.6	97.7	98.3	97.7	106.7	105.2	111.9	105.6	98.8	102.3	89.2
Virginia	429.9	176.9	436.1	402.9	186.8	228.6	435.1	172.7	187.7	160.9	180.6	149.4	157.6	188.2	167.9	155.8	167.9	176.5	151.0	145.6	143.9	168.2	447.0	179.8	451.6	421.3	182.0	226.1	449.5	153.7	224.5	163.5	187.9	257.1	151.3	320.4	275.6	189.0	178.9	279.2	140.2	153.9	142.4	135.7	124.0	124.2	139.6	131.3	124.9	135.8	135.2	120.3	122.4	118.9	120.8
West Virginia	411.5	419.4	364.5	468.8	247.0	269.6	279.5	296.1	316.2	337.3	280.1	212.6	206.2	244.3	215.5	216.3	200.4	218.1	219.7	213.0	211.0	227.0	427.0	333.5	378.0	475.7	254.9	278.0	297.2	304.0	284.0	351.2	298.1	411.5	319.4	366.5	468.8	247.0	269.6	279.5	296.1	316.2	337.3	280.1	212.6	206.2	244.3	215.5	216.3	200.4	218.1	219.7	208.7	213.0	211.0
East South Central	216.7	359.0	156.7	314.4	420.5	141.8	170.1	250.9	128.9	154.4	150.8	113.6	114.7	111.0	107.6	108.9	103.7	104.1	109.6	101.6	104.7	108.0	226.0	375.8	168.6	342.8	437.5	149.2	171.5	257.5	138.8	161.1	163.9	204.7	317.2	152.4	287.5	444.8	149.1	165.4	219.8	122.3	138.9	136.1	109.1	111.7	110.5	107.3	110.3	106.2	103.3	110.2	102.0	100.9	102.8
Alabama	113.0	175.4	101.4	127.5	948.8	103.0	233.7	126.3	99.0	135.9	138.6	93.6	128.0	100.6	95.5	105.4	97.4	92.0	93.3	91.0	103.3	92.5	114.6	192.8	106.9	136.5	1,023.0	103.7	112.1	113.8	108.0	121.7	147.0	149.4	186.9	145.1	164.3	732.4	123.5	202.3	160.5	111.2	124.9	139.6	113.6	122.8	119.8	110.3	112.6	109.3	102.8	108.3	99.3	109.4	110.1
Kentucky	301.0	463.4	202.4	457.7	210.0	126.3	228.0	144.7	132.5	154.1	149.9	119.8	124.5	118.6	115.0	113.7	107.1	115.6	109.8	109.2	105.2	108.9	329.2	507.5	215.2	476.7	224.5	134.8	256.3	151.5	151.3	177.0	170.7	331.7	456.3	194.1	462.8	209.0	126.3	227.6	144.2	131.7	153.8	149.5	116.1	122.9	116.7	114.8	113.8	107.4	115.6	109.6	108.9	104.9	106.1
Mississippi	244.7	334.1	210.2	519.6	677.5	231.7	158.7	273.5	148.4	169.1	136.8	148.3	126.2	140.7	150.3	144.9	135.0	130.8	138.3	110.1	125.8	131.3	255.7	338.3	230.7	575.1	656.3	249.4	165.9	253.5	157.9	164.4	158.2	221.9	295.2	184.8	479.3	595.7	258.6	153.8	258.2	143.9	157.6	131.9	135.6	118.0	125.4	143.8	142.1	136.9	129.6	134.5	109.4	125.1	125.7
Tennessee	149.2	330.7	128.8	157.9	290.6	118.5	111.2	333.2	117.9	144.1	156.1	97.0	101.9	97.6	89.8	93.9	90.0	85.4	96.2	90.1	89.5	95.7	149.4	336.5	138.6	164.2	299.9	121.8	112.4	344.0	120.9	147.4	157.7	139.3	305.1	126.4	149.9	274.8	124.1	105.1	284.0	110.7	125.8	124.8	90.4	98.1	96.6	87.8	94.4	90.0	82.7	97.0	92.3	83.8	84.4
West South Central	568.9	355.7	136.8	633.9	530.9	175.9	131.0	255.9	153.2	166.1	133.5	113.5	113.6	112.9	130.1	117.8	119.3	111.3	106.6	105.2	108.6	103.2	508.6	376.3	142.7	464.0	581.5	177.7	138.0	265.3	161.5	160.5	159.9	469.0	314.2	138.0	542.9	477.9	186.4	129.2	260.4	153.2	184.2	161.1	109.3	113.0	115.2	123.7	116.5	116.5	110.0	108.6	105.9	110.7	109.0
Arkansas	247.0	431.2	202.5	184.2	415.3	232.5	192.3	194.2	192.2	159.1	129.5	124.8	146.2	155.1	142.3	148.5	149.8	145.4	118.9	124.5	125.1	136.6	209.2	460.4	226.5	199.6	436.2	224.3	202.1	206.1	216.8	175.2	272.8	239.3	433.4	196.9	190.5	386.5	226.3	182.3	193.3	195.4	154.8	131.1	122.7	144.0	155.2	141.7	142.7	147.1	141.6	122.8	124.2	123.8	136.8
Louisiana	267.7	352.5	162.6	1,749.4	1,297.0	244.4	140.6	186.8	212.5	180.8	167.1	130.0	132.8	135.7	148.8	134.1	138.6	117.8	114.8	108.9	109.9	105.8	272.8	360.3	165.3	1,886.8	1,345.8	222.3	141.0	197.3	224.7	194.1	170.4	267.2	275.1	146.4	1,459.8	1,122.7	218.0	131.7	170.6	185.5	159.3	130.1	117.8	118.8	127.5	123.5	125.7	126.3	112.0	111.2	104.7	104.7	100.5
Oklahoma	139.3	644.3	114.0	109.2	316.2	116.4	108.7	132.6	193.0	319.2	103.8	95.9	109.2	96.9	99.2	116.2	103.4	94.8	99.7	94.4	96.0	94.5	150.4	591.2	121.4	114.3	322.9	118.8	111.2	244.9	223.9	218.7	98.0	150.5	481.8	135.6	128.1	1,384.5	218.9	131.9	109.3	113.0	115.2	123.7	116.5	116.5	110.0	108.6	105.9	110.7	109.0
Texas	704.2	308.7	120.1	449.4	256.3	153.5	119.3	287.8	132.3	151.8	132.9	109.7	108.1	109.8	126.5	108.5	110.4	104.9	103.9	102.5	106.8	97.9	759.9	340.0	122.3	194.0	276.4	160.4	123.0	298.8	134.9	155.8	140.9	600.9	281.5	128.1	405.2	194.8	173.8	120.4	286.5	131.8	152.6	133.5	106.2	106.1	105.9	122.7	110.2	108.9	104.4	104.3	101.8	106.3	98.5
Mountain	148.8	122.0	146.7	147.1	175.8	129.1	118.4	117.9	121.6	125.8	110.7	106.2	106.5	105.5	105.6	104.4	101.3	103.5	106.7	100.5	102.8	99.4	152.9	114.5	128.3	140.8	186.1	134.3	118.5	121.4	133.1	130.0	112.2	152.1	121.8	147.0	146.2	177.0	131.1	122.7	143.3	125.2	138.6	116.3	108.1	108.3	107

