UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit AA: CoPUC, Decision No. R24-0602, issued on August 22, 2024,
in Proceeding No. 23A-0585E

Decision No. R24-0602

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23A-0585E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

RECOMMENDED DECISION GRANTING UNOPPOSED JOINT MOTION TO APPROVE COMPREHENSIVE SETTLEMENT AGREEMENT, APPROVING COMPREHENSIVE SETTLEMENT AGREEMENT, AND GRANTING ELECTRIC RESOURCE PLAN APPLICATION AS AMENDED BY COMPREHENSIVE SETTLEMENT AGREEMENT

Issued Date: August 22, 2024

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I. STATEMENT

A. Procedural Background[1]

1. On December 1, 2023, Tri-State Generation and Transmission Association, Inc. ("Tri-State") filed its 2023 Electric Resource Plan ("ERP") Application ("Application"), including the Direct Testimony of eight witnesses and attachments to the same. The filing of the ERP Application commenced this Proceeding.

2. By Decisions No. R24-0080-I and R24-0085-I[2], issued February 6 and February 8, 2024, respectively, the undersigned Administrative Law Judge ("ALJ"), among other things: acknowledged the interventions of the trial staff of the Colorado Public Utilities Commission ("Staff"), Office of Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"), and Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrlec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., Garland Light & Power Co., (collectively, the "Wyoming Cooperatives"), Poudre Valley Rural Electric Association, Inc. ("PVREA"), Highline Electric Association ("Highline"), K.C. Electric Association ("K.C."), San Isabel Electric Association, Inc. ("SIEA"), Southeast Colorado Power Association ("SECPA"), and Y-W Electric Association, Inc. ("Y-W"); granted the interventions of the Natural Resources Defense Council and the Sierra Club (together, the "Conservation Coalition"), White River Electric Association ("WREA"), Western Resource

[1] The entire procedural history of this proceeding is provided in previous decisions and is partially repeated here, to the extent necessary to provide procedural context for the above-titled decision.

[2] Decision No. R24-0085-I provided certain clarifications for Decision No. R24-0080-I.

Advocates ("WRA"), Office of Just Transition ("OJT"), the Colorado Independent Energy Association ("CIEA"), Colorado Department of Public Health and Environment ("CDPHE"), Interwest Energy Alliance ("Interwest"), La Plata Electric Association, Inc. ("LPEA") and Mountain Parks Electric, Inc. ("MPE") (together, "LPEA/MPE"), the Colorado Solar and Storage Association ("COSSA") and the Solar Energy Industries Association ("SEIA") (together, "COSSA/SEIA"), and Moffat County ("Moffat") and the City of Craig ("Craig"), Colorado (together, "Moffat/Craig"); and a procedural scheduled to govern this Proceeding.

3. By Decision No. R24-0138-I, issued March 5, 2024, the undersigned ALJ adopted a revised procedural schedule to govern this Proceeding. Among other deadlines, the decision set a June 26, 2024 deadline for Stipulations/Settlement Agreements; a July 1, 2024 deadline for Witness Lists, Cross-Examination Estimates, and Final Exhibits List; a July 11, 2024 deadline for Settlement Testimony; a July 16-19, 2024 Evidentiary Hearing; and an August 1, 2024 deadline for Statements of Position.

4. On April 22, 2024, Tri-State filed Supplemental Direct Testimony, providing additional information in support of the Application.

5. On May 15, 2024, the Colorado Air Pollution Control Division ("APCD") filed its Verification Report ("Emissions Report"), verifying Tri-State's calculation of a forecasted emissions reduction of 89 percent by 2030 from Colorado sales for the submitted preferred portfolio.

6. By Decision No. R24-04060-I, the ALJ again modified the procedural schedule, extending the filing deadline for any settlement agreements through June 28, 2024.

7. On June 27, 2024, Tri-State, Highline, PVREA, Y-W, Interwest, Staff, UCA, CEO, Moffat/Craig, OJT, CIEA, COSSA/SEIA, Conservation Coalition, and WRA (the "Settling

Parties") filed their Unopposed Comprehensive Settlement Agreement ("Settlement Agreement"). With the Unopposed Comprehensive Settlement Agreement, the Settling Parties also filed their Joint Unopposed Motion to Approve the Unopposed Comprehensive Settlement Agreement, Amend the Procedural Schedule, and Waive Response Time ("Motion"). In the Motion, the Settling Parties indicate that the Wyoming Cooperatives, LPEA/MPE, WREA, K.C., SIEA, and SECPA do not oppose the Motion or the Settlement Agreement.[3]

8. By Decision No. R24-0496-I, issued July 10, 2024, the undersigned ALJ waived response time for the Motion, vacated the evidentiary hearing and the deadline for the filing of Statements of Position, and indicated that any additional relief sought in the Motion will be ruled upon by separate decision.

9. On July 7 and 9, 2024, the undersigned ALJ held Public Comment Hearings in this matter.

10. On July 10, 2024, Hearing Exhibit 203, the Settlement Testimony of Rebecca V. Lim (Staff's Settlement Testimony) was filed by Staff.

11. On July 11, 2024, Hearing Exhibit 122, the Settlement Testimony and Attachments of Susan K. Hunter on Behalf of Tri-State Generation and Transmission Association, Inc. ("Hearing Exhibit 122" or "Ms. Hunter's Settlement Testimony") Hearing Exhibit 123, the Settlement Testimony and Attachments of Lisa K. Tiffin on Behalf of Tri-State Generation and Transmission Association, Inc. ("Hearing Exhibit 123" or "Ms. Tiffin's Settlement Testimony"), Hearing Exhibit 124, the Settlement Testimony and Attachments of Brian L. Thompson on Behalf of Tri-State Generation and Transmission Association, Inc. ("Hearing Exhibit 124" or "Mr. Thompson's Settlement Testimony"), and Hearing Exhibit 125, the Settlement Testimony and

[3] Motion at 2.

Attachments of Chad Orvis on Behalf of Tri-State Generation and Transmission Association, Inc. (collectively, "Tri-State's Settlement Testimony") were filed by Tri-State.

12. On July 12, 2024, Hearing Exhibit 903 Testimony of Clare Valentine in Support of Settlement on Behalf of Western Resource Advocates ("Hearing Exhibit 903" or "WRA's Settlement Testimony") was filed by WRA.

13. On July 11, 2024, Hearing Exhibit No. 1603 Settlement Testimony of Commissioner Melody Villard on Behalf of the Coal Transition Communities, Moffat County and the City of Craig, Colorado ("Hearing Exhibit 1603" or "Moffat/Craig's Settlement Testimony") was filed by Moffat/Craig.

14. On July 11, 2024, Hearing Exhibit 1501 Settlement Testimony of Mike Kruger on Behalf of Colorado Solar and Storage Association and Solar Energy Industries Association ("Hearing Exhibit 1501" or "COSSA/SEIA's Settlement Testimony) was filed by COSSA/SEIA.

15. On July 12, 2024, the Answer Testimony of Wade Buchanan on Behalf of the Colorado Office of Just Transition Hearing Exhibit 1000[4] was filed by OJT.

B. Background for This Proceeding

16. Tri-State is a generation and transmission cooperative that provides electric transmission service and is a wholesale seller of electric energy to 42 Utility Members in its service territory of four states using facilities located in five states.[5] Tri-State owns, operates, or has a major equipment ownership interest in more than 5,665 miles of high-voltage transmission lines and approximately 409 substations and switchyards.[6] Tri-State's interstate transmission facilities

[4] Although the title of this filing included the words "Answer Testimony," its timing and content make it clear it was intended as to be filed as OJT's Settlement Testimony and is therefore considered herein as such.

[5] Hearing Exhibit 107 at 6:9-11 (Direct Testimony and Attachments of Ryan J. Hubbard on Behalf of Tri-State Generation and Transmission Association, Inc.).

[6] *Id*. at 6:11-14.

are interconnected to other utilities, including Western Area Power Administration, Nebraska Public Power District, Black Hills Colorado Electric, Inc., PacifiCorp, Public Service Company of Colorado, Platte River Power Authority, Colorado Springs Utilities, Basin Electric Power Cooperative, Tucson Electric Power, Public Service Company of New Mexico, and Deseret Generation & Transmission Cooperative.[7]

17. This Proceeding concerns Tri-State's second ERP application submitted pursuant to Rule 3605.[8] The Application, with its supporting testimony and attachments, are intended to describe how Tri-State will ensure reliability and resource adequacy, maintain affordability for its members, and meet compliance obligations, including environmental responsibility obligations.[9]

18. A significant component underlying the Application is that on September 13, 2023, Tri-State submitted a Letter of Interest to the United States Department of Agriculture ("USDA"), seeking significant funding through the Empowering Rural America ("New ERA") program of the Rural Utilities Service. The New ERA program, which was established through the Inflation Reduction Act ("IRA"), includes $9.7 billion in federal funding for financial assistance to support the purchase of renewable energy, zero-emission, and carbon capture systems.[10] In its Application, Tri-State put forward as its preferred portfolio an IRA Scenario that included several actions based on its application to the New ERA program. These actions included the acquisition of 255 MW owned renewable energy projects, 1,380 Megawatt ("MW") renewable and hybrid power purchase agreement projects, and 210 MW battery storage projects; and the retirements of Craig Unit 3 as of January 1, 2028, and Springerville Unit 3 no later than September 15, 2031.

[7] *Id*. at 6:15-21.
[8] Application at 1. *See also*, Proceeding No. 20A-0528E, which concerned Tri-State's first ERP Application with the Commission.
[9] *Id*. at 2.
[10] Attachment 1 to the Application (Stipulation between Tri-State, CEO, COSSA, UCA, County Electric Cooperative, Inc., Mountain View Electric Association, Inc., Sierra Club, and WRA), at 2-3.

19. With its Application, Tri-State submitted a stipulation with certain external stakeholders who agreed to support its acquisition in Phase II of resources pursuant to Tri-State's application to USDA, if its request for federal funding is approved in full.[11] Subsequently, in Supplemental Direct Testimony, Tri-State announced that it had received a notice to proceed from the USDA, and would thus be submitting a full application for New ERA funding.[12] At the time of this Decision, no announcements have been made by USDA regarding New ERA program awards.

C. Settlement Agreement[13]

1. General Terms, Contents of the Phase II Implementation Report, and Injection Study

20. The Settlement Agreement, which is attached to this Recommended Decision as Appendix A, sets forth the Settling Parties' agreement resolving all disputed issues in this Proceeding.[14]

21. The Settling Parties have agreed that the Commission should grant Tri-State's Application for approval of its 2023 ERP, subject to the terms of the Settlement Agreement. The Settling Parties agree that the compromise reached between the Settling Parties constitutes a just and reasonable resolution of all issues as part of Phase I of the ERP.[15]

22. In addition to certain specific terms which are discussed below, the Settling Parties also have agreed to numerous General Terms and Conditions, found in Section 6 of the Settlement Agreement.[16]

[11] *Id*. at 8.
[12] Hr. Ex. 101, Tiffin Supplemental Direct, p. 6.
[13] The following is intended as a summary of some of the main terms of the Settlement Agreement, rather than a full recitation of the same.
[14] Settlement Agreement, ¶1.3.
[15] *Id*.
[16] *See id*., at 31-34.

23. The Settling Parties have agreed upon certain contents of the Phase II Implementation Report, which is to be submitted 165 days after Phase II RFPs have been released.[17] The Implementation Report will include the items listed in Hearing Exhibit 101, Attachment LKT-3; annual emissions in short tons; a map of all Phase II bids, with an overlay identifying Disproportionately Impacted ("DI") Communities; highly confidential technical specifications for any gas resource bids advanced to Phase II modeling; identification of any bids located in Moffat County or the West End of Montrose County; and, for any bids located in the same areas, an estimate of the annual property tax expected to be paid to the county for bids selected and an explanation of why a given bid is not advanced to Phase II modeling, if applicable.[18]

24. Following Phase II, Tri-State agrees to conduct an injection study reflecting the anticipated Colorado transmission system in 2031, as further set forth in ¶4.11 of the Settlement Agreement.[19]

2. Requests for Proposals

25. The Settling Parties have agreed that the Commission should approve a Dispatchable Request for Proposals ("RFP"), a Standalone Storage RFP, and a Renewable RFP for issuance in Phase II.[20] While resources that are included within Tri-State's New ERA application will retain certain requirements related to geographic location, size, and technology type, Tri-State will remove those restrictions for RFPs seeking resources that are not included within the New ERA application.[21]

[17] Hr. Ex. 101, Attachment LKT-2, Rev. 1.
[18] Settlement Agreement, ¶4.10.
[19] *Id*., ¶4.11.
[20] *Id*., ¶4.2.
[21] *Id*. at ¶¶4.2.1., 4.2.3., 4.2.4., 4.2.5.

26. Furthermore, within one week of receiving a notice of award from USDA regarding New ERA funding, Tri-State commits to request a meeting with USDA to discuss flexibility related to funded projects. Tri-State will then file an informational notice with the Commission.[22] If New ERA guidance is provided at least 10 days before the issuance of the RFPs, Tri-State will modify its RFPs to match that guidance and informationally refile them with the Commission.[23]

27. The Settling Parties have agreed that Tri-State will modify Phase II Bid Security and refundability requirements, as further set forth in ¶4.2 of the Settlement Agreement. Among such modifications is the requirement for selected bidders to submit $10,000 per nameplate capacity megawatt ("MW") on a given project, due within 21 days of Tri-State filing its Phase II ERP Implementation Report.[24]

28. The Dispatchable RFP process will be modified so that the geographic location for gas plant bids (except tolling agreements) will be limited to Moffat County, no limits will be imposed on technology type or MW size, and Dispatchable RFPs must meet the carbon dioxide emission rate and performance requirements identified in the greenhouse gas emissions rules promulgated by the Environmental Protection Agency, as further set forth in ¶ 4.2.6 of the Settlement Agreement.

29. For each Phase II portfolio modeled by Tri-State pursuant to ¶4.3 of the Settlement Agreement, Tri-State is required to model an Extreme Weather Event ("EWE") sensitivity ("EWE Sensitivity"), including the requirement on Tri-State to model the EWE Sensitivity in the dispatch only, without informing the expansion plan of the EWE modeling parameters, and otherwise comply with the remaining terms set forth in ¶4.4 of the Settlement Agreement.

[22] *Id*. at ¶ 4.2.7.
[23] *Id*. at ¶¶4.2.8., 4.2.8., 4.2.10.
[24] *Id*., ¶4.2.2.1.

30. Bids with commercial operational dates in 2026 and 2027 also will be required to have an established generator interconnection queue position.[25] Bids beyond those dates without an interconnection queue position will be entered into the Tri-State interconnection queue.[26]

31. The Settling Parties agree that Tri-State will update certain non-price factor bid evaluation criteria for its RFPs. Tri-State will make the relevant non-price factor information available to bidders as well as assumptions for use of surplus interconnection service at Tri- State-owned facilities. Among other changes, Tri-State will amend the "Development and Siting Status" narrative topics requested from bidders to address Community Stewardship, Tribal Consultation, and Land Use considerations—and specifically to seek information on community engagement and wildlife surveys--as further set forth in ¶4.7 of the Settlement Agreement.

3. Phase II Portfolios and Modeling and 2027 ERP

32. The Settling Parties have further agreed upon eight portfolios to be modeled in Phase II, with the potential for two additional portfolios to be modeled. These include Tri-State's preferred plan; a version of the preferred plan that allows other gas plant technology types (in addition to natural gas carbon capture and storage); a version of the preferred plan in which the model will not be required to select a gas resource, and constraints would be removed for non-New-ERA resources; a version of the preferred plan that limits gas resources to tolling agreements; an unconstrainted portfolio that allows the model to choose resources; a "no new gas" portfolio, contingent on whether all other portfolios select new gas resources; an optional portfolio of Tri-State's choosing; and back-up bid portfolios, as further set forth in ¶4.3 of the Settlement Agreement.

[25] *Id*., ¶4.5.
[26] *Id*.

33. Tri-State agreed to update modeling assumptions for non-tolling agreement gas plant bids to have a useful life of no later than 2050.[27]

34. For each Phase II portfolio modeled by Tri-State pursuant to ¶4.3 of the Settlement Agreement, Tri-State is required to model an EWE Sensitivity and comply with the remaining terms set forth in ¶4.4 of the Settlement Agreement. Tri-State will also remodel any portfolios that fail to meet the Level II reliability criteria related to EWE Sensitivity.[28]

35. Tri-State also agreed to aim to control at least 5.5% of Tri-State's Colorado peak load through demand response programs by 2030.[29] Tri-State also agreed to model in-house demand response offerings to that effect.[30]

36. Tri-State will further subject each portfolio to at least 24 hours of run time in its modeling software, EnCompass.[31]

37. Tri-State will use the Phase II bids that pass bid evaluation as inputs to inform its 2027 ERP generic resource assumptions used in Phase I modeling of that ERP, as further set forth in ¶4.12 of the Settlement Agreement. Applicable federal environmental compliance obligations will be reflected in this modeling.[32]

4. Facility Retirements

38. The Settling Parties agree that the Commission should approve retirement date of January 1, 2028 for Unit 3 of Tri-state's Craig Station ("Craig 3"). The Settling Parties agree that the Commission should approve a retirement date of September 15, 2031 for Unit 3 of the Springerville Generating Station ("Springerville 3"), subject to New ERA funding award as

[27] *Id*., ¶4.4.6.
[28] *Id*., ¶4.8.1.
[29] *Id*., ¶4.9.1.
[30] *Id*., ¶4.9.2.
[31] *Id*., ¶4.4.7.
[32] *Id*., ¶4.12.

requested from USDA and successful Tri-State negotiation of contractual agreements impacted by the unit's retirement.[33] Depending on whether New ERA funding is awarded to Tri-State, the Settling Parties agree to convene a meeting to discuss the modeling of Springerville 3, or for Tr-State to update common facilities costs for Springerville 3 and model the cost of any applicable federal environmental compliance obligations for Springerville 3 for Phase II modeling, as set forth in ¶4.6.1 of the Settlement Agreement.

5. Community Assistance

39. The Settlement Agreement also includes Section 5, which represents specific agreements between Tri-State and Craig/Moffat regarding community assistance.[34] While not joined by other Settling Parties, other parties convey their support or non-opposition for these provisions.

40. Tri-State agrees to provide a direct benefit payment for community assistance to Moffat/Craig in the amount of $5.5 million per year, to be paid between 2026 through 2029. The payment will go to an economic development fund established and administered by Moffat/Craig.[35]

41. Tri-State and Moffat/Craig agree that Phase I modeling identified the need for a gas plant in western Colorado with the potential to be cited in Moffat, consistent with Tri-State's siting study. Accordingly, in Phase II of its ERP, Tri-State will solicit bids for a gas plant to be sited in Moffat.[36] Tri-State and Moffat/Craig agree that no additional Commission approvals should be required for the gas plant if selected and approved in Phase II, however, Moffat/Craig agree to

[33] *Id*., ¶4.6.
[34] *Id*., ¶5.1.
[35] *Id*., ¶5.2.
[36] *Id*., ¶5.3.

support any further filings if required by the Commission, and Tri-State commits to provide drafting and/or administrative support for Moffat/Craig.[37]

42. Tri-State agrees to make certain "minimum backstop payments," to an economic development fund designated by Moffat/Craig. The backstop payments will total $48 million and will be paid out in decreasing increments, beginning in 2028 and ending in 2038. The minimum backstop payments are subject to offset for various items, including property tax revenues paid by Tri-State, federal or state grant funds, and other items agreed-upon items, as further set forth in ¶¶5.3.5, 5.3.6 and 5.3.7 of the Settlement Agreement.

43. In the evaluation and modeling of bids located in Moffat, Tri-State agrees to implement a $1/MWh price improvement over the life of a proposed project or contract.[38] The 2023 ERP Phase II "preferred portfolio" will be modeled with and without this price improvement.[39]

44. Within six months of the retirement of all three units at Craig Station, Tri-State will transfer to Moffat (upon consent of the Colorado River Water Conservation District), at no cost, storage water rights from Elkhead Reservoir, Second Enlargement (originally decreed in 02CW106), in an amount sufficient for the augmentation plan that is approved in Case No. 23CW3025 as determined by the Colorado Division of Water Resources and/or the Division 6 Water Court, and as further set forth in ¶5.5 of the Settlement Agreement.

45. Tri-State agrees to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3, as further set forth in ¶5.6 of the Settlement Agreement.

[37] *Id*., ¶5.3.3.
[38] *Id*., ¶5.4.1.
[39] *Id*.

46. Moffat/Craig and Tri-State agree to meet twice annually from 2025 to 2028 leading up to the Craig Station closure to identify opportunities where Tri-State's assets can be utilized to facilitate development in Moffat while also benefiting Tri-State's member systems, as further set forth in ¶5.7 of the Settlement Agreement.

47. Moffat/Craig agree not to seek further community assistance or workforce transition benefits from Tri-State in the future, or take positions on workforce transition reporting before a regulatory body, court, legislative body, or through discussions or communications with others that are inconsistent with the terms of the Settlement Agreement, as further set forth in ¶55 of the Settlement Agreement.

II. ANALYSIS

A. Burden of Proof

48. Except as otherwise provided by statute, the Administrative Procedure Act imposes the burden of proof in administrative adjudicatory proceedings upon "the proponent of an order."[40] The Settling Parties filed the Joint Motion and, as a result, bear the burden of proof.[41] The Settling Parties must establish by a preponderance of the evidence that the Settlement Agreement is just and reasonable and in the public interest. The Commission has an independent duty to determine matters that are within the public interest.[42]

B. Modified Procedure

49. The Application, as modified by the Settlement Agreement, is uncontested. The Settlement Agreement was executed by each of the Settling Parties and is otherwise unopposed as

[40] Section 24-4-105(7), C.R.S.
[41] Section 24-4-105(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500 of the Rules of Practice and Procedure, 4 CCR 723-1.
[42] *See Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984).

is the Motion.[43] In addition, the parties agree that a hearing is unnecessary.[44] Finally, the Application and Settlement Agreement are supported by sworn testimony and attachments that verify sufficient facts to support the Application and Settlement Agreement. Accordingly, pursuant to § 40-6-109(5), C.R.S. and Rule 1403 of the Rules of Practice and Procedure, 4 *Code of Colorado Regulations* ("CCR") 723-1,[45] the Application, as modified by the Settlement Agreement, will be considered under the modified procedure, without a formal hearing.

C. Analysis

50. Based upon substantial evidence in the record as a whole, the ALJ finds and concludes that the Settlement Agreement is just and reasonable and not contrary to the public interest. The ALJ shall approve the Settlement Agreement without material modifications and shall grant the Application, as modified and clarified by the Settlement Agreement and the testimony referenced therein.[46] In so doing, the ALJ approves Tri-State's assessment of need during the resource acquisition period, its plans for acquiring additional resources, and its proposed model contracts and evaluation criteria.

51. Paragraphs 4.2. and 5.3 of the Settlement Agreement (and the subparagraphs contained therein) thoroughly set forth the process and requirements for Phase II RFPs as well as the location (Moffat) of a gas plant for which Tri-State would solicit RFPs during Phase II. Multiple public comments addressed the public's concern as to the construction of a gas plant in Moffat.[47] Nonetheless, the ALJ is satisfied by the flexibility in the modeling requirements set forth

[43] Motion at 4-5.
[44] *Id*.
[45] 4 CCR 723-1.
[46] *See* Settlement Agreement, ¶4.3.7.
[47] *See, e.g.*, Public Comment Hr. Tr. for July 11, 2024 Public Comment Hr. at 13:1-8, 15:21-16:2, 20:1-13, and 35:12-21.

by the Settlement Agreement, which includes a requirement to model at least one portfolio with no new gas resources, should all other portfolios incorporate new gas resources.

52. Paragraph 4.2.2 of the Settlement Agreement set forth requirements regarding bid fees and bid security for Phase II RFPs. The ALJ finds that these provisions appropriately address concerns previously raised by COSSA/SEIA and Staff and are otherwise reasonable and not contradictory to the public interest.[48]

53. Paragraphs 4.2.7 – 4.2.10 of the Settlement Agreement addresses the New ERA Application. The New ERA Application was a primary area of concern for Staff prior to the execution of the Settlement Agreement.[49] The ALJs agree with the Settling Parties that the changes to Tri-State's Phase II RFPs provide reasonable flexibility while still ensuring that Tri- State can leverage federal funding. Moreover, Tri-State commits specifically to address grant flexibility with USDA and to provide informational updates to the Commission. The ALJ finds that the terms relating to the New ERA Application are reasonable and not contradictory to the public interest.

54. Paragraph 4.3 of the Settlement Agreement addresses the portfolios to be modeled by Tri-State in Phase II. The ALJ agrees with the Settling Parties that the portfolios to be modeled by Tri-State in Phase II promote flexibility and ensure the availability of sufficient options and combinations which would allow evaluation of backup options and help to inform the decision as to the need for additional gas resource.[50]

55. Paragraphs 4.4.1, 4.8.1, 4.8.2, and 4.8.3 of the Settlement Agreement address EWE Sensitivity. Notably, Tri-State will model the EWE Sensitivity in the dispatch only, without informing the expansion plan of the EWE modeling parameters. This approach is different than

[48] *See* Hr. Ex. 1501, p. 2:15-19; Hr. Ex. 203, p. 9:5-12; See also Hr. Ex. 122, pp. 5:22-6:16.
[49] *See* Hr. Ex. 200, pp. 38:15-39:11.
[50] *See* Hr. Ex. 903, p. 8:5-12; Ex. 402, pp. 8:19-9:2; Hr. Ex. 203, pp. 13:7-14:16; and Hr. Ex. p. 4:12-15.

the Phase I approach to EWE modeling. The ALJ finds that the EWE Sensitivity provisions are reasonable and not contradictory to the public interest.

56. As mentioned above, ¶4.1 of the Settlement Agreement states that the Settling Parties agree that Tri-State's 2023 ERP should be approved pursuant to Commission Rule 3605(g)(III), subject to the terms of the Settlement Agreement, without modification. The Wyoming Cooperatives, LPEA/MPE, WREA, K.C., SIEA, and SECPA do not oppose the Motion or the Settlement Agreement.[51] In its Answer Testimony,[52] LPEA/MPE stated that the Commission should "[d]irect Tri-State to model at least one 'lower load' scenario under which one or more additional members exit the Tri-State system, and consider the results of that scenario in the Phase I decision…"[53] As the lack of any objection by LPEA/MPE to the Motion or the Settlement Agreement and Tri-State's Rebuttal Testimony[54] suggests, this issue was satisfactorily resolved by Tri-State's commitment to update its load forecast during Phase II modeling to incorporate LPEA's departure beginning in April 2026 and the removal of Partial Requirements starting January 2026.[55] However, this commitment by Tri-State is not specifically set forth in the Settlement Agreement. Therefore, the Supplemental Direct Testimony of Lisa K. Tiffin, Hr. Ex. 110, which specifically addresses this commitment by Tri- State, will be incorporated by reference to the Settlement Agreement, as ordered below.

57. Paragraphs 4.4.4, 4.4.5, and 4.4.6 discuss modeling assumptions and obligations by Tri-State regarding CO2 emission rate, carbon capture and sequestration, federal production tax credits, and the useful life of gas plants. The ALJ agrees that these modeling assumptions and

[51] Motion at 2; Settlement Agreement, ¶1.2.
[52] Hr. Ex. 1400.
[53] *Id*., p. 6:6-8.
[54] Hr. Ex. 113.
[55] *Id*. 8, 9-11.

obligations "align with the recommendations that WRA put forward in answer and cross-answer testimony, while reflecting a degree of compromise in the interest of settlement[;]"[56] are intended to be consistent with the New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, published in the Federal Register on May 9, 2024[.][57] Therefore, the ALJ finds that the provisions in the Settlement Agreement that address modeling assumptions and obligations by Tri-State regarding CO2 emission rate, carbon capture and sequestration, federal production tax credits, and the useful life of gas plants, are reasonable and not contradictory to the public interest.

58. Paragraphs 4.4.7 and 4.4.8 of the Settlement Agreement sets forth guidelines for Tri-State's use of the EnCompass software to run its modeling. Staff notes, and the ALJ agrees, that the guidelines for Tri-State's use of the EnCompass software to run its modeling, as set forth in the Settlement Agreement, addresses Staff's prior concerns about Tri-State's EnCompass software configuration.[58] The ALJ finds that the provisions in the Settlement Agreement that address Tri-State's use of the EnCompass software to run its modeling are reasonable and not contradictory to the public interest.

59. Paragraph 4.5 of the Settlement Agreement sets forth Phase II bid generator interconnection criteria, including the requirement for bids for the years 2026-2027 to include generator interconnection queue position. The ALJ finds that that these criteria are reasonable and not contradictory to the public interest.

[56] Hr. Ex. 903, p. 7:18-20.
[57] Hr. Ex. 402, pp. 11:18-12:2 and Hr. Ex. 124, pp. 5:22-64.
[58] Hr. Ex. 203, pp.12:14-13:3.

60. Paragraph 4.6 of the Settlement Agreement states that the Settling Parties agree that the Commission should approve a retirement date of January 1, 2028 for Craig 3. The Settling Parties note, and the ALJ agrees, that the setting of a definite Craig 3 retirement date provides certainty for Moffat/Craig,[59] and while not easy to bear, is agreeable by Moffat/Craig.[60] The ALJ finds that a retirement date of January 1, 2028 for Craig 3 is reasonable and not contradictory to the public interest.

61. Paragraph 4.6 of the Settlement Agreement also states that the Settling Parties agree that the Commission should approve the retirement date of September 15, 2031 for Springerville 3, subject to certain conditions. Staff's concerns regarding modeling assumptions related to the cost of the retirement of Springerville 3 were appropriately addressed by the Settlement Agreement.[61] Further, Tri-State notes that the retirement date of Springerville 3 aligns with the New ERA application, which would facilitate the reduction of the cost of retiring Springerville 3 for Tri-State Members and enable exiting of contractual agreements to not result in undue financial impact on Tri-State Members.[62] The ALJ finds that a retirement date of September 15, 2031 for Springerville 3 is reasonable and not contradictory to the public interest.

62. Paragraph 5.6 of the Settlement Agreement discusses the requirements imposed on Tri-State to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3. Moffat/Craig believe, and the ALJ agrees, that these requirements would enhance communication between Tri-State and Moffat/Craig and assist Moffat/Craig with local economic development planning efforts.[63] The ALJ notes that a single commenter in this

[59] Hr. Ex. 402, p. 11:10-14.
[60] Hr. Ex. 1603, p. 5:3-12.
[61] Hr. Ex. 203, p. 15:1-13.
[62] Hr. Ex. 123, p. 8:15-23.
[63] Hr. Ex. 1603, pp. 16:13-17:9.

Proceeding stated that the labor force of Craig 3 was excluded from the negotiation table as it relates to the Settlement Agreement. The commenter noted that while the Craig 3 labor force has a letter of agreement in place with Tri-State, the letter does not fully address workforce transition or timing; and the labor force has not had sufficient time to consider and respond to the terms of the Settlement Agreement.[64] The ALJ considered this public comment and finds that the Settlement Agreement appropriately addresses workforce transition issues in light of Tri-State's legal obligations and its continued willingness to engage in discussions regarding the local economy. Section 5 of the Settlement Agreement incorporates certain community assistance opportunities that were identified in the Informational Community Assistance Plan ("ICAP") developed by Moffat/Craig, Tri-State, OJT, CEO, and UCA.[65] However the ICAP includes other opportunities that are not limited to the actions of this Commission. Therefore, the ALJ finds that the commitments made by Tri-State to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3 are reasonable and not contradictory to the public interest.

63. Paragraphs 5.2, 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, 5.3.6, 5.3.7, 5.7, and 5.9, of the Settlement Agreement set forth the parameters for the monetary community assistance to be provided by Tri-State to Moffat/Craig. A significant number of public comments emphasized the support of individual customers and local officials for community assistance.[66] COSSA/SEIA note that they strongly support the "Direct Benefit" to Moffat/Craig that the community assistance provisions of the Settlement Agreement provide.[67] COSSA/SEIA further state that while they do

[64] Public Comment Hr. Tr. for July 9, 2024 Public Comment Hr. at 48:4-19, 49:1-7, and 49:19-50:4.
[65] Hrg. Ex. 1601, Att. CN-1, at p. 4-7.
[66] *See, e.g.*, Public Comment Hr. Tr. for July 9, 2024 Public Comment Hr. at 15:25-165, 19:14-19, 22:19-23:4, 25:19-26:13, 26:23-27:3, 28:10-21, 29:12-14, 30:9-14, 31:4-6, 32:19-33:11, and 53:10-54:2.
[67] Hr. Ex. 1501, p. 4:14-16.

not support the construction of a gas plant in Moffat/Craig, the Settlement Agreement provides for a competitive solicitation process that a natural gas plant will ultimately be constructed in Moffat/Craig.[68] Similarly, WRA states it supports the community assistance provisions of the Settlement Agreement, the community assistance provisions of the Settlement Agreement do not prematurely lock in the acquisition of new natural gas resources in Phase I of this Proceeding, and the construction of a gas facility in Moffat would provide an economic benefit to Moffat.[69] CEO, too, supports the community assistance provisions of the Settlement Agreement, as those are consistent with CEO's recommendations regarding Tri-State's Phase II gas resources modeling.[70]

64. Moffat/Craig state that community assistance provisions of the Settlement Agreement align with the ICAP process that originated from the Tri-State 2020 ERP Settlement Agreement and brings many of the ICAP Report's community assistance opportunities to fruition.[71] Moffat/Craig further state that Moffat/Craig have the most to lose in terms of annual tax base as a result of Colorado's transition away from coal, and the direct benefit payments and minimum backstop payments by Tri-State would help ease these impacts.[72] Moffat/Craig also state that the goal of Tri-State's community assistance fund is to attract new industries and support existing local businesses in the area to help with replacement tax base sources and job creation resulting from the loss of Craig 3 and two coal mines.[73] Lastly, Moffat/Craig state that tax base sources and job creation could be assisted by the establishment of a natural gas facility in Moffat, which also aligns with the need for a dispatchable energy resource in Western Colorado to ensure

[68] *Id*., p. 7:6-9.
[69] Hr. Ex. 903, p. 12:4-12.
[70] Hr. Ex. 402, p. 12:4-10.
[71] Hr. Ex. 1603, p. 8:10-13.
[72] *Id*., p. 10:1-9.
[73] *Id*., pp. 11:10-15, 13:13-14.

grid reliability.[74] Similarly, Staff "applauds" all parties involved in negotiating the community assistance provisions of the Settlement Agreement.[75] Tri-State states that the minimum backstop payments provisions of the Settlement Agreement, which allow for Tri-State's payments to be reduced based on Tri-State's investments in Moffat/Craig, can deliver value for Tri-State members and are otherwise aligned with Tri-State's functions as a non-for-profit organization.[76] The ALJ agrees with the justifications set forth above and finds that the community assistance to be provided by Tri-State to Moffat/Craig is reasonable and not contradictory to the public interest.

65. Paragraph 5.5 of the Settlement Agreement sets forth the parameters for the free transfer of Tri-State's water rights in Elkhead Reservoir to Moffat. Moffat/Craig state that securing Tri-State's water rights was the third-ranked CAO in the Final ICAP Report because the Yampa River upstream of the confluence with the Little Snake River, including all of its tributaries, was designated as "Over-Appropriated" and Moffat relies on water replacement augmentation through a lease agreement with the Colorado River Water Conservancy District.[77] Moffat/Craig further state that being able to secure the transfer of water rights from Tri-State would ultimately allow Moffat to expand housing opportunities for workers of any industry and attract new residents to Moffat.[78] The ALJ agrees that the free transfer of water rights from Tri- State to Moffat provides a substantial benefit to Moffat/Craig, is reasonable under the circumstances, and not contradictory to the public interest.

[74] *Id*., pp. 13:13-14:13.
[75] Hr. Ex. 203, p. 16:10-14.
[76] Hr. Ex. 123, p. 23:5-9.
[77] Hr. Ex. 1603, p. 15:8-18, *citing* Colorado Division of Water Resources, Over Appropriation of the Yampa River above the Confluence with the Little Snake River Letter (January 19, 2022), https://dnrweblink.state.co.us/dwr/0/edoc/3863278/DWR_3863278.pdf?searchid=20139195-951f-4bbd-a0fb-35562c8ddfee.
[78] *Id*., p. 16:2-9.

66. Paragraphs 5.3, 5.4.1, 5.4.2, and 5.4.3 of the Settlement Agreement set forth parameters relating to gas plant bid solicitation, energy cost, letters of support to be produced by Moffat in connection with Tri-State's 2023 ERP Phase II, 2027 ERP Phase I and II processes, and Moffat/Craig's advocacy in connection with any bids in Moffat County selected as part of Tri-State's preferred portfolio in Phase II of Tri-State's 2027 ERP. According to Moffat/Craig, Tri-State's application of a $1/MWh price improvement over the life of the proposed project and siting replacement for gas plant bids could assist local communities without having to take more extreme measures that threaten Colorado's marketplace.[79] According to CEO, the "price adder" set forth in the Settlement Agreement will help with bids located in Moffat not to be eliminated from the bid evaluation screening process before the non-price factor screen can be completed.[80] According to Moffat/Craig, gas plant bids siting replacement is in alignment with the third-party Generation Siting Study report authored by 1898 & Co., which selected a 239-acre Moffat County site in close proximity to Craig Station as the top location for a gas plant.[81] The ALJ agrees that the siting and price preferences given by Tri-State to Moffat in the context of the Settlement Agreement are a reasonable methodology that balances providing a locational preference with offering competitive flexibility, and thus are reasonable and not contradictory to the public interest.