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								
							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

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

		Reduction Factor							
Nitrogen Oxides Control Technology	**EIA Code**	**Coal**	**Residual Fuel Oil and Distallate 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%

		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 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 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 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 nth digit if the (n+1) digit is 5 or larger and keep the nth digit unchanged if the (n+1) digit is less than 5.

Percent Change: The following formula is used to calculate percent changes:

$$\text{Percent Change} = \left(\frac{x\,(t_2) - x\,(t_1)}{x\,(t_1)} \right) x\,100,$$

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
	WDS	Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
Liquid Renewable (Biomass) Fuels	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
Prime Movers:
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
Environmental Equipment:
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 (CO_2) from electric generating plants for 1989 through the present, as well as the estimated emissions of sulfur dioxide (SO_2) 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 SO_2 and NOx 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 x 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 SO_2 emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO_2 emissions.

For some fuels, the calculation of SO_2 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 x Emission Factor x Sulfur Content

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A.1., which lists the SO_2 emission factors used for this report.

In the case of SO_2 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 SO_2 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 SO_2 is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO_2 emission factors shown in Table A.1. for fluidized bed boilers already account for 90 percent removal of SO_2 since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO_2 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 CO_2 are incomplete and are not used in this report.) The CEMS data account for the bulk of SO_2 and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO_2 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 CO_2 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.

CO_2 Emissions: CO_2 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 CO_2 emissions, the fuel-specific emission factor from Table A.3. is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO_2 emissions. CO_2 control technologies are currently in the early stages of research and there are no commercial systems installed. Therefore, no estimates of controlled CO_2 emissions are made.

SO_2 and NO_x Emissions: To comply with environmental regulations controlling SO_2 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 fuels[4] 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 SO_2 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 SO_2, 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 SO_2 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

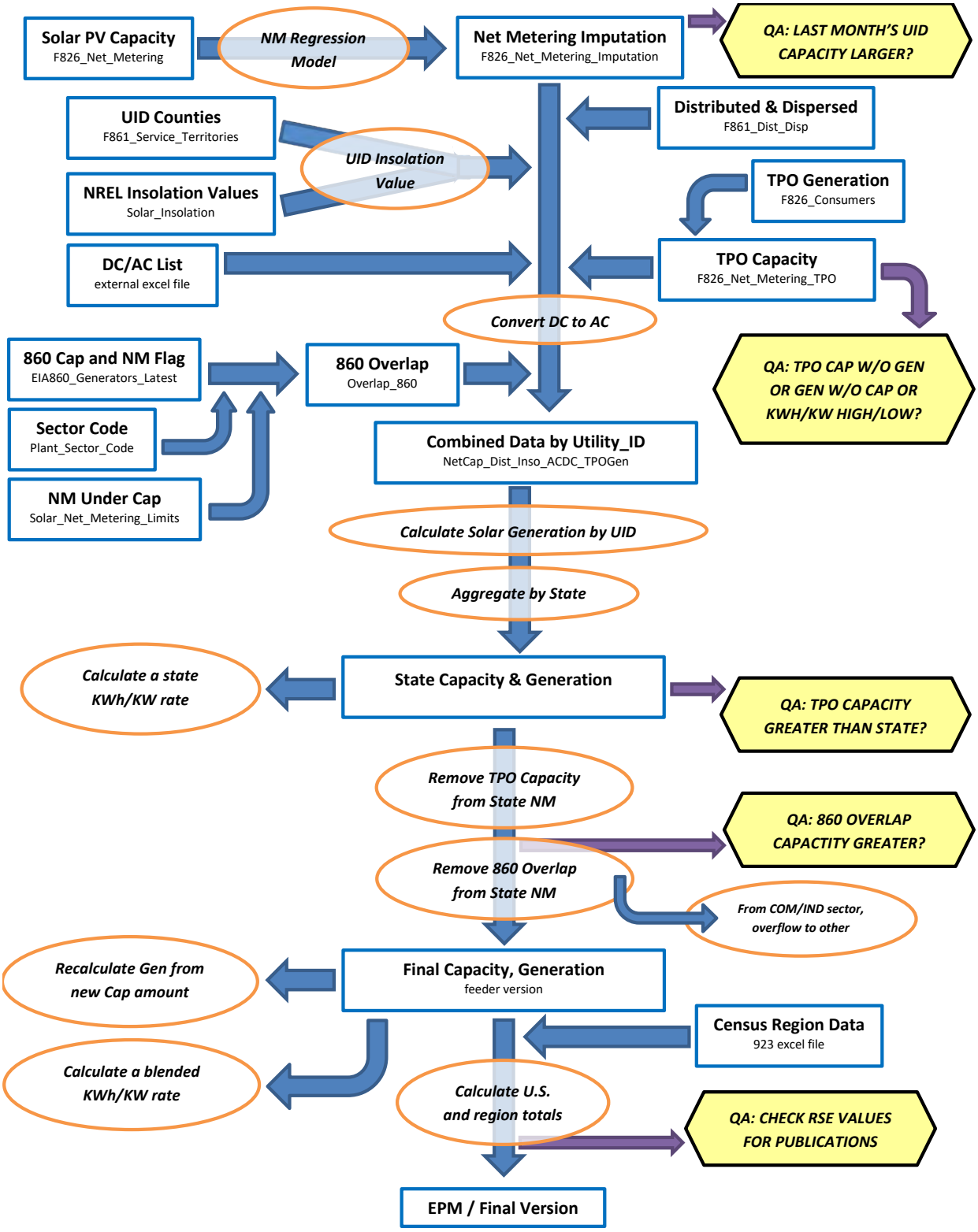
TMY3 (1991-2005) Weather Stations by MSA

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 Worchester 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 Worchester 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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

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.