67. Paragraphs 4.7.1, 4.7.3.1, and 4.7.3.2 of the Settlement Agreement set forth parameters relating to non-price bid factors for Tri-State's Phase II of the 2023 ERP. According to WRA, Tri-State's agreement to make information available to bidders regarding each of the listed non-price factors in the bid policy, including, where possible, the factors' relative weight,

[79] Hr. Ex. 1501, pp. 4:19-5:15.
[80] Hr. Ex. 402, p. 15:2-11, *citing* Hr. Ex. 400, Answer Testimony of Kathleen Gegner, p. 39:10-13.
[81] Hr. Ex. 1603, pp. 7:15-8:2, *citing* 1898 & Co. Generation Siting Study Report (Hr. Ex. 112, Tri-State Supplemental Direct Testimony of Chris E. Pink, Rev. 1, Attachment CEP-2 (Public Version of Generation Siting Study Report), at 37 (filed April 22, 2024)).

will improve transparency about the proposed framework at the outset of Phase I and satisfy WRA's concerns in this regard.[82] CEO states that it supports the non-price bid evaluation criteria set forth in the Settlement Agreement and explains that, as it understands it, tribal consultations, wildlife surveys, and/or plans to conduct such assessments, consultations, or surveys, will be offered on an informational basis and be otherwise consistent with Tri-State's existing and proposed processes, and that it is not creating additional requirements on bidders. The ALJ agrees that the non-price bid process outlined in the Settlement Agreement does not impose unreasonable requirements on developers, the process is otherwise reasonable under the circumstances, and is not contradictory to the public interest. The ALJ further notes that ¶4.7.1 of the Settlement Agreement, is consistent with §40-2-129(1)(b) and Rule 3605(h)(I)(A)(iii) of the Rules Regulating Electric Utilities, 4 CCR 723-3, which require Tri-State to provide the Commission with the best value employment metrics information provided by bidders as a part of its Phase II ERP Implementation Report.

68. Paragraph 4.9 of the Settlement Agreement sets forth three demand response requirements Tri-State must follow. According to WRA, the requirements on Tri-State to aim to control at least 5.5 percent of its Colorado peak load through demand response programs by 2030, although a compromise from WRA's initial proposal, represents a meaningful increase in Tri-State's future demand response capacity objectives.[83] According to Tri-state, the requirements set forth in ¶4.9 of the Settlement Agreement are "reasonable stretch goals." The ALJ agrees that the requirements set forth in 4.9 of the Settlement Agreement are reasonable and not contradictory to the public interest.

[82] Hr. Ex. 903, p. 9:11-17.
[83] Hr. Ex. 903, p. 8:15-22.

69. Paragraph 4.10 of the Settlement Agreement sets forth the minimum requirements for Tri-State's Phase II Implementation Report. CEO previously suggested, and supports, the requirements on Tri-State to provide the annual carbon dioxide and methane emissions in short or metric tons in its ERP Implementation Report, for each proposed Phase II portfolio and map all Phase II bids against an overlay of the EnviroScreen data layer that identifies DI communities.[84] The ALJ finds that the requirements set forth in¶4.10 of the Settlement Agreement are reasonable and not contradictory to the public interest.

70. Paragraph 4.11 of the Settlement Agreement sets forth criteria for Tri-State's Post-Phase II Transmission Injection Study. The ALJ finds that the requirements set forth in ¶4.11 of the Settlement Agreement are reasonable and not contradictory to the public interest.

71. Paragraphs 4.7.2, 4.9.3, 4.12 of the Settlement Agreement set forth certain requirements relating to Tri-State's 2027 ERP. According to WRA, the requirement on Tri-State to provide information in future annual progress reports on Regional Transmission Organization ("RTO") impacts to resource adequacy determination is "an appropriate starting place for understanding the impacts of RTO participation on electric resource planning," and complements other approaches for evaluating RTO participation and impacts on utility operations.[85] Tri-State explains that after the start of its participation in the Southwest Power Pool ("SPP"), which is scheduled for April 1, 2026, Tri-State will begin including certain SPP information in its ERP Annual Progress Reports, as specified in ¶4.12.3 of the Settlement Agreement.[86] The ALJ finds that the provisions of the Settlement Agreement relating to Tri-State's 2027 ERP are reasonable and not contradictory to the public interest.

[84] Hr. Ex. 402, p. 9:17-10:4.
[85] Hr. Ex. 903, pp. 10:16-11:2.
[86] Hr. Ex. 123, pp. 18:19-19:6.

72. Accordingly, in accordance with § 40-6-109, C.R.S., it is recommended that the Commission enter the following Order.

III. ORDER

A. It is Ordered That:

1. For the reasons stated above, the Joint Unopposed Motion to Approve the Unopposed Comprehensive Settlement Agreement, Amend the Procedural Schedule, and Waive Response Time, filed on June 27, 2024 by Tri-State Generation and Transmission Association, Inc., Highline Electric Association Highline, Poudre Valley Rural Electric Association, Inc., Y- W, Interwest Energy Alliance, Trial Staff of the Colorado Public Utilities Commission, the Office of the Utility Consumer Advocate, the Colorado Energy Office, Moffat County and the City of Craig, Office of Just Transition, the Colorado Independent Energy Association, Colorado Solar and Storage Association and the Solar Energy Industries Association, Conservation Coalition, and Western Resource Advocates (the "Settling Parties") is granted.

2. The Unopposed Comprehensive Settlement Agreement ("Settlement Agreement"), filed by the Settling Parties on June 27, 2024 is approved, consistent with the discussion above. The Settlement Agreement is attached to this Decision as Appendix A.

3. The Supplemental Direct Testimony of Lisa K. Tiffin, Hearing Exhibit 110 is incorporated by this reference into the Settlement Agreement and is included as Appendix B to this Decision.

4. The 2023 Electric Resource Plan Application, filed by Tri-State on December 1, 2023, as modified by the Settlement Agreement, is granted.

5. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

6. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

a. If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b. If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

7. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Aviv Segev

Administrative Law Judge

ATTEST: A TRUE COPY

Rebecca E. White,
Director

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit BB: CoPUC, Decision No. C25-0892, issued on December 10, 2020,
in Proceeding No. 25V-0480E

Decision No. C25-0892

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 25V-0480E

IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS.

COMMISSION DECISION GRANTING JOINT PETITION WITH MODIFICATIONS AND ESTABLISHING PARTIES

Issued Date: December 10, 2025
Adopted Date: December 3 and 10, 2025

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I. BY THE COMMISSION

A. Statement

1. Through this Decision we grant, with modifications, the Joint Petition that Trial Staff of the Public Utilities Commission ("Staff"), the Colorado Energy Office, ("CEO"), the Colorado Office of the Utility Consumer Advocate ("UCA"), and Public Service Company of Colorado ("Public Service" or the "Company") (collectively, "Joint Petitioners") filed on November 10, 2025 ("Petition"). We specifically grant the requested variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Comanche Unit 2 ("Pueblo Unit 2") coal-fired facility from December 31, 2025, to December 31, 2026. In addition, we provide additional reporting and future filing direction regarding the proposed two-step process in the Petition and establish the parties to this Proceeding.

B. Background

2. On November 10, 2025, Joint Petitioners filed the Petition seeking a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Commission

deems necessary, to modify the planned retirement date of Comanche Unit 2 ("Pueblo Unit 2") from December 31, 2025, to December 31, 2026.

3. Through Decision No. C25-0812-I, issued November 12, 2025, the Commission granted the Petition's request for a shortened notice and intervention period and established a deadline for responses to the Petition and replies to the responses. Interventions and responses, which were to be filed concurrently, were due on November 20, 2025, and any replies due on November 26, 2025.

4. Several parties filed timely motions to permissively intervene and responses on the November 20, 2025 deadline, and multiple public comments have been filed thus far.

5. Joint Petitioners filed a Joint Reply on November 26, 2025.

6. An unopposed late-filed motion to intervene was filed on December 2, 2025, by CORE Electric Cooperative ("CORE").

C. Joint Petition

7. The Petition requests a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761.[1] The requested variance would extend the planned retirement date of Comanche Unit 2 from December 31, 2025, to December 31, 2026. The Joint Petitioners assert that good cause exists to grant the variance and that the limited modification is in the public interest. The Petition also requests a shortened notice and intervention period of ten days and proposes a procedural schedule to allow for Commission deliberation and action by December 10, 2025.

8. Joint Petitioners contend that recent events have resulted in challenges to the planned retirement. As set forth in the Petition, these events fall generally into four categories: (1) the impact of the extended outage of Pueblo Unit 3 on Public Service's system; (2) increasing

[1] Issued September 10, 2018, in Proceeding No. 16A-0396E.

peak load growth in Public Service's territory; (3) supply chain and geopolitical/macroeconomic impacts; and (4) reassessment of resource accreditation and planning reserve margin methodologies.

9. Joint Petitioners therefore seek relief in the form of a variance from the Commission's directive to file a certificate of public convenience and necessity ("CPCN") amendment to effectuate a retirement of the Pueblo Unit 2 by the end of this year, as well as any other requirements the Commission deems necessary.

10. Additionally, Joint Petitioners propose a two-step process for further evaluation in which the Company will provide two updates to the Commission on work in the extended review period. For the first step, the Company will provide a report to the Commission on March 1, 2026, which will include, among other things, an update on the repair and return to service status of Pueblo Unit 3, including forecasted cost of repairs, any resource options identified in collaborative work with the Joint Petitioners for potential near-term resource adequacy benefits, and other analysis relevant to the four areas outlined above.

11. For the second step, the Company commits to submitting an application on June 1, 2026, which would consist of any additional variances or resource approvals building on the report and will include, among other things, updated loads and resources tables and loss of load calculations that include analysis of new resources projected to come on-line from the Company's Near-Term Procurement, the Just Transition Solicitation ("JTS") Phase II resource solicitation, or other relevant proceedings.

D. Establishment of Parties

12. Under Rule 1200(a)(I), 4 *Code of Colorado Regulations* ("CCR") 723-1, parties shall include any person that initiates action through the filings of a complaint, application, or

petition. Therefore, Public Service, Staff, UCA, and CEO—as the Joint Petitioners—are parties to this Proceeding.[2]

13. The following parties filed timely motions for permissive intervention: the City of Boulder ("Boulder"); the Board of County Commissioners of Pueblo County, the City of Pueblo, and the Pueblo Economic Development Corporation (collectively, "Pueblo Intervenors"); GreenLatinos, GRID Alternatives, Ebony Advocates, NAACP Pueblo Branch, Roots to Resilience, and Vote Solar (collectively, the "Environmental Justice Coalition" or "EJC"); Western Resource Advocates ("WRA"); Colorado Energy Consumers ("CEC"); Natural Resources Defense Council and Sierra Club (collectively, the "Conservation Coalition"); the Colorado Renewable Energy Society ("CRES"); and Climax Molybdenum Co. ("Climax").

14. Boulder is a home rule city and municipal corporation and a large customer of Public Service. Boulder states its residents and businesses are also customers of the Company and that it has a longstanding interest in proceedings affecting electric generation, greenhouse gas emissions, and customer rates. Boulder asserts its climate goals depend on the decarbonization of Public Service's generation mix and that the early retirement of Pueblo Unit 2 was a key component of the Colorado Energy Plan portfolio it supported in the 2016 Electric Resource Plan ("ERP"). Boulder seeks to intervene to address the prudence, cost, and emissions implications of extending Pueblo Unit 2's operation.

15. The Pueblo Intervenors state they have substantial tangible and pecuniary interests in the continued operation of Pueblo Units 2 and 3. Pueblo Intervenors assert these units provide critical electric service to the Pueblo Steel Mill, a major employer and economic driver in the region, and contribute significantly to local tax revenues. Pueblo Intervenors argue that the

[2] Staff reiterates this point in its Notice to Rule 1007(a), filed on November 20, 2025.

outcome of this Proceeding will directly impact the economic stability of the community and the viability of ongoing industrial operations in Pueblo. Pueblo Intervenors support the variance and seek to ensure that community interests are adequately represented.

16. EJC represents community members in Pueblo and assert that the continued operation of Pueblo Unit 2 would disproportionately harm a historically impacted community already burdened by pollution from the Pueblo coal plant. EJC opposes the Petition as filed and instead supports an Alternate Plan that includes operational limits on Units 2 and 3, enhanced transparency, and a more robust process for evaluating the future of Pueblo Unit 3. EJC emphasizes the Commission's statutory equity mandate and urges action that prioritizes public health and environmental justice.

17. WRA is a nonprofit environmental advocacy organization focused on reducing greenhouse gas emissions and promoting clean energy across the Interior West. WRA states it has long participated in Commission proceedings, including the 2016 and 2021 ERP/Clean Energy Plan ("CEP") proceedings, and that it joined the settlement agreements that established the early retirement of Pueblo Units 2 and 3. WRA asserts the proposed variance could undermine those agreements and increase emissions, and therefore seeks to ensure that any delay in retirement is narrowly tailored and accompanied by operational limits and transparency measures to protect public health, the environment, and ratepayers.

18. CEC is an unincorporated association composed of various industrial and commercial customers of Public Service. CEC states its members operate facilities within the Company's service territory and are among its largest customers. CEC asserts the outcome of this Proceeding will directly impact its members' electric rates and service reliability, particularly due to the proposed extension of Pueblo Unit 2's retirement. CEC further states that it was a party to

the 2016 ERP and the 2021 ERP/CEP proceedings, and that the proposed variance would alter the assumptions underlying the Updated Settlement Agreement approved in those prior proceedings.

19. The Conservation Coalition is composed of two nonprofit environmental organizations with longstanding participation in Commission proceedings. The Conservation Coalition states it does not oppose a one-year variance for Pueblo Unit 2's retirement but objects to the breadth of the relief requested in the Petition. The Coalition supports an Alternate Plan that includes operational limits on combined generation from Pueblo Units 2 and 3, enhanced transparency and reporting, and a more timely and robust follow-on proceeding. The Conservation Coalition asserts its interests in environmental protection, public health, and ratepayer impacts would be substantially affected by the outcome of this Proceeding.

20. CRES is a nonprofit organization that promotes energy efficiency and renewable energy across Colorado. CRES states it represents a broad membership of individuals and businesses committed to accelerating the transition from fossil fuels to clean energy. CRES asserts that the proposed extension of Pueblo Unit 2's retirement would result in increased greenhouse gas and pollutant emissions and could delay the integration of renewable resources. CRES requests a more thorough, litigated process to evaluate the Petition and urges the Commission to ensure that any extension is supported by a complete evidentiary record.

21. Climax operates the Climax and Henderson molybdenum mines and is one of Public Service's largest electric customers. Climax states that its mining and milling operations depend on reliable and cost-effective electric service from the Company. Climax asserts that the outcome of this Proceeding will directly affect its operations due to potential impacts on system reliability and replacement power costs associated with the proposed extension of Pueblo Unit 2. Climax supports the requested variance with reservations and urges the Commission to clarify that

any costs incurred as a result of the extension or the Pueblo Unit 3 outage carry no presumption of prudence.

22. Pursuant to Rule 1401(c) of the Rules of Practice and Procedure, 4 CCR 723-1, persons seeking permissive intervention must show the following, in pertinent part:

> A motion to permissively intervene shall state the specific grounds relied upon for intervention; the claim or defense within the scope of the Commission's jurisdiction on which the requested intervention is based, including the specific interest that justifies intervention; and why the filer is positioned to represent that interest in a manner that will advance the just resolution of the proceeding. The motion must demonstrate that the subject proceeding may substantially affect the pecuniary or tangible interests of the movant (or those it may represent) and that the movant's interests would not otherwise be adequately represented.

23. We find that each party entity seeking timely permissive intervention has sufficiently demonstrated that this Proceeding may substantially affect its pecuniary or tangible interests, as is required by Rule 1401(c). Each also has demonstrated that its interests would not otherwise be adequately represented. Therefore, we grant each of the timely unopposed requests for permissive intervention.

24. On December 2, 2025, CORE filed a late-filed Motion to permissively intervene in this Proceeding. CORE includes in its filing that it is a wholesale purchaser of electric power and energy from Public Service, is a joint owner of the Pueblo Unit 3 facility with Public Service and Holy Cross Electric Association, Inc., and has significant contractual and regulatory relationships with Public Service. Thus, CORE includes that its direct, tangible, and pecuniary interests will be materially affected by the outcome of this proceeding, specifying that a variance in Comanche Unit 2's retirement date and the impact, if any, on changes to Comanche Unit 3's operations will affect CORE and its members. CORE states that, while untimely, its intervention is unopposed and will not broaden the scope of the Proceeding. CORE states that, following consideration of

the responses filed by potential parties, some parties indicate possible expansion of the Petition's scope to request operational changes at Unit 3, which could impact CORE as a joint owner.

25. Pursuant to Rule 1401(a) of the Rules of Practice and Procedure, 4 CCR 723-1, the Commission may, for good cause shown, allow late intervention, subject to reasonable procedural requirements. We find that CORE's late-filed intervention will not broaden the scope of this Proceeding or its process and otherwise meets the intervention standard set forth in Rule 1401. Therefore, we grant CORE's late-filed intervention.

E. Party Responses

1. WRA

26. WRA supports a limited variance to extend the retirement of Unit 2 but conditions its support on the Commission's adoption of the "Alternate Plan,"[3] which it developed in collaboration with the Conservation Coalition and the Environmental Justice Coalition. WRA summarizes the Alternate Plan as follows: (1) place a status quo operational limitation on the operation of Unit 2 and Unit 3, designed to limit the total, combined generation from Units 2 and 3 to 3,942,000 MWh in 2026; (2) provide transparent, regular reporting related to the continued operations of Unit 2 and Unit 3 and associated costs incurred; and (3) institute an appropriately accelerated process to determine Public Service's resource adequacy position, identify near-term solutions, and provide direction on the continued operation of Unit 2 and Unit 3.[4]

27. WRA emphasizes that the Alternate Plan is necessary to preserve the emissions reductions contemplated in prior Commission decisions and settlement agreements.[5]

[3] Attachment WRA-1 Alternate Plan.
[4] WRA Response at pp. 7-8.
[5] WRA Response at p. 8.

The Plan proposes a combined generation cap of 3,942,000 MWh for Units 2 and 3 in 2026, consistent with the 60 percent annual capacity factor limit previously approved for Unit 3. WRA argues this cap is essential to prevent an increase in emissions beyond what was previously authorized and to maintain the integrity of the Commission's prior resource planning decisions.

28. In addition to operational limits, WRA requests that the Commission require monthly reporting on a range of operational and financial metrics, including hourly generation, emissions, and costs associated with the continued operation of Unit 2 and the outage of Unit 3.[6] WRA also recommends that the Commission initiate a new application proceeding within 60 days of its decision on the Joint Petition to evaluate near-term resource adequacy and the future of Units 2 and 3.

29. Specifically, and as set forth in the Alternate Plan, WRA recommends the Company provide monthly reports on the 15th of each month with the following information:

(1) The MW produced each hour that Comanche 2 and Comanche 3 were operating;

(2) The total MWh produced by Comanche 2 and Comanche 3;

(3) The total CO_2, SO_x, NO_x, and PM10 emissions produced by Comanche 2 and Comanche 3;

(4) Any estimated future costs, and/or actual costs incurred, related to the outage of Comanche 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;

(5) Any updates on the repair and return to service status of Comanche 3, including the expected date for resuming operation;

(6) Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Comanche 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,

[6] WRA Response at pp. 12-13.

(7) Large Load Reporting:

- **a.** Information about actual load growth from large load customers, including MW and number brought online;
- **b.** Information about forecasted large load growth in the queue, including MW and number of large load interconnection requests and status (projected in-service date and load ramp forecast); and
- **c.** Information about large load requests that have exited the queue, including MW and number.[7]

30. In addition, WRA argues the Commission should adopt the accelerated procedural framework set forth in the Alternate Plan. WRA asserts that adopting the Petition's proposed timeline for Step 1 and Step 2 would limit the Commission's ability to direct the Company to pursue alternative solutions.[8] Instead, through the Alternate Plan WRA recommends the Commission direct Public Service to file an application within 60 days of the Commission's final decision on the Petition. The purpose of such an application would be to receive Commission guidance on Public Service's near-term resource adequacy position for years 2026-2028 as well as on the future operation and life of Comanche 2 and 3. WRA contemplates that the Commission decision ruling on the application would address near-term capacity needs (2026-2028), whether to revise the retirement dates and operational restrictions for Unit 2 and 3, and the possible authorization for additional resource procurements.[9]

31. WRA strongly opposes the use of Unit 2 to serve new large loads, arguing that the Company's resource adequacy concerns stem solely from the outage of Unit 3 and not from broader system needs. WRA contends that the Petition's reliance on supply chain issues, load growth, and accreditation changes is an improper attempt to relitigate issues already addressed in the JTS and other proceedings.

[7] WRA Response, Attachment WRA-1 at pp. 2-3.
[8] WRA Response at p. 13.
[9] WRA Response, Attachment WRA-1 at pp. 3-4.

2. Conservation Coalition

32. Conservation Coalition requests the Commission deny the Petition and adopt the Alternate Plan, which is supported by Conservation Coalition, WRA, and EJC. Conservation Coalition states it does not object to a one-year variance from the requirements to retire Unit 2, but argues the Alternate Plan is necessary to resolve three problems with the Petition. First, Conservation Coalition argues the Petition would allow Unit 2 and Unit 3 to be run simultaneously with no limit on generation or emissions. Second, Conservation Coalition contends the Petition's proposition that the application proceeding to investigate dealing with near-term resource needs would not be filed until June 2026. Third, Conservation Coalition argues the Petition fails to address whether it is in the public interest to repair Unit 3 given its long-standing reliability and cost overrun issues.[10]

33. Conservation Coalition argues the only procedural and substantive basis for extending Unit 2 is the unexpected outage of Unit 3. They argue that Unit 3's outage is the new information that was not available during the JTS. According to Conservation Coalition, the other arguments put forth in the Petition—the increase in the Company's load forecast over time; supply chain and geopolitical delays in procuring resources from the 2021 ERP/CEP; and changes to the resource accreditation and planning reserve margin—are all improper attempts to relitigate issues that were addressed in the JTS.[11] Conservation Coalition states the Unit 3 outage is the only legally permissible basis for granting a variance, and Conservation Coalition reserves their rights to challenge a decision that grants a variance for any other reason.[12] Given that the only legitimate justification for extending Unit 2 is the unexpected outage at Unit 3, Conservation Coalition argues

[10] Conservation Coalition Response at pp. 1-2.
[11] Conservation Coalition Response at pp. 3-4.
[12] Conservation Coalition Response at p. 5.

that the combined generation from Unit 2 and 3 in 2026 must not be allowed to exceed what is permitted from Unit 3 in 2026.[13]

34. Conservation Coalition also argues that the two-step process proposed in the Petition—consisting of a March 1, 2026 report and a June 1, 2026 application—is insufficient and untimely. The Coalition characterizes the proposed timeline as "too little, too late" and asserts that the Commission should instead initiate a litigated proceeding as soon as possible to evaluate the least-cost, lowest-emission options for the continued operation or retirement of Pueblo Units 2 and 3 after 2026.[14] The Coalition contends that such a proceeding should address whether Unit 3 should be repaired at all, whether Unit 2 should continue to operate in lieu of Unit 3 after 2026, and what near-term capacity or energy needs exist, along with the most appropriate options for meeting those needs.[15]

35. According to Conservation Coalition, the Petition contemplates that Public Service may seek another variance in June 2026 to extend Unit 2's operation beyond 2026. Conservation Coalition notes that such a request would come only six months before the end of 2026 and would replicate the rushed nature of the current proceeding. In contrast, the Alternate Plan would provide the Commission with a more proactive and structured opportunity to evaluate near-term needs and the future of Units 2 and 3. The Conservation Coalition further observes that the June 2026 filing would occur after Unit 3 is expected to return to service, thereby presuming the prudence of the repair before the Commission has had an opportunity to evaluate alternatives. This timing, they argue, would also delay the acquisition of any necessary replacement resources.[16]

[13] Conservation Coalition Response at p. 7.
[14] Conservation Coalition Response at p 9.
[15] Conservation Coalition Response at p. 10.
[16] Conservation Coalition Response at p. 10.

36. Conservation Coalition also objects to the June 2026 filing framework on the grounds that it would leave the scope of the proceeding entirely to the discretion of the Company. Conservation Coalition urges the Commission to provide clear direction on the topics that must be addressed and the alternatives that must be modeled. Under the Alternate Plan, the Company would be required to present testimony and modeling results addressing updated estimates of energy and capacity needs for 2026 through 2028; an assessment of all reasonable supply-and demand-side options for meeting those needs; and modeling of portfolios that include new options for Units 2 and 3, such as early retirement or seasonal operations, compared to baseline expectations.[17] Conservation Coalition clarifies that the modeling should include scenarios such as extending Unit 2's operation beyond 2026 while retiring Unit 3 earlier than currently planned—*e.g.*, in 2028 or 2029—with or without seasonal operation of Unit 3 prior to retirement.

37. Conservation Coalition concludes by reiterating that the Commission should find there is no presumption of prudence for any costs associated with repairing Unit 3. They request that Public Service be required to notify the Commission of the estimated cost to repair Unit 3 before incurring such costs. Conservation Coalition further recommends that the Commission place the Company on notice that if it proceeds with repairs prior to conducting a modeling analysis demonstrating that such repairs are the least-cost option relative to alternatives, the Company may be at risk of a future disallowance.

3. EJC

38. EJC similarly recommends the Commission not approve the Petition but instead approve the Alternate Plan developed and supported by WRA, Conservation Coalition, and EJC. EJC argues that extending the life of Unit 2 will harm disproportionately impacted ("DI")

[17] Conservation Coalition Response at pp. 13-14.

communities in Pueblo., and states the Pueblo coal plants have emitted large amounts of pollution into the nearby community for more than five decades. EJC asserts that retiring Units 2 and 3 as planned will benefit the Pueblo community and reduce the pollution burdens that Pueblo has experienced since the 1970s.[18]

39. EJC notes that, under Senate Bill 21-272, the Commission has a statutory duty to minimize harms and correct the historical inequities experienced by DI communities such as Pueblo. To comply with its statutory equity mandate, EJC argues the Commission must thoroughly consider alternatives to address the outage of Unit 3 and approve an option that would best provide equity, address the historical inequalities, and minimize impacts and prioritize benefits in Pueblo. According to EJC, such alternatives include requiring operating guardrails that limit the overall generation at Unit 2 and Unit 3, utilizing market purchases while Unit 3 is offline, and reassessing the retirement date of Unit 3.[19]

4. City of Boulder

40. Boulder argues the requested variance is the result of Public Service's inability to properly operate Unit 3, asserting there is no evidence suggesting that, but for Unit 3's outage, this variance would be necessary. Boulder notes the Joint Petitioners do not request the acquisition of any other generation resources to address the four identified events, and that the Joint Petitioners claim the cost to buy market power is higher than the cost to continue operations at Unit 2, yet provide no evidence or financial analysis to support this conclusion.[20]

41. Boulder agrees that the unplanned outage of Pueblo Unit 3, combined with delays in implementing new generation from the 2021 ERP/CEP, has left customers vulnerable to

[18] EJC Response at p. 4.
[19] EJC Response at pp. 6-8.
[20] Boulder Response at p. 3.

capacity shortfalls in 2026. Nevertheless, Boulder recommends that the Commission adopt several conditions to ensure ratepayer protection and to provide greater clarity regarding the Company's future resource planning.[21]

42. Boulder argues that ratepayers should be shielded from the cost increases associated with the failure of Unit 3 and the proposed extension of Unit 2. Specifically, Boulder recommends that the Commission prohibit Public Service from recovering any incremental costs related to the continued operation of Unit 2 or the repair of Unit 3 unless and until the Company demonstrates prudence in a future proceeding.[22] Boulder also supports the proposed March 1, 2026 Step 1 report and encourages the Commission to use that report to evaluate updated retirement dates for Pueblo Unit 3 and to explore additional demand response and distributed energy resources as near-and mid-term solutions.[23] However, Boulder expresses concern that the proposed June 1, 2026 Step 2 application timeline is unrealistic, and argues that the timeline does not allow sufficient time for the Commission to approve new resources and for those resources to be acquired and placed in service in time to address any capacity shortfall in 2026.[24] Boulder also notes that while the Petition suggests Public Service may seek expedited approval to acquire new resources, it fails to explain how such acquisitions would be feasible outside of the typical ERP, demand-side management, or renewable energy standard proceedings.[25]

43. Boulder further contends that the Joint Petitioners have not provided sufficient evidence to support their claim that a resource gap exists or that extending Unit 2 is the most cost-effective solution. Boulder recommends the Commission resolve these issues of Petition

[21] Boulder Response at p. 6.
[22] Boulder Response at p. 7.
[23] Boulder Response at p. 7.
[24] Boulder Response at p. 7.
[25] Boulder Response at p. 8.

adequacy before issuing a decision and certainly before the June 1, 2026 application is filed.[26] In addition, Boulder recommends that Public Service be required to acquire generation and storage resources to replace Unit 3 prior to its currently scheduled retirement date of January 1, 2031, and suggests that the Near-Term Procurement and JTS solicitations could be used to accomplish this.

44. Additionally, absent clear evidence in the Step 1 report that Unit 3 can return to service before the end of 2026, Boulder recommends that the Commission order Unit 3's immediate retirement.[27] Boulder also proposes that the Commission declare Unit 3 no longer "used and useful" and prohibit Public Service from earning its authorized return on equity until the plant is either returned to reliable operation or retired. Finally, Boulder encourages the Commission to consider a financial remedy to address the costs ratepayers have incurred due to the now-aborted retirement of Unit 2 and the Company's mismanagement of Unit 3.

5. CRES

45. CRES requests a hearing, discovery, and answer testimony to allow due process to investigate the Petition's claims. CRES acknowledges that such a fully litigated process would extend through the end of 2025 when Unit 2 is scheduled to retire and concludes that it may be prudent to grant the Petition only until more information is available and the evidentiary record for this Proceeding is complete.[28]

46. CRES also notes that allowing the 335 MW Unit 2 to continue operating for even one more year will emit a large amount of carbon dioxide and other harmful pollutants into the Pueblo community and surrounding area. Given the considerable consequences for air quality and

[26] Boulder Response at p. 8-9.
[27] Boulder Response at p. 10.
[28] CRES Response a p. 5.

public health, CRES requests that the Commission ensure that the Petition's claims are substantiated through a more traditional litigated proceeding. [29]

6. CEC

47. CEC argues that Unit 2's extension would not be necessary but for Unit 3's persistent operational failures, and generally supports granting the Petition to allow Unit 2 to continue operating, but argues the Commission should condition such a grant on several conditions.

48. CEC recommends the Commission impose several conditions to protect ratepayers from the financial consequences of Unit 3's outage. CEC notes that in prior instances of Unit 3 failures, the Commission has ordered disallowances through the Energy Cost Adjustment ("ECA"), and asserts that similar treatment is warranted here, where Unit 2 is being extended to serve as replacement power for Unit 3.[30] CEC argues there should be no presumption of prudence for any costs associated with Unit 2's extended operation, and that all costs related to Unit 3's outage should be disallowed. CEC recommends that the Company absorb all replacement power costs, including those associated with Unit 2, and return those costs to customers through the deferred balance in the next applicable ECA filing.

49. Specifically, CEC requests that the following rate-related conditions apply to the grant of the Petition: (1) all costs and investments associated with Unit 2's extended operation should be denied any presumption of prudence and evaluated in Public Service's next Phase I electric rate case; (2) Public Service must exclude from its revenue requirement all costs and expenses associated with Unit 3's outage in the test period, including gross plant, depreciation,

[29] CRES Response a p. 5.
[30] CEC Response at p. 6.

insurance, labor, and operations and maintenance; (3) Public Service must absorb all replacement power costs, including those from Unit 2 and any third-party sources, and flow those costs back to customers through the ECA; and (4) Public Service must include Unit 2's extended operation and emissions in any CEP compliance calculations and future emissions performance incentive mechanisms.[31]

50. CEC also raises concerns about the risk of over-procurement and overpayment for resources, given that the 2021 ERP/CEP modeling assumed Unit 2 would retire at the end of 2025. CEC warns of a scenario in which Public Service could simultaneously earn a return on Unit 2's extended operation, Unit 3 (once operational), and any new Company-owned generation approved to replace Unit 2. CEC questions whether the approved resource portfolio remains cost-effective in light of Unit 2's continued operation.[32]

51. To address these concerns, CEC recommends the Commission impose additional resource planning conditions as part of granting the variance. These include: (1) requiring Public Service to evaluate its loads and resource needs, accounting for Unit 2's extension and the results of the Near-Term Procurement, before commencing the JTS Request for Proposals; (2) requiring Public Service to evaluate and report on how the extension of Unit 2 affects the cost-effectiveness of its selected portfolios from the Company's 2021 ERP/CEP,[33] as modified by the CEP Delivery Plan and Neat Term Procurement results; and (3) granting any other relief the Commission deems necessary to hold ratepayers harmless from the effects of Unit 3's inoperability.[34]

[31] CEC Response at pp. 6-7.
[32] CEC Response at p. 10.
[33] Proceeding No. 21A-0141E.
[34] CEC Response at p. 7.

7. Climax

52. Climax supports granting the variance to extend Unit 2's retirement date to December 31, 2026, but argues the Petition lacks any substantial evidence to support the prudence or reasonableness of any costs associated with Unit 2's extension. Climax argues the Commission should clearly state that all costs incurred as a result of the Unit 3 outage and Unit 2 extension carry no presumption of prudence. If the Company proposes to recover these costs, it must clearly identify and distinguish them. According to Climax, Public Service must have the burden of proving such costs are not redundant or otherwise unreasonable or imprudent.[35]

8. Pueblo Intervenors

53. Pueblo Intervenors support the Petition, including the request to continue the operations of Unit 2 through next year and the expedited process and reporting requirements. They argue that the Company is facing a severe capacity shortage, and the Pueblo Steel Mill, an important industrial business in Pueblo, requires firm reliable electricity. Pueblo Intervenors argue the Company has been warning the Commission about its resource adequacy issues since February 2025 and that it would be reckless and dangerous to close Unit 2 with this type of resource shortage.[36]

54. Pueblo Intervenors further assert the coal units in Pueblo are necessary to provide electricity to one of the largest employers in the Pueblo Area—the Pueblo Steel Mill. They acknowledge the Pueblo Steel Mill is partly powered by a solar array and electric arc furnace but assert it still requires at times electricity from the Pueblo station. [37] Pueblo Intervenors add that

[35] Climax Response at p. 4.
[36] Pueblo Intervenors Response at pp. 2-3.
[37] Pueblo Intervenors Response at p. 4.

Unit 2 and the Pueblo Steel Mill provide family supporting jobs, and assert the continued operation of Unit 2 alone will also provide approximately $2.5 million a year in taxes for an additional year.[38]

9. Public Comments

55. The Commission received numerous public comments regarding the Petition reflecting a wide range of perspectives. Several environmental and community organizations, including 350 Colorado and Colorado Communities for Climate Action ("CC4CA"), oppose the extension of Unit 2 and call for stronger safeguards. 350 Colorado argues that the Petition lacks transparency and data, and characterizes it as an attempt to relitigate the JTS. The organization urges the Commission to deny the Petition or, at a minimum, require additional information before making a decision. CC4CA acknowledges that extending Unit 2 may be unavoidable but recommends that the Commission prohibit simultaneous operation of Units 2 and 3, cap cost recovery from ratepayers, and consider accelerating the retirement of Unit 3 if operational issues persist.

56. Other commenters, including the International Brotherhood of Electrical Workers ("IBEW") Local 111 and Colorado Concern, support the Petition. IBEW argues that closing Unit 2 at the end of 2025 would be reckless given current capacity shortages and emphasizes the importance of the jobs supported by the plant. Colorado Concern highlights the need for reliability and affordability amid rising energy demand and argues that approving the Petition demonstrates a disciplined approach to the energy transition. Several individual commenters also weighed in, with some expressing concern about ratepayer impacts and pollution, while others emphasized the need for reliable power and supported the extension.

[38] Pueblo Intervenors Response at p. 7.

57. Through its late-filed intervention and response, CORE claims that the Petition narrowly seeks a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Commission deems necessary to modify the plan to retire Pueblo Unit 2 from December 31, 2025 to December 31, 2026. CORE recognizes the importance of the continued operation of Pueblo Unit 2 to meet the needs of Public Service customers and does not object to the modification of the plan to retire Pueblo Unit 2 as requested. However, CORE argues that any consideration to changing the operations at Pueblo Unit 3 are outside the scope of the Petition's request and would require a separate application to allow for adequate time for all parties to prepare to respond and provide meaningful evidence.

F. Joint Reply

58. The Joint Reply states that few intervenors oppose the requested relief but rather most parties raise recommendations outside the narrow scope of this Proceeding. More specifically, the Joint Reply observes how several intervenors raise ratemaking issues, including arguments that the costs associated with repairing Unit 3 and extending Unit 2 should not receive a presumption of prudence. The Joint Reply notes, however, that the Petition does not seek a presumption of prudence but expressly states the Petitioners do not seek any ratemaking relief.[39]

59. The Joint Reply argues that issue of cost recovery associated with replacement power should be deferred to the relevant ECA and Purchased Capacity Cost Adjustment ("PCCA"). The Joint Reply adds that replacement power costs are currently unknown.

60. The Joint Petitioners oppose intervenor recommendations for additional reporting and an application filing prior to June 2026. The Joint Petitioners argue the two-step

[39] Joint Reply at pp. 2-3.

process—with a report in March and an application filing in June—is specifically designed to provide the Commission with an analysis of new resources projected to come on-line from the Near Term Procurement, JTS Phase II resource solicitation, or other relevant proceedings. In addition, the two-step process proposes to address operational concerns by first assessing operational parameters in Step 1 and giving the Company time to develop data-based recommendations to include in the application described in Step 2. The Joint Petitioners argue that—unlike the expedited track of the Alternate Plan—the June 1, 2026 application (Step 2) allows time to develop comprehensive solutions, for parties to provide meaningful input on these solutions, and for the Commission to consider alternatives. The Joint Petitioners add that neither the two-step process nor the Alternate Plan framework moves quickly enough to review options for Summer 2026 capacity needs.[40]

61. Regarding the monthly reporting the Alternate Plan requests, the Joint Petitioners agree that reporting is important. They argue, however, that so is taking time to assess options and present the result of that assessment to the Commission. They argue the cadence of the two-step process balances the need for reporting with the work required to assess and develop a plan to address resource adequacy needs. Nevertheless, in the Joint Reply the Company agrees to incorporate the reporting requested in the Alternate Plan in the Step 1 March report and the Step 2 June application filing, to the extent such information is available.[41]

62. The Joint Petitioners also oppose the Alternate Plan's operational limits on Unit 2 and Unit 3. They argue that addressing such operational limits is premature. The Joint Petitioners assert the Alternate Plan proposes the operational limits "without any analysis of current system

[40] Joint Reply at p. 6.
[41] Joint Reply at p. 5.

conditions or Comanche Unit 2's operating capabilities, and without taking into consideration the needs of the Company's system operators."[42]

63. The Joint Petitioners warn the Commission against relying on the loads and resources table put forth by WRA and Conservation Coalition, two of the three supporters of the Alternate Plan. They argue the loads and resources table has not been validated and it relies on assumptions that are likely to be contested in the fully adjudicated JTS proceeding.[43] More broadly, the Joint Petitioners caution against solely focusing on a loads and resources table when other metrics such as loss of load calculations are also relevant. The Joint Petitioners likewise ask the Commission to reject arguments that the Petition tries to improperly relitigate issues that could have been raised in the JTS. They note the JTS Phase I proceeding is still moving forward with RRRs and that the Petition's requested relief is narrow.[44]

G. Findings and Conclusions

1. Unit 2's Extension

64. Consistent with the Petition, we grant the requested variances from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Pueblo Unit 2 from December 31, 2025, to December 31, 2026. Extending Unit 2 is consistent with the arguments from Pueblo Intervenors and certain public commenters emphasizing the importance of reliable electricity. With this determination, we reject requests from CRES and others for a hearing, discovery, and answer testimony prior to a year-long extension of Unit 2. Such due process will be afforded in subsequent proceedings, including the Step 2 application filing and when Public Service seeks to recover costs associated with Unit 3's outage and the

[42] Joint Reply at p. 4.
[43] Joint Reply at p. 6.
[44] Joint Reply at p. 7.

extension of Unit 2. Given the prolonged, unplanned outage of Unit 3, we must move swiftly to allow Unit 2 to continue operating, but doing so in no way impedes the Commission from later finding that Public Service acted imprudently. Consistent with Climax's recommendations, if Public Service intends to recover the costs associated with Unit 3's breakdown and Unit 2's extension, the Company will have the burden of proving such costs are not redundant or otherwise unreasonable or imprudent.

65. As part of our decision to grant the requested variance, we find that Unit 3's prolonged, unplanned outage is the single justification for extending Unit 2. As set forth by intervenors like WRA, Conservation Coalition, Boulder, and CEC, the Joint Petitioners have failed to demonstrate that the other reasons set forth in the Petition—supply chain and geopolitical issues, changes to the Company's resource accreditation methodology, and increasing peak demand—justify Unit 2's extension.

66. Regarding increasing peak demand, the most recent forecast provided in the Petition shows a 2026 peak demand of about 7,150 MW.[45] However, the Company's preferred updated base forecast that it endorsed in the JTS Rebuttal had a higher 2026 peak demand of 7,235.[46] Even though the Company had a higher demand forecast in its JTS Rebuttal, Public Service never requested or even suggested that it would need to extend Unit 2 to maintain resource adequacy. To be sure, Public Service raised concerns with its capacity position in recent proceedings, including in the JTS, but the Company never suggested the retirement date of Unit 2 should be reconsidered until now. An extension of Unit 2 was unnecessary until Unit 3 suffered its prolonged outage.

[45] Petition at p. 5.
[46] Hr. Ex. 117, Ihle Rebuttal, p. 30 filed in Proceeding No. 24A-0442E.

67. A similar analysis applies to the Petition's arguments regarding supply chain and geopolitical issues and modifications to its resource accreditation methodology. The Petition provides no new evidence regarding supply chain and geopolitical issues but simply states that "[t]he Company addressed this in the CEP Delivery Plan in September 2024."[47] The Petition adds that while the CEP Delivery Plan assists with geopolitical and supply chain issues, it does not cure them. Although not recounted in the Petition, geopolitical and supply chain issues were also an issue in the JTS—as demonstrated by issues such as the tariff passthrough mechanism the Phase I Decision adopts. In neither the CEP Delivery Plan nor the JTS did Public Service raise the possibility that geopolitical and supply chain issues could necessitate the extension of Unit 2. Again, Unit 2's extension was unnecessary until Unit 3 went down.

68. The Petition similarly provides no new information regarding the modified resource accreditation methodology. Instead, the Petition recounts how it worked with a consultant in the JTS proceeding to update its resource accreditation methodology. The Petition does not indicate that there have been subsequent changes since the JTS Phase I Decision but simply states that the updated resource accreditation methodology "affects the Company's loads and resource balance."[48] Although the Company cited its updated resource accreditation methodology in both the CEP Delivery Plan and the JTS as a justification for additional resources, Unit 2's extension was never raised as a potential solution until Unit 3 broke down.

2. Two-Step Process

69. On balance, we largely adopt the two-step process put forth in the Petition. This includes the March 1, 2026 report and analysis (Step 1) and the application filing the

[47] Petition at p. 5.
[48] Petition at p. 6.

Company must file no later than June 1, 2026 (Step 2). Although we share the frustrations expressed by several intervenors with the June 2026 date for the Step 2 application filing, we are sensitive to the Company, CEO, UCA, and Staff's timeline recommendations. In addition, even with an early 2026 filing as the Alternate Plan requested, the Commission would likely not be in a position to proactively determine whether repairing Unit 3 is prudent given the Company's expectations that Unit 3 will be fully repaired and return to service in June 2026. To be clear, the Step 2 application filing must be filed no later than June 1 2026, but we encourage and would accept earlier filings. The decision not to make earlier filings may in and of itself be imprudent if there are approvals or actions the Company should have raised earlier to the Commission and for party consideration.

70. While we do not require the expedited application filing requested in the Alternate Plan, we again emphasize that there is no presumption of prudence at this time for the repair of Unit 3 or operation of Unit 2. Public Service cannot assume that repairing Unit 3 is a prudent approach if better alternatives are available. For example, if continuing to operate Unit 2 through 2030 together with market purchases and additional demand side resources is a more cost-effective option than repairing Unit 3, Public Service would be at risk for disallowance if it brings Unit 3 back to service.[49] This is consistent with Boulder's recommendation to specifically seek out demand response and distributed energy resources to meet near- and mid-term resource adequacy. In sum, it appears the Company has decided to repair Unit 3 without first seeking guidance from the Commission—despite the plant's well-documented reliability issues, the fact that Unit 3 is slated to retire in January 2031, and the fact that the settlement agreement from the 2021 ERP

[49] Even aside from the issue of whether there are better alternatives to repairing Unit 3, Public Service may be at risk for disallowance if the Commission finds that the Company's imprudent operation of the plant led to its outage.

significantly limits the plant's annual capacity factor in its remaining years of life. Public Service's strategy on Unit 3 puts the Company at risk if its actions are later found to be imprudent.

71. Nevertheless, we are not deciding at this juncture to disallow the replacement power costs and repair costs associated with Unit 3's outage. Doing so here would be premature. We thus deny CEC's request to apply several rate-issue conditions such as directing that the Company exclude from its revenue requirement in the next electric rate case all costs and expenses associated with Unit 3's outage as well as Boulder's recommendations to prohibit cost recovery associated with any incremental costs of extending Unit 2's operations or repairing Unit 3. While the Commission may ultimately disallow such costs, Public Service does not request cost recovery in this Proceeding, and we lack the necessary information to make such findings.

3. Additional Reporting

72. Although we mostly accept the Petition's proposal for the two-step process, we find intervenor arguments regarding the need for additional reporting persuasive. In particular, we largely adopt the requested reporting set forth in the Alternate Plan. The Joint Petitioners provide little reasoning for their opposition to the reporting requests, but they imply that such reporting will leave insufficient time to assess options and present the results of that assessment to the Commission.[50] We find, however, that the requested reporting information will likely prove useful in future proceedings, including cost-recovery proceedings and the June 1, 2026 application proceeding. Proactively providing this information to the parties will hopefully make such future proceedings more expedient and effective. We acknowledge the Company's statement that it will include the requested information in the Step 1 and Step 2 filing, to the extent available, but we are persuaded that monthly reports will be more helpful to the Commission and parties.

[50] Joint Reply at p. 5.

73. While we generally adopt the cadence and substance of the reporting set forth in the Alternate Plan, we find certain clarifications to be necessary. First, we clarify that any estimated material future capital costs for the repair of Unit 3 must be reported to the Commission before such costs are obligated. Second, for the information concerning large loads, Public Service must include such data in the same format as it presented in the JTS proceeding in which each large load is correlated to its industry, the probability of the load materializing, the requested in-service date, and the forecasted load by year through 2040.[51] In addition, out of all of the large loads listed, Public Service must clearly identify those that meet the Phase I Decision's requirements to be included in the base load forecast (*e.g.*, those loads that have executed an electric service agreement and interconnection agreement with the commercial principles including the fair notice provision).[52]

74. Thus, Public Service shall provide monthly reports beginning on January 15, 2026, that contain the following information:

- The MW produced each hour that Unit 2 and Unit 3 were operating;
- The total MWh produced by Unit 2 and Unit 3;
- The total CO_2, SOx, NOx, and PM10 emissions produced by Unit 2 and Unit 3;
- Any estimated material future capital costs for the repair of Unit 3, before they are obligated;
- Any additional future or actual costs incurred related to the outage of Unit 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;
- Any updates on the repair and return to service status of Unit 3, including the expected date for resuming operation;

[51] *See* Hr. Ex. 141, Updated Base Forecast Large Load filed in Proceeding No. 24A-0442E.
[52] *See* Decision No. C25-0747 at ¶ 68 issued in Proceeding 24A-0442E on November 6, 2025.

- Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Unit 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,
- Large Load Reporting:
  - **a.** Information about actual load growth from large load customers, including MW and number brought online;
  - **b.** Information about forecasted large load growth in the queue, including MW and number of large load interconnection requests and status (projected in-service date and load ramp forecast); and
  - **c.** Information about large load requests that have exited the queue, including MW and number.[53]

75. The Commission emphasizes that simply complying with these reporting requirements does not constitute a request for Commission approval. As a corollary, any Commission inaction regarding the submitted information is in no way tacit approval of the information or expenditures. If Public Service desires Commission guidance on its activities regarding Unit 3's outage, the Company must make an appropriate application filing.[54]

76. In addition to the reporting set forth above, Public Service shall describe in its March 1, 2025, Step 1 report whether the outage at Unit 3 and the continued operation of Unit 2 impairs the ability of the Arroyo 2 solar facility—or any other resource—from delivering energy as planned. For instance, it appears the Arroyo 2 solar project was designed to use the same transmission capacity as Unit 2: "The Arroyo 2 Project … will utilize the replacement interconnection rights that will become available due to the planned retirement of Comanche Unit 2 at the end of 2025."[55] If Arroyo 2 or any other resources cannot be operated as planned due

[53] *See* WRA Response, Attachment WRA-1 at pp. 2-3.

[54] Should the Commission require additional information, process, or directives regarding the Step 2 application filing or other necessary direction following review of the reporting provided, it will do so through separate order, if needed.

[55] Hr. Ex. 101, Pascucci Direct, p. 11 filed in Proceeding No. 24A-0140E.

to Unit 3's outage or while Unit 2 is operating, this is potentially another cost of Unit 3's breakdown that Public Service must track.

4. Operational Limitations on Unit 2 and Unit 3

77. One of the main requests of the Alternate Plan backed by WRA, Conservation Coalition, and EJC, is to place an operational limitation on Unit 2 and Unit 3 so that the two units together could not generate more than 3,942,000 MWh in 2026. This 3,942,000 MWh limit is what Unit 3 could produce in 2026 given its 60 percent annual capacity factor limit agreed upon in the 2021 ERP. The Joint Petitioners oppose the operational limitation, arguing that it is premature and that further evaluation is necessary before the Commission imposes such limits.

78. We agree with arguments from intervenors that the various settlements contemplating the closure of Unit 2 and the operational restrictions on Unit 3 should be respected.[56] Public Service never suggested in the CEP Delivery Plan or the JTS that the Company would need to surpass the 60 percent annual capacity factor limit on Unit 3 in order to maintain resource adequacy. Nor has the Company set forth sufficient evidence in this Proceeding to justify this result. Given that Unit 2 and Unit 3 are now intended to work together to do the work that Unit 3 would have done but for its closure, it is reasonable to apply Unit 3's operational limit from the 2021 ERP to both units. Finally, the Joint Petitioners' argument to wait until the Step 2 application filing in June 2026 is unhelpful. Even with a 120-day expedited schedule, the Commission would not issue a decision on the Step 2 application filing until October, and RRR could push a final decision into late November. This would leave approximately one month in 2026 to implement operational limitations on Unit 2 and Unit 3.

[56] Chair Blank dissents from this point and would require additional reporting on the collective operation of Unit 2 and Unit 3 but would not impose the operational limitation. Chair Blank expresses concerns about non-economic dispatch and how much the operational limitation would cost.

79. We therefore approve the 3,942,000 MWh operational restriction at Unit 2 and Unit 3 as proposed in the Alternate Plan. If Public Service has concerns with the 3,942,000 MWh limitation, the Company may file an appropriate request supported by testimony and other evidence. This pathway maintains the emissions status quo the parties agreed upon in the respective settlements while appropriately putting the burden on the Company to explain why exceeding the agreed upon limit is in the public interest.

5. CEC's Resource Planning Recommendations

80. As set forth above, CEC recommends the Commission impose certain resource planning conditions, warning of a situation in which Public Service can simultaneously earn a return of and on its investment in Unit 2's extended operation, the resources acquired to replace Unit 2, and Unit 3 (once operational).[57]

81. We decline to adopt CEC's resource planning conditions. The resources selected in the 2021 ERP/CEP and that will be selected in the JTS will serve Public Service's system for 10 years or more. While the extension of Unit 2 changes the Company's loads and resources table in the short term, it is unlikely to have a significant impact on long-term resources acquired in these proceedings, especially if the Company remains in a capacity short position. Unit 2 running together with Unit 3 would have a more significant impact, especially if both are kept operating past 2026. At this point, however, the Commission and parties do not have sufficient information to assess the likelihood of this situation.

[57] CEC Response at p. 10.

II. ORDER

A. The Commission Orders That:

1. The Motion seeking to permissively intervene filed by the City of Boulder on November 20, 2025, is granted.

2. The Motion seeking to permissively intervene jointly filed by the Board of County Commissioners of Pueblo County, City of Pueblo, and Pueblo Economic Development Corporation, on November 20, 2025, is granted.

3. The Motion seeking to permissively intervene filed jointly by GreenLatinos, GRID Alternatives, Ebony Advocates, NAACP Pueblo Branch, Roots to Resilience, and Vote Solar on November 20 2025, is granted.

4. The Motion seeking to permissively intervene filed by Western Resource Advocates on November 20, 2025, is granted.

5. The Motion seeking to permissively intervene filed by Colorado Energy Consumers on November 20, 2025, is granted.

6. The Motion seeking to permissively intervene filed jointly by Sierra Club and Natural Resources Defense Council on November 20, 2025, is granted.

7. The Motion seeking to permissively intervene filed by the Colorado Renewable Energy Society on November 20, 2025, is granted.

8. The Motion seeking to permissively intervene filed by Climax Molybdenum Company on November 20, 2025, is granted.

9. The late-filed Motion seeking to permissively intervene filed by CORE Electric Cooperative on December 2, 2025, is granted.

10. The Joint Petition filed by Trial Staff of the Public Utilities Commission, Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service Company of Colorado on November 10, 2025, is granted with modifications, consistent with the discussion above.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective immediately upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING December 3 and December 10, 2025.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK[58]

MEGAN M. GILMAN

TOM PLANT

Commissioners

COMMISSIONER ERIC BLANK
DISSENTS, IN PART

[58]Eric Blank dissents in part.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit CC: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1-Attachment F (*Electric Energy and Demand Forecast*, Public)

Electric Energy and Demand Forecast

This section summarizes Tri-State's approach to development of its base electric energy and demand forecast, and forecast variations, for Phase I ERP scenario modeling. Key assumptions and resulting forecast data are provided, including for compliance with Commission Rule 3605(b).

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Colorado PUC E-Filings System

Description of Process

This subsection addresses forecast requirements in Commission Rule 3605(b)(IV). The base long-term load forecast is prepared utilizing input from each of Tri-State's Utility Member Systems every year. Tri-State has a four-state service territory, with 42 Utility Member Systems[1] and each consists of up to nine retail classes in which a bottom-up forecast methodology is employed.

Inputs

Gross Load Forecast

The primary source for historical retail data by each class of consumers is Rural Utilities Service (RUS) Form 7, which is compiled by each of Tri-State's Utility Member Systems after the end of each calendar year. Information by month and class on the number of accounts, energy use per account, total energy, and the average price of electricity is collected for each Member. In addition, data on large commercial accounts is gathered on RUS Form 345. Historical wholesale Utility Member System hourly demand and load shapes are generated using data obtained from Tri-State's member billing system, which pulls data from delivery point meters on Tri-State's system.

Weather data from 20 weather stations within Tri-State's region is supplied through DTN Meteorlogix. Tri-State's database includes temperature, heating and cooling degree-days, and precipitation. Weather normalizations of this data are used in forecasting models (defined as 10-year average values).

Tri-State obtains economic and demographic data from Woods & Poole Economics, Inc. (W&P) for the county/counties that make up each Utility Member System. The majority of data from W&P originates with the Bureau of Economic Analysis (BEA), an agency within the U.S. Department of Commerce. All projections of economic and demographic data have been performed by W&P. Tri-State uses more than 20 measures demographic data as well as of employment and income activity by sector from the W&P data set.

Tri-State incorporates data from ITRON's Residential Statistically Adjusted End-Use (SAE) models for the West Mountain region into residential use-per-customer forecasts. Residential use-per-customer estimates include projections related to household thermal efficiency, heating and cooling unit saturation, appliance efficiency, lighting efficiency, and household size.

Tri-State periodically conducts a Residential End-Use Survey to identify residential characteristics specific to each Member. Questions include data on type of heating and cooling technology, appliance data, and thermal shell metrics. Heating and cooling saturations by member as of the survey year are calibrated using the percent growth in technologies for the Rocky Mountain Region from the SAE model.

The electricity that Tri-State Utility Member Systems provide to their Member Consumers (retail customers) often competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and

[1] Beginning February 1, 2025, Tri-State anticipates having 39 Utility Member Systems.

Annual Energy Outlook. Tri-State bases its price projections for each of these alternative fuels on information from the EIA. These price projections for alternative fuels are exogeneous drivers that are available for use in econometric model development and are incorporated as a variable into some member estimates for residential and commercial classes.

Using annual historical data from 2003 through 2021, historical trends, as well as future projections for demographic and economic drivers, lighting efficiency and household heating and cooling profiles, Tri-State's statistical models estimate future gross load and demand.

Input Adjustments to Gross Load Forecast

While the above inputs are used to derive Tri-State's gross load and demand by member, additional inputs are collected to calculate adjustments related to partial requirements, distributed generation, energy efficiency, and beneficial electrification.

Tri-State allows Utility Members to serve a portion of their load from non-Tri-State resources, including partial requirements and distributed energy generation.

Partial Requirements[2] reflects a reduction in Utility Member load due to the election of members to buy out of a portion of their wholesale contract. Tri-State offers Utility Members two versions of this. The first is "MAX," which allows a member to source a fixed amount of around the clock demand and energy from another provider. To estimate load for this option, Tri-State uses the expected contract start date, amount of demand, hours per month, and region. The second option, "MARS," allows a member to elect to purchase energy from another provider using supply of a utility-scale resource. To estimate MARS load, Tri-State collects data on the expected contract start date, name and type of resource, and region. In addition, Tri-State collects three-year historical average hourly load profile for a resource of similar size in close proximity for use in shaping the estimated hourly partial requirements output.

To model distributed generation resource load and demand, Tri-State utilizes the contract dates, resource type (such as wind, hydro, tracking solar, or non-tracking solar), nameplate, and average hourly history for three to five years.

Estimates for energy efficiency and beneficial electrification are calculated using ERP targets and data provided by a third-party vendor. They are layered onto load estimates – with energy efficiency being a reduction in energy and beneficial electrification increasing electricity – during post-processing by other modeling groups.

Demand response is modeled as a generating resource; Attachment B of the ERP Report (LKT-1) provides additional details related to these estimates. In the financial estimates, which are concerned with energy billed, demand response energy is shown *net of any load shifts*. That is, if load is shifting from a peak hour to a non-peak hour, it does not impact the amount of energy billed to a customer and is not shown in

[2] After beginning of Phase I scenario modeling, FERC accepted the withdrawal of Tri-State's partial requirements filing. Tri-State is working with its Members to revise the approach to partial requirements supply. Phase I scenario modeling reflects initial partial requirements elections and methodology.

billing estimates. Only the net change in energy billed to customers will be reflected in demand response aggregates in financial modeling.

Forecasting Process

Gross Load Forecast Process

The nine retail classes include residential, seasonal, irrigation, small commercial, large commercial, public authorities, streetlights, resales to RUS, and resales to others. Each retail class, with the exception of large commercial, is broken into the number of customers and use-per-customer, which are then modeled separately and aggregated to arrive at forecast energy. By separating the demand forecast into the use per-customer and customer components, Tri-State can better distinguish between the trends driving growth in the number of customers versus technology or weather impacts on customer-level usage. There is also a separate category for the Utility Member's own use.

For all forecasts except for Large Commercial and Own Use, the number of customers and the use-per-customer are projected using a combination of econometric techniques, time series regressions, and simple trend analyses that generally utilize 20 years of history. Time series regressions typically utilize Auto Regressive Integrated Moving Average (ARIMA) modeling over a period of 20 years of historical data. If a defensible and statistically significant model can't be found, analysts may use an average, often over 5 years. Energy for these classes is derived by multiplying the number of customers by use-per-customer. The Large Commercial class energy forecast used in the ERP are derived from the combination of a statistical regression model over 20 years of history and Form 345 projections, whichever is greater. Own use only has one customer, the Utility Member, and Tri-State forecasts the energy directly based on historical trend.

Forecasts of residential customers are derived through multivariate regression models with explanatory variables including, but not limited to, population, employment, and income. Other models for the number of customers may rely on forecasted employment, trend, or a historical average.

Use-per-customer is also modeled using econometric models or weighted averages. Multivariate regressions on use-per-customer generally consider trend and weather; residential use-per customer forecasts incorporate data on area lighting and appliance efficiency, heating and cooling profiles, and building thermal efficiency that are derived from end use surveys and the ITRON's SAE models for the West Mountain region. If there is not a good model fit for use-per-customer for the various classes, a five-year average is generally utilized as a default. The residential use forecast is an exception and utilizes the end-use model when possible.

Once the nine classes and own use are forecasted, Tri-State aggregates them and then applies a retail loss factor that is generally an average from recent history. Retail losses are added to the aggregate energy by class to arrive at total annual energy purchases for each Utility Member System across the resource planning period (RPP). For each member, the monthly load shapes are based upon the Seasonal Index method utilizing a 2x12 centered moving average. Monthly forecasts are then used to generate a calendarized hourly dispatch based upon on the most statistically representative months from the last five years of history. After all estimates are generated, a draft report is then sent to each Member for

their review and feedback; periodically Tri-State will incorporate Member-requested adjustments that reflect each Member's intimate knowledge of conditions in their area.

Once the forecasts are finalized and completed for each Utility Member System, the final step is forecast aggregation to arrive at gross forecasts for state, planning region, and Tri-State as a whole. During the annual update process, for members that are split either between a state or grid boundary, Tri-State uses an average of the last three calendar years to determine state and planning regions for the forecast. These splits are generally carried forward in forecast estimates for the entire planning period until a new full calendar year is available.

Gross Demand Forecast

The projected values of the Member Coincident Peak (MCP) gross demands are based upon an hourly load forecast. Hourly loads are generated for each calendar month by applying the projected purchased energy requirement to a corresponding normalized historical load duration curve. The resultant hourly loads are dispatched chronologically based upon known historical loads and seasonal indices from a calendarized representative month. Once individual members' hourly demand forecasts have been determined, they are summed to arrive at a total Tri-State hourly load forecast (using a bottom-up approach), allowing the system coincident peak demand to be established.

The peak period used for billing is defined as the period between 12:00 (noon) and 10:00 PM, Monday through Saturday, except certain holidays. The Tri-State aggregate billing peak is the sum of the individual member peaks from the hourly demand forecasts, which occur within the defined peak period. The Tri-State Coincident Peak (TCP) for capacity planning is the highest hourly sum of Utility Member System hourly demand forecasts. Tri-State's peak occurs in July throughout the planning period, as Tri-State is a summer peaking system. Of note, Tri-State aggregates demand by state and planning region in a manner similar to the aggregation for energy. Hourly profiles for energy efficiency, partial requirements, beneficial electrification, and distributed generation are layered onto gross demand forecasts within the expansion and production cost models. This total demand is used in the expansion plan for resource planning and transferred to the Hyperion financial model in a manner similar to energy, to arrive at demand served by Tri-State.

Additional details on energy efficiency, demand response, and beneficial electrification modeling assumptions can be found in Attachment B and G-3 of the ERP Report (LKT-1).

Process for Calculating or Incorporating Load Forecast Adjustments

Several adjustments are made to gross load to arrive at load served by Tri-State, including distributed generation, partial requirements, energy efficiency, and beneficial electrification.

Distributed generation (DG) is a subtraction from gross load to arrive at the Utility Member load served by Tri-State. Distributed generation forecasts consist of energy and demand forecasts on a project level for member self- supply options, including Board Policy 115 (renewable self-generation on Member Systems), Board Policy 119 (community solar on Member systems). To calculate energy served by behind the meter or distributed generation resources, Tri-State estimates load using load shapes based on a three- year hourly average. For new or prospective distributed generation resources, rather than using the three-year history for the resource, Tri-State forecasts the energy and demand by scaling the three-

year historical average hourly load profile by the relative nameplate size to an existing resource in close proximity and same technology type (for example, wind, tracking solar, non-tracking solar, hydro) over the contract period.

As of February 2023, Members have over 66 renewable or distribution generation projects, totaling 143 MW of capacity and capable of producing ~300 GWh/year are operating or under development. By capacity, approximately 85% of Utility Member System distributed generation is located in Colorado and 14% is in New Mexico. By technology, 81% of distributed generation is solar, 6% is wind, and 7% is waste heat, with the remaining comprised of hydro or landfill methane.

The calculation of Partial Requirements adjustments depends on whether the Member elected the MAX or MARS Partial Requirements option. For the MAX option, Tri-State uses the around-the-clock demand elected by the member and derives energy by multiplying the demand by the number of hours in the month. Under the MARS option, Tri-State estimates partial requirements energy by scaling the three-year historical average hourly load profile for a similar type resource in close proximity to the planned resource to the nameplate of the expected resource; the existing MARS Partial Required election is currently modeled as a tracking solar resource. Once Partial Requirements are operational, for MARS, Tri-State would use the three-year historical average to estimate the energy and demand. As Partial Requirements reflects energy that would be provided to the Member by third-party providers, the energy and demand is a reduction of gross Member energy and demand needs.

Energy efficiency estimates are compiled from multiple sources; annual Colorado energy efficiency estimates are calculated consistent with the 2020 ERP Phase I Settlement Agreement,[3] with estimates derived as the target percentage by year multiplied by annual Colorado gross load net of partial requirements. These annual targets are shaped based on the weighted average of the aggressive incentive level of hourly program profiles provided by a third-party consultant for the Colorado load area. Annual energy efficiency potential for Wyoming and New Mexico, as well as hourly and monthly profiles for each planning region, are developed by compiling the individual measure and program hourly profiles into an hourly shape for each area and incentive level. Wyoming and New Mexico energy efficiency are not part of the native load, but rather a supply side resource option for the expansion model to select.

Energy efficiency estimates are a reduction of gross Member load in the calculation of load served by Tri-State. In contrast, beneficial electrification estimates, which are also calculated by a third-party consultant, are added to gross member load. These are layered onto the gross Member load estimates in Hyperion financial modeling.

Additional details on energy efficiency and beneficial electrification modeling assumptions can be found in Attachments B and G-3 of the ERP Report (LKT-1).

[3] Section 3.11.9.

Range of Forecasts

This subsection addresses forecast requirements in Commission Rule 3605(b)(II). Tri-State developed a base forecast, as well as two forecast variations, including a low load and high load forecast. To develop the low load and high load forecasts, Tri-State established prediction intervals to express uncertainty around the expected value forecast. The total variance includes both economic and weather-related uncertainty. The low and high load intervals are generated at the 90% confidence interval, meaning that the actual value should be within the given interval with a probability of 90%.

Tri-State did not model resource planning scenarios related to the upper and lower 90% confidence intervals for the purpose of this Resource Plan. However, both the High Load forecast and Low Load forecast are presented in the following subsection, as well as in Attachment F-1 of the ERP Report (LKT-1).

Base Load Forecast

The gross Base Case load forecast of annual energy, and Tri-State summer and winter coincident peak (TCP) demand is shown, by year of the RPP, in Table 1 below, in compliance with Commission Rule 3605(b)(I)(A). Please note that the base forecast for this, and for all load data presented below and in Attachment F-1 (unless otherwise specified), is gross load, meaning it is gross of Partial Requirements, distributed generation, energy efficiency, beneficial electrification, demand response, member self-generation, and transmission losses. Partial Requirements load assumptions are provided in Table 2 below. Load for the three Utility Member Systems that have provided Tri-State with notice of their intent to depart the system has been excluded as of the noticed departure date.[4] Of note, Tri-State's winter peak is forecasted to shift to January in 2024 due to expected member departures; in all other years of the forecast, the winter peak occurs in December.

Table 1: Tri-State Gross Annual Energy, Summer Coincident Peak, and Winter Coincident Peak[5]

Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2024	14,325,075	2,419	2,230
2025	13,016,605	2,381	1,761
2026	13,027,503	2,403	1,779
2027	13,161,110	2,423	1,800
2028	13,310,698	2,448	1,807
2029	13,437,397	2,466	1,825
2030	13,578,717	2,489	1,845
2031	13,720,347	2,511	1,867
2032	13,875,367	2,536	1,887
2033	14,002,551	2,554	1,906
2034	14,149,447	2,578	1,927

[4] United Power and NRPPD departures are May 1, 2024; Mountain Parks' departure is January 15, 2025.

[5] The energy and demand shown in the tables reflects the sum of member gross energy needs and excludes aggregates that were layered on top of the load forecast, including energy efficiency, beneficial electrification, and partial requirements.

2035	14,300,790	2,601	1,950
2036	14,468,551	2,628	1,973
2037	14,613,014	2,649	1,994
2038	14,771,813	2,674	2,017
2039	14,932,199	2,698	2,041
2040	15,101,613	2,725	2,064
2041	15,247,115	2,746	2,085
2042	15,405,534	2,770	2,108
2043	15,571,769	2,796	2,133



Table 3 details the relative share of Tri-State load forecasted in each state.

Table 3: Percentage of Tri-State Load by State, 2025 and 2030

	Colorado	New Mexico	Wyoming	Nebraska
2025	61%	19%	14%	7%
2030	62%	18%	14%	6%

Table 4 shows a comparison of base total member energy requirements forecast and the load that Tri-State expects to provide (before transmission losses). Of note, the share of energy provided by Tri-State to Members decreases starting in 2026 due to increased energy self-supplied by Members through partial requirements.



[6] Variance reflects adjustments including partial requirements and Member distributed generation. The variance between Member gross load and load served by Tri-State increases in magnitude starting in 2026 due to the expected start of partial requirements.

[redacted]

Table 5 reflects the difference of gross and net peak demand for select years throughout the RPP.

[redacted]

High Load Forecast

A number of factors exist which could significantly increase Tri-State's load above the base forecast. This includes:

- Delay in the departure of Utility System Members that have submitted exit notices to Tri-State or their inability to fully exit Tri-State.
- Delay of members to reduce their load from Partial Requirements, due to delay in regulatory approvals or supply chain issues. In the 2023 ERP Phase I modeling, all Partial Requirements load reductions are anticipated to start as of January 1, 2026.
- Increased demand resulting from higher than expected economic or population growth (including increased migration to the Tri-State service territory).
- Increased beneficial electrification, including faster than expected adoption of electric vehicles due to government incentives.

Low Load Forecast

Potential factors exist which could significantly reduce Tri-State's load, including:

- Increased Utility Member distributed generation beyond forecasted amounts due to trend and to Members taking advantage of IRA project funding.
- Higher than forecasted energy efficiency and demand-side management.
- Reduced demand stemming from increased inflation or economic downturns, and
- Load loss related to environmental and regulatory impacts from extractive industries, including natural gas, oil, and coal.

[7] For simplicity, we are showing Tri-State peak demand net of both MAX and MARS partial requirements. Expected impact of Member self-generation under policies 115 and 119 are small. MARS partial requirements is reflected at 5% ELCC.

Utility Member Sales Forecasts

This subsection addresses forecast requirements in Commission Rule 3650(b)(I)(A). The following graphs show Tri-State's load forecasts for the RPP for the Tri-State System. Tri-State's annual system gross energy average growth from 2024-2043 is 0.44%, while gross summer coincident system demand has an annual average growth rate of 0.76%. Where appropriate, data is presented for a range of forecasts, including Base, High and Low Load forecasts.

Tri-State System Annual Energy Sales, Summer Peak & Winter Peak

The below graphs detail base, high load, and low load gross system annual energy sales, summer peak, and winter peak for the Resource Planning Period by year.