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

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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 Conven-tional	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 Electricty Generators			Average Cost of Fuel at All Electricty 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 (CO2)	Sulfur Dioxide (SO2)	Nitrogen Oxides (NOx)
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

	Savings		Incremental Costs		Life Cycle Savings		Life Cycle Costs	
Year	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

	Yearly Energy and Demand Savings				Program Costs	
Year	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 muncipal 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, commerical 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.
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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 2.6. 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

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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 2.7. 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.
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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.
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, 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.
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 2.10. 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.
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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 2.11. 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)

	Canada		Mexico		U.S. Total	
Year	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)

	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
Period	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	28,213	-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											
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	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.
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 3.2.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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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 3.3.A. Net Generation by Energy Source: Independent Power Producers, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities											
Period	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydroelectric Conventional	Solar	Renewable Sources Excluding Hydroelectric and Solar	Hydroelectric Pumped Storage	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.
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.
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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.
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, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
Period	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.
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.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.
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, 2009 - 2019
(Thousand Megawatthours)

	Generation at Utility Scale Facilities												Small Scale Generation	Net Generation From Utility and Small Scale Facilities	
Period	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)

	Small Scale Generation
Period	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)

	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	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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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, 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	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.
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, 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

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 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

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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 3.13. Utility Scale Facility Net Generation from Nuclear Energy 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	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

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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 3.14. Utility Scale Facility Net Generation from Hydroelectric (Conventional) Power 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	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

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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 3.15. 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

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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 3.16. Utility Scale Facility Net Generation from Hydroelectric (Pumped Storage) Power 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	-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

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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 3.17. Utility Scale Facility Net Generation from Other Energy Sources 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	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

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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 3.19. Utility Scale Facility Net Generation from Biomass 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	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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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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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		Generation at Utility Scale Facilities		Generation at Utility Scale Facilities		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	
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	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	0	6	5	4	1	1	0	3	1	50	27
Montana	54	54	0.5%	29	34	24	20	0	0	29	34	7	6	0	0	7	6	0	0	0	0	0	0	17	14
Nevada	5,331	4,909	8.6%	4,650	4,413	680	496	170	41	4,413	4,306	175	171	64	64	111	107	40	35	2	3	38	32	532	357
New Mexico	1,667	1,599	4.2%	1,366	1,349	301	250	317	264	1,049	1,085	88	81	0	0	88	81	1	1	0	0	1	1	212	168
Utah	2,646	2,618	1.1%	2,186	2,224	460	394	0	0	2,186	2,224	88	79	0	0	88	79	9	8	0	0	9	8	362	307
Wyoming	189	7	NM	180	1	9	6	0	0	180	1	2	2	0	0	2	2	0	0	0	0	0	0	7	4
Pacific Contiguous	42,407	38,373	10.5%	26,814	25,100	15,593	13,273	476	526	26,146	24,407	3,895	3,445	152	148	3,744	3,297	2,229	1,914	40	20	2,189	1,895	9,660	8,081
California	41,256	37,446	10.2%	26,094	24,527	15,162	12,919	471	519	25,432	23,840	3,778	3,336	152	148	3,626	3,188	2,213	1,899	40	20	2,173	1,879	9,362	7,851
Oregon	903	776	16.3%	676	572	227	205	5	6	671	566	88	86	0	0	88	86	16	15	0	0	16	15	123	104
Washington	248	151	64.3%	44	2	205	150	0	0	43	1	30	24	0	0	30	24	1	0	0	0	1	0	175	126
Pacific Noncontiguous	1,385	1,216	13.9%	268	185	1,117	1,031	40	38	228	147	436	407	0	0	436	407	4	3	0	0	4	3	677	622
Alaska	4	3	48.8%	0	0	4	3	0	0	0	0	1	1	0	0	1	1	0	0	0	0	0	0	3	2
Hawaii	1,381	1,213	13.8%	268	185	1,112	1,029	40	38	228	147	435	406	0	0	435	406	4	3	0	0	4	3	674	620
U.S. Total	103,676	89,773	15.5%	68,719	60,234	34,957	29,539	6,757	4,865	61,290	54,796	11,588	10,324	587	525	11,002	9,798	3,127	2,683	85	47	3,041	2,636	20,914	17,105

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.
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.
Sources: U.S. Energy Information Administration, Form EIA-923, Power Plant Operations Report;
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 3.22. Utility Scale Facility Net Generation from Solar Thermal 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	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 seperating 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.
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 seperating 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.
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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 3.25. 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 seperating 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.
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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.
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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)

Year	Utility Scale Capacity							Utility and Small Scale Capacity		
	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)

	Generator Additions				Generator Retirements			
Energy Source	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

	Other Changes to Existing Capacity			
Energy Source		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)