Figure 1: Tri-State System Annual Energy Sales to Utility Member Systems

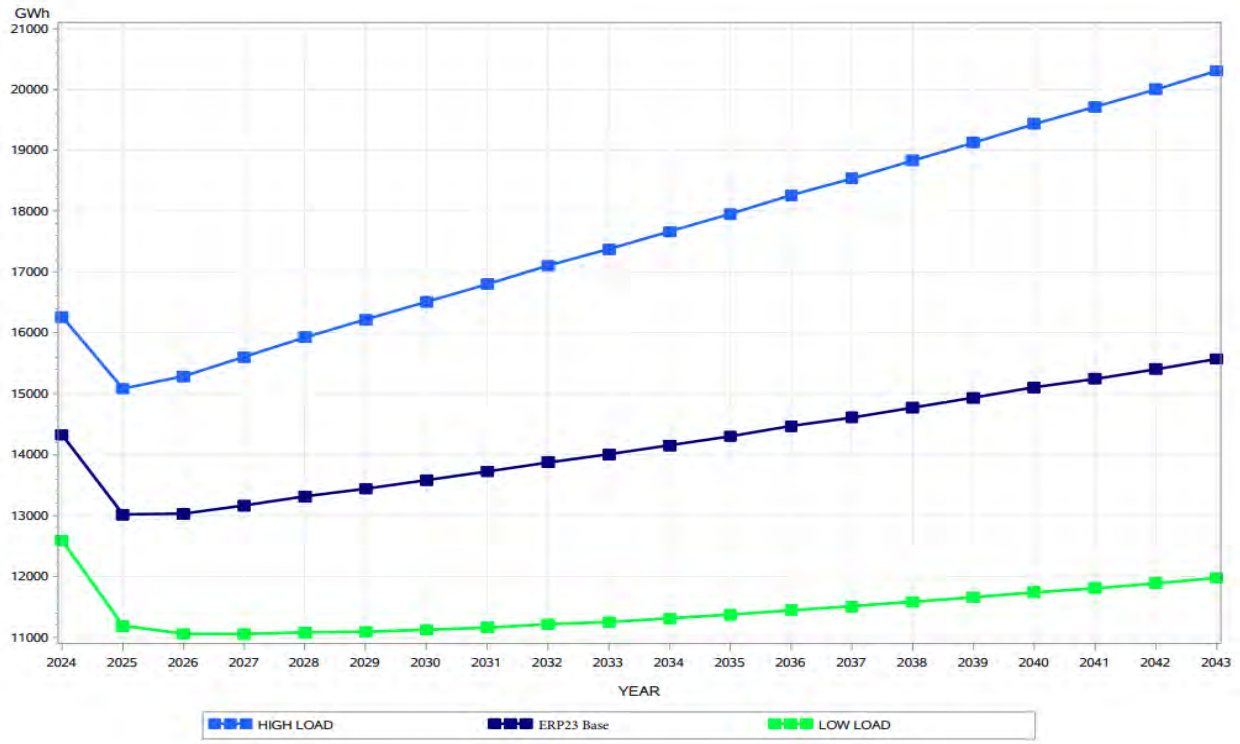


Figure 2: Tri-State System Annual Coincident Summer Peak

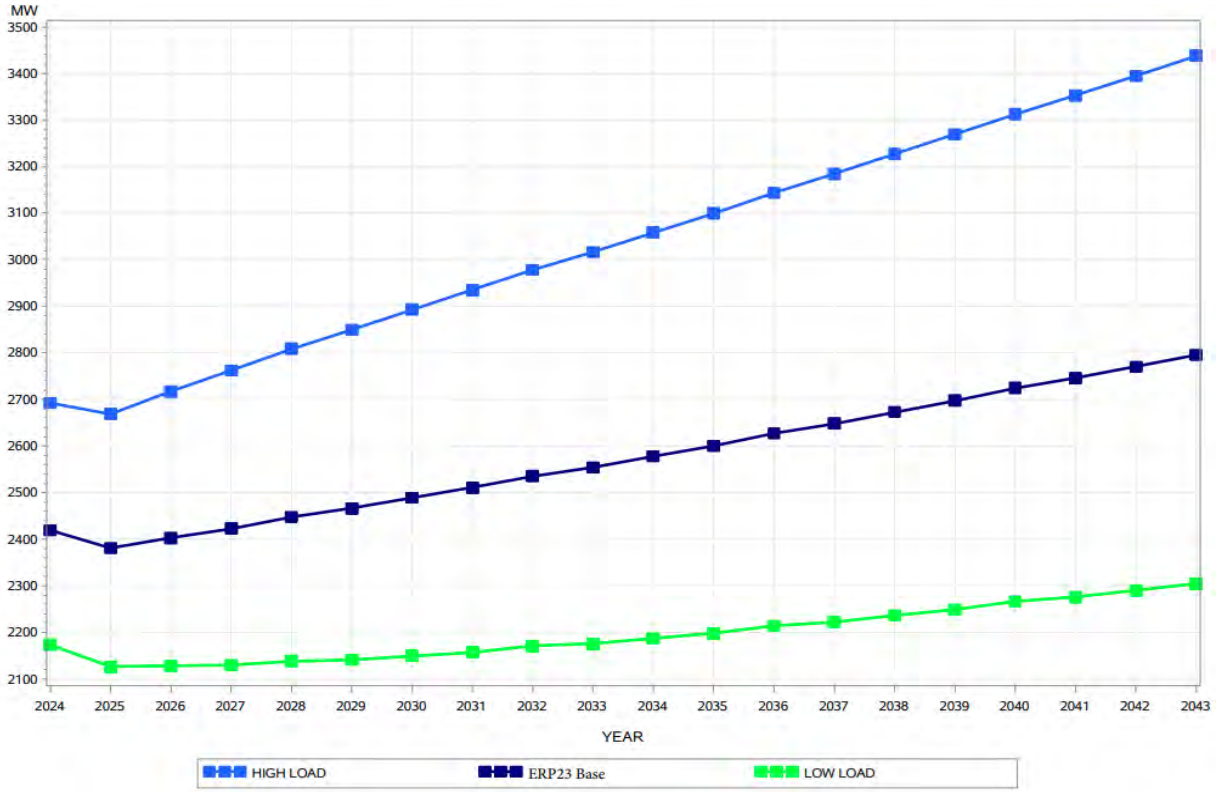
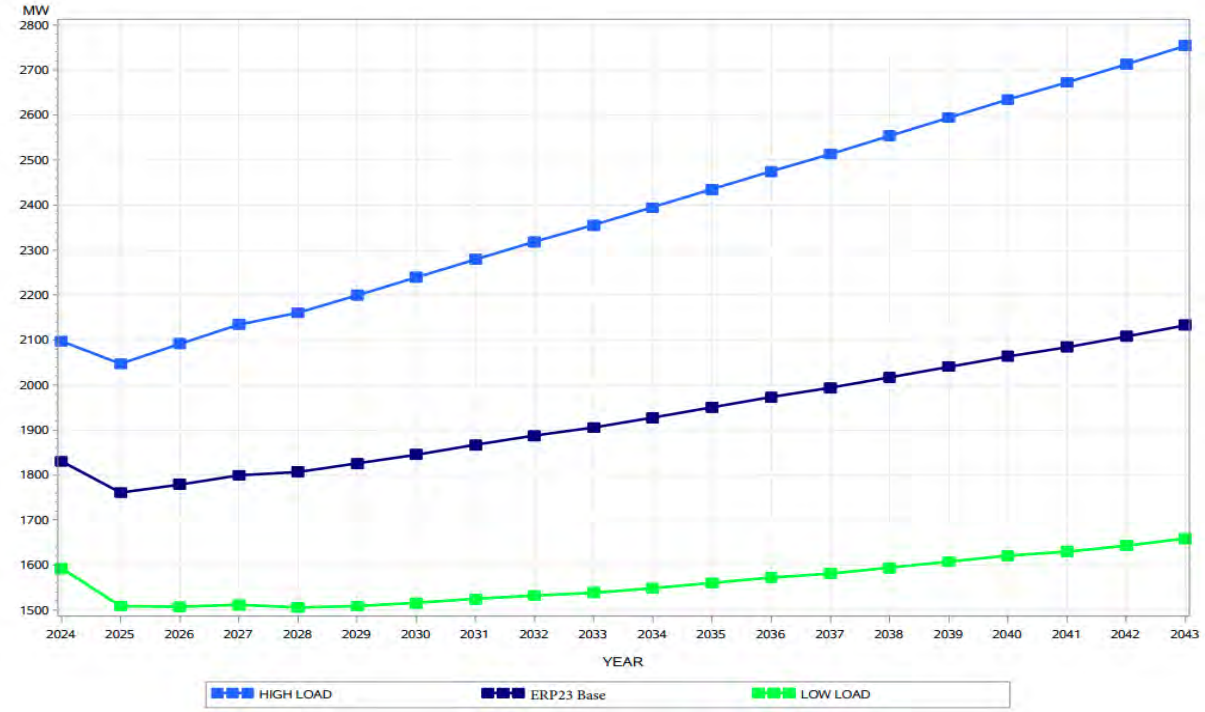


Figure 3: Tri-State System Annual Coincident Winter Peak



Additional graphs showing gross energy sales, winter peak, summer peak, and daily profiles for Tri-State, State, and Utility Member Systems can be found in Attachment F-1 of the ERP Report (LKT-1). Table 6 references the page in the attachment that corresponds to the compliance requirement.

Table 6: Reference Guide for Attachment F-1, Load Graphs by Member and State

Rule	Item	Granularity	Page(s)
3605(b)(I)(A)	Annual Energy Sales	States	1
3605(b)(I)(A)	Annual Energy Sales	Utility Member System	5
3605(b)(I)(A)	Annual Coincident Summer Peak	States	47
3605(b)(I)(A)	Annual Coincident Summer Peak	Utility Member System	51
3605(b)(I)(A)	Annual Coincident Winter Peak	States	93
3605(b)(I)(A)	Annual Coincident Winter Peak	Utility Member System	97
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	States	139
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	Utility Member System	187
3605(b)(I)(E)	Hourly Off-Peak Day by Calendar Month	States	656
3605(b)(I)(E)	Hourly Off-Peak Day by Calendar Month	Utility Member System	703
3605(b)(I)(E)	Hourly Average Day by Calendar Month	States	1171
3605(b)(I)(E)	Hourly Average Day by Calendar Month	Utility Member System	1219

Comparison of 2020 ERP Phase II to 2023 ERP Phase I Load Forecast[8]

The gross base load forecast—which is the sum of individual gross load member forecasts in the 2023 ERP Phase I—was produced in summer 2022 and is the same vintage of annual estimate that was used in the 2020 ERP Phase II due to timing of the long-term load forecasting cycle and a short time span between modeling for both ERPs. While the underlying estimates are the same for most members, the 2023 ERP base load forecast is lower due to the removal of load for members expected to depart in 2024 and 2025, as detailed above. The reduction in gross member energy attributed to member departures ranges from 2,288 GWh (14%) in 2024 to 5,254 GWh (26%) in 2040[9] compared to 2020 ERP Phase II. The expected reduction in Tri-State's gross system peak resulting from expected member departures ranges from 646 MW in 2024 (21%) to 966 MW in 2040 (26%). Graphs of the 2020 ERP Phase II (with upper and lower confidence intervals) and the 2023 ERP Phase I gross member load, summer, and winter coincident peaks are shown below.

[8] Rule 3605(b)(III).
[9] 2040 values are shown as 2040 was the final year modeled in the 2020 ERP Phase II.

Figure 4: Tri-State System Annual Energy Sales to Utility Member Systems

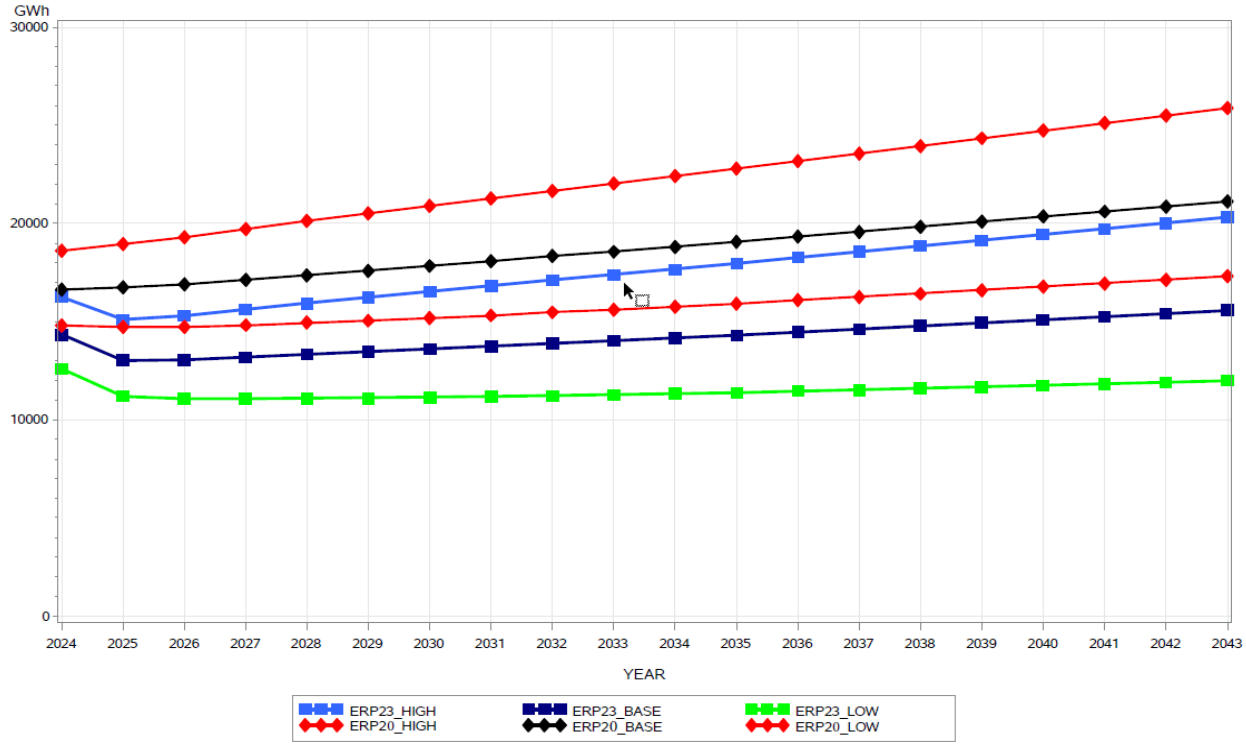


Figure 5: Tri-State System Annual Summer Coincident Peak

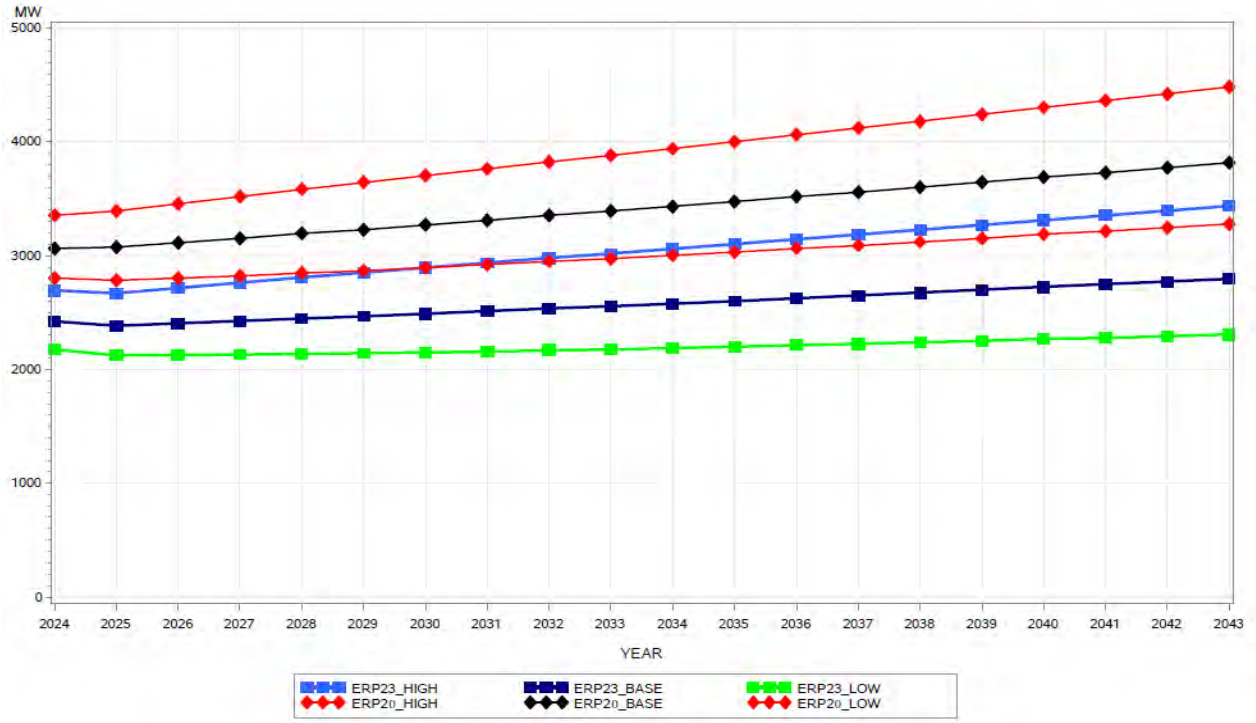
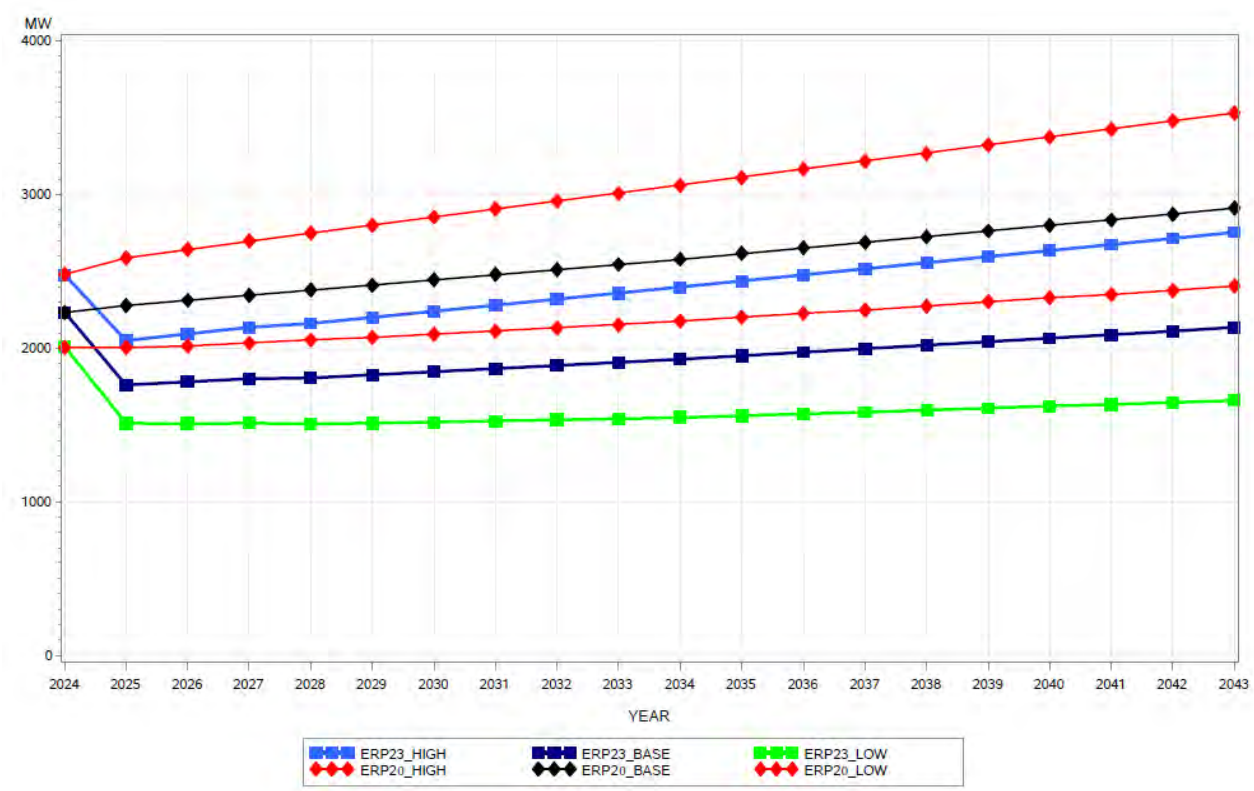


Figure 6: Tri-State System Annual Winter Coincident Peak



When comparing the 2023 ERP Phase I load that Tri-State is expecting to serve (inclusive of adjustments) to the 2020 ERP Phase II load, Tri-State made additional adjustments, as noted above. These include the delay of partial requirements to 2026, addition of beneficial electrification, change in energy efficiency targets as a result of member exits, and changes to member-supplied energy contracts, such as community solar. In the 2020 ERP Phase II, Tri-State modeled 300 MW of Partial requirements, with 233 MW starting as of January 1, 2024 and the remaining 67 MW beginning on January 1, 2025. Table 7 below shows the changes and the variance as a percent of 2020 ERP Phase II expected load deliveries for select years.



Comparison of Historical Forecasts & Actuals

Tables 8 through 10 show the energy sales, summer peak, and winter peak for the prior five years of actuals as well as the annual forecasts in the most recently filed resource plan to the annual forecasts in the current resource plan, in accordance with Commission Rule 3605 (b)(III).

Table 8: Tri-State System Annual Energy Sales to Utility Member Systems (GWh)

		BASE FORECAST		HIGH LOAD		LOW LOAD	
YEAR	ACTUALS	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023
2018	16,179	.	.	.	.	.	.
2019	16,203	.	.	.	.	.	.
2020	15,983	.	.	.	.	.	.
2021	16,037	.	.	.	.	.	.
2022	16,872	.	.	.	.	.	.
2023	.	16,370	16,370	18,059	18,108	14,809	14,776
2024	.	16,613	14,325	18,610	16,259	14,792	12,586
2025	.	16,733	13,017	18,956	15,084	14,727	11,190
2026	.	16,879	13,028	19,292	15,285	14,722	11,058
2027	.	17,110	13,161	19,701	15,604	14,812	11,053
2028	.	17,360	13,311	20,118	15,927	14,933	11,076
2029	.	17,583	13,437	20,494	16,214	15,041	11,089
2030	.	17,824	13,579	20,882	16,511	15,171	11,122
2031	.	18,065	13,720	21,265	16,802	15,308	11,161
2032	.	18,323	13,875	21,662	17,106	15,463	11,216
2033	.	18,547	14,003	22,018	17,372	15,593	11,251
2034	.	18,794	14,149	22,397	17,659	15,746	11,306
2035	.	19,046	14,301	22,780	17,950	15,905	11,368
2036	.	19,318	14,469	23,184	18,258	16,083	11,445
2037	.	19,561	14,613	23,554	18,537	16,239	11,505
2038	.	19,821	14,772	23,942	18,832	16,411	11,579
2039	.	20,083	14,932	24,332	19,128	16,585	11,656
2040	.	20,356	15,102	24,733	19,434	16,770	11,741
2041	.	20,600	15,247	25,100	19,710	16,932	11,808
2042	.	20,859	15,406	25,484	20,002	17,108	11,887
2043	.	21,128	15,572	25,880	20,303	17,292	11,973

Table 9: Tri-State System Annual Summer Coincident Peak (MW)

		BASE FORECAST		HIGH LOAD		LOW LOAD	
YEAR	ACTUALS	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023
2018	2,887	.	.	.	.	.	.
2019	2,922	.	.	.	.	.	.
2020	2,896	.	.	.	.	.	.
2021	2,975	.	.	.	.	.	.
2022	3,070	.	.	.	.	.	.
2023	.	3,023	3,023	3,269	3,274	2,796	2,793
2024	.	3,065	2,419	3,352	2,693	2,803	2,173
2025	.	3,073	2,381	3,393	2,669	2,785	2,126
2026	.	3,113	2,403	3,458	2,718	2,804	2,128
2027	.	3,151	2,423	3,521	2,762	2,823	2,130
2028	.	3,194	2,448	3,585	2,809	2,849	2,139
2029	.	3,230	2,466	3,643	2,850	2,868	2,141
2030	.	3,271	2,489	3,704	2,893	2,894	2,150
2031	.	3,310	2,511	3,763	2,935	2,920	2,157
2032	.	3,355	2,536	3,825	2,978	2,951	2,171
2033	.	3,390	2,554	3,880	3,017	2,972	2,176
2034	.	3,433	2,578	3,941	3,059	3,002	2,187
2035	.	3,473	2,601	4,000	3,100	3,030	2,198
2036	.	3,520	2,628	4,062	3,144	3,065	2,214
2037	.	3,559	2,649	4,120	3,184	3,090	2,223
2038	.	3,602	2,674	4,181	3,227	3,122	2,237
2039	.	3,645	2,698	4,241	3,270	3,153	2,249
2040	.	3,691	2,725	4,303	3,313	3,188	2,267
2041	.	3,730	2,746	4,360	3,353	3,214	2,276
2042	.	3,773	2,770	4,420	3,395	3,246	2,290
2043	.	3,817	2,796	4,482	3,438	3,278	2,304

Table 10: Tri-State System Annual Winter Coincident Peak (MW)

		BASE FORECAST		HIGH LOAD		LOW LOAD	
YEAR	ACTUALS	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023
2018	2,233	.	.	.	.	.	.
2019	2,199	.	.	.	.	.	.
2020	2,106	.	.	.	.	.	.
2021	2,120	.	.	.	.	.	.
2022	2,322	.	.	.	.	.	.
2023	.	2,245	2,231	2,491	2,475	2,019	2,009
2024	.	2,276	2,230	2,556	2,098	2,021	1,592
2025	.	2,279	1,761	2,586	2,047	2,003	1,509
2026	.	2,310	1,779	2,641	2,092	2,015	1,507
2027	.	2,344	1,800	2,696	2,135	2,031	1,511
2028	.	2,378	1,807	2,750	2,161	2,051	1,506
2029	.	2,409	1,825	2,801	2,200	2,067	1,509
2030	.	2,443	1,845	2,853	2,240	2,087	1,515
2031	.	2,478	1,867	2,905	2,279	2,110	1,525
2032	.	2,512	1,887	2,956	2,318	2,132	1,533
2033	.	2,544	1,906	3,006	2,355	2,151	1,539
2034	.	2,579	1,927	3,057	2,394	2,174	1,548
2035	.	2,616	1,950	3,110	2,434	2,200	1,561
2036	.	2,653	1,973	3,163	2,475	2,225	1,572
2037	.	2,687	1,994	3,215	2,513	2,247	1,581
2038	.	2,724	2,017	3,268	2,554	2,273	1,594
2039	.	2,762	2,041	3,321	2,594	2,300	1,608
2040	.	2,799	2,064	3,374	2,634	2,326	1,620
2041	.	2,833	2,085	3,425	2,673	2,349	1,630
2042	.	2,870	2,108	3,478	2,713	2,376	1,643
2043	.	2,910	2,133	3,532	2,755	2,405	1,659

Other Load Aggregates and Impacts

Losses[10]

Tri-State adds a 3.5% transmission loss factor to load across Tri-State's system in the Western Interconnection, excluding in the PNM BA area[11], for modeling purposes. Tri-State load in the Western Interconnection is located in multiple BA and TP systems. The 3.5% transmission loss factor is meant to represent an average of expected transmission losses. Tri-State's load in the Eastern Interconnection is covered by a full requirements contract.

[10] Rule 3605(b)(I)(D).
[11] Losses in PNM BA are handled financially and included in the financial forecast.

Energy and Capacity Sales to Other Utilities[12]

Annual contract energy and capacity sales to other utilities and counterparties are described in Attachment B of the ERP Report (LKT-1), as well as modeled proxy sales in anticipation of the ability to sell excess power upon Member exits.

Intra-Utility Energy and Capacity Use[13]

Tri-State intra-utility loads consist of a number of service centers and the headquarters building. For these loads, Tri-State takes retail service from the local provider. Accordingly, Tri-State has no intra-utility loads that contribute to energy and capacity requirements for purposes of Tri-State resource planning.

Potential Benefits of Strategically Locating Distributed Energy Storage within Member Cooperative Territories

Tri-State allows for distributed energy storage projects through Tri-State Board Policy 115. Members elect whether or not to pursue Policy 115 projects, including determination of technology type, project size (within policy limitations), and project location. Tri-State works with interested Members to develop programs that are beneficial, while minimizing program impacts to all Members.

[12] Rule 3605(b)(I)(B).
[13] Rule 3605(b)(I)(C).

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit DD: CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN L. THOMPSON ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

December 1, 2023

Colorado PUC E-Filings System

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ATTACHMENTS

BLT-1	Statement of Qualifications for Brian L. Thompson

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Brian Thompson. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Resource Planning Manager.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND QUALIFICATIONS?

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment BLT-1**.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY.

A: I have 16 years of experience in the electric utility industry. I manage the resource planning group at Tri-State. We are responsible for short-term and long-term modeling of the Tri-State system, including scenario and portfolio modeling associated with the ERP/IRP process. Previously, I held the following positions at Tri-State: Associate Real Time Marketer, Senior Energy Portfolio Analyst, Term Marketer, and Senior Engineer Resource Planning. I have a Bachelor of Science in Manufacturing Engineering Technology from Brigham Young University.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: My testimony addresses the 2023 Electric Resource Plan ("ERP") model set-up based on the Tri-State system topology and key data input assumptions for Tri-State's Phase I ERP, including generic resource parameters, as well as summarizes third-party study results.

Q: ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR DIRECT TESTIMONY?

A: Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- Attachment BLT-1: Statement of Qualifications for Brian L. Thompson

II. TRI-STATE'S APPROACH TO MODELING

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I describe the systems and analytical methodologies utilized by Tri-State to develop its 2023 ERP, including the modeling software used for expansion plan and dispatch modeling.

Q: WHAT MODELING TOOL IS BEING USED IN THE 2023 ERP?

A: Tri-State is continuing to use EnCompass software for the 2023 ERP, which was also utilized for Phase II of the 2020 ERP.

Q: PLEASE DESCRIBE THE SYSTEMS AND ANALYTICAL METHODOLOGIES EMPLOYED TO DEVELOP THE 2023 ERP.

A: The ERP Report (**Attachment LKT-1**) describes the systems Tri-State utilized for modeling the 2023 ERP and it also identifies the flow of input and output data between each system. As stated above, Tri-State utilizes EnCompass software for the expansion plan and dispatch modeling, as was done for Phase II of the

2020 ERP. The modeling setup is reflective of Tri-State's four-state system and location of our generation, load pockets, markets, transmission availability and constraints, and power flows between regions (visually represented in **Attachment** LKT-13 ~~**B-6** of the ERP Report (**Attachment LKT-1**)~~. The system topology is largely similar to what was modeled in Phase II of the 2020 ERP, with three updates:

- Assumed energy transfer capability from the Eastern Colorado ("ECO") to New Mexico ("NM") planning regions was modified from 200 MW to 191 MW.
- 100 MW of energy transfer capability, at an incremental cost of $8.06/MWh, was added from the NM to the ECO planning region.
- 76 MW of energy transfer capacity, at an incremental cost of $2.39/MWh, was added from the ECO to Western Colorado ("WCO") planning region.

In addition to the base modeling set-up to reflect the Tri-State system, numerous financial, operational, and environmental data assumptions are input into the model. Once the topography design and all input assumptions are input and tested in EnCompass, scenario modeling can begin.

Q: PLEASE PROVIDE AN OVERVIEW OF TRI-STATE'S RESOURCE PLAN SCENARIO MODELING PROCESS.

A: Tri-State models several resource plan scenarios. Each scenario is grounded in the base modeling assumptions, but with unique modeling assumptions applied as identified in **Attachment** LKT-10 ~~**B-3** of the ERP Report (**LKT-1**)~~. In the first step, the model output results in an optimal expansion plan, which includes selected new generation needs, selected unit retirements, and levels of demand-side

management. In the second step, the model dispatches the generation to meet load across the planning period based on the given expansion plan, existing resources, and system constraints. The 8760 dispatch run results in modeling outputs such as forecasted unit capacity factors, market sales and purchases, energy required, curtailments, unit starts, heat required, fuel costs, and transmission flows. The expansion plan and dispatch outputs are analyzed by Tri-State's financial and transmission planning teams to assess the forecasted financial impact of the generation and transmission requirements of each scenario.

Q: HOW MANY SCENARIOS DID TRI-STATE MODEL?

A: Tri-State modeled five scenarios. Each scenario reflected the base modeling assumptions, but with alterations to the assumptions based on Tri-State and stakeholders' desired parameters. The modeling of each scenario results in a unique expansion plan, dispatch, and financial result for each scenario. Following the completion of each scenario modeling run, the scenarios were tested and analyzed to evaluate their performance under two sensitivity conditions. A sensitivity analysis maintains the same expansion plan (i.e., generation units available to meet load in a given year) but modifies assumptions about the system operational environment (e.g., weather, prices) to test the performance of a scenario under potential hardship circumstances that could arise. I discuss the details of modeling sensitivities further below.

Q: WHAT ARE SOME OF THE PRIMARY DATA INPUTS FOR SCENARIO MODELING?

A: Data inputs fall into three core categories: 1) operational/technical, 2) financial, and

3) environmental. Some of the primary data inputs for scenario modeling include:

- Operational/Technical: load forecast, transmission constraints, outage rates, Electric Load Carrying Capability ("ELCC"), contracts, operational data related all resources, demand-side management and beneficial electrification potential, etc.
- Financial: capital expenditure forecast, operations and maintenance ("O&M") forecast, generic resource pricing, forward pricing of power and gas curves, etc.
- Environmental: carbon emission limits.

These are a sampling of the numerous data inputs that are included in the model. A list of all modeling assumptions can be found in **Attachment ~~B~~** ~~of the ERP Report (**LKT-1**).~~ LKT-7

Q: PLEASE IDENTIFY THE MOST SIGNIFICANT UPDATES TO MODELING INPUT ASSUMPTIONS FOR THE 2023 ERP.

A: Tri-State reviews all of the operational, financial, and environmental data inputs to assess the need for updates or modification based on current operating conditions and policy requirements. The significant modeling modifications of note include:

- Planning Reserve Margin ("PRM") adjustment, starting at 22% and transitioning to 30.5% after Craig 3 retires;
- Updated ELCC values for wind, solar, and storage, and capacity credit for thermal units;
- Updated load forecast that removes exiting Members' loads and loads to be

served through Partial Requirements;

- Numerous updated financial assumptions, such as decommission cost, generic resource pricing, fixed and variable O&M costs, and the forecast of capital expenditures; and
- Inclusion of several new innovative technologies not previously modeled by Tri-State for the model to evaluate.

Q: WHAT OUTPUTS RESULT FROM THE ERP MODELING FOR EACH SCENARIO?

A: Through the modeling, we are able to forecast our resource mix, new resource additions, financial and environmental impacts, and the level of reliability achieved by each scenario, among other outputs. The modeling results for each scenario are shown in the ERP Report (**LKT-1**).

III. STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I provide a description of the third-party studies and analyses supporting the 2023 ERP Phase I.

Q: PLEASE PROVIDE AN OVERVIEW OF THE STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING.

A: There were four studies completed to inform Tri-State's 2023 ERP modeling, these include:

- Benchmarking Analysis: This study was completed by Black & Veatch in October 2023. It compares existing resources and generic resources, in regard to cost and performance. This study is provided as **Attachment G-**

LKT-30

~~**2** of the ERP Report (**LKT-1**).~~

- ELCC and PRM Study: Tri-State engaged Astrape to perform an ELCC Study for establishing ELCCs for solar, wind, and storage at various penetration levels, and capacity credits for thermal resources, as well as for establishing an appropriate PRM. This study was completed in August 2023 and is provided as **Attachment** LKT-29 ~~**G-1** of the ERP Report (**LKT-1**).~~
- IRA Scenario Reliability Evaluation: Astrape performed a supplemental analysis of the IRA Scenario's reliability in year 2032 of the planning period. This analysis is provided as **Attachment** LKT-32 ~~**G-4** of the ERP Report (**LKT-1**).~~
- DSM Potential Study and BE Potential Study: Mesa Point updated the 2020 Potential Studies in May 2023 to refresh the level of Demand-Side Management ("DSM") energy savings and beneficial electrification ("BE") potential within the Tri-System resulting from the exit of three Members from the system, updated equipment use and saturations, as well as updated avoided costs, emissions rates, and social cost of carbon. This study is provided as **Attachment** LKT-31 ~~**G-3** of the ERP Report (**LKT-1**).~~

a. Benchmarking Analysis

Q: PLEASE DESCRIBE THE BENCHMARKING ANALYSIS.

A: Tri-State engaged Black & Veatch ("B&V") to perform an analysis of cost and performance of existing owned resources, contracted resources, and generic resources. The study provides a resource ranking for each existing and generic resource, with and without sunk costs. Key insights from the B&V's Benchmarking Analysis include:

- On a Levelized Cost of Energy ("LCOE") basis, wind and solar PPAs and build-transfers, and pumped storage resources are the lowest cost;[1] and
- On a Levelized Cost of Capacity ("LCOC") basis, simple cycle combustion turbine resources are the lowest cost.[2]

Not surprisingly, the study acknowledges that sunk costs (depreciation, decommissioning, etc.) are a significant driver in the cost-effectiveness of Tri-State owned resources.[3]

Q: HOW DO THE RESULTS OF THE BENCHMARKING ANALYSIS INFORM TRI-STATE'S ERP APPLICATION?

A: The Benchmarking Analysis identifies the levelized cost of each resource in Tri-State's fleet, as well as the levelized cost of potential new generic resources to be added to our fleet and identifies how they perform in comparison to one another. These results offer the opportunity for Tri-State to assess which units are out-performing others, based on certain factors. While the benchmarking results are informative, resource plan modeling is able to take into consideration a number of key assumptions, including environmental and transmission constraints which ensures a comprehensive approach to resource planning analysis.

b. <u>ELCC and PRM Study</u>

Q: PLEASE DESCRIBE THE ELCC COMPONENT OF THE ASTRAPE STUDY.

A: The Astrape study determines the appropriate ELCCs for solar, wind and battery

[1] **Attachment ~~G-2,~~** pg. 10. LKT-30
[2] **Attachment ~~G-2,~~** pg. 11. LKT-30
[3] **Attachment ~~G-2~~**, pg. 12. LKT-30

storage resources on the Tri-State system given an anticipated resource mix, and capacity credits for thermal units. Applying appropriate ELCCs, represented as a percent of nameplate capacity, enables calculation of the amount of dependable capacity that can be counted on by the system for resource adequacy purposes. The primary result of ELCC Study is a three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any level of penetration of solar, wind, and batteries. Astrape provided Tri-State ELCCs for Tri-State's anticipated resource mix but also provided a tool to enable calculation of the average and marginal ELCCs for a given penetration level of solar, wind, and batteries in each scenario modeled in the event any scenario deviated substantially from the anticipated mix.

Q: HOW IS THE ELCC METHODOLOGY USED IN TRI-STATE'S PHASE I MODELING?

A: As resource penetrations increase over time, the technology-specific ELCCs decline. The appropriate ELCC is applied in EnCompass for each existing and new generating unit based on the level of installed capacity of the technology, as shown in **Table BLT-D-1**. The ELCC values result from the Astrape Study.

Table BLT-D-1. ELCC Values for 2023 ERP Phase I

Solar		Wind		4-hour Batteries	
Levels (MW)	ELCC	Levels (MW)	ELCC	Levels (MW)	ELCC
0 to 820	5%	0 to 790	17%	0 to 100	97%
821 to 1200	3%	791 to 1200	10%	101 to 200	89%
1201 to 1600	3%	1201 to 1600	9%	201 to 400	65%
1601 to 2000	1%	1601 to 2000	6%	401 to 800	45%

Q: DID TRI-STATE PREVIEW THE ELCC METHODOLOGY AND RESULTS WITH STAKEHOLDERS PRIOR TO PERFORMING SCENARIO MODELING?

A: Yes. Tri-State committed to hold at least two meetings with interested stakeholders in advance of beginning Phase I modeling to seek input on ELCCs.[4] Ultimately, five discussions were convened on this topic. Tri-State first shared its approach to the ELCC Study during a meeting with stakeholders on January 17, 2023. During that initial meeting, Tri-State indicated its intention to calculate ELCC values based on a deterministic approximation method developed by the National Renewable Energy Laboratory ("NREL"). On February 23, 2023, Tri-State again met with stakeholders to share updates to the ELCC calculations. However, during a meeting on March 14, 2023, stakeholders questioned whether a probabilistic method for determining ELCCs could be used instead of the NREL method. On

[4] 2020 ERP Settlement Agreement, Section 3.11.13.

April 24, 2023, Tri-State met with stakeholders again to discuss two possible paths forward for the ELCC Study: (1) one that would require several months to hire a third-party consultant to complete a probabilistic study for Phase I, and (2) one that would maintain the NREL method for Phase I and update ELCCs using a probabilistic study in advance of Phase II. Stakeholders indicated preference for a probabilistic study to be performed for Phase I. Tri-State met with stakeholders on this topic again on July 19, 2023 to present the results of the probabilistic study completed by Astrape.

Q: PLEASE DESCRIBE THE ELEMENT OF THE ASTRAPE STUDY RELATING TO PRM.