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	
	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	1,865.3	1,776.8	295.6	295.4	2,720.9	2,720.9	30.7	30.7	0.0	0.0	5,179.8	5,091.1	1,433.4	1,251.3	3,298.7	3,028.1	3,594.3	3,323.5
Colorado	3,757.9	3,703.7	606.6	531.3	0.0	0.0	684.1	686.4	28.7	28.7	0.0	0.0	5,077.3	4,950.1	386.7	357.5	993.3	888.8	993.3	888.8
Idaho	970.4	970.4	242.0	240.0	0.0	0.0	2,764.2	2,764.2	88.7	83.9	10.0	10.0	4,075.3	4,068.5	44.2	26.3	286.2	266.3	286.2	266.3
Montana	791.3	783.5	17.0	17.0	0.0	0.0	2,782.7	2,767.7	3.0	3.0	0.0	0.0	3,594.0	3,571.2	17.8	13.9	34.8	30.9	34.8	30.9
Nevada	150.0	150.0	2,152.6	1,721.7	178.5	178.5	1,051.4	1,051.4	9.8	9.8	567.4	554.0	4,109.7	3,665.4	413.8	301.6	2,566.4	2,023.3	2,744.9	2,201.8
New Mexico	2,035.9	1,815.4	671.7	561.4	0.0	0.0	82.9	82.9	5.4	5.4	8.6	8.6	2,804.5	2,473.7	168.4	135.6	840.1	697.0	840.1	697.0
Utah	388.2	388.2	916.7	859.1	0.0	0.0	259.6	269.4	12.8	12.8	70.7	73.0	1,648.0	1,602.5	272.8	237.1	1,189.5	1,096.2	1,189.5	1,096.2
Wyoming	1,485.9	1,487.3	92.0	92.0	0.0	0.0	307.1	307.1	0.0	0.0	0.0	0.0	1,885.0	1,886.4	6.3	4.5	98.3	96.5	98.3	96.5
Pacific Contiguous	12,628.9	12,339.0	11,799.9	10,756.0	1,284.0	1,284.0	39,774.0	39,867.7	1,889.5	1,904.8	1,855.7	1,755.7	69,232.0	67,907.2	9,490.4	8,154.9	21,290.3	18,910.9	22,574.3	20,194.9
California	6,140.5	6,055.7	11,379.8	10,423.8	1,284.0	1,284.0	10,231.6	10,184.3	1,190.1	1,205.7	1,836.2	1,736.2	32,062.2	30,889.7	9,150.8	7,869.3	20,530.6	18,293.1	21,814.6	19,577.1
Oregon	3,415.3	3,210.2	400.4	312.5	0.0	0.0	8,317.0	8,402.3	315.0	314.7	19.5	19.5	12,467.2	12,259.2	171.4	154.6	571.8	467.1	571.8	467.1
Washington	3,073.1	3,073.1	19.7	19.7	0.0	0.0	21,225.4	21,281.1	384.4	384.4	0.0	0.0	24,702.6	24,758.3	168.2	131.0	187.9	150.7	187.9	150.7
Pacific Noncontiguous	266.6	266.2	267.7	124.1	0.0	0.0	503.0	496.5	160.9	273.9	43.0	43.0	1,241.2	1,203.7	671.5	612.6	939.2	736.7	939.2	736.7
Alaska	61.0	60.6	0.0	0.0	0.0	0.0	470.6	470.6	7.0	7.0	0.0	0.0	538.6	538.2	5.6	3.2	5.6	3.2	5.6	3.2
Hawaii	205.6	205.6	267.7	124.1	0.0	0.0	32.4	25.9	153.9	266.9	43.0	43.0	702.6	665.5	666.0	609.4	933.7	733.5	933.7	733.5
U.S. Total	103,571.2	94,417.7	35,710.2	30,120.5	1,758.1	1,757.9	79,773.1	79,871.8	13,113.3	13,733.2	2,555.4	2,444.3	236,481.3	222,345.4	23,213.6	19,547.1	58,923.8	49,667.6	60,681.9	51,425.5

NM = Not meaningful due to large relative standard error.
Values are final.

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.'
Estimated small scale solar photovoltaic capacity is based on data from Form EIA-861M, Form EIA-861, and from estimation methods described in the technical notes.

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	12,626.0	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	1,504.0	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	55.4%	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

Year/Month	Geothermal		Hydroelectric		Nuclear		Other Biomass		Other Gas		Solar				Wind		Wood	
											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

	Battery		Pumped Storage	
Year/Month	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)										
Year	Internal Combustion	Combustion Turbine	Steam Turbine	Hydro	Wind	Photovoltaic	Storage	Other	Wind and Other	Total	Number of Generators
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

Generators by Technology and Sector						
Year	Residential	Commercial	Industrial	Transportation	Direct Connected	Total
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

	Capacity (MW)					Customers				
Year	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.
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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.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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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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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

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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.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.
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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.
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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

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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

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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 5.2.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.
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 5.3.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.
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.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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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.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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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.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.
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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.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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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.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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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.
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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 5.4.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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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

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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.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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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

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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 5.6.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.
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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.
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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.
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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.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.
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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.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.
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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 5.6.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.
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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.

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.
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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.
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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 5.7.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

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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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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, 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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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, 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.
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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

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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

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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.
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Table 5.9. Consumption of Coal for Electricity Generation by State by Sector, 2019 and 2018 (Thousand Tons)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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.
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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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, 2019 and 2018 (Million Cubic Feet)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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.
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, 2009 - 2019

	Electric Power Sector			Electric Utilities			Independent Power Producers		
Period	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									
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.

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- 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, 2009 through 2019

	Bituminous			Subbituminous			Lignite		
Period	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

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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:
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 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

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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 - 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, 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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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.
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 7.5. 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)	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	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

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NM = Not meaningful due to large relative standard error or excessive percentage change.
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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 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 7.6. 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:
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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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- See the Technical Notes for fuel conversion factors.
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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:
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 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 7.8. 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:
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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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

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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 7.10. 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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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)	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	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

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 7.12. 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

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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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- 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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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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NM = Not meaningful due to large relative standard error or excessive percentage change.
W = Withheld to avoid disclosure of individual company data.

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	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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)

Census Division and State	All Sectors			Electric Power Sector				Commercial Sector		Industrial Sector	
				Electric Utilities		Independent Power Producers					
	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

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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

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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 Utilties 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 (CO2)	Sulfur Dioxide (SO2)	Nitrogen Oxides (NOx)
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 combusition 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 combusition 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 nth digit if the (n+1) digit is 5 or larger and keep the nth 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:

$$\text{Percent Change} = \left(\frac{x\ (t_2) - x\ (t_1)}{x\ (t_1)} \right) x\ 100,$$

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 included 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-423[2] 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 estimates[3].

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
Other Renewable Energy Sources	SUN	Solar (including solar thermal)
	WND	Wind
	GEO	Geothermal
Other Energy Sources	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
Prime Movers:
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
Environmental Equipment:
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 (CO_2) from electric generating plants for 1989 through the present, as well as the estimated emissions of sulfur dioxide (SO_2) 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 SO_2 and NOx 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 x 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 SO_2 emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO_2 emissions.

For some fuels, the calculation of SO_2 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 x Emission Factor x Sulfur Content

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A.1., which lists the SO_2 emission factors used for this report.

In the case of SO_2 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 SO_2 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 SO_2 is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO_2 emission factors shown in Table A.1. for fluidized bed boilers already account for 90 percent removal of SO_2 since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO_2 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 CO_2 are incomplete and are not used in this report.) The CEMS data account for the bulk of SO_2 and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO_2 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 CO_2 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.

CO_2 Emissions: CO_2 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 CO_2 emissions, the fuel-specific emission factor from Table A.3. is multiplied by the fuel consumption in MMBtu.

The estimation procedure calculates uncontrolled CO_2 emissions. CO_2 control technologies are currently in the early stages of research and there are no commercial systems installed. Therefore, no estimates of controlled CO_2 emissions are made.