A: The study completed by Astrape also calculated a PRM for Phase I of the 2023 ERP. Astrape modeled the system using thousands of simulations varying weather, hourly and peak loads, and unit outages, with the calculated PRM being based on the weighted average results. The result being a PRM of 22 percent, transitioning to 30.5 percent after retirement of Craig Station.[5]

Some of the factors noted by Astrape in their study that influenced the PRM include:

- Impact of "shaft risk," which is the risk associated with the potential loss of units that are large relative to peak load. With Tri-State's load being reduced by approximately one-third due to Member exits and the Craig Station retiring, more risk relative to load is placed on the remaining

[5] **Attachment ~~G-1~~**, pg. 67. LKT-29

dispatchable units.

- The PRM calculation also discounts the capacity of conventional resources by their Equivalent Forced Outage Rate and several of Tri-State's thermal resources have relatively high and increasing forced outage rates.

c. <u>IRA Scenario Reliability Evaluation</u>

Q: PLEASE DESCRIBE THE PURPOSE OF THE IRA SCENARIO RELIABILITY EVALUATION.

A: Astrape was engaged by Tri-State to conducts an analysis of the IRA Scenario's reliability in 2032.

Q: WHAT DOES THE EVALUATION SHOW?

A: The evaluation shows that the IRA Scenario is reliable with a very low LOLE of 0.036 days/year in 2032, providing additional assurance of reliability as a result of this plan.

d. <u>DSM Potential Study</u>

Q: PLEASE DESCRIBE THE DSM POTENTIAL STUDY.

A: The DSM Potential Study identifies potential energy savings and associated costs for attaining energy savings under varying DSM Potential Study scenarios. The potential is derived from measure-level analysis, incentive and avoided cost assumptions, and factors related to the Tri-State system and consumer behavior. While Tri-State does not directly offer retail consumer services or programs, we work closely with our Members to facilitate their DSM program offerings and ease program administration burdens.

Q: IS OUTPUT FROM THE DSM POTENTIAL STUDY USED TO MODEL THE

COLORADO ENERGY EFFICIENCY TARGETS THAT TRI-STATE HAS COMMITTED TO STARTING IN 2023?

A: No. Tri-State models the 2023, 2024, 2025, and 2030 EE Targets[6] as a "must-take" level of energy savings in the resource planning period ("RPP") in all 2023 ERP Phase I scenarios, for the ECO and WCO planning regions. The EE Targets are identified in **Attachment B** of the ERP Report (**LKT-1**). LKT-7 The 2025 EE Target is held constant from 2025-2029 and the 2030 target is held constant through the remainder of the planning period.

Q: HOW ARE THE RESULTS OF THE DSM POTENTIAL STUDY USED IN TRI-STATE'S 2023 ERP PHASE I MODELING?

A: For any ERP scenarios that allows for either deeper levels of energy savings in ECO and WCO, or DSM as a selectable option for the NM or Wyoming/West Nebraska ("WYO/WNE") regions, the DSM Potential Study determines the level of energy savings assumed. Tranches of energy savings opportunity are selectable only based on the DSM Potential Study scenario levels (e.g., Low, Moderate, etc.). The costs to achieve the level of assumed energy savings also reflects input from Tri-State DSM program staff.

e. <u>BE Potential Study</u>

Q: PLEASE DESCRIBE TRI-STATE'S BE POTENTIAL STUDY.

A: The BE Potential Study identifies potential load growth opportunities from electrification and associated costs for attaining the additional load under varying

[6] 2020 ERP Settlement Agreement, section 3.11.9.

BE Potential Study scenarios. The potential is derived from measure-level analysis, incentive and avoided cost assumptions, and factors related to the Tri-State system and consumer behavior. While Tri-State does not directly offer retail consumer services or programs, we do work closely with our members to facilitate their BE program offerings and ease program administration burdens.

Q: HOW ARE THE RESULTS OF THE BE POTENTIAL STUDY USED IN TRI-STATE'S PHASE I MODELING?

A: The BE Potential Study determines the level of new load assumed based on study's scenario levels (e.g., Low, Moderate, etc.). For all scenarios in the 2023 ERP Phase I, Tri-State's load forecast is adjusted to reflect inclusion of the Achievement-Moderate level of BE. This approach is pursuant to the 2020 ERP Phase I Unopposed Comprehensive Settlement Agreement in Proceeding No. 20A-0528E ("2020 ERP Settlement Agreement").[7]

Q: DID TRI-STATE FULFILL ITS COMMITMENT TO HOLD STAKEHOLDER MEETINGS ON BE PRIOR TO MODELING?

A: Yes. Pursuant to 2020 ERP Phase I Settlement Agreement, Tri-State held two stakeholder meetings on BE best practices in advance of the 2023 ERP modeling, as identified in the ERP Report (**Attachment LKT-1**).

IV. GENERIC RESOURCE MODELING

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I discuss Tri-State's approach to generic

[7] 2020 ERP Settlement Agreement, section 3.11.11.

resources modeled in the ERP**.**

Q: PLEASE DESCRIBE TRI-STATE'S APPROACH TO GENERIC RESOURCES.

A: New to the 2023 ERP Phase I, Tri-State included several new emerging technologies as generic resource options available for scenario modeling. Tri-State also held meetings with stakeholders, prior to modeling, to share data and assumptions for both new and existing generic resource options.[8] Tri-State also refreshed data and assumptions for the generic resource types that had been modeled in the 2020 ERP.

Q: HOW ARE GENERIC RESOURCES MODELED IN THE ERP?

A: In expansion plan modeling in EnCompass, a given scenario results in the selection of a unique set of generic resource types, locations, and target commercial operation dates ("CODs"). The modeling assesses a variety of factors in determining the expansion plan needed to meet Tri-State system load and PRM over the resource planning period. Such factors include, but are not limited to, financial assumptions regarding resource costs, resource operational parameters, and environmental characteristics of the available technologies. The expansion plan output reflects the optimal solution for economically meeting the numerous constraints input into the model, such as transmission and new build constraints (**Attachment B-1, B-2** of the ERP Report (**LKT-1**)), emissions reduction targets, and others.[9]

LKT-8 AND LKT-9

[8] Pursuant to 2020 ERP Settlement Agreement, Section 3.11.15., Tri-State held several meetings with stakeholders to discuss new generic resources (as identified in the ERP Report (**Attachment LKT-1**)) and shared generic resource assumptions with stakeholders in advance of modeling.
[9] 2020 ERP Settlement Agreement 3.3.4. and 3.3.5.

Q: WHAT NEW TECHNOLOGIES DID TRI-STATE INCLUDE IN ITS GENERIC RESOURCE DATASET?

A: New technologies modeled in the Phase I 2023 ERP are identified in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**)~~ and include:

- 10-hour Battery Storage
- Molten Salt Long-Term Storage;
- Iron Air Multi-Day Storage;
- Advanced and Enhanced Geothermal;
- Green and Blue Hydrogen;
- Natural Gas Combined Cycle with Carbon Capture and Sequestration ("NGCCS"); and
- Small Modular Reactors ("SMRs").

Key financial, operational, and environmental assumptions about each technology type are included in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**).~~ The sources for this data include third-party experts, technology vendors, and trusted industry research sources such as the National Laboratories. Not all technologies are assumed to be deployment-ready during the first year of the RPP. Additionally, several of the new technologies were not selected in any of the scenario expansion plans.

Q: HOW DID TRI-STATE CONSIDER THE IMPACT OF FEDERAL FUNDING OPPORTUNITIES IN PRICING GENERIC RESOURCES?

A: The financial assumptions for the generic resources reflect applicable available

federal tax incentives, including the Investment Tax Credit ("ITC") or Production Tax Credit ("PTC"). The following technology types are assumed to be eligible for a 40 percent ITC:

- battery component of hybrid build-transfer;
- 4- and 10-hr batteries;
- pumped storage;
- advanced geothermal;
- enhanced geothermal baseload;
- enhanced geothermal with 12-hour storage;
- green hydrogen; and
- SMRs.

Molten salt and iron air technologies are assumed to be eligible for a 50 percent ITC, due to the expectation that they could qualify for the domestic content bonus credit.

The following technology types are assumed to be eligible for an energy-production based PTC:

- solar
- wind;
- solar and wind hybrids;
- blue hydrogen; and
- NGCCS.

For both existing and generic resources, that were assumed to be build-

transfer projects owned by Tri-State, it is assumed that Tri-State would be eligible for direct pay of tax credits, as described in the Direct Testimony of Lisa Tiffin.

V. MARKET DEPTH ASSUMPTIONS

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I discuss how Tri-State's planned market participation is reflected in the modeling approach.

Q: HOW DOES TRI-STATE'S MODELING ACCOUNT FOR TRI-STATE'S CURRENT AND PLANNED MARKET PARTICIPATION?

A: As identified in Proceeding No. 23M-0195E, Tri-State plans for its loads, resources, and transmission system in the Western Area Power Administration Colorado-Missouri Region ("WACM") balancing authority to join the Southwest Power Pool ("SPP") Regional Transmission Organization ("RTO") in the Western Interconnection on April 1, 2026. In Tri-State's 2023 ERP Phase I modeling, we simulate the impact of this portion of our system entering the market by increasing market sales and purchase depths starting in 2026. Additional detail on the specific depths and assumptions can be found in **Attachment B** ~~of the ERP Report (**LKT-1**).~~ LKT-7

Q: IS THIS A REASONABLE MODELING APPROACH?

A: Yes. Because Tri-State does not yet have the capacity to employ a nodal model, adjusting market depth parameters is the best approach available. As Tri-State continues to make progress toward SPP RTO market participation for its WACM load and resources, we anticipate transitioning our EnCompass model to employ a nodal approach for the 2027 ERP.

VI. SENSITIVITY ANALYSES

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I discuss the two sensitivity analyses that Tri-State modeled for each scenario.

Q: WHAT SENSITIVITIES DID TRI-STATE MODEL?

A: Tri-State assessed each scenario's performance under two sensitivity analyses—one that simulated extreme weather event ("EWE") conditions and one that evaluated High Gas prices.

Q: PLEASE DESCRIBE THE SENSITIVITY ANALYSES TRI-STATE COMPLETED FOR EACH SCENARIO.

A: For each scenario, Tri-State tested system performance under both EWE and High Gas conditions, separately. For the EWE sensitivity, transmission, load, renewable and thermal generation, and gas and power market prices were stressed (as described in **Attachment ~~B-5~~** LKT-12 ~~of the ERP Report (**LKT-1**))~~ for a one-week period in each winter and summer season during the Resource Acquisition Period ("RAP") to evaluate each scenario's performance under those conditions. Each scenario maintains its base expansion plan throughout the sensitivity analyses, but each scenario is re-dispatched in EnCompass with the stressed parameters to model the impact of an extreme weather or high gas event.

The approach to EWE sensitivity modeling in Phase I of the 2023 ERP is different from the approach in Phase II of the 2020 ERP in that the EWE stress assumptions are included in the modeling of each scenario's expansion plan. This approach resolved the issue that occurred in the 2020 ERP Phase II of scenarios

not meeting the Level II reliability metrics under initial modeling runs due to lack of expansion plan visibility into the EWE parameters. The base dispatch for each scenario does not reflect the EWE stress, to enable assessment of the financial results for each scenario under assumed normal system conditions.

For the High Gas sensitivity, stressed gas and power market prices[10] were applied in the modeling to evaluate each scenario's financial performance under that condition (as described in **Attachment E** ~~of the ERP Report (**LKT-1**)),~~ LKT-25 providing another look at dispatch results.

Q: DID TRI-STATE ENGAGE STAKEHOLDERS IN IDENTIFYING AND DEVELOPING THE SENSITIVITIES MODELED?

A: Yes. Tri-State held several meetings with interested stakeholders between January 17 and July 19, 2023, prior to beginning modeling, to discuss potential scenarios and sensitivities to be modeled and Tri-State's approach to EWE data and related reliability metrics. During those meetings, Tri-State reviewed potential scenarios and sensitivities and made adjustments based on stakeholder feedback. Tri-State also shared its approach to the EWE stress, detail on historical EWE data evaluated, planned EWE resource and transmission stresses and how each differed from the 2020 ERP Phase II EWE modeling, and provided options for potential approaches to the EWE load stress for stakeholder input. These meetings are identified in ERP Report (**LKT-1**).

Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE EWE SENSITIVITY?

[10] Market prices are provided by a third-party vendor, Horizons Energy—a analytics, data, and consulting company.

A: The EWE sensitivity simulates a 168-hour period in the summer and in the winter where extreme weather occurs, during a forecasted peak load period and resource availability and system operations are constrained. The EWE stress assumptions are described in detail within **Attachment ~~B-5~~** LKT-12 ~~of the ERP Report (**LKT-1**)~~ and reflect modifications from historical EWE conditions to address the Commission's statement in Decision No. C23-0437 that "…an EWE that merely replicates past heat waves or winter storms might be an insufficient test of the resource adequacy of the portfolios under consideration in future ERPs."[11]

Q: PLEASE DESCRIBE THE DATA INPUTS FOR THE EWE SENSITIVITY.

A: Tri-State primarily utilized historical data from EWE periods to develop EWE sensitivity stresses. These data informed the length of the EWE, the initial resource profiles, and expected transmission constraints. The following periods of historical EWEs were evaluated:

- July 2018 Heat Wave: 7/7-7/11 (5-day event)
- July 2022 Heat Wave: 7/17-7/19 (3-day event)
- Feb 2021 Winter Storm Uri: 2/13-2/17 (5-day event)
- Dec 2022 Winter Storm Elliot: 12/21-12/26 (6-day event)

Tri-State also utilized renewable resource performance profiles from some of these events, where available for existing resources on the Tri-State system. EWE stress data is applied on a regional basis, reflective of Tri-State system diversity. From these data, Tri-State made any necessary adjustments to reflect a

[11] Decision No. C23-0437, at ¶ 57.

reasonable time period for events (month of occurrence and length of days), to sync profiles of resource stresses to load as both are impacted by weather, and to ensure a robust but reasonable stress not solely based on past weather conditions. The approach to these adjustments is described in **Attachment ~~B-5~~** ~~of the ERP Report (**LKT-1**).~~ LKT-12

Q: BEYOND THE CHANGE IN APPROACH TO MODELING, WHAT INPUT ASSUMPTIONS WERE CHANGED FOR EWE SENSIVITIES SINCE THE 2020 ERP?

A: Nearly all of the EWE modeling assumptions were modified for the 2023 ERP. Data input assumption modifications for the EWE sensitivity include:

- **Length of EWE:** The timeframe for each EWE was shortened from two weeks to one week (168 hrs).
- **Load Stress:** Instead of a 90 percent confidence interval load stress applied equally to each hour, the load stress was based on a statistical model difference between the actual storm event weather in terms of precipitation for the month of the event and temperatures and 10-year weatherized normal weather by region. The EWE week was grossed up by the difference and the shape of the storm replaced the normalized shape used for the storm week. EWE dates were selected such that the demand peak in the months with EWE overlapped with the peak date of the storm. Please see the Direct Testimony of Lisa A. Lynn for additional detail on the load forecast assumptions and the extreme weather load forecasting methodology.

- **Renewable Resource Stress:** Renewable resource stresses were based on historical actual performance of renewable resources during prior EWEs where available, as well as actual wind speed or solar irradiance during prior EWEs. Renewables were stressed by an additional percentage, by region, for 72 hours during the peak period of the EWE to reflect that future events can be more severe than past events.
- **Thermal Resource Stress:** Outages and derates for existing thermal units were applied based on actual performance during historical actual EWEs.
- **Transmission Constraint Stress:** The TOT 3 transmission path (a corridor between southern Wyoming and northern Colorado) was reduced to 75 percent of Tri-State's share of its transfer capacity for three days during the winter EWE, and six hours (HE16-HE21) of every summer EWE period.
- **Limited Availability of Market Purchases:** Market purchases were modeled in the dispatch as available during limited hours of each EWE.

Each of these stresses are described in **Attachment ~~B-5~~** LKT-12 ~~to the ERP Report (**LKT-1**).~~

Q: DID TRI-STATE EVALUATE THE POTENTIAL FOR APPLYING A PROBABILISTIC MODELING APPROACH TO EWE?

A: Given the short period of time between receipt of the 2020 ERP Phase II decision[12] and the start of 2023 ERP Phase I modeling, Tri-State was not able to consider the pursuit of probabilistic modeling for the EWE sensitivity. Tri-State will continue

[12] Decision No. C23-0437, at ¶56 (Proceeding No. 20A-0528E).

to evaluate opportunities to further enhance approaches to EWE sensitivity modeling over time.

Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE HIGH GAS SENSITIVITY?

A: The only modification for the High Gas Sensitivity is to stress the gas and electric prices, to assess scenario performance. High Gas Sensitivity assumptions and results are provided in **Attachment E** of the ERP Report (**LKT-1**). LKT-25

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF ____COLORADO____)
) ss:
COUNTY OF __ADAMS_____)

I, Brian Thompson, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Subscribed and sworn to before me this 16th day of November 2023, at Westminster, Colorado.

TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC.

By: _____
Brian Thompson
Resource Planning Manager

Witness my hand and official seal.

_____
Notary Public

My Commission expires: 12/28/25.

Kimberly M. Strasburger
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134072316
MY COMMISSION EXPIRES December 28, 2025

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit EE: PRPA, *2024 Integrated Resource Plan* (Apr. 2023)

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

2024

Integrated Resource Plan



Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

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Glossary

Term or acronym	Definition
ATB	Annual Technology Book
BE	Beneficial building electrification
CDPHE	Colorado Department of Public Health and Environment
CIG	Colorado Interstate Gas
CPI	Consumer Price Index
DER	Distributed energy resources
DG	Distributed generation
DR	Demand response
ELCC	Effective Load Carrying Capability
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EV	Electric vehicle
GW	Gigawatt
GWh	Gigawatt-hour
HVAC	Heating, ventilation and air conditioning
IRP	Integrated resource plan or integrated resource planning process
ITC	Federal solar tax credit
JDA	Joint dispatch agreement

LOLE ..... Loss of Load Expectation

LOLH ..... Loss of Load Hours

MISO ..... Midcontinent Independent System Operator

MW ..... Megawatt

MWh ..... Megawatt-hours

NEM ..... Net energy metering

NEVI ..... National Electric Vehicle Infrastructure Formula Program, a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors

NREL ..... National Renewable Energy Laboratory

ODTY ..... One Day in Ten Years

PPA ..... Power purchase agreement

PRM ..... Planning reserve margin

RDP ..... Resource Diversification Policy

RFP ..... Request for proposals

RP22 ..... Platte River's Resource Plan 2022

RTO West ..... Regional Transmission Organization West

SPP ..... Southwest Power Pool

TOU ..... Time of use

VPP ..... Virtual power plant

WAPA ..... Western Area Power Administration

WECC ..... Western Electricity Coordination Council

WEIS ..... Western Energy Imbalance Service market

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01 Executive summary

Platte River Power Authority's 2024 Integrated Resource Plan (IRP) presents a comprehensive strategy to reduce carbon emissions for the communities we serve in Northern Colorado while upholding our foundational pillars of reliability, financial sustainability and environmental responsibility. Developed amidst unprecedented market changes, the IRP addresses the challenges of long-range planning by evaluating various decarbonization scenarios and incorporating feedback from our board of directors, customers and stakeholders.

The IRP explores a diverse range of resource options for continuing our work toward the Resource Diversification Policy (RDP) goal, including renewable energy, battery energy storage, distributed generation, energy efficiency and demand response. The plan also shows how we will maintain reliability with an energy portfolio composed primarily of weather-dependent, renewable resources.

Given the inherent uncertainties in long-term planning, the IRP is based on projections of future electricity demand, costs of renewable resources, advancements in technology, and evolving market and regulatory environments. Acknowledging that these factors will change, the plan is intended to serve as a roadmap, allowing for adjustments and modifications to optimally reflect changing market conditions and continue the implementation of our decarbonization strategy.

This IRP informs Platte River's next steps toward achieving a low-carbon energy portfolio by illustrating how we will reduce carbon emissions by at least 80% below 2005 levels by 2030 to meet state goals, and by supporting our board-adopted RDP.



Outreach and engagement

Building on what we learned from the last IRP, we expanded our outreach and engagement efforts considerably for the 2024 IRP.

We partnered with our owner communities to help educate customers about the relationship between Platte River and their cities. Over a six-month period, we presented our IRP process and updates to numerous community organizations, stakeholder groups and city leadership. We coupled these presentations with two engagement sessions hosted by Platte River to share IRP milestones, and offered digital resources including a dedicated website, email address and robust database of frequently asked questions and answers.

The feedback we collected between June and November 2023 helped inform the development of the portfolios.



Portfolios

The IRP is designed to align Platte River's future portfolio with our continued work toward the RDP, with a primary focus on reducing carbon while maintaining reliability. All portfolios will emit some carbon in 2030 because commercially viable noncarbon dispatchable options are not available. After 2030, we model no new thermal generation and plan for long-duration energy storage. Energy prices assumed embedded carbon taxes in the evaluation of each portfolio.

No new carbon: Focuses on wind, solar and energy storage, testing the viability of excluding new thermal generation to meet demand and reliability.

Minimal new carbon: Adds a modest amount of new thermal generation (80 megawatts) to support reliability and evaluates potential emerging technologies.

Carbon-imposed cost: Adds a carbon cost to discourage new carbon-emitting resource additions to the resource mix.

Optimal new carbon: Balances cost, reliability and carbon considerations between the additional new carbon and carbon-imposed cost portfolios.

Additional new carbon: Presents a least-cost portfolio without specific carbon constraints, prioritizing cost and reliability.



Because external risks to executing the clean energy transition have substantially increased, Platte River developed a risk-adjusted plan to address the challenges of integrating renewable resources as modeled. The primary risks are supply chain issues; engineering, procurement and construction delays; regulatory uncertainty on pricing; the mismatch in timing between customer demand and the availability of renewable generation; and market price volatility. This plan also allows for adjustments to market prices, emerging technologies and regulatory developments.

Conclusion

We are pleased to present the third iteration of the resource plan since our board passed the RDP. While we have made significant progress diversifying our portfolio since 2018—adding renewable energy to serve about one third of the owner communities' energy needs on an annual basis—we will immediately begin work on the fourth iteration as factors continue to change and evolve around us.

As you review our latest plan, we hope you take away a greater understanding of the complexity and challenges of replacing coal with renewables, firming up the intermittency of renewables with dispatchable resources, and doing right by the owner communities and our employees while pursuing one of the most accelerated decarbonization goals in the country.

This clean energy transition is a journey that will continuously evolve with changing circumstances and advancements in technology. Platte River is committed to making the transition on behalf of the owner communities to create a diverse, low-carbon energy portfolio for a sustainable future.

02 Introduction



Platte River Power Authority's 2024 IRP is a living document that guides and informs our efforts to supply reliable, environmentally responsible and financially sustainable energy and services to our owner communities while we work toward a noncarbon energy future. Throughout this document, we highlight how Platte River will address high-level policy goals while incorporating staff recommendations and research, third-party studies, and legislative, regulatory, market and technology changes.

Platte River developed this IRP with involvement from our owner communities and their customers. The board of directors approved the previous IRP document in 2020. Platte River is required to update the IRP and file it with the Western Area Power Administration (WAPA) every five years.

The report is organized as follows:

- The remainder of this section provides a general overview, background and history of Platte River, illustrating the foundational pillars and board-adopted policy that guide our planning activities and decisions.
- While IRPs are common among electric utilities, Platte River's approach is unique. Chapter 3 describes our process and timeline, the progress we made since our last IRP, and the industry challenges we face, including persistent impacts from the COVID-19 pandemic. Chapter 4 further highlights the variables and challenges Platte River faces as we pursue a clean, reliable energy future.
- Most of the report provides technical background data, assumptions and methodology that influence and shape our IRP, including demand, impacts of distributed energy resources (DER) and electrification, supply-side assumptions, extreme weather events and more. Chapter 7 of this report details the IRP design, including the studies, portfolios and our modeling methodology.
- Chapter 8 shows our modeling results; Chapter 9 highlights the resulting action plan from this IRP.



Public power utilities

Platte River is one of more than 2,000 community-owned electric utilities in the U.S. These utilities are operated by local governments and provide their owner communities with reliable, responsive, not-for-profit electric service. Public power utilities serve one in seven electricity customers across the U.S. – more than 54 million citizens – and operate in 49 states and in several U.S. territories.[1]

The American Public Power Association emphasizes the following characteristics of public power utilities:

- **Service-oriented:** We exist to serve and add value to our owner communities.
- **Community-owned:** We help advance the good of the community.
- **Local control and decision-making:** Decisions reflect our owner communities' needs and values.
- **Not-for-profit:** We focus on safely providing reliable, environmentally responsible and financially sustainable energy and services.
- **Responsive:** Because we are part of our communities, we react quickly to their needs.

[1] American Public Power Association website, www.publicpower.org







2.1 Platte River overview

Until the mid-1960s, many Colorado municipal utilities separately received wholesale electric service from the Bureau of Reclamation's system of hydroelectric generating facilities throughout the Colorado and Missouri River basins. In late 1965, 31 municipal utilities created the Platte River Municipal Power Association to manage and protect their collective hydropower rights, particularly due to the Bureau's announcement that it could not meet growing energy needs beyond the mid-1970s and no new (hydroelectric) energy projects would be built.

In 1973, four of the original 31 municipal utilities—Estes Park, Fort Collins, Longmont and Loveland—collaborated to pass legislation to form the Platte River Power Authority, a not-for-profit entity that would provide its owner communities with long-term energy above their limited allotment of federal hydropower. Following voter approval of a constitutional amendment, Platte River reformed in 1975 as a joint action agency, empowered to acquire assets to better serve its owner communities. These assets are discussed in greater detail throughout this document.

Also in 1975 (after the Colorado legislature passed enabling legislation), the four communities signed the organic contract establishing Platte River as a political subdivision of the state of Colorado. The organic contract is the agreement between the four owner communities that creates Platte River, establishing its purpose and governance structure.

Platte River is governed by an eight-person board of directors. The board includes the mayor (or a designee of the mayor) of each owner community and four other directors who are appointed to four-year staggered terms by the governing bodies of the owner communities. The board meets nine times per calendar year to establish and guide policy for the organization.

2.1.1 Foundational pillars

Platte River is guided by three pillars that drive its mission. Together with our vision and values, these pillars inform all activities and serve as the foundation for Platte River's decarbonization efforts.

Reliability

Providing a highly reliable supply of power to our owner communities

Environmental responsibility

Achieving noncarbon energy goals and protecting our natural resources

Financial sustainability

Managing financial risks, providing stable, competitive wholesale rates that generate adequate cash flow and maintain access to low-cost capital

2.1.2 Vision, mission and values

Our vision

To be a respected leader and responsible power provider improving the region's quality of life through a more efficient and sustainable energy future.

Our mission

While driving utility innovation, Platte River will safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities of Estes Park, Fort Collins, Longmont and Loveland.



Our values

Safety: Without compromise, we will safeguard the public, our employees, contractors and assets we manage while fulfilling our mission.

Integrity: We will conduct business equitably, transparently and ethically while complying fully with all regulatory requirements.

Service: As a respected leader and responsible energy partner, we will empower our employees to provide energy and superior services to our owner communities.

Respect: We will embrace diversity and a culture of inclusion among employees, stakeholders and the public.

Operational excellence: We will strive for continuous improvement and superior performance in all we do.

Sustainability: We will help our owner communities thrive while working to protect the environment we all share.

Innovation: We will proactively deliver creative solutions to generate best-in-class products, services and practices.

Environmental leadership

Platte River continually demonstrates a strong commitment to environmental responsibility while safely providing reliable and financially sustainable energy and services to the four owner communities. Below are examples of our environmental stewardship:

- Incorporated state-of-the-art emissions controls on the coal-fired Rawhide Unit 1, consistently positioned among the lowest SO2-emitting coal-fired plants in the country, according to data available from the U.S. Environmental Protection Agency (EPA).
- Became the first utility in Colorado to offer wind energy to the owner communities through the Medicine Bow Wind Project in 1998.
- Began commercial operation of 30 MW of solar at the Rawhide Energy Station in 2016. Platte River later added another 22 MW of solar to the area, with a 2 megawatt-hour (MWh) battery storage facility.
- Completed construction of a new headquarters campus in Fort Collins in 2020 that is designed to serve as an example of energy efficiency. The campus received Gold LEED Certification by the U.S. Green Building Council in 2023.
- Adopted the Resource Diversification Policy in 2018, becoming one of the first utilities in Colorado and the country to set a goal of a 100% noncarbon energy mix by 2030.

2.2 Resource Diversification Policy

In 2018, Platte River's Board of Directors passed a landmark policy (Figure 1) that directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon energy resource mix by 2030 while maintaining the foundational pillars. The policy also lists several advancements (or caveats) that must occur for Platte River to meet this ambitious goal.

Purpose

This policy is established to provide guidance for resource planning, portfolio diversification and carbon reduction.

Policy

The board of directors (the board) directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

The board recognizes the following advancements must occur in the near term to achieve the 2030 goal and to successfully maintain Platte River's three pillars:

- An organized regional market must exist with Platte River as an active participant
- Battery storage performance must mature and the costs must decline
- Utilization of storage solutions to include thermal, heat, water and end user available storage
- Transmission and distribution infrastructure investment must be increased
- Transmission and distribution delivery systems must be more fully integrated
- Improved distributed generation resource performance



- Technology and capabilities of grid management systems must advance and improve
- Advanced capabilities and use of active end user management systems
- Generation, transmission and distribution rate structures must facilitate systems integration

Resource planning is an ongoing process and Platte River continuously evaluates opportunities to add noncarbon resources. Platte River reviews its generation portfolio annually as part of the budgeting and planning process. This process sets the foundation for developing an IRP submitted to the Western Area Power Administration every five years as required. The resource planning process includes evaluating the progress of energy storage, distributed power sources and new technologies. As a leader in the utility industry in Colorado for many years, Platte River will continue to move forward to meet the resource needs and wants of the four owner communities. The board recognizes the integration of noncarbon resources and new technologies will shape the future of Platte River's and the four owner communities' energy supply.

Figure 1. *Resource Diversification Policy*



03 IRP process overview

3.1 What is an IRP?

A utility IRP[2] compares the supply-side resources (generated or purchased by the utility) and demand-side resources (contributed by customers, including DER) with projected energy needs (load) and selects an optimal set of resources to meet future needs while meeting the regulatory requirements and policy goals at the highest level of reliability.

Key components of an IRP include:

- Customers' future electricity needs (or load forecast)
- Future costs and availability of supply and demand side resources
- Regulatory and policy requirements including environmental considerations
- Community engagement to hear stakeholder feedback and questions
- An assessment of future technologies

These components and other inputs are used in a complex planning and optimization model to develop a 10-to-20-year roadmap of investments to provide reliable supplies during the planning horizon. An IRP model optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM[3]) or other reliability criteria, to ensure adequate electricity supply under all reasonably expected variations of weather, customer demand and resource availability.

A key component of an IRP is an action plan that outlines the specific activities the utility plans to conduct in the next three to five years while developing the next IRP. An IRP is a snapshot in time; planning is an ongoing and dynamic process. An IRP acts as a roadmap or guide, while the actual investment decisions are made based on the best information available at the time of the decision.

[2] In this document the acronym IRP is used in two different ways–an integrated resource plan and as an integrated resource planning process

[3] PRM is defined as the additional generating capacity available to meet a future year peak demand. It is expressed as a percentage of peak demand. Historically, Platte River has maintained a 15% PRM which means if the load forecast expects a peak demand of 100 MW in a future year, Platte River would build or acquire 115 MW of generation or DER capacity to reliably meet that peak demand.

3.2 Why do an IRP now?

In 2020, Platte River developed an IRP that outlined several paths to work toward the RDP goal. The plan's recommendations were developed before the global COVID-19 pandemic, which put many things on hold for two years, including construction of renewable energy projects. The pandemic triggered widespread supply chain issues and contributed to increased costs for labor, capital, equipment and new resources, which resulted in multiple rounds of contract renegotiations for renewable projects. State and federal clean energy policies also created intense competition for renewable resource projects and related equipment and staffing.

Meanwhile, Winter Storm Uri in February 2021 was a wakeup call about the increased frequency of extreme weather events and the need for a reliable power supply. While the emergence of new technologies and the passage of the Inflation Reduction Act are positive developments, the industry continues to face inflationary pressures and supply chain challenges.

This 2024 IRP captures these developments, re-affirms our commitment to the RDP and charts a path toward that goal. While Platte River is not required to file an IRP with WAPA before 2025, we expedited this IRP to support the accelerated integration of renewable resources. We finalized our assumptions underlying this IRP in summer 2023, so this IRP provides portfolios or snapshots of the future viewed from 2023. This IRP will need updating as technology and circumstances evolve. Platte River will prepare the next IRP in 2028.

3.2.1 IRP timeline

The 2024 IRP process started in 2022 by commissioning pre-IRP studies from external consultants and continued through early 2024. Figure 2 illustrates a high-level timeline and list of major activities. Community engagement is an important part of the IRP process and is highlighted in yellow.

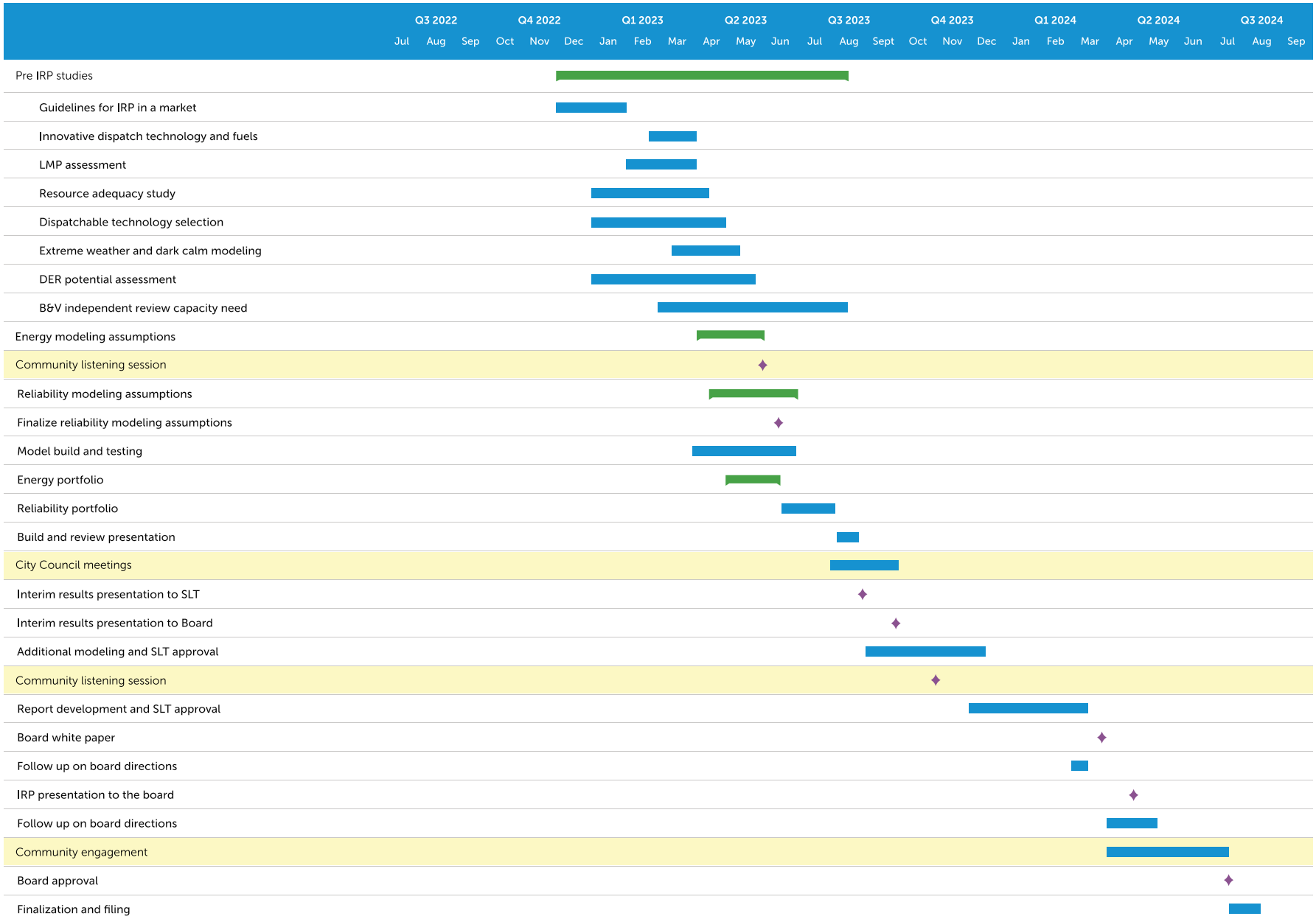


Figure 2. *Timeline of 2024 Integrated Resource Plan activities and milestones*

3.3 Progress since the last IRP

Platte River continued to work toward achieving the RDP after submitting our last IRP, acquiring more renewable generation, expanding efforts to join a regional market and working with the owner communities to expand DERs. Specific annual achievements are summarized below.

2020

- Began receiving energy from the Roundhouse Wind Energy Center, a 225-megawatt (MW), 80-turbine wind farm. Additionally, Platte River purchased the 230-kilovolt generator outlet line from the project, securing energy delivery to the owner communities throughout the 22-year power purchase agreement (PPA).
- Launched the DER strategy committee with staff members from Platte River and the owner communities. The DER strategy committee explores how to integrate systems that will better balance supply and demand as we transition our energy portfolio.
- Finalized closure dates for remaining coal units in Platte River's portfolio. Rawhide Unit 1 will close by the end of 2029, 16 years before its planned retirement. Craig Unit 2 will close by September 2028. (The 2025 closure date for Craig Unit 1 was announced in 2016.)
- Signed a PPA to build Platte River's largest solar project, which, when operational, will provide up to 150 MW of power.

2021

- Commissioned the 22 MW Rawhide Prairie Solar project, including a 2 megawatt-hour battery.
- Created the transition and integration division, combining DER and energy solutions with resource planning and information and operations technology departments to foster the innovation needed to achieve a noncarbon electric system that includes integrated DERs.
- Together with the owner communities, developed a comprehensive DER strategy providing a path forward to jointly attain the full value of DERs to the benefit of customers and the grid.
- The Efficiency Works Business team launched the Community Efficiency Grant to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community.
- Issued a request for proposals (RFP) to competitively procure up to 250 MW of solar generation and co-located battery resources connected at the distribution or transmission level.

2022

- Accelerated the timeline for new noncarbon energy resources to maintain the reliability and financial sustainability of the resource portfolio ahead of retiring coal-fired generation resources.
- Confirmed the purchase of 150 MW of solar energy from the vendor for the Black Hollow Solar project, restating an agreement originally signed in 2020. Logistical challenges delayed the project, now scheduled to begin commercial operation in 2025.
- Analyzed and evaluated large-scale four-hour storage and longer duration energy storage and evaluated adding an additional wind project to Platte River's portfolio. Developed a revised portfolio (RP22) that added about 105 MW more capacity by 2030 than the 2020 IRP. RP22 called for 450 MW of solar, 300 MW of wind, 200 MW of four-hour storage and 166 MW dispatchable thermal generation.
- Together with the joint dispatch agreement (JDA) partners, Platte River announced plans to join the existing Western Energy Imbalance Service (WEIS) operated by the Southwest Power Pool (SPP). The WEIS replaces the JDA and allows Platte River to gain experience operating in a larger imbalance market. Investments began in 2022 to prepare for entry into the WEIS.
- Launched an interactive electric vehicle (EV) shopper guide website with information on currently available EVs, including cost, performance specifications and available incentives, as well as a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles.



2023

- Issued an RFP to competitively procure 150-250 MW of wind generation. Responses to the RFP were received in late 2023, with evaluation of the responses continuing in 2024.
- Began operating in the SPP WEIS market.
- Selected a vendor for battery storage facilities located in the owner communities. The projects' expected capacity will range from 20-25 MW, consisting of four-hour duration lithium-ion batteries.
- Expanded the EV website to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions.
- Enhanced program offerings through the partnership between Efficiency Works and Energy Outreach Colorado to actively engage with participants on more significant home upgrades including energy efficiency and building electrification, resulting in nearly $1 million of investments to support the income-qualified residential upgrades in Platte River's owner communities.
- Expanded Efficiency Works programs to include multiple building electrification measures, supporting 359 heat pump installations with over $1 million in incentives to help customers to overcome financial hurdles and investing nearly $10,000 training local contractors on building electrification.
- Actively supported over 100 income-qualified customers to upgrade their homes, with plans to support over 250 customers annually in future years.
- Signed a commitment agreement to join the SPP Regional Transmission Organization West (RTO West) on April 1, 2026.
- Committed to advancing EV infrastructure by launching one of the highest incentives in the state, of $5,000 per public charging port, to promote public charger hosting by local business and multifamily properties by offsetting some of the installation cost.

3.4 External developments since the 2020 IRP

3.4.1 Pandemic

The COVID-19 pandemic brought unprecedented challenges worldwide and the power sector was no exception. Immediately after the pandemic started, the economic slowdown resulted in electricity demand reduction and changing demand patterns. As economic activity slowly resumed, the electricity demand started coming back with residential demand increasing (compared to pre-

[4] https://www.iea.org/reports/renewable-energy-market-update-june-2023/executive-summary

pandemic levels) due to a significant increase in citizens working from home.

Supply chain slowdowns are among the pandemic's biggest impacts and are detailed in the next section. The pandemic also slowed down construction and new renewable project development due to reluctance of investors to commit capital amid market volatility and uncertainty about future energy demand.

As the world began adapting and recovering after the first few months of the pandemic, it prompted many governments to reevaluate energy policies and regulatory frameworks to address emerging challenges and support economic recovery efforts. The pandemic also highlighted the importance of resilient and sustainable energy systems. Significantly higher demand and sustained challenges with supply chains contributed to the cost of renewable resources and energy storage projects nearly doubling post pandemic.

3.4.2 Supply chain issues

Supply chains were impaired by factory shutdowns, component shortages, labor shortages and financial, economic, demand and policy uncertainty during the pandemic. While this slowed down the supply side of electricity, the demand side recovered quickly and in fact, significantly increased. Renewable energy project supply chains are global and reflect worldwide demand. According to the International Energy Agency, the world added less than 200 gigawatts (GW) of new renewable resources in 2019 and more than 440 GW in 2023.[4] Although renewable supply chains are recovering from pandemic-related stress, the surge in demand is increasing pressure. In the U.S., the Inflation Reduction Act has significantly increased incentives to expand the domestic supply chain of renewable generation. But this further strains the supply chain as companies rush to develop U.S. renewable manufacturing.

This supply chain pressure directly impacts Platte River's resource procurement. For example, Platte River conducted an RFP in 2019 to add 100-200 MW of new solar capacity by 2023. The winning project, a 150-MW solar farm called Black Hollow Solar, is now expected to start commercial operation in 2025. Similar risks exist for projects planned for 2026 and 2027.



3.4.3 Renewable resource pricing

Due to supply chain issues and increased demand, the prices for renewables have significantly increased since the last IRP. As shown in Figure 3 from Level Ten Energy[5], PPA prices in the U.S. doubled by the end of 2023 compared to 2020 levels.

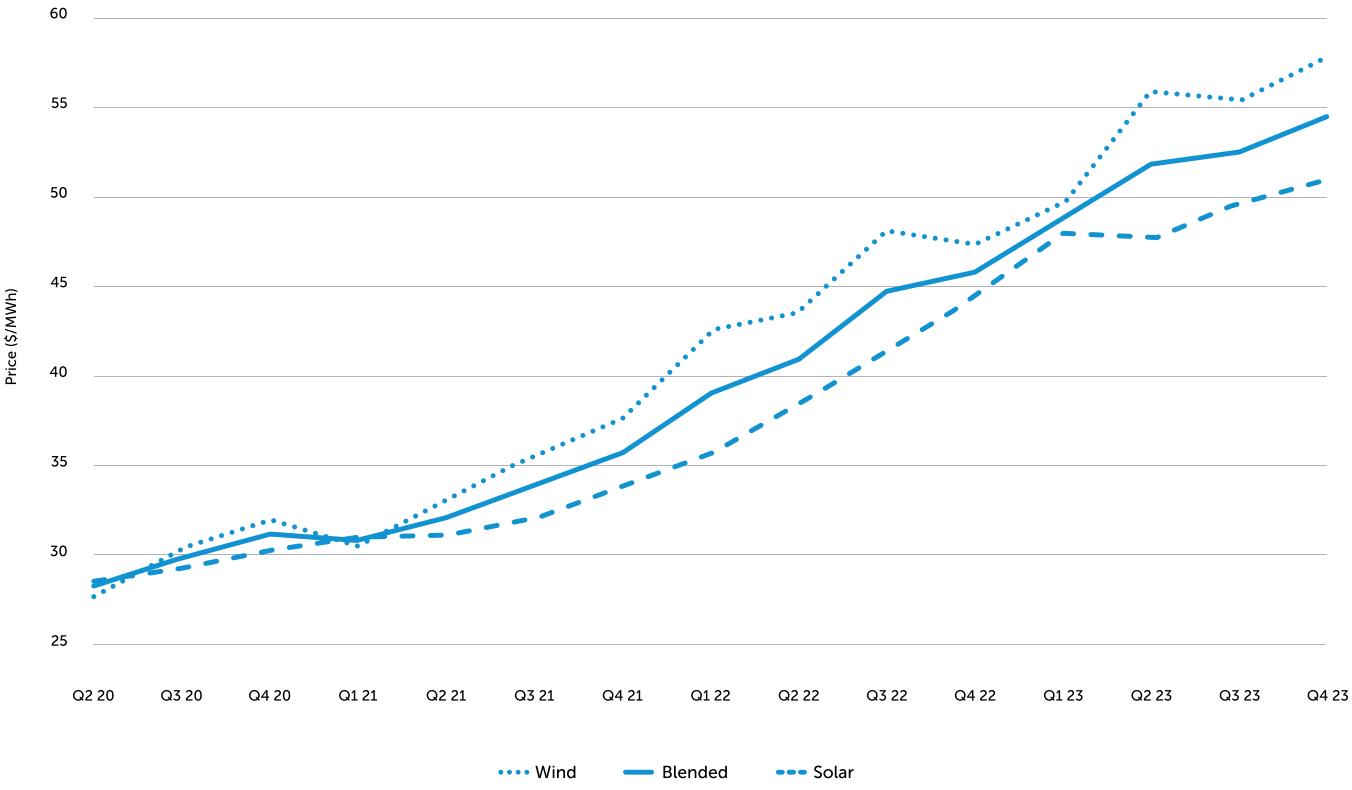


Figure 3. *PPA prices in the U.S. between 2020 and 2023*

Major drivers for this price increase are higher demand, higher cost of capital, higher inflation rates, higher transmission costs, higher risk premiums and trade policy changes. These drivers are detailed below.

Higher demand: Consistent with the global increase in demand for renewable generation, demand in the U.S. has also increased, especially after the passage of the Inflation Reduction Act, as illustrated in Table 1. According to the U.S. Energy Information Administration (EIA), the U.S. is expected to add 62.8 GW[6] of new capacity in 2024, 55% more than the 40.4 GW added in 2023. This represents the most capacity added annually since 2003.

Of this new capacity, the 36.4 GW of added solar is double the 18.4 GW added in 2023. Expected 2024 battery storage additions of 14.3 GW will be more than double the 6.3 GW added in 2023. The significant increase in demand for renewable energy, both domestically and globally, puts upward pressure on prices.

	2023	2024
New capacity	40.4 GW	62.8 GW
Solar	18.4 GW	36.4 GW
Battery	6.3 GW	14.3 GW

Table 1. *U.S. demand for renewable generation*

Higher cost of capital: Most of the renewable projects built by third-party developers and sold under long term PPAs are financed with up to 80% debt. Therefore, interest rates (especially long-term debt rates) affect PPA prices. U.S. long-term interest rates, as measured by the yield on 10-year U.S. Treasury Securities, have more than doubled in the past few years as shown by Figure 4 from the Federal Reserve's Economic Data.[7]

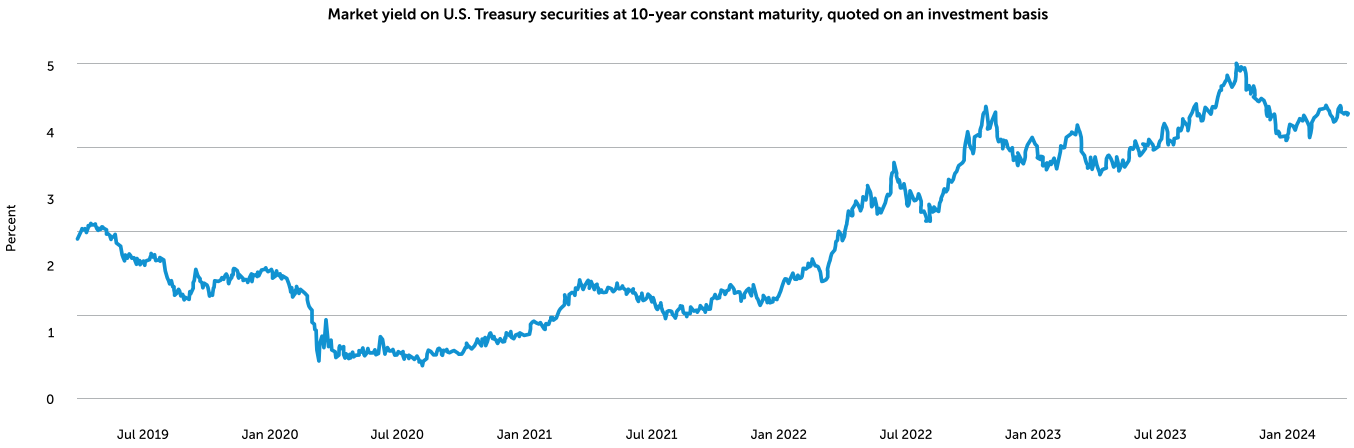


Figure 4. *Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis*

[5] https://www.leveltenenergy.com/ppa

[6] https://www.eia.gov/todayinenergy/detail.php?id=61424

[7] https://fred.stlouisfed.org/series/DGS10

Corresponding to the 10-year Treasury Securities yield increases, the developer's cost of capital for financing a project has approximately doubled over the last few years from 3-4% to over 7%. This increased cost of debt has significantly increased the carrying cost of projects, raising PPA prices for utilities.

Higher inflation: According to the U.S. Bureau of Labor Statistics, the Consumer Price Index (CPI), which is a general measure of inflation, increased 17% in the past three years (January 2021 to January 2024), almost three times the prior three-year period (January 2018 to January 2021), when it increased 6%. This increase in CPI has affected all sectors of the economy, including the price of renewable generation. More specifically, labor costs have seen significant increases in the past few years as shown in Figure 5.

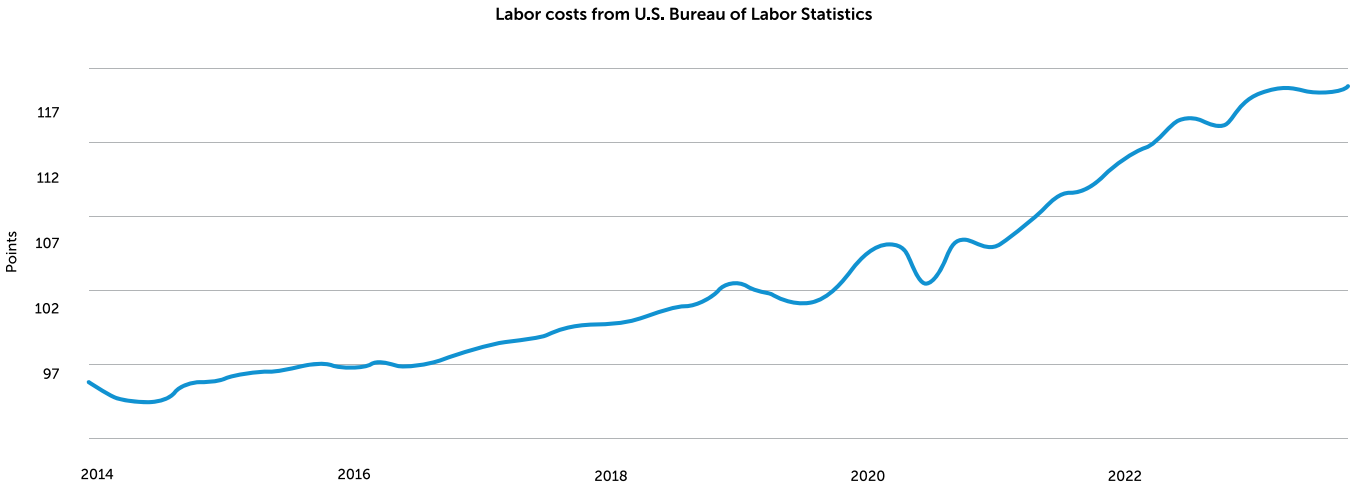


Figure 5. *Labor costs from U.S. Bureau of Labor Statistics*

Similarly, metal costs have seen more volatility and net increase over the past few years, as shown in Figure 6.[8]

Higher transmission costs: Transmission costs to interconnect renewables are increasing at two levels. First, inflation increases transmission interconnection equipment costs. Second, as more and more renewable resources are added to the grid, the cost to interconnect the next renewable project is often higher due to the need to upgrade the existing transmission infrastructure.

[8] https://fred.stlouisfed.org/series/PMETAINDEXM

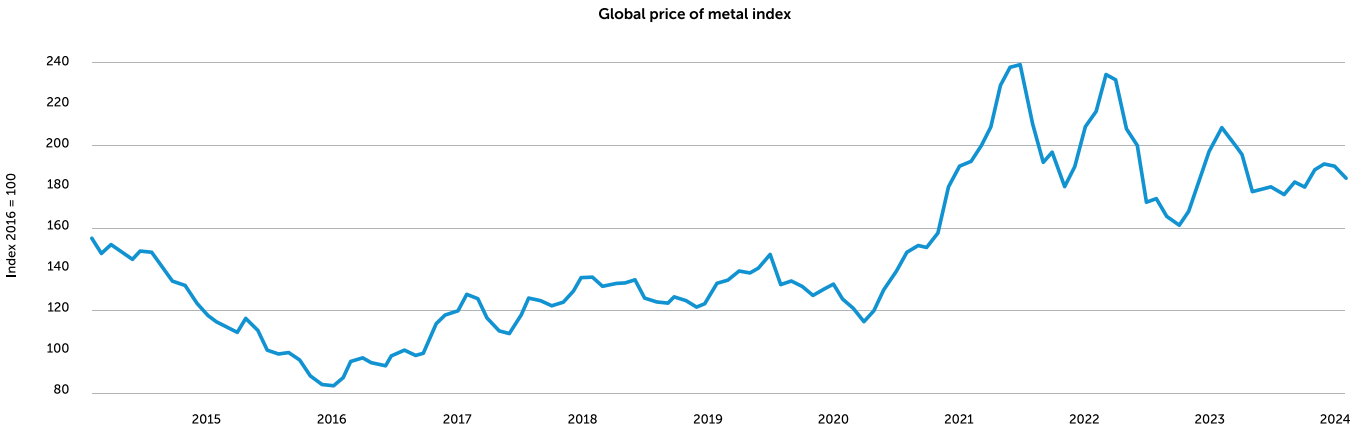


Figure 6. *Global price of metal index*

Higher risk premiums: Recent inflation and uncertainty about future inflation mean that developers assume the recent increase in equipment and labor prices will continue in the future. For example, developers have experienced a significant increase in engineering, construction, and procurement costs and assume these annual cost increases will continue. Recently, Platte River agreed to higher pricing on previously signed PPAs to enable project construction.

Additionally, Anti-Dumping and Countervailing Duties and Uyghur Forced Labor Prevention Act policies created uncertainty for imports from certain countries. These policies, coupled with other factors mentioned earlier, has pushed the price of renewable generation higher. The Inflation Reduction Act and other policies will expand domestic manufacturing, but it may take years before we see any downward pressure on prices.



3.5 Resource planning refresh in 2022

Following the pandemic and associated impacts on cost, Platte River staff updated the recommended portfolio from the 2020 IRP in 2022. The revised plan is called RP22 and includes the following:

3.5.1 Acceleration of renewable integration

The 2020 IRP had assumed all new generation and storage would come online on Jan. 1, 2030, after Platte River's last coal plant closed. RP22 adds renewables, storage and dispatchable resources while considering project development timelines and supply chain issues. Platte River seeks to have most, if not all, new resources ready by 2028 to give at least one full year of operating experience to Platte River staff before retiring Rawhide Unit 1. This accelerated timeline shows a gradual increase in renewable generation after 2025.

3.5.2 Extreme weather modeling

While Platte River's 2020 IRP simulated average weather and load conditions, the impact of Winter Storm Uri in February 2021 on power supply across the midsection of the continental U.S. provided a valuable lesson for enhancing future power supply reliability. During Uri, northern Colorado experienced extremely cold weather and saw little to no renewable generation for three days. We refer to this event of no renewable generation as a "dark calm" and simulated these events in future planning.

To enhance the reliability of the future power supply, RP22 simulates 24 years of hourly historical weather (with its unique hourly load, wind and solar profiles) and dark calm events. To meet this enhanced reliability requirement, RP22 added 62 MW of additional dispatchable capacity and reduced reliance on four-hour storage relative to the 2020 IRP recommended portfolio.

3.5.3 Expanded DER impact

Working closely with our owner communities, Platte River completed its DER strategy in July 2021. The strategy brought an expanded focus on DERs. Since the completion of 2020 IRP, customers have rapidly adopted EVs and distributed solar. Similarly, there is increased interest in heating electrification to replace natural gas-fueled heating. As a result, RP22 models rapid growth in DERs, including EVs, heating electrification and demand response.

3.5.4 Renewable supply chain impact

As discussed above, the renewable generation costs and project lead times increased after the pandemic. RP22 considers these increased costs and longer development times for the future portfolio.

3.6 Regulatory environment

This section outlines the legislative, regulatory and policy environment in which Platte River developed this IRP. It covers current legislative requirements with which Platte River must comply (both state and federal) as well as political assumptions that influenced the resource plan. This IRP addresses applicable state and federal laws, including those highlighted below.

Platte River is accountable to its board, to the Colorado Department of Public Health and Environment (CDPHE) through commitments made in its voluntarily filed Clean Energy Plan, and to the EPA through its contributions to Colorado's regional haze state implementation plan. The Colorado Public Utilities Commission does not regulate Colorado municipal utilities.

3.6.1 Colorado policy review

Since the passage of Platte River's RDP in 2018, Colorado's legislature has increased its attention to energy and environmental policies. Many recent bills impact utilities' resource planning and operations. The following bills are relevant to Platte River's resource planning and this IRP:

HB19-1261: The Climate Action Plan to Reduce Pollution set aggregated and sector-specific targets for reducing statewide greenhouse gas pollution. The bill set aggregate reduction targets at 26% by 2025, 50% by 2030 and 90% by 2050 compared to 2005 levels. The General Assembly encouraged consumer-owned electric utilities to file Clean Energy Plans demonstrating at least an 80% reduction in emissions by 2030 compared to 2005 levels. Platte River subsequently filed a voluntary Clean Energy Plan in line with the standards of HB19-1261. In addition to rulemakings for utilities, HB19-1261 also ushered in sweeping changes for other sectors, such as transportation and buildings, that have a direct impact on future electric load and utilities' resource planning.

SB19-096: This bill directed CDPHE's Air Quality Control Commission to collect greenhouse gas emissions data from emitting entities and report on the data to support the state in meeting its greenhouse gas emission reduction goals.

HB22-1244: This bill created a new program within CDPHE's Air Pollution Control Division to regulate toxic air contaminants. It also gave the Air Quality

Control Commission permission to create air toxics rules more restrictive than those of the federal Clean Air Act. Starting in 2024, regulated organizations must submit annual toxic emissions reports that the Air Pollution Control Division will make available to the public.

SB23-198: Expressing legislative concern that utilities are on track to meet the greenhouse gas reduction goals set out in HB19-1261, this bill requires any utility that submitted a Clean Energy Plan before Jan. 1, 2024, to model at least one portfolio that achieves a 46% emissions reductions by 2027 (as compared to 2005 levels) and at least one portfolio that achieves greater emissions reductions than the Clean Energy Plan submitted. The Air Pollution Control Division must subsequently confirm that utilities have adequate resources to achieve the 2030 clean energy target. As part of this IRP process, Platte River's board will consider portfolios that meet the requirements of SB23-198.

Table 2 illustrates how these Colorado policies are either considered in Platte River's RDP, modeled in this IRP or apply only to reporting functions.

Colorado policy	Reporting	Considered by RDP	Modeled by 2024 IRP
HB19-1261: The Climate Action Plan to Reduce Pollution		✓	
SB19-096: Collect Long-term Climate Change Data	✓		
HB22-1244: Public Protections from Toxic Air Contaminants	✓		
SB23-198: Clean Energy Plans			✓

Table 2. *How Colorado policies are considered, modeled or reported by Platte River*

In 2018, Colorado Governor Jared Polis ran on a platform of achieving 100% renewable energy by 2040 and continues to direct his staff to achieve this goal. To drive and monitor Colorado's adherence to the greenhouse gas emissions reductions goals set out in HB19-1261, the state released its first Greenhouse Gas Pollution Reduction Roadmap in January 2021.

Concurrent with this IRP process, the Polis administration published its Greenhouse Gas Pollution Reduction Roadmap 2.0 in February 2024, which will accelerate Colorado's clean energy goals.

3.6.2 Federal policy overview

As a hydropower customer of WAPA, Platte River must file an IRP with WAPA every five years. This IRP document complies with WAPA requirements as detailed in Appendix A.

On June 16, 2020, Platte River announced its plans to retire Rawhide Unit 1 no later than Dec. 31, 2029. Colorado incorporated Unit 1's planned retirement into its state implementation plan for the regional haze program, making the retirement federally enforceable.

The U.S. Congress passed the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law, in 2021 and the Inflation Reduction Act in 2022. Together these bills resulted in unprecedented federal investments in the clean energy transition through tax credits (including for not-for-profits that have historically not paid taxes and therefore have not been eligible for tax credits) and competitive grant programs. In response, Platte River has dedicated resources to submitting grant applications and to exploring tax credits for new renewable energy assets. To date, Platte River has mainly captured these benefits through PPAs with renewable developers, whose prices reflect federal subsidies. In partnership with trade associations such as the American Public Power Association and Large Public Power Council, Platte River is continuing to explore opportunities.

Platte River is carefully monitoring the EPA's new regulations on power plants with coal- or new natural gas-fired generating units. In May 2024, the EPA finalized rules to reduce greenhouse gas emissions from power plants. Platte River will continue to closely follow these and other federal developments.



3.7 Stakeholder engagement process

3.7.1 Outreach strategy

Platte River's communications, marketing and external affairs team worked closely with the transition and integration team to develop a robust community engagement strategy for the 2024 IRP. We collaborated with the four owner communities' distribution utility communications and community relations staff. Owner communities' staff recommended which neighborhood groups, community and nonprofit organizations and customer accounts to engage and helped coordinate presentations for city councils and council-appointed boards. This allowed for a more targeted approach on engaging with stakeholders across Platte River's service region, responding to questions and addressing concerns surrounding the reliability, environmental responsibility and affordability of future energy portfolios.

3.7.1.1 Community meetings

While some owner community stakeholder groups knew Platte River as a wholesale power provider, many constituents were unaware who generates their power and how. An added value of the IRP community meetings was the opportunity for citizens to engage with their community-owned generation and transmission utility.

Mindful of equity and access, Platte River either visited every group we presented to or provided a virtual option, provided information in Spanish and equipped meetings with translators and listening assistance options.

While the audiences were widespread across Platte River's service region with diverse backgrounds, there were general themes that surfaced. Those themes include:

- Discussions around customer behavior changes and impacts to resource planning
- The increasing trend of beneficial electrification and growth in demand and load
- Impacts of climate change and extreme weather modeling
- Clarity on what is a dispatchable resource
- Equity and affordability


Timeline
June
July
Aug
Sept
Oct
Nov
Dec
Jan
Feb
Mar
April
May
June
Community engagement
Resource planning
• Pre-IRP studies
• Load forecasting
• Other inputs, assumptions

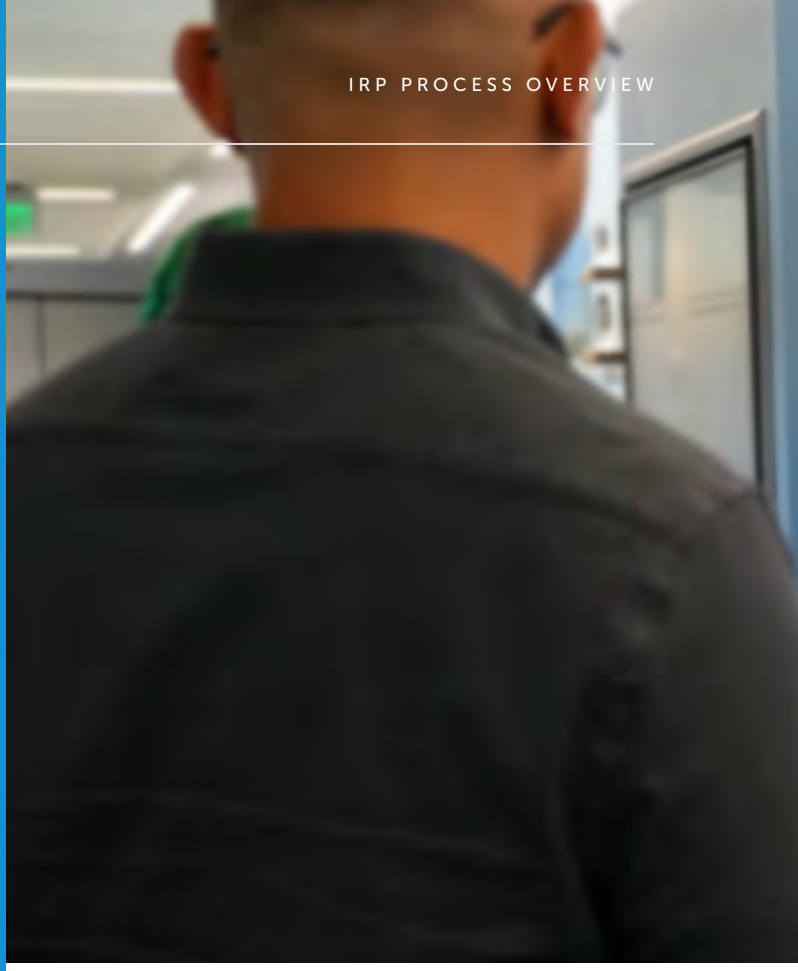
Each presentation gave the audience an opportunity to ask questions. The Platte River team continues to receive questions via email, social media and in-person. To date, we have logged and answered over 150 questions.

Presentations per owner community:

- Estes Park: 2
- Fort Collins: 8
- Longmont: 5
- Loveland: 4

Presentations per community group type:

- Neighborhood group: 2
- Community organization: 6
- Nonprofit: 5
- Customer account: 1
- Council-appointed board: 3
- City/town councils: 4



3.7.1.2 Business community engagement

Platte River engaged the business community primarily through downtown development authorities and local chambers of commerce: the Estes Park Chamber of Commerce, the Fort Collins Area Chamber of Commerce, the Longmont Chamber of Commerce and the Loveland Chamber of Commerce. We presented to chamber staff, committee appointees and members, sharing information about Platte River, the RDP, the IRP process and forecasts of our shared energy future. We captured questions and feedback from the business community, who are integral drivers of economic and workforce development in the region.



3.7.1.3 Consulting with industry experts

Platte River's resource planning staff actively consulted with national institutes and public power councils, including the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL) and the Large Public Power Council.

3.7.2 Campaigns and resources

Platte River's first brand awareness and public education campaign launched soon after the start of our 2024 IRP community engagement. The parallel run of these two efforts aimed to educate the utility's service region about who Platte River is while driving users to Platte River's digital platforms to learn more about our aggressive decarbonization efforts.

Platte River used both organic and paid media to support community engagement activities for the 2024 IRP, including:

- Digital technologies like social media, email distribution and websites
- Cross-functional organic outreach through support from platforms across each owner community and distribution utility
- Paid media with advertisements placed in traditional and digital platforms with high visibility across each owner community
- Engagement with local media, including hosting an editorial meeting with local media partners



In addition, Platte River developed and maintains the following resources for continued engagement with the public.

3.7.2.1 Microsite

Staff developed a detailed and interactive IRP microsite (prpa.org/2024irp) that is updated as information evolves and additional details are available. Members of the public are encouraged to visit this site to learn more about Platte River's plans and to access more in-depth information including the studies conducted as part of the IRP.

Our staff captured and answered all questions asked during the community engagement phase. These answers are provided in an appendix to this IRP. A subset of high frequency questions was extracted from the full list to develop a 'frequently asked questions' page published to the IRP microsite.

3.7.2.2 Dedicated email

Platte River created a dedicated email for IRP specific questions and comments at 2024IRP@prpa.org. This approach allows for direct communication with engaged citizens and allows staff to track their contributions.

3.7.3 Results

The 2024 IRP reflects extensive collaboration among Platte River teams and gathering input from key stakeholders and the communities we serve. This process was designed to provide an open and transparent view of Platte River's resource planning strategy, accountability to our owner communities and the state of Colorado's clean energy goals and to underscore the value of equally maintaining our three foundational pillars.

One of the major takeaway messages we identified across each outreach effort: Platte River must continue to safely provide affordable and reliable power to its owner communities and their customers while addressing the evolving landscape in which we operate. Each owner community served by Platte River has set, or is in the process of setting, its own clean future initiative and is challenging Platte River to match these efforts to provide northern Colorado with electric service in an increasingly sustainable manner.

04

Platte River's path to a clean, reliable energy future



4.1 Key variables and strategic considerations

Platte River considered whether the advancements identified in the RDP have been met while working toward the RDP goal. Other variables in this IRP include:

4.1.1 Load forecast

Load forecast refers to how load, or aggregate electricity demand, is changing and the impacts of those changes to the energy mix.

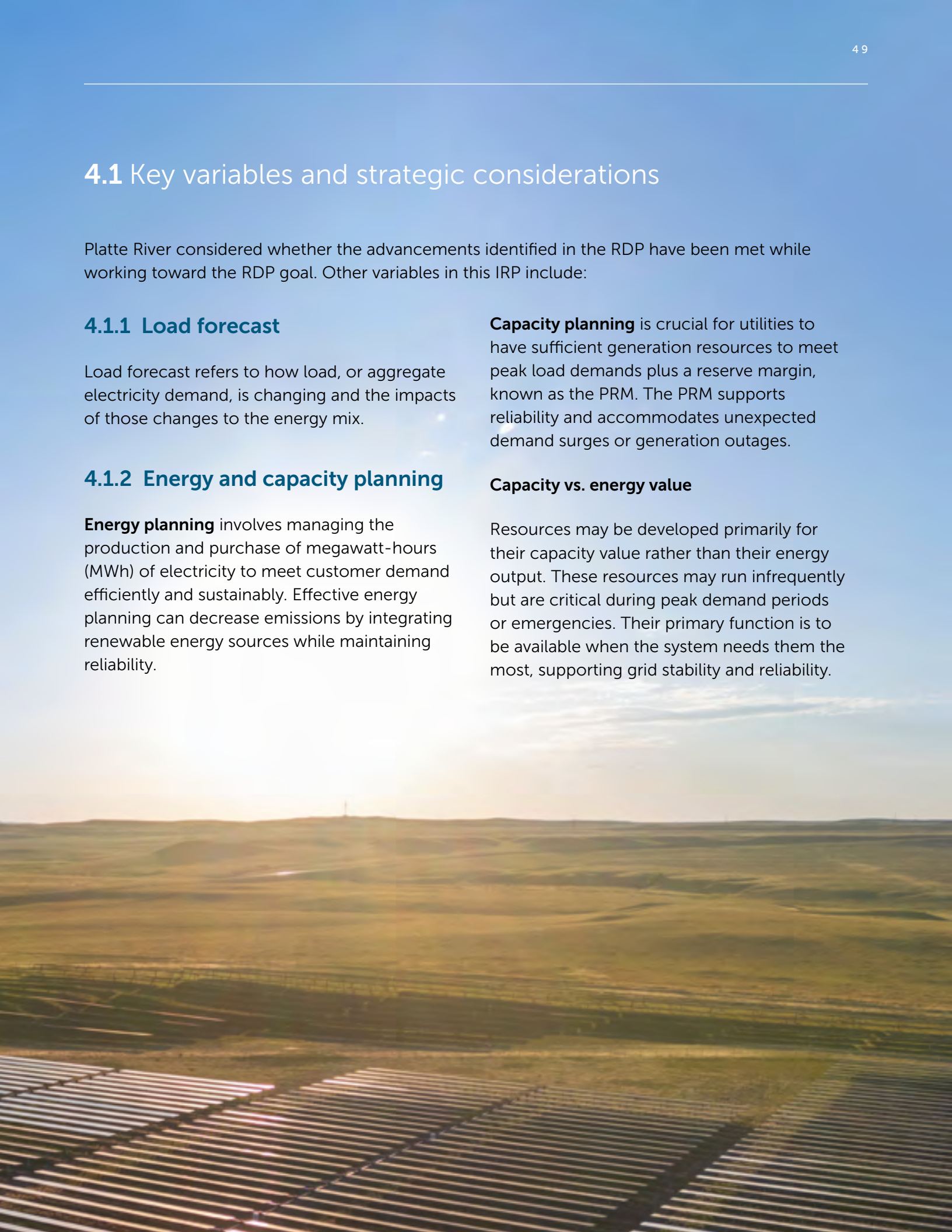
4.1.2 Energy and capacity planning

Energy planning involves managing the production and purchase of megawatt-hours (MWh) of electricity to meet customer demand efficiently and sustainably. Effective energy planning can decrease emissions by integrating renewable energy sources while maintaining reliability.

Capacity planning is crucial for utilities to have sufficient generation resources to meet peak load demands plus a reserve margin, known as the PRM. The PRM supports reliability and accommodates unexpected demand surges or generation outages.

Capacity vs. energy value

Resources may be developed primarily for their capacity value rather than their energy output. These resources may run infrequently but are critical during peak demand periods or emergencies. Their primary function is to be available when the system needs them the most, supporting grid stability and reliability.



4.1.3 Customer programs

Customer programs is the term to describe how existing energy efficiency programs are performing today, how they will evolve tomorrow, and how the behaviors that result from program adoption will impact load forecast.

Most of Platte River's existing customer programs are geared toward energy efficiency, access to renewable energy, support for low-income residents or electrification. Our IRP accounts for these programs' impact on total demand and peak demand for electricity.

The IRP also anticipates an increased focus on energy efficiency, battery storage and electrification. These needs will draw on existing customer programs and will be enhanced by new or expanded programs over the next several years.

4.1.4 Emerging technologies

Resource planning staff engaged with an engineering consulting team to evaluate the viability, long-term scalability and technological performance of emerging technologies. Platte River must balance the adoption of these technologies with the impacts they may have on the three foundational pillars.