SO_2 and NO_x Emissions: To comply with environmental regulations controlling SO_2 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 fuels[7] 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 SO_2 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 SO_2, 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 SO_2 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

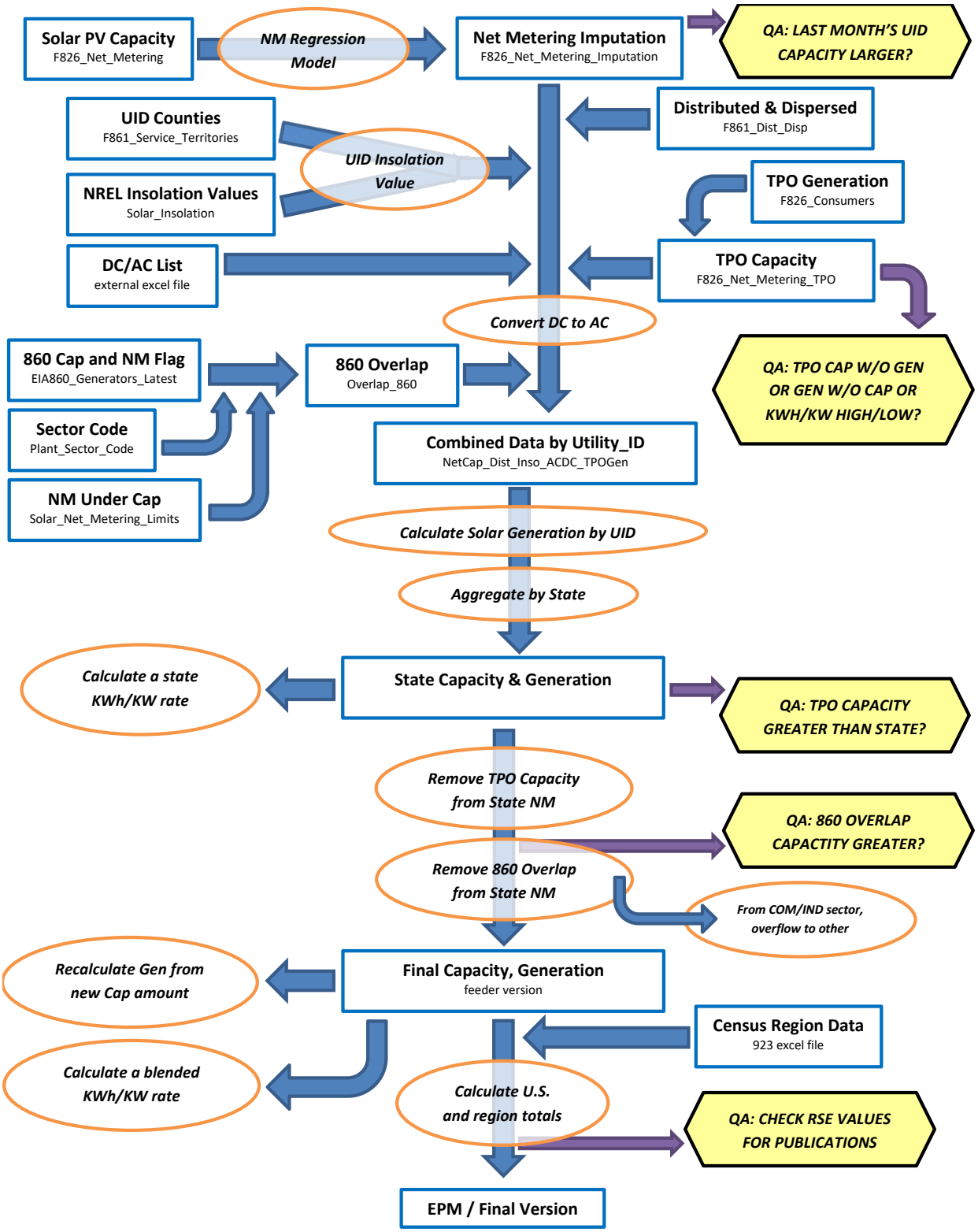
TMY3 (1991-2005) Weather Stations by MSA

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 Worchester 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 Worchester 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	))))))	Order No. 202-26-21

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

Filed April 28, 2026

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 (FCe-) 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 FCe- 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

All authors abide by the disclosure policies of the University of Texas at Austin. The University of Texas at Austin is committed to transparency and disclosure of all potential conflicts of interest. All UT investigators involved with this research have filed their required financial disclosure forms with the university. Through this process the university has determined that there are neither conflicts of interest nor the appearance of such conflicts.

The University of Texas at Austin
energy institute

The History and Evolution of the U.S. Electricity Industry

The University of Texas at Austin

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Tuttle, David P., Gülen, Gürcan, Hebner, Robert, King, Carey W., Spence, David B., Andrade, Juan, Wible, Jason A., Baldwick, Ross, Duncan, Roger, "The History and Evolution of the U.S. Electricity Industry," White Paper UTEI/2016-05-2, 2016, available at http://energy.utexas.edu/ the-full-cost-of-electricity-fce/.

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]

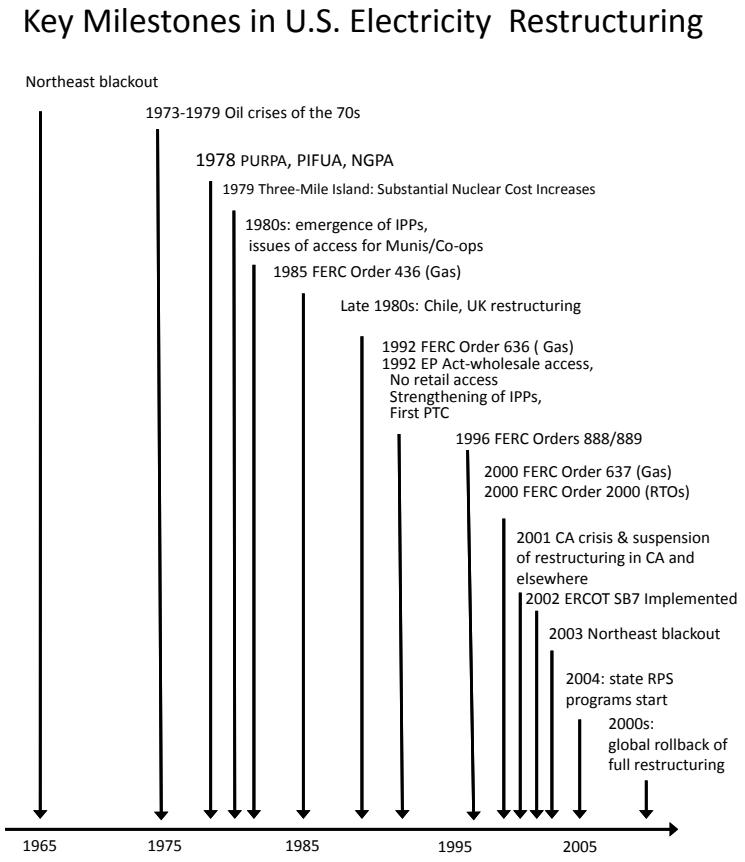
Congress responded to the 1970s' energy crises by reorganizing the FPC into to the Federal Energy Regulatory Commission (FERC) in 1978 to streamline regulations, encourage greater energy security, and contain the increases in energy costs. An important aspect of these efforts was to wean U.S. power generation 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 plants or independent power producers, or IPPs.