4.1.5 Power markets

Participation in an organized market is needed for Platte River to achieve the clean energy transition. Over the years, Platte River has participated in numerous forums related to organized markets. Platte River, along with Xcel Energy, Black Hills Energy and later Colorado Springs Utilities, participated in the JDA for several years. The JDA was a small-scale, regionally focused market operated by Xcel Energy that allowed for more efficient use of generating resources and balancing renewable resources.

Although the JDA benefited Platte River, the opportunity to join an energy imbalance market was the next step in the path toward full energy market participation. This led to three of the JDA participants joining the SPP WEIS market in April 2023. While it functions like the JDA, the WEIS has a larger footprint and SPP serves as the independent market operator.

In September 2023, Platte River announced plans to join the SPP RTO West. Platte River, along with other utilities, expects to transition into this market on April 1, 2026. When the RTO West market is functioning, Platte River will sell all its generation into the market and purchase all its load obligations from the market.

4.1.6 Resource adequacy

Resource adequacy refers to the ability of Platte River to have sufficient resources to constantly deliver electricity to all consumers, even under challenging conditions. Resource adequacy is a critical aspect of resource planning and operation, to maintain enough generation capacity to meet the peak demand plus a reserve margin for unforeseen events, such as generator failures, weather events, sudden spikes in demand or other system disruptions.

4.1.7 Transmission and distribution infrastructure

As Platte River's energy portfolio continues to diversify, new resources will be interconnected to the transmission network. In a regional transmission network owned by more than one entity, the new resources may be interconnected directly to Platte River's transmission lines or to transmission lines owned by others.

Each transmission line owner manages a generator interconnection process to require the new generation resources to be interconnected in a way that does not adversely impact the reliability of the transmission network. New generation resources will require new interconnection infrastructure and if necessary, transmission network upgrades. The transmission network upgrades will be identified during the interconnect study process. The upgrades may include new transmission lines or modifying existing transmission lines.

As new resource projects are established, network upgrades or modifications will be evaluated and identified. Platte River has included the costs to fund future transmission projects in our long-term capital budget. Current budget estimates will be refined as the details of the new resources are identified.

4.1.8 DER adoption and integration

Traditionally, customer electricity needs consisted solely of aggregate electricity demand. With the growth of DERs, today's customer demand must also include a seamless and economic integration of distributed resources.





4.2 Navigating challenges and maintaining the foundational pillars

The foundational pillars serve as guideposts for all Platte River activities, including the resource planning and modeling activities documented in this IRP.

4.2.1 Reliability – dispatchable capacity

Dispatchable capacity refers to any resource that can start, stop, and change output level quickly to produce more or less power when needed. The reliability challenges during extreme weather events and dark calms (characterized by the absence of solar and wind energy due to adverse weather conditions for multiple days) highlight the vulnerability of serving load with weather-dependent energy sources. These events underscore the critical role of dispatchable capacity in maintaining power supply.

Platte River commissioned a study with ACES to analyze different weather patterns from the past five decades across a broad region to understand the frequency and impact of extreme weather and dark calm events. The findings emphasize the need for a diversified energy portfolio and supply strategies that can withstand varying weather conditions, including rare and extreme events.

The future of energy reliability hinges on supporting renewable resources with dispatchable resources (including innovative energy storage solutions) to provide continuous power supply during all weather scenarios.

4.2.2 Environmental responsibility – cost of carbon

The portfolios modeled in this IRP assume that future electricity prices will also include carbon taxes.

The carbon-imposed cost portfolio imposes additional costs disincentivizing dispatch of high-carbon energy sources unless needed to maintain reliability of the system even after accounting for their environmental impact. This factors environmental ramifications of carbon emissions into decision-making, steering energy strategies toward more sustainable pathways.

The evaluation process for including technologies in a carbon-imposed cost portfolio prioritizes renewable energy sources like wind and solar due to their minimal carbon footprint. Dispatchable capacity resources are also considered for their potential to balance reliability with reduced emissions, aligning the portfolio with environmentally responsible objectives.



4.2.3 Financial sustainability – rates and affordability

As a not-for-profit utility, Platte River's revenues from its wholesale power rates fund ongoing operations and are reinvested into the system for the benefit of the owner communities. The owner communities' distribution utilities integrate Platte River's wholesale rates into their retail and commercial electric rates.

Platte River's rate-setting policy calls for established service offerings and supporting rate structures that complement the strategic objectives and values of the organization. Platte River's rate structure strives to meet the following objectives:

- Align wholesale pricing signals with cost of service
- Adapt to cost structure changes
- Integrate noncarbon resource additions

In support of Platte River's foundational pillars of providing reliable, environmentally responsible and financially sustainable energy and services, and Platte River's mission, vision and values and strategic initiatives, the strategic financial plan provides direction to preserve long-term financial sustainability and manage financial risk. The objectives of the strategic financial plan are:

- Generate adequate earnings margins and cash flows



- Maintain sufficient liquidity for operational stability
- Maintain access to low-cost capital
- Provide wholesale rate stability
- Maximize cost savings through pricing signals that provide system benefits and revenue stability
- Navigate resource acquisition costs increases and delays

Platte River is also subject to financial and rate requirements in the Power Supply Agreements and the General Power Bond Resolution. Platte River's Board of Directors has the exclusive authority to establish electric rates and must review rates at least once each calendar year.

To meet these objectives and requirements, staff established financial metrics and rate stability strategies, taking into consideration rating agency guidelines. Following its strategic financial plan, Platte River will maintain long-term financial sustainability by implementing appropriate rates and strategies that:

- Reduce significant single-year rate hikes
- Provide greater rate predictability to support owner communities with more accurate, long-term planning
- Maintain a strong financial position and AA credit rating

Competitive wholesale rates give the owner communities economic benefits for their customers. Platte River strives to maintain services and rates offered at competitive prices compared to similar services and products provided by other wholesale electric utilities in the region. Platte River's fiscal responsibility and rate stability strategies help reduce long-term rate pressure and give the owner communities greater rate predictability.

Platte River's long-term rate forecast is prepared and presented to the board of directors in the spring of each year. The IRP results, along with the most current assumptions, will be included in the rate forecast prepared in spring 2024.



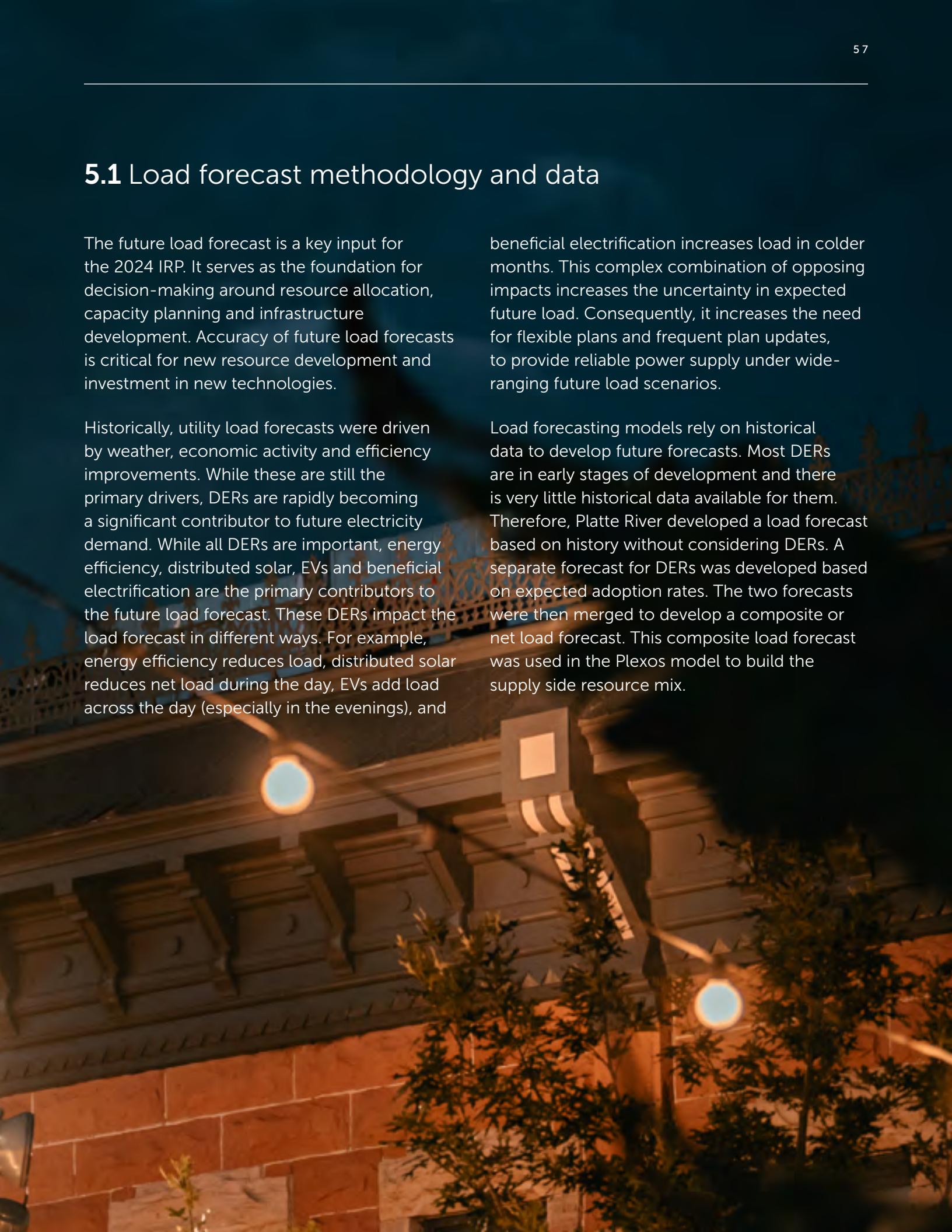
05 Electricity demand

5.1 Load forecast methodology and data

The future load forecast is a key input for the 2024 IRP. It serves as the foundation for decision-making around resource allocation, capacity planning and infrastructure development. Accuracy of future load forecasts is critical for new resource development and investment in new technologies.

Historically, utility load forecasts were driven by weather, economic activity and efficiency improvements. While these are still the primary drivers, DERs are rapidly becoming a significant contributor to future electricity demand. While all DERs are important, energy efficiency, distributed solar, EVs and beneficial electrification are the primary contributors to the future load forecast. These DERs impact the load forecast in different ways. For example, energy efficiency reduces load, distributed solar reduces net load during the day, EVs add load across the day (especially in the evenings), and beneficial electrification increases load in colder months. This complex combination of opposing impacts increases the uncertainty in expected future load. Consequently, it increases the need for flexible plans and frequent plan updates, to provide reliable power supply under wide-ranging future load scenarios.

Load forecasting models rely on historical data to develop future forecasts. Most DERs are in early stages of development and there is very little historical data available for them. Therefore, Platte River developed a load forecast based on history without considering DERs. A separate forecast for DERs was developed based on expected adoption rates. The two forecasts were then merged to develop a composite or net load forecast. This composite load forecast was used in the Plexos model to build the supply side resource mix.



5.2 Load forecast without DER

Platte River hired The Energy Authority (TEA), a third-party consultant, to develop a 20-year load forecast for the planning period of 2024-2043. TEA developed a load forecast without considering DERs, referred to as the base load forecast. TEA developed a forecast of monthly energy consumption and monthly peak demand as well as hourly load shapes.

5.2.1 Methodology

The monthly load forecast used a "least squares linear regression" model, using historical data to derive a linear relationship between a dependent variable and one or more independent variables. The dependent variable was forecasted using linear relationships and projections for each independent variable as discussed below.

Forty years of historical weather data, along with 20 years of load and economic data, were used to train three linear regression models. The first model considered total monthly energy as the regression's dependent variable. The remaining two models considered peak load as the dependent variable, with a model specifically for June through September and another for all remaining months in the year. This split was due to the contrast in peak load history between summer, which has grown consistently, and winter, which has seen a slight decrease since the late 2000s. Figure 7 illustrates the total and peak load history for Platte River, aggregated by year.

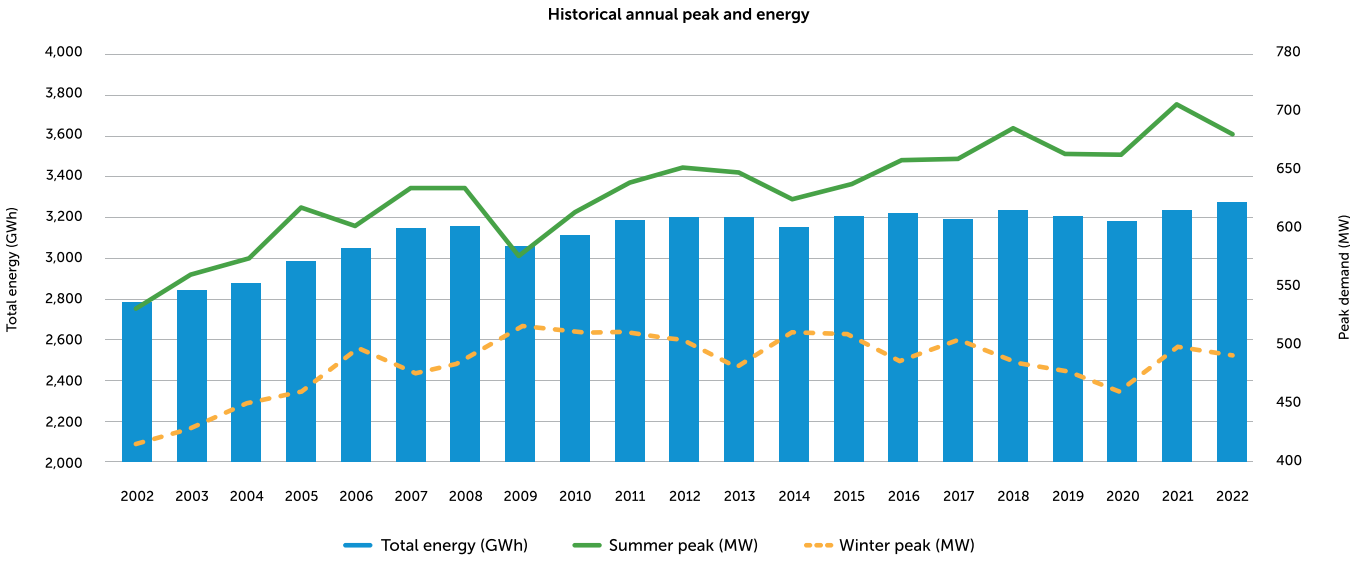


Figure 7. *Historical annual peak and energy*

Once the regression model was trained using historical data, a projection for each of the forecast drivers was input into the three models, creating monthly forecasts for total energy and peak load.

5.2.2 Forecast drivers

Future load growth can be driven by weather trends, economic factors or specific changes in customer usage patterns. To project future load patterns, Platte River's linear regression model used temperature, number of households and changes in air conditioning use.

Weather and seasonal impacts. One of the fundamental metrics to quantify the severity of weather is degree days. This metric takes the difference between the average daily temperature and a set point. In this case, the set point was 65 degrees Fahrenheit (˚F). Heating degree days take the sum of this calculation for temperatures below 65˚F, while cooling degree days use this calculation for temperatures above 65˚F. The distinction between heating and cooling degree days was made because hot and cold weather have different impacts on customer energy usage.

Based on the past 40 years of historical temperature data, a weather-normal forecast was developed for both heating and cooling degree days. Forty years of data were used to better capture the slight warming trend that has been observed in temperature history. This warming trend was incorporated into the weather-normalized forecast, resulting in a slight decrease in annual heating degree days and a slight increase in annual cooling degree days over time, as illustrated in Figure 8.

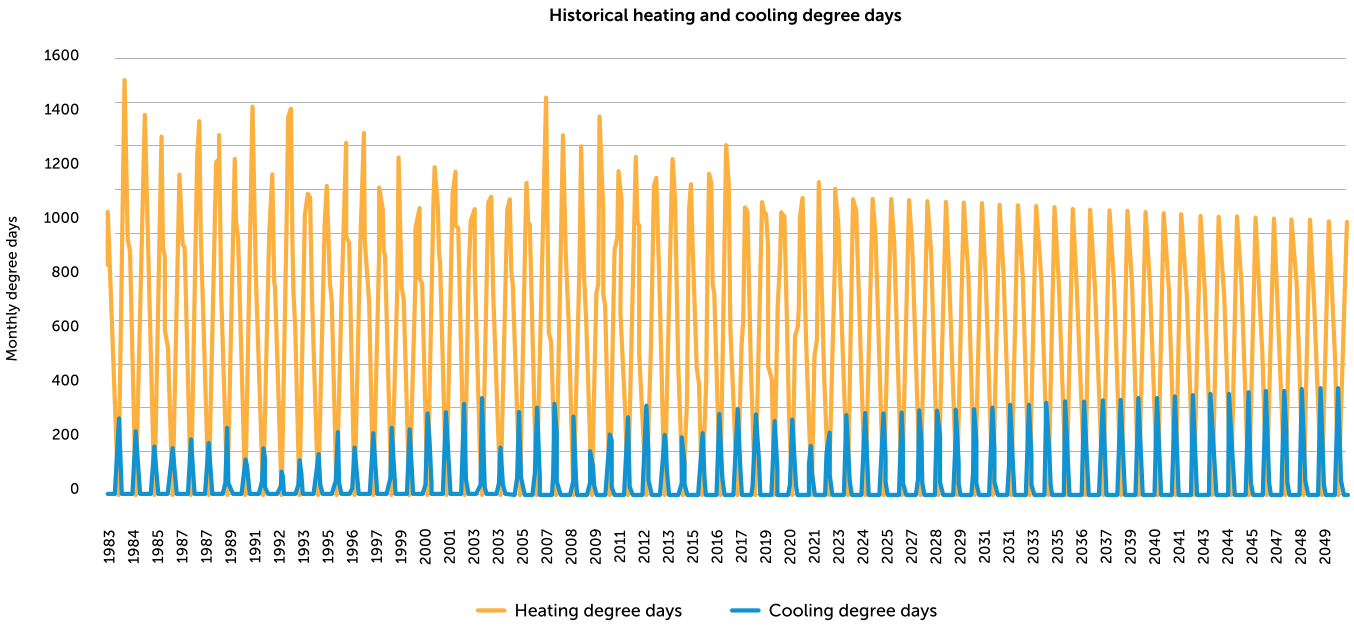


Figure 8. *Historical heating and cooling degree days*

Another factor incorporated into the load forecast model was the month of the year. This was used both to smooth the monthly forecast and to better consider seasonal impacts that may not be captured solely using heating or cooling degree days.

Number of households. Number of households was used to project economic growth within Platte River's service territory. These projections were obtained for Larimer County from Woods and Poole, an economic forecasting firm. While sections of Platte River's service territory exist in surrounding counties, the model assumes that economic growth in Larimer County reflects the growth of nearby areas as well. Growth in number of households is expected to continue to soften through the 2030s, following the trend observed since 2011. From 2040 onward, growth in number of households slightly flattens as illustrated in Figure 9.

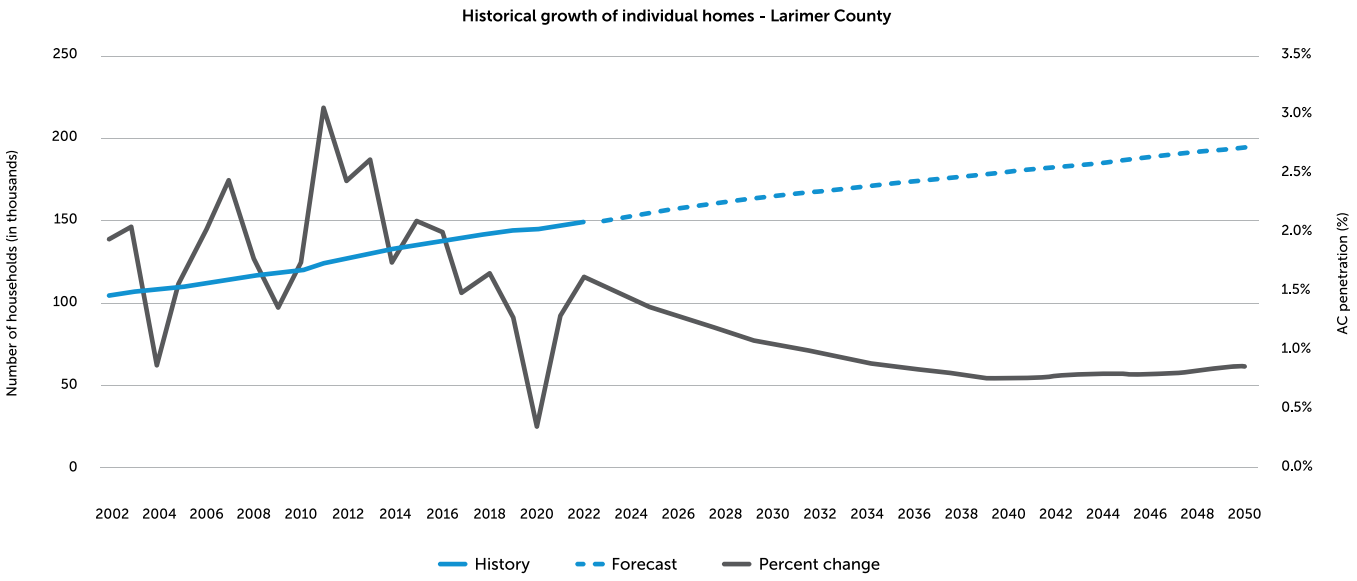


Figure 9. *Historical growth of individual homes*

Air conditioning use. A large driver for load growth over the past 20 years is an increase in the percentage of single-family homes with central air conditioning. This has increased both total energy consumption and peak demand during the summer months. Growth in air conditioner use is expected to slightly decrease in the future, with an average of 0.6% year-over-year increase through 2050, as illustrated in Figure 10.

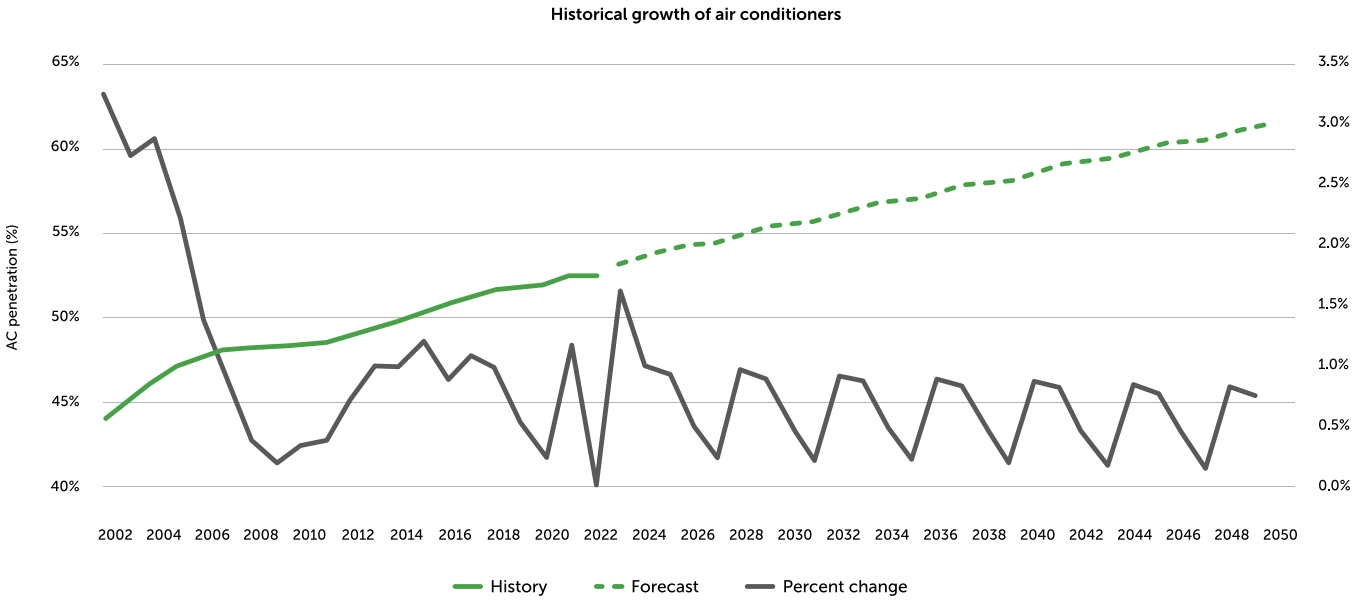


Figure 10. *Historical growth of air conditioners*

5.2.3 Forecast results

Figure 11 displays the annual total energy forecast, summer peak demand and winter peak demand through 2050. The growth in summer peak demand is expected to outpace growth in total energy, reflecting the trend observed since the early 2010s. While winter peak demand is projected to increase, it is at a lower rate than both summer peak and total energy forecasts. Average summer peak and total energy growth rates for the first 10 years of the plan are shown in Table 3.

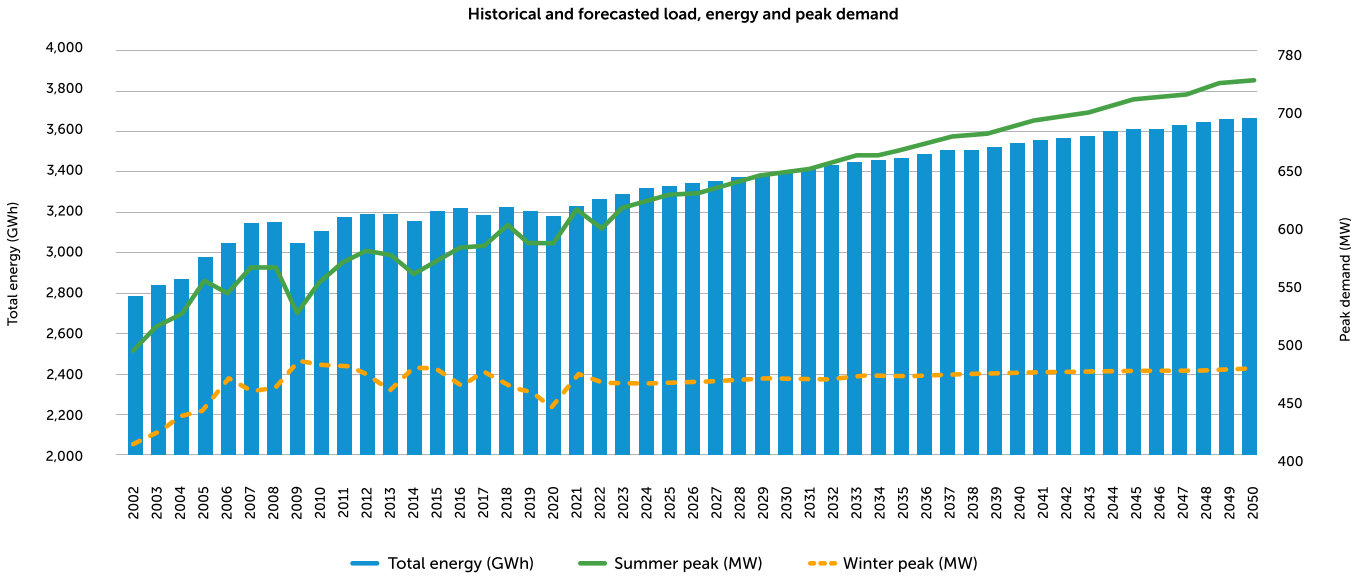


Figure 11. *Historical and forecasted load, energy and peak demand (base forecast without DERs)*

2024 – 2033 year-over-year average growth – base load forecast	
Total energy	0.5%
Summer peak load	0.8%

Table 3. *Average annual load growth, energy and peak demand*

5.2.4 Hourly load shape

In addition to monthly forecasts, an hourly load shape forecast was developed for hourly dispatch modeling purposes. Rather than using a linear regression tool, a more robust model was chosen to develop the hourly shape due to the many nuances observed between hourly load and temperature changes over time. Hourly load data for 2013-2022 and temperature data for 2002-2022 was input into the model. The model created an hourly weather normal temperature forecast using the rank and average method. After the hourly load forecast for 2023 was developed, the total energy and peak load shape for each month was then normalized to the monthly projections for 2023. While there were not large discrepancies between the hourly and monthly model projections prior to normalization, this was done to ensure consistency between the two forecasts.

Figure 12 compares the average hourly shape, by month, for the 10 years of historical hourly data and the 2023 projections. There are increases in average hourly load between the load history and forecast, but these reflect load growth observed during 2013-2022. The forecasted load shape is commensurate with historical load shapes.

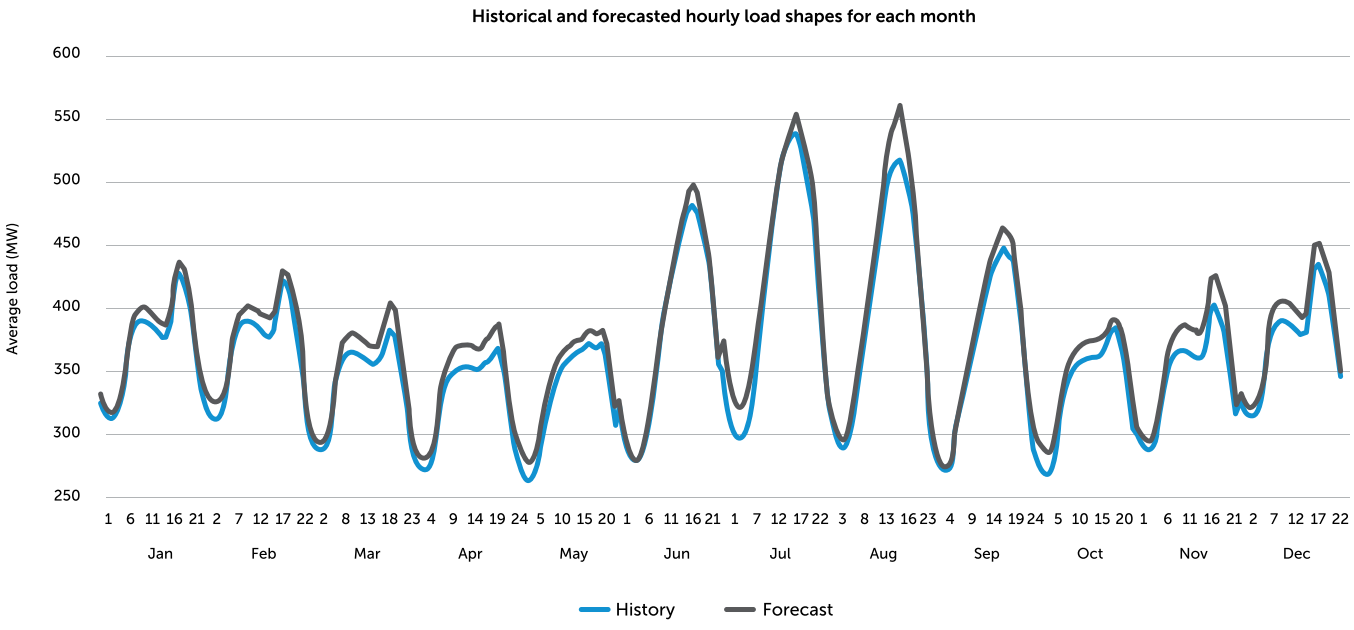


Figure 12. *Historical and forecasted hourly load shapes for each month*

5.3 DER integration, flexible DERs and the virtual power plant

The term "DER" encompasses a range of technologies installed and used at a customer's premises or within the distribution system. DER can be either on the customer or utility side of the meter. These assets potentially provide advantages to both the electric system and customers alike. These resources include energy efficiency, building electrification, transportation electrification, distributed generation, distributed energy storage and demand response.

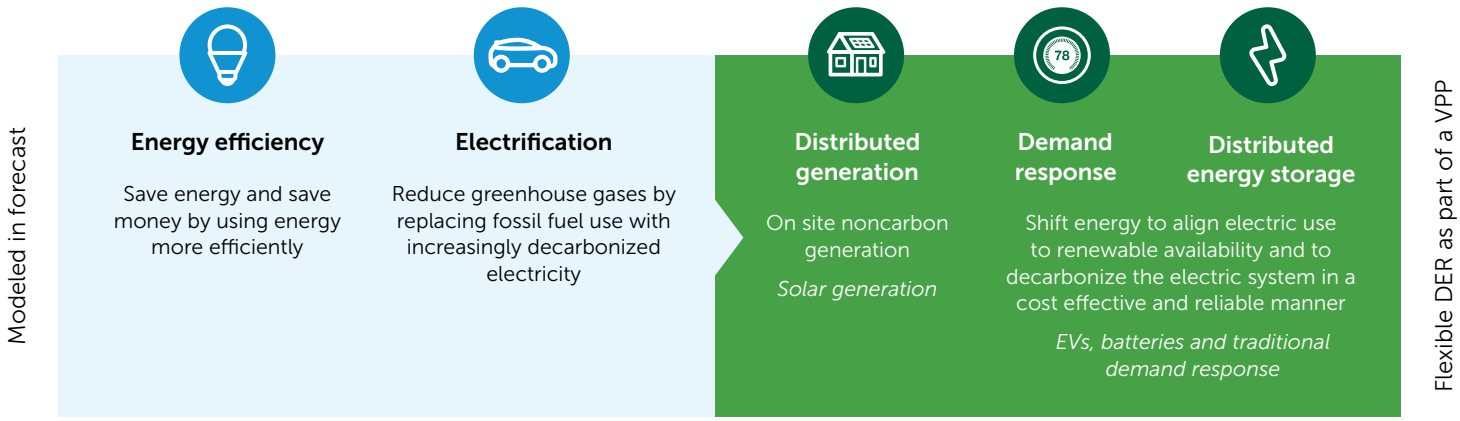
DERs are, as stated in the name, resources. For resources to provide value, they must be put to effective use. Effectively using DERs to provide system-wide benefits is often referred to as "integrating" DERs. Integrating DERs means they have been made a functioning part of the electric system. This includes some or all of the following:

Visibility and forecasting. DERs must be "visible" to and predictable by electric system planners and operators for their effects to be taken into consideration. To support system planning, DER impacts must be forecast years in advance. To support system operations, DER forecasts must look seconds, minutes, or days into the future.

Dispatchability or control. Flexible DERs can be controlled or dispatched by utility system operators to maintain reliability or to achieve system-wide financial benefits.

Customer awareness, engagement and participation. The customer is provided support and services to help them understand their opportunities, benefits and responsibilities as participants in the electric system.

When flexible DERs are integrated in this manner and aggregated into coordinated operational programs, they are considered a virtual power plant (VPP). A VPP is a network of aggregated flexible DERs that can be controlled by Platte River and the owner community distribution utilities through advanced software to support grid reliability and financial sustainability.



5.3.1 DER forecast studies

Platte River commissioned two DER forecast studies to support DER and resource planning. The first, Platte River Power Authority Beneficial Building Electrification Forecast, Mar. 12, 2022, was completed by Apex Analytics, LLC ("Building Electrification Study"). The second, Distributed Energy Resources Forecast and Potential Study, Aug. 28, 2023, was completed by Dunsky Energy+Climate Advisors ("DER Study").[9] A summary of the studies and their results is included below, and the full studies are available in the appendices of this report.

The Building Electrification Study scope included the following:

- Study period: 24 years (2023 through 2046)
- Building electrification categories: space heating, water heating and cooking
- Sectors/segments: residential and commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state and local codes, standards, or incentives) and program or utility factors and inputs (like incentives or rates)
- Outputs: annual energy impacts, hourly and peak demand impacts

The DER Study scope included the following:

- Study period: 20 years (2024 through 2043)



- DER categories: energy efficiency, transportation electrification, distributed generation + storage, and demand response (or flexible DER, including EV charge management, battery storage management and traditional demand response)
- Sectors/segments: residential single family, residential multi-family, small commercial, large commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state, and local codes, standards, or incentives) and program or utility factors and inputs (like incentives, rates, or avoided costs)

[9] Platte River did not consider cogeneration and district heating/cooling in these studies because of the lack of interest by our customers and the future trend of electrifying heating and cooling to reduce gas burning.



- Outputs: technology adoption (number of units), annual energy impacts, hourly and peak demand impacts, program metrics (budgets)

The results of these studies inform load forecasts and DER program plans as discussed below.

5.3.2 Energy efficiency

Energy efficiency programs help customers reduce their energy consumption through a variety of interventions, including outreach, education, contractor engagement and incentives. Platte River and the owner communities deliver energy efficiency programs under the Efficiency Works™ brand, jointly funded and administered by Platte River and its owner communities. These programs give communities a cost-effective way to manage load growth, reduce carbon emissions and help customers reduce electricity costs, and provide a cost-effective option when compared to the cost of supply-side resources otherwise needed.