FIGURE 1:

Milestones in U.S. electricity restructuring



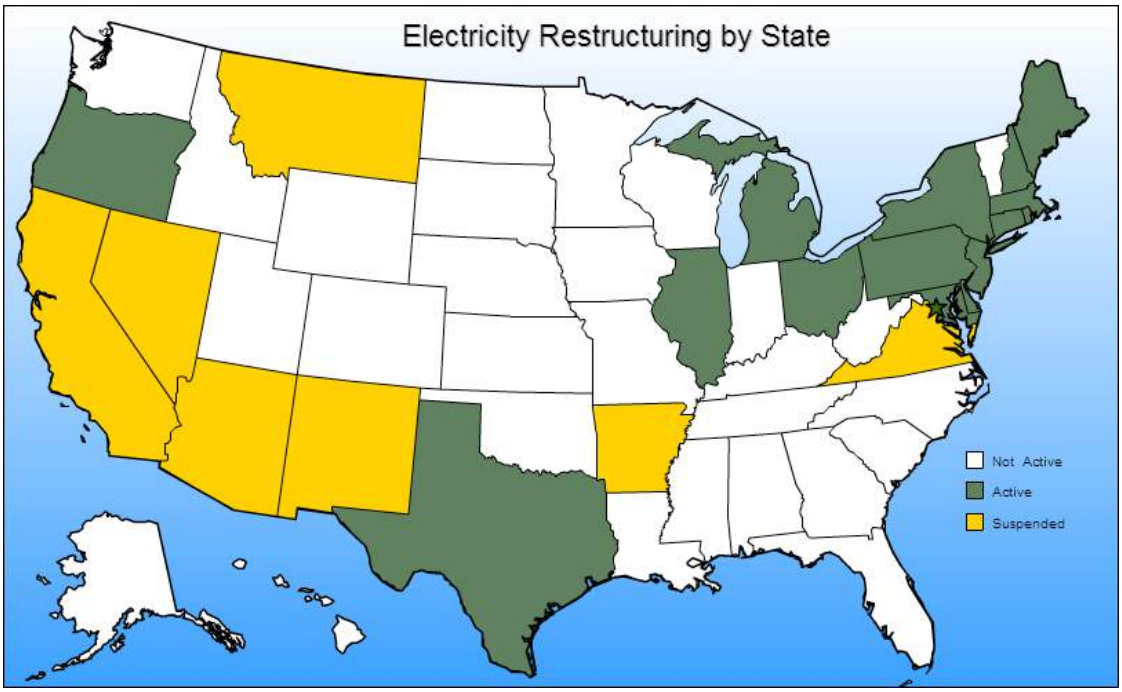
Using many of the concepts and lessons from the restructuring of the natural gas industry in the 1980s, FERC also pursued similar reforms in the electricity sector; Orders 888 and 889, issued on April 24, 1996, were particularly significant. These orders:

- 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].

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 2:

Electricity Restructuring by state (Source EIA [11]). Restructuring implies that a monopoly system of electric utilities has been replaced with competing sellers.



Additional reforms by FERC and Congress have continued to progress towards electricity market restructuring after 1996. FERC Order 2000 called for formation of regional transmission organizations (RTOs), an enhanced version of independent system operators (ISOs) with better regional control of transmission grids. In the wake of the California electricity crisis of 2000-01 the FERC has continued to work on the institutional design of wholesale electricity markets. In 2002, FERC proposed, but later withdrew in response to concerns raised by states and other stakeholders, rules for a Standard Market Design (SMD). The Energy Policy Act of 2005 (EPACT2005) gave FERC new authorities to police manipulative behavior in electricity markets. EPACT2005 also repealed the Public Utility Holding Company Act of 1935, formally bringing to a close the original federal regulatory structure established by New Deal-era legislation. While FERC was opening wholesale power markets to competition in the late 1990s and early 2000s, some state Public Utility Commissions became more active in pushing market restructuring and/or alternative technologies and demand-side participation while others mostly maintained the traditional utility structure.

The major milestones in the U.S. restructuring process are presented in Figure 1.

Figure 2 presents a summary of the situation at state level for actions initiated. ■

3 ELECTRICITY INDUSTRY ORGANIZATIONAL STRUCTURES

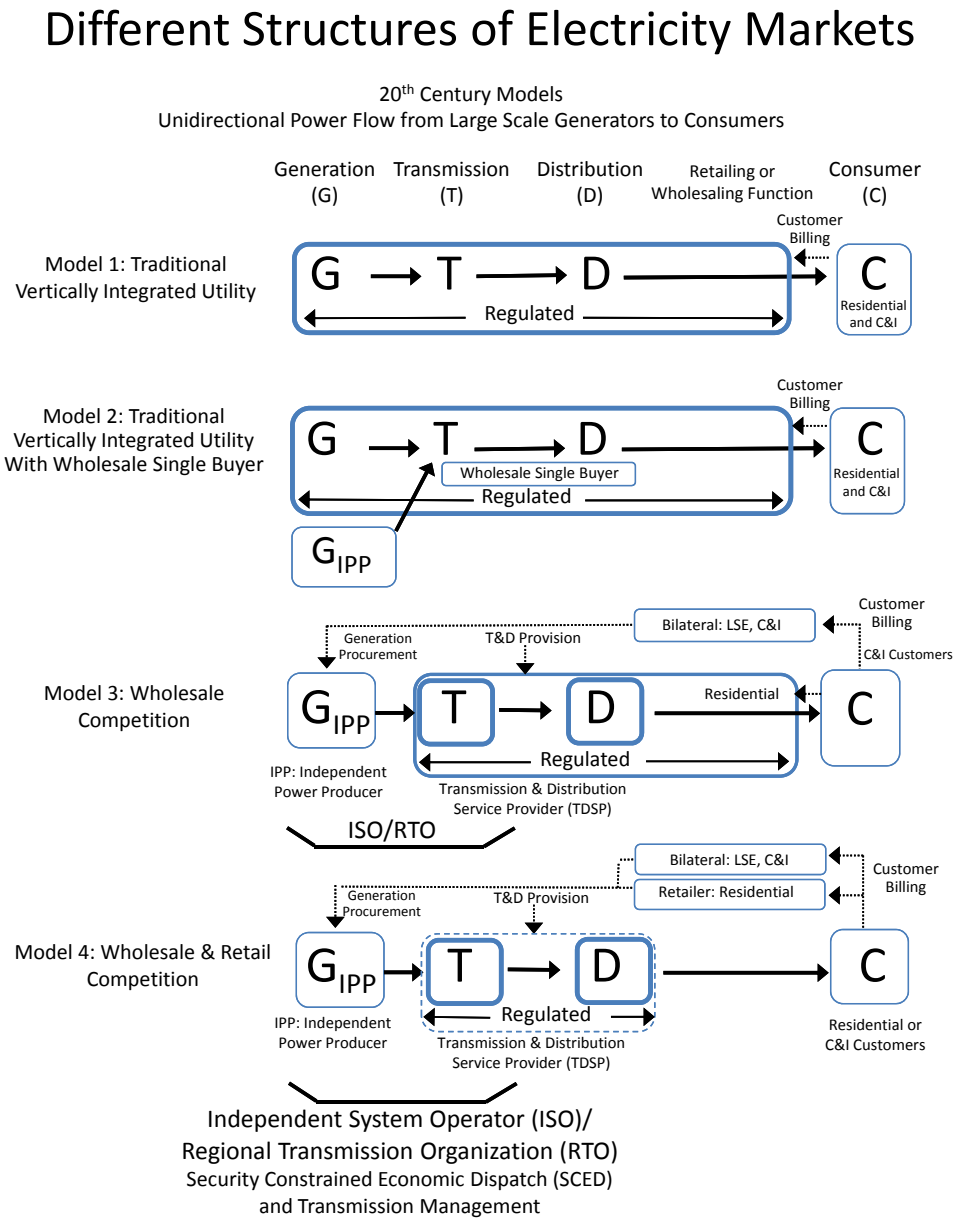
Now that we have provided an overview of the historical interplay of technology, finance, and regulation that has shaped the electricity industry, we now represent the various electric grid regulatory structures via a framework of six simplified models.

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



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 Discos[3] or load serving entities (LSEs) to buy wholesale electricity[4] 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.

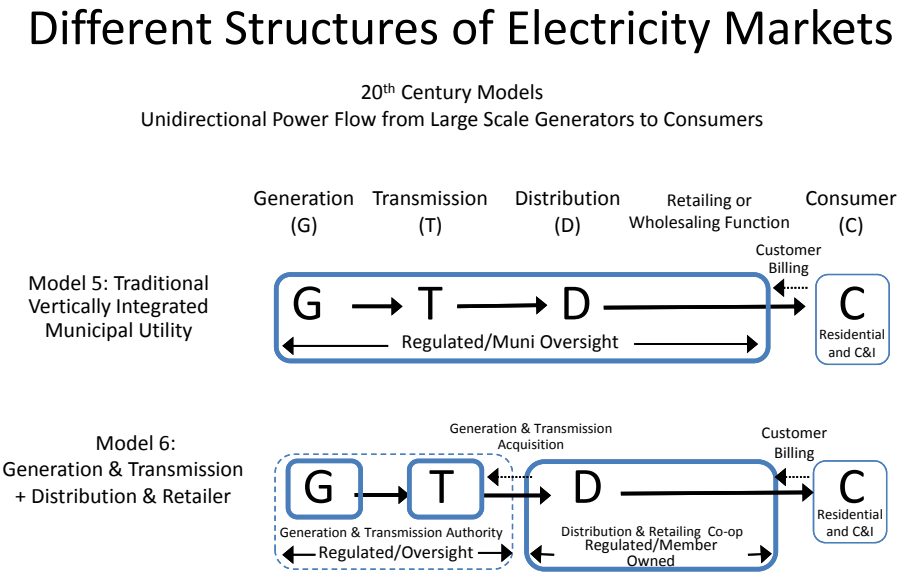
The UK, Norway, Chile, Australia, and some U.S. states have systems that approximate to this model, or are in a phased transition. The retail choice program in Electric Reliability Council of Texas (ERCOT) represents arguably the most competitive retail electricity market in the U.S. The market has been 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



(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 CO_2 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 CO_2 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.

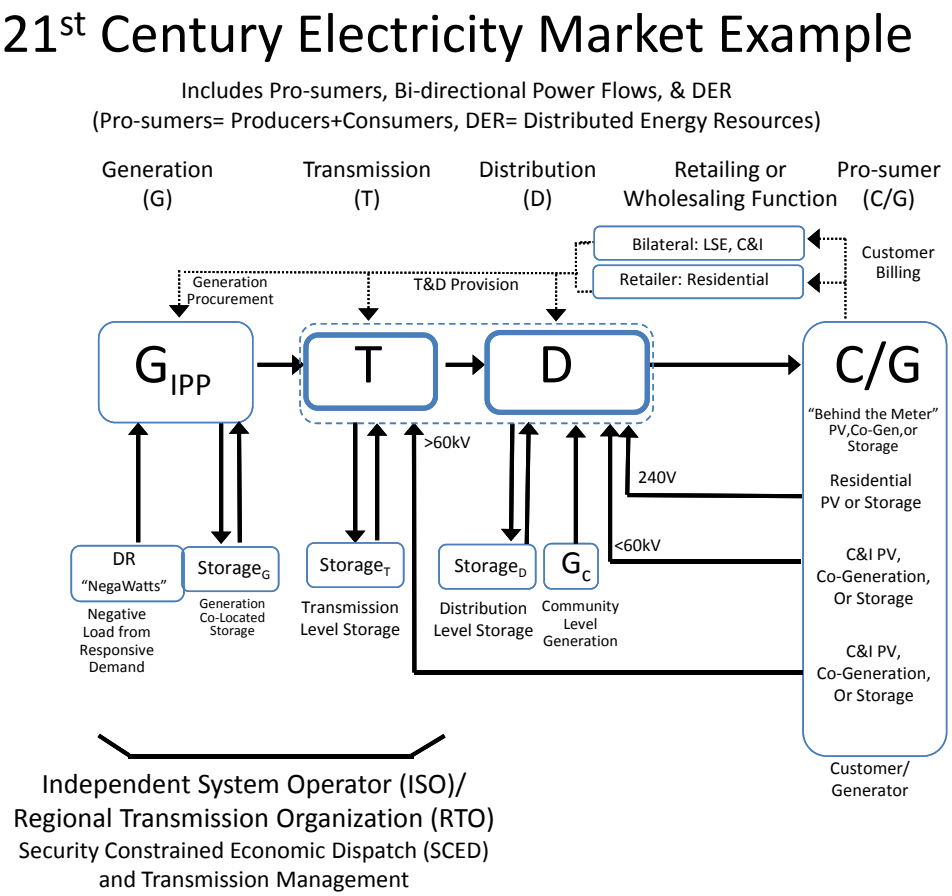
Historically, reliability has been an important objective of all electricity systems. In some competitive regions, generators are compensated for the capacity they make available to the grid via long-term capacity markets in addition to energy they sell into the energy markets every hour. These capacity 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



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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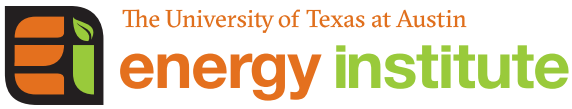

The University of Texas at Austin
energy institute

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	)	Order No. 202-26-21

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

Filed April 28, 2026

Exhibit 2-109:
PacifiCorp 2025 Oregon RFP

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

October 15, 2025

VIA ELECTRONIC FILING

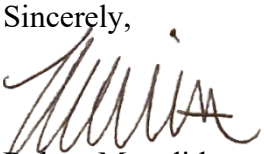
Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

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,



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: 2025ORSitus RFP@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 service[5], 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 evidence[6] 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 757.306[11] 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.	

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 ORGANIAZATION 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 modification[13] 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 (PVRR) and the risk-adjusted PVRR 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	)	Order No. 202-26-21

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

Filed April 28, 2026

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.

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[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, design[4], 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 ELIGIBILTY 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 DISCLAMERS

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 lease[6] for book purposes pursuant to ASC 842, (ii) a contract be accounted for by Company as a capital lease for tax purposes[7], 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.

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[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) *Please note: OATT references are to PacifiCorp's Open Access Transmission Tariff v.2.0.0 dated April 1, 2020*	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 CO_2 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 CO_2 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 CO_2 reduction (in metric tons) will be adjusted to 50% of its original value.

The adjusted CO_2 reduction (in metric tons) will be compared among all Initial Short List bids. The bid with the largest adjusted CO_2 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 Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

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

Filed April 28, 2026

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

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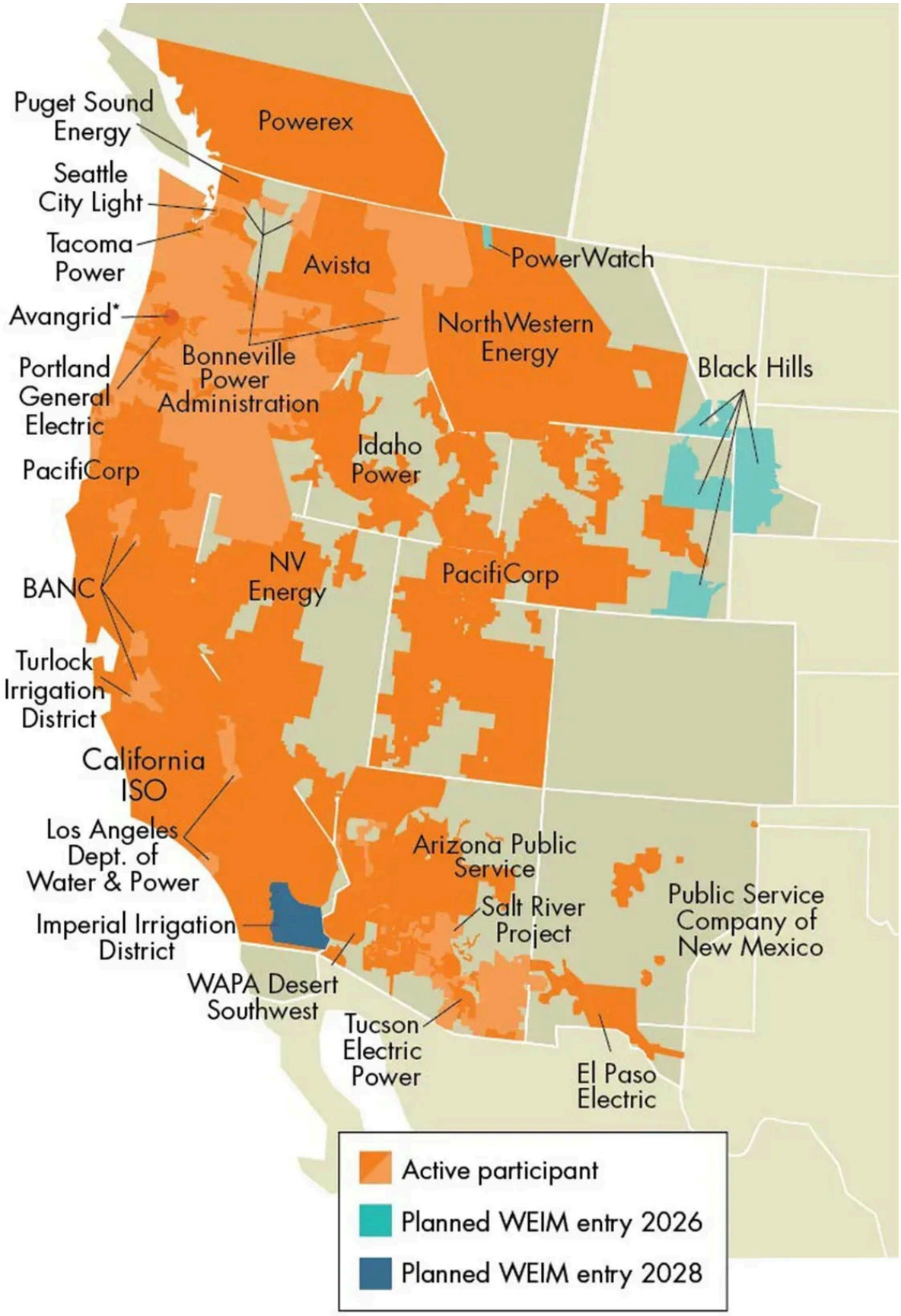
- Bonneville Power Administration – entered 2022
- Tucson Electric Power – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021
- Public Service Company of New Mexico – entered 2021
- Turlock Irrigation 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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