5.3.2.1 Energy efficiency forecast study results

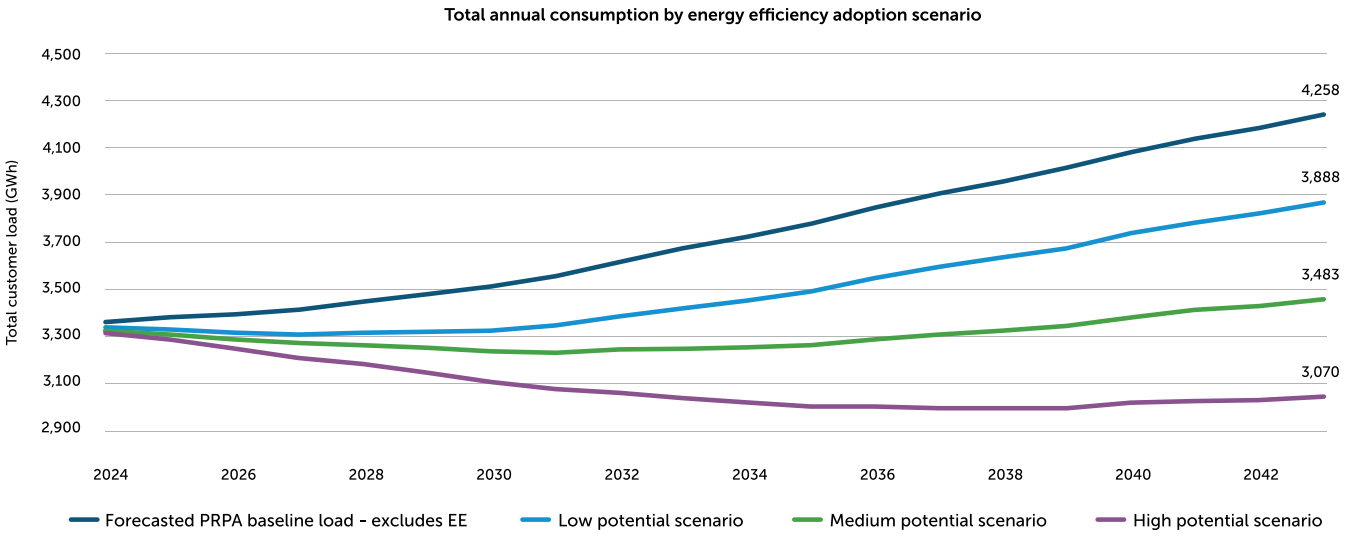
The DER Study evaluated the energy efficiency potential, identifying three adoption scenarios: low, medium and high. The adoption scenarios were evaluated based on three other utility potential studies, taking into consideration local factors, such as the owner communities' customer segmentation, historical participation

data for existing Platte River energy efficiency programs and the building electrification forecast study identifying heat pump adoption rates. Two of the key takeaways from the study include:

- Platte River could achieve an average incremental savings rate of almost 0.78% of annual load each year between 2024 and 2030 in the low scenario, 1.15% in the medium scenario, 1.71% in the high scenario. This would come at a cumulative cost (2024-2030) of about $105 million, $200 million and $460 million, respectively.

- Energy efficiency savings for lighting, heating, ventilation and air conditioning (HVAC) pumps and fans and plug load (energy used by equipment that is plugged into an outlet) make up over 60% of total forecasted savings by 2043 for the commercial sector. For the residential sector, heating provides almost 60% of the energy efficiency savings, due in part to growing residential heating electrification, followed by plug load and domestic hot water.

The study applied the energy efficiency potential scenarios to the estimated customer baseload forecast. Figure 13 shows the effect of energy efficiency on load forecast and Figure 14 shows energy savings by market segment.



Note: The baseline load includes expected customer load growth and electrification growth (PRPA baseline load + building electrification Low projection). Transportation electrification and distributed solar are not included in the baseline load.

Figure 13. *Total annual consumption by energy efficiency adoption scenario*

Platte River continues to invest significant resources in a portfolio of energy efficiency programs, which include some of the highest incentives in the region. These investments are intended to help avoid the need for new generation resources due to customers using energy more effectively.

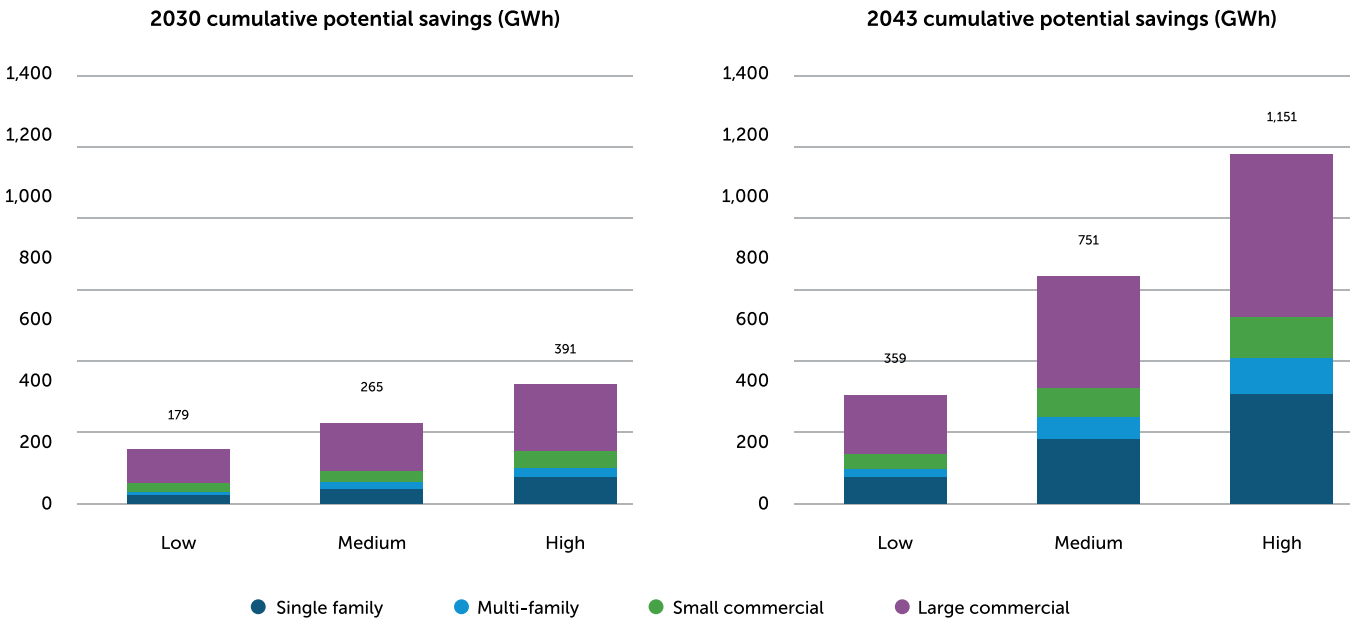


Figure 14. *Cumulative potential savings (GWh)*

However, current participation rates are consistent with the low forecast contained in the DER study. Platte River plans to continue investment in energy efficiency at current levels through 2030 and beyond with adjustment for inflation, as long as the investment provides value through customer participation and energy-saving benefits. See figures 15, 16 and 17 for estimated future investments and associated savings within the owner communities for energy efficiency services. These ongoing investments in energy efficiency services will continue to evolve and provide a strong foundation of programming for other DER technologies to build upon in future years.

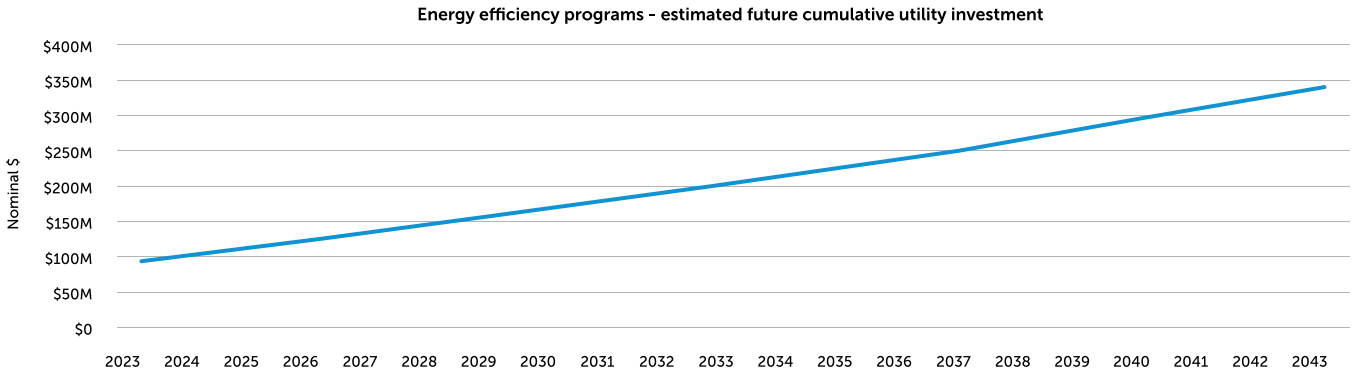


Figure 15. *Energy efficiency programs - estimated future cumulative utility investment*

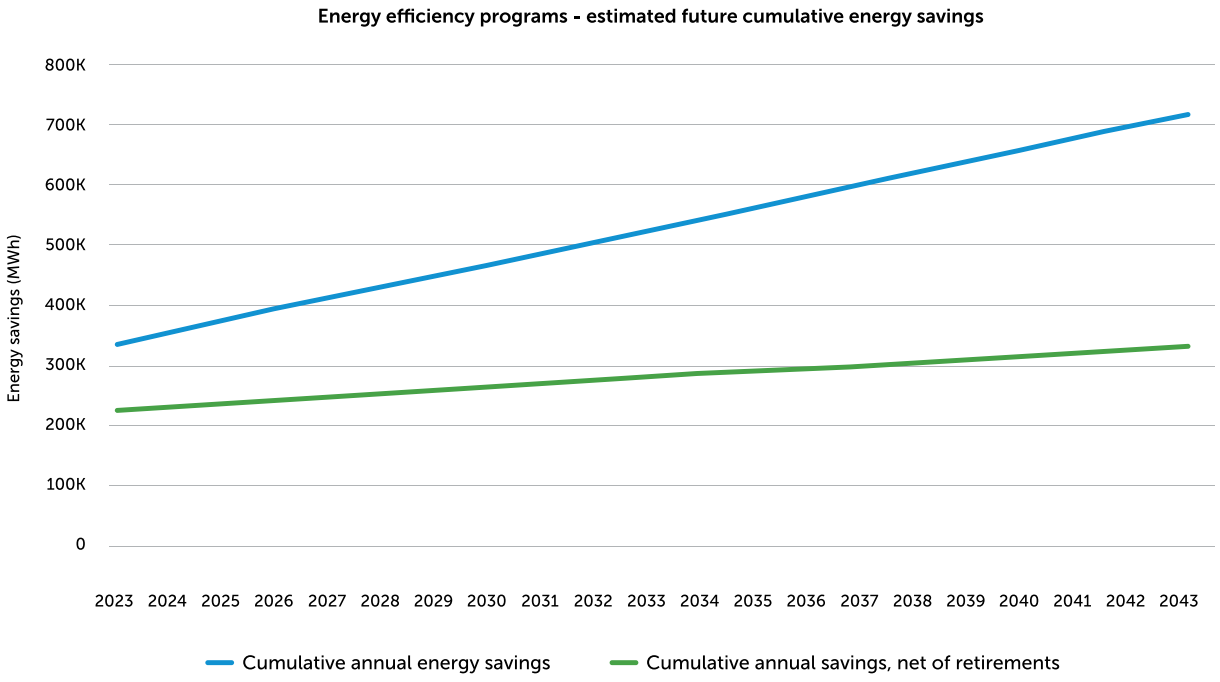


Figure 16. *Energy efficiency programs - estimated future cumulative energy savings*

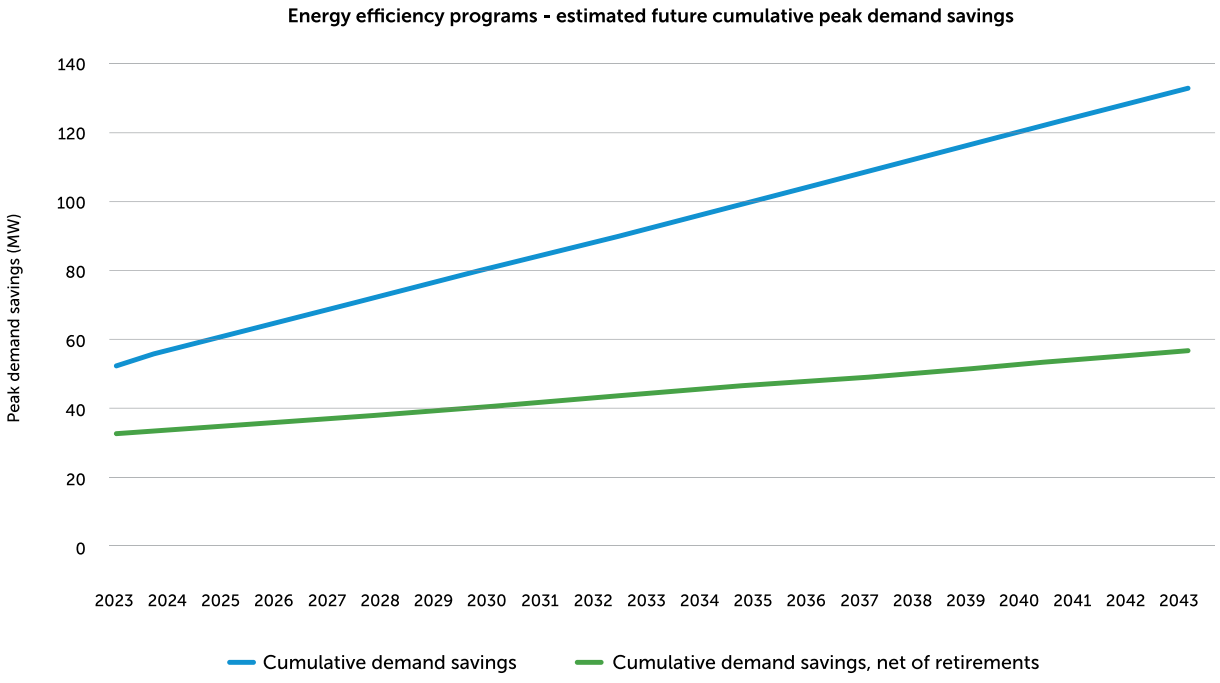


Figure 17. *Energy efficiency programs - estimated future cumulative peak demand savings*

5.3.3 Electrification

5.3.3.1 Buildings

Building electrification refers to new uses for electricity that replace other sources of energy used in buildings. When building electrification provides additional economic benefits, grid benefits and environmental benefits, it is referred to as beneficial building electrification. Typically, building electrification involves the replacement of natural gas or propane appliances in residential and commercial properties with more carbon-efficient appliances that consume electricity.

As Platte River's owner communities pursue carbon emission reduction and as Platte River decarbonizes its generation, building electrification becomes an attractive alternative that can be incorporated into existing Efficiency Works customer programs.

Building electrification forecast study results. In 2022, Platte River completed a Building Electrification Study to provide a range of forecasts for building electrification adoption and effects on electric consumption. The study evaluated the adoption electrification of end uses with a focus on those with the most significant potential: space heating, water heating and cooking. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions and technology types. Medium utility incentives were assumed for all three scenarios. Some key findings from the study include:

- Only minor impacts on overall electricity consumption are expected through 2030. However, starting in the 2030s, building electrification impacts become larger.
- Most of the energy and demand growth occurs in the winter; summer impacts are minimal.
- Full electrification of heating during extreme cold will cause Platte River to become a winter peaking utility sometime after 2035.
- Policies requiring all-electric new homes or businesses could push impacts sooner – winter peaking will occur within five to 10 years of requiring all-electric new homes.
- Electrifying residential space heating with heat pumps is the highest impact building electrification technology and supports ongoing energy efficiency options.
- Full electrification of heating causes significant cost and reliability challenges.
- Without program or policy support, or significant changes to heat pump technology, efficiency and economics, cost and accessibility challenges will limit adoption of building electrification.

Results of the study are shown in Figures 18 and 19. Additional details on building electrification impacts can be found in the APEX Analytics study at prpa.org/2024irp/information.

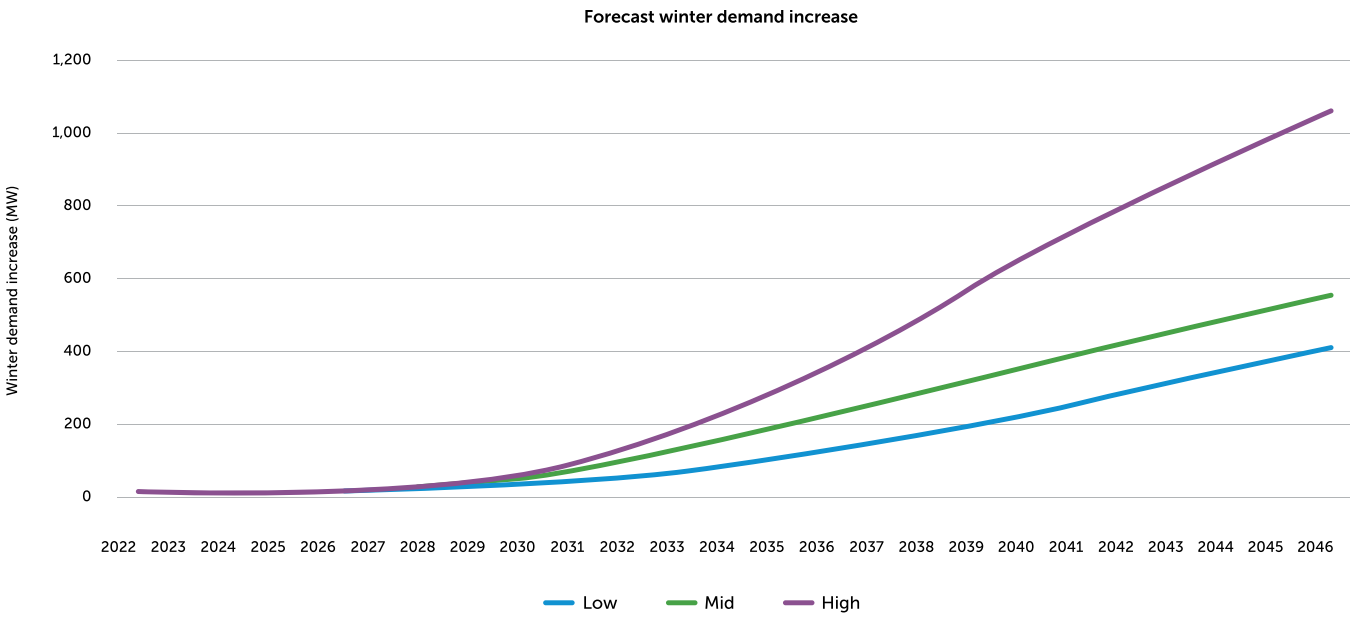


Figure 18. *Forecasted winter demand increase*

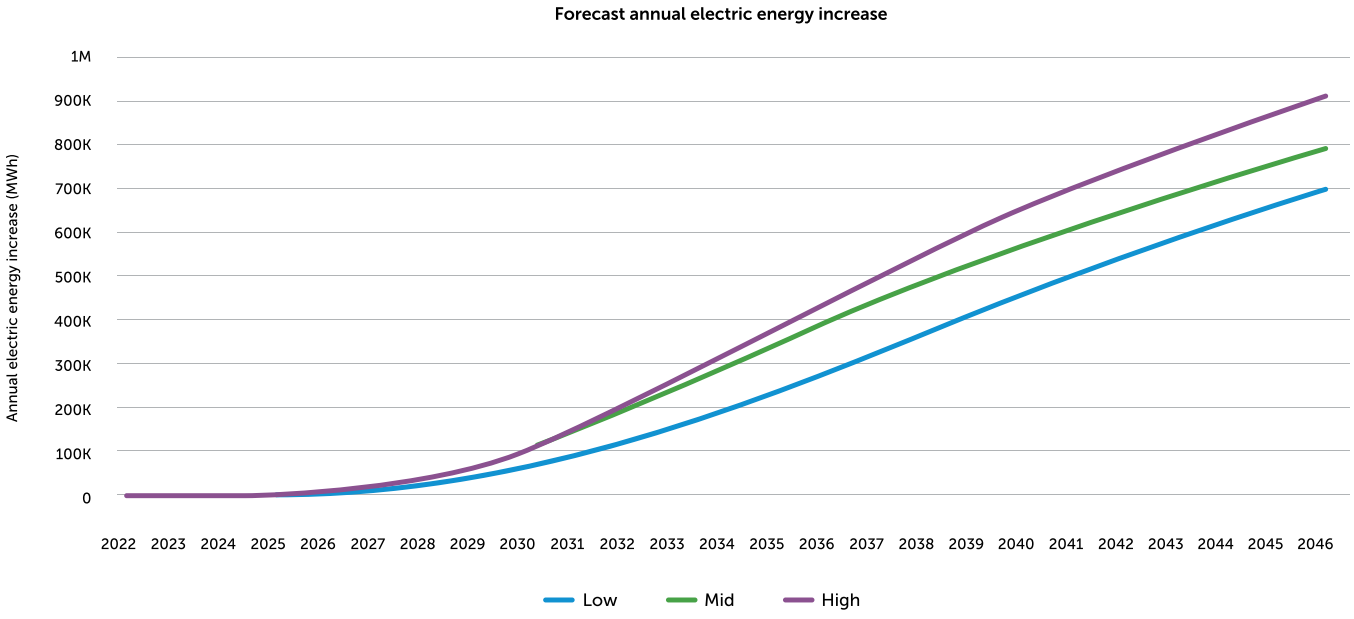


Figure 19. *Forecasted annual electric energy increase*

Platte River initially adopted the low forecast for its load forecast in 2022. However, it now appears the medium forecast best reflects recent changes observed in the market. These include increasing availability of federal and state tax incentives, along with the increasing acceptance of heat pump technology by local HVAC contractors.

5.3.3.2 Transportation

Transportation electrification refers to the shift from vehicles with internal combustion engines powered predominantly by fossil fuels (gasoline and diesel) to vehicles powered by batteries charged from the electric grid. Transportation electrification reduces dependence on fossil fuels and reduces emissions from burning fossil fuels, including greenhouse gases. Transportation electrification is driving challenges and opportunities for vehicle owners and operators; businesses involved in the sales, service and fueling of vehicles; and for electric utilities.

Transportation electrification forecast study results. The DER Study evaluated the adoption of EVs in the following categories: light-duty vehicles (including personal vehicles and commercial fleets), medium-duty-vehicles, heavy-duty vehicles and buses. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions; technology availability and cost declines; and market factors (for example, electric rates, fuel prices). Utility rebates were not evaluated. Table 4 summarizes the driving factors for each scenario considered in the study.



Parameter	Low scenario	Medium scenario	High scenario
Policy/program interventions			
Public charging infrastructure expansion	Limited Planned investments + current growth trajectory	Moderate Planned investments + accelerated growth trajectory aligned with Colorado National EV Infrastructure Formula Program (NEVI[10])	Significant Expanded infrastructure to ensure adoption is not constrained
Vehicle incentives	Current federal and state EV incentives, phase out prematurely in 2028 and 2026, respectively	Current federal and state EV incentives, phased out as currently planned in 2032 and 2028, respectively	Increased incentives and extended beyond currently planned in 2035 and 2030, respectively
Existing building charging infrastructure retrofits	Limited 15% of multi-unit buildings with access to charging by 2035	Moderate 40% of multi-unit buildings with access to charging by 2035	Significant 90% of multi-unit buildings with access to charging by 2035
Zero-emission vehicle mandates	None	None	Stringent 100% by 2035
Technology factors			
Battery costs	Limited cost declines	Moderate cost declines	Aggressive cost declines
EV model availability	Limited availability	Moderate availability	High availability
Market factors			
Vehicle sale		Maintain historical trends	
Fuel prices	Limited escalation	Moderate escalation	Rapid escalation

Table 4. *Primary drivers for transportation electrification*

Figures 20, 21 and 22 depict the anticipated adoption for the three scenarios in terms of number of vehicles, annual energy and summer peak demand.

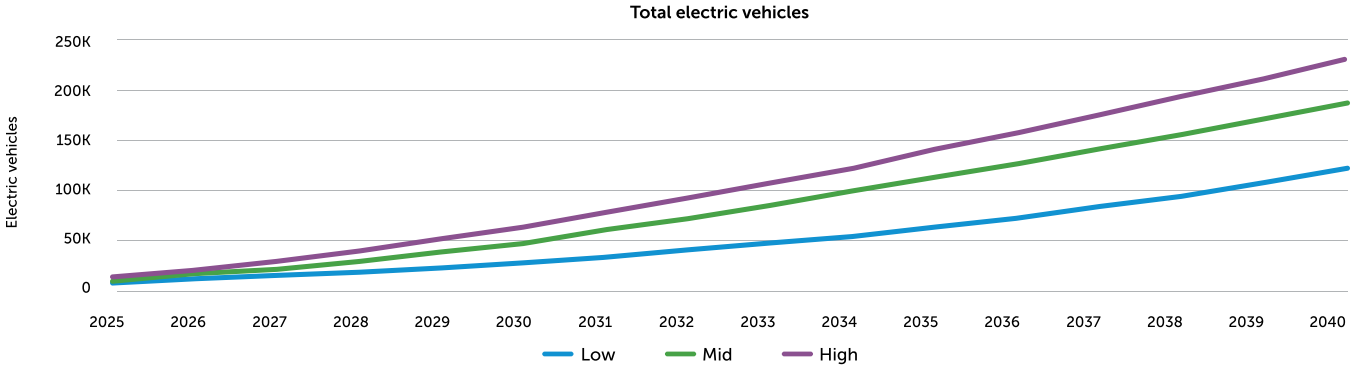


Figure 20. *Total electric vehicles*

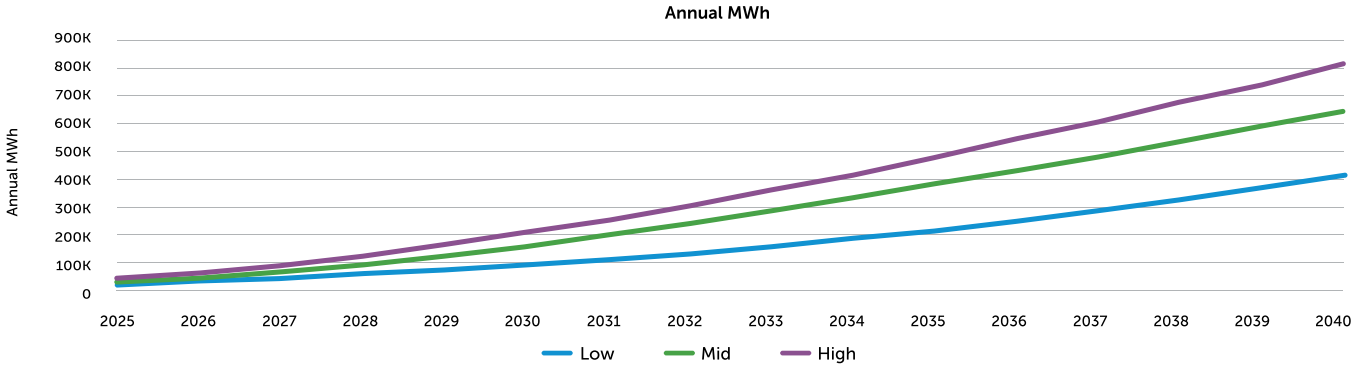


Figure 21. *Annual MWh*

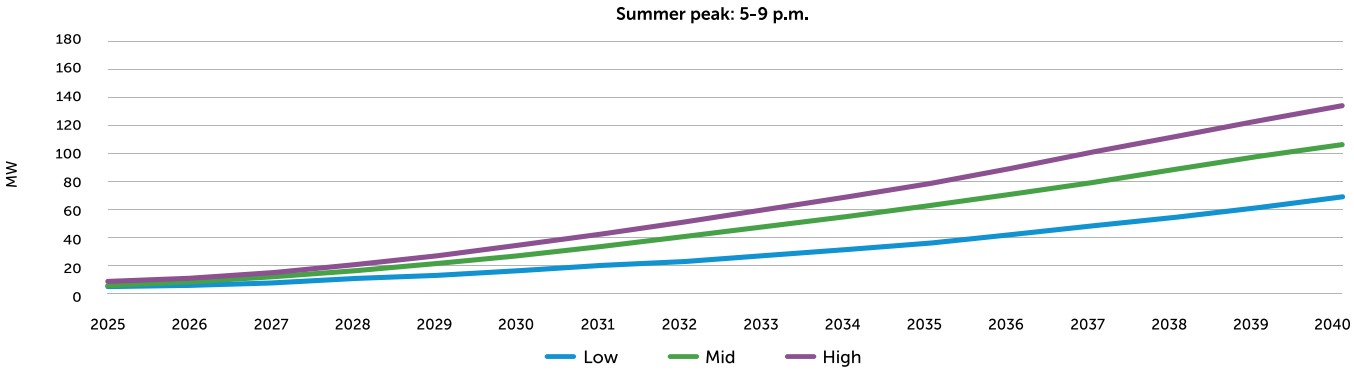


Figure 22. *Summer peak: 5-9 p.m.*

[10] National Electric Vehicle Infrastructure Formula Program (NEVI) is a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors.



Note that the summer peak demands are based on a diverse set of EV charging profiles (home charging, workplace charging, public charging, commercial fleet charging). These profiles assume some customers will respond to time-of-use pricing, where available. Winter peak demand effects are expected to be about 70% higher than summer peak due to the additional use of electricity in EVs to provide heat in the occupant compartment and to the batteries.

In all three growth scenarios the forecasted growth in EV adoption is poised to escalate significantly during the study period of 2023-2043.

Monitoring and forecasting EV adoption. As of the end of 2022, Platte River's owner communities witnessed a notable surge in the adoption of EVs. The number of estimated registered EVs within the communities at the end of 2022 was around 2,900. Throughout 2023 EV adoption has seen a steady increase, with an estimated 4,000 EVs by the end of the year, slightly under the previous forecast of 4,500. This growth within the owner communities follows closely with the Colorado state trend of a 3% growth each month, or 43% annually, in new EV registration.

The DER Study evaluated a range of adoption scenarios to inform the load forecast used for resource planning. Platte River has chosen the medium forecast, approximately 48,000 EVs by the end of 2030, which represents 42% compound annual growth from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

5.3.4 Transitioning Efficiency Works programs to distributed energy solutions

The Efficiency Works program offerings through Platte River's distributed energy solutions department are shifting focus to meet the customer needs through additional product education,

energy advisory services and repurposing incentives to business and home upgrades that support future load flexibility. A few examples of this transition include:

- Supporting building electrification upgrades that can provide future flexibility or load control throughout the year (not just a summer peak reduction of air conditioner loads).
- Incentivizing public EV charger infrastructure to provide more charging locations for EV drivers throughout the day to accommodate different charge control program models.
- Optimizing commercial HVAC equipment though the Building Tune-up program that will provide an eventual path for advanced system automation control installations and ongoing system performance visibility.

A variety of new customer program offerings have been developed and launched in recent years to support this transition as described in sections below.

5.3.5 New customer programs to address future electrification requirements

5.3.5.1 Building electrification activities

In 2023, the Efficiency Works programs continued to support owner community initiatives and began shifting to include multiple building electrification measures. These measures mostly focused on heating and cooling equipment within residential properties while leveraging the existing energy efficiency contractor networks. The initial building electrification programming is focused on the following areas to support customers as they decarbonize their homes and business:

- Retrofitting existing residential properties
- Educating residential and commercial customers on effective ways to use their energy with building electrification upgrades
- Providing incentives to the income qualified community sector to support building electrification initiatives
- Developing programs to support distributors selling building electrification equipment in the commercial HVAC sector
- Engaging and training local contractors about the benefits of building electrification upgrades

The shift in building electrification programming also aligns with possible incentives offered through the Inflation Reduction Act and state tax credits. As interest in building electrification continues to grow, customer programs will encourage energy efficiency upgrades like building envelope improvements. In combination with the building electrification upgrades, these improvements will allow for the potential to call on demand response activities for longer durations in the future.

Including income-qualified communities in the energy transition

For several years, Platte River has offered various programs to support income-qualified customers. In 2021, the Efficiency Works Business team launched the **Community Efficiency Grant** to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community. This effort has increased the number of participating entities **eight-fold** on an annual basis, resulting in 103 upgrades, saving an estimated $385,000 annually on the businesses' electric costs through the investment of nearly $2.1 million of the Efficiency Work Business programs. The Community Efficiency Grant is expanding eligibility in 2024 to more entities that serve the community.

In addition, Efficiency Works has partnered with Energy Outreach Colorado (EOC) since 2016 to provide free energy advising and upgrades to eligible participants. In 2023, Efficiency Works revamped the partnership structure and services available, resulting in significant positive impacts for the residential income-qualified segment. The offerings have shifted focus to actively engage with participants on more significant home upgrades including energy efficiency and building electrification. According to the EOC, this partnership has grown to be one of the most well-funded income-qualified programs and has the strongest participation impact goals in the state of Colorado. In 2023, investments of nearly $1 million have been made to support the income-qualified residential upgrades in our communities and this level of annual investment is expected to continue.





5.3.5.2 Transportation electrification activities

Platte River supports customers on their transportation electrification journey as they evaluate options and consider adopting EVs. This support starts with information. Platte River and the owner communities offer information on EVs through Efficiency Works.

In 2022, Platte River launched an interactive EV shopper guide website. The website includes information on currently available EVs, including cost, performance specifications and available incentives. It also includes a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles. In 2023, the website was expanded to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions. In 2024, expansion in the EV space will continue to support commercial customers with additional technical services to plan for EV fleet transitions and work closely with the distribution utilities on potential service upgrades and interconnection requirements.

Platte River's commitment to advancing EV infrastructure is exemplified by the 2023 initiative offering one of the highest incentives in Colorado - $5,000 per public charging port. This incentive aims to encourage local businesses and multifamily properties to host public chargers by offsetting some of the installation cost. Promoting more public charging options and making EV charging more available and visible are intended to reduce "range anxiety" among EV drivers and potential EV drivers.

5.3.5.3 Commercial HVAC system optimization activities

In 2021, Efficiency Works relaunched an improved Building Tune-up program focusing on supporting commercial customers to optimize more complex systems. The program is one of the few in the nation that focuses on upgrades and services ranging from enhanced maintenance practices to complex retrocommissioning. In its current form, the programming engages with large commercial and industrial customers to optimize complex building automation systems and local HVAC contractors performing ongoing maintenance services, and engages many small and medium commercial properties in the owner communities.

Since the relaunch, the program has increased energy savings at commercial properties from an annual average of four participants to over 50. The program has also increased the number of properties participating through increased engagement of local contractors in the HVAC industry. Program staff are currently evaluating options to expand services into monitoring-based commissioning and installing advanced rooftop unit controls during routine maintenance visits. Both expansion options will provide pathways for commercial customers to participate in a future VPP, providing additional energy consumption flexibility within the system.

5.3.6 Distributed generation and distributed energy storage

Distributed generation refers to electric generation sources, typically solar facilities, located near the point of use, within customer premises or on the distribution system. Similarly, distributed storage refers to energy storage, typically battery storage, located near the point of use, within customer premises or on the distribution system. Distributed generation and distributed storage are considered together in this section due to the synergy between them.

From Platte River's perspective, storage is essential to achieving a noncarbon electric system because it helps align variable renewable generation, like wind and solar, with load. It does this by storing surplus energy when wind and solar generation exceed load and by discharging storage when wind and solar output drop below load. Similarly, from a customer's perspective, distributed storage paired with distributed solar generation helps the customer make use of more of their on-site generation to serve their own load. This reduces the energy they would otherwise export to the grid and later repurchase from the grid when solar production does not align with their use.

5.3.6.1 Distributed generation solar and distributed storage forecast study results

The DER Study evaluated the adoption of distributed generation solar and distributed storage. The solar adoption forecast model considered historical rates of adoption and evaluated future adoption based on several parameters that varied across four scenarios. Some solar was assumed to be adopted alone, some was assumed to be adopted with distributed storage and some distributed storage was assumed to be adopted alone. Table 5 summarizes the driving factors for each scenario considered in the study.

Parameter	Low scenario	Medium scenario	Medium export-rate scenario	High scenario
Policy/program interventions				
Solar and storage incentives	Federal ITC (solar tax credit) benefits phased out early (2028). No owner community incentives.	Federal ITC, phased out on schedule (2035) Current Fort Collins incentives, phased out 2028		Federal ITC extended to 2040. Fort Collins incentives adopted by all owner communities.
Codes and standards	No mandates	All new buildings must have solar beginning 2030. A gradual increase is assumed 2024 – 2030.		All newly constructed buildings must have solar beginning in 2024 (commercial) and 2027 (residential)
Retail net energy metering (NEM) and export compensation	Current NEM and export compensation (Fort Collins time of use and other owner communities' flat rates)	New NEM: All communities adopt time of use (TOU) rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail	New NEM with exports valued at forecasted wholesale energy market rates	New NEM: All communities adopt TOU rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail
Incentive for storage participation in VPP	None	$150/kW-yr.		$216/kW-yr.
Storage adoption relative to solar	10% of solar includes storage	30% of solar includes storage	50% of solar includes storage	30% of solar includes storage
Technology factors				
Distributed solar cost	Limited cost decline (historical regional cost + future NREL solar cost decline)	Moderate cost decline (historical regional cost + future NREL solar cost decline)		Aggressive cost declines (historical regional cost + future NREL solar cost decline)
Distributed storage cost	Limited NREL storage cost decline	Moderate NREL storage cost decline		Aggressive NREL storage cost decline

Table 5. *Adoption of distributed generation – solar and storage*

The DER Study considered a range of assumptions. First, the DER Study assessed the impact of federal investment tax credits, with the assumption ranging from early phaseout, in 2028, compared to scheduled phaseout, in 2035, and extended phaseout in 2040. Owner community incentives were also considered, ranging from none to Fort Collins's current incentives, to adoption of Fort Collins' incentives by the other three owner communities. In all cases, the incentives were assumed to phase out in 2028, coinciding with the significant increase in Platte River's noncarbon portfolio. The study evaluated new building standards ranging from no solar requirement to increasingly stringent requirements for new construction to include solar.

The study also considered the effect of retail rates, and specifically net energy metering (NEM), on distributed generation solar and distributed storage adoption. NEM refers to the financial compensation customers with solar (and increasingly customers with solar and distributed storage) can receive due to both reduced purchases of electricity from their retail electricity provider and due to exporting excess solar and distributed storage output to the grid whenever solar and storage produce more energy than the customer consumes.

The study evaluated a range of possible NEM rates. The **low scenario** assumed existing NEM rates apply. This includes Fort Collins's existing time-of-use rate, which charges higher rates during on-peak periods (weekdays, 2 to 7 p.m. during summer months and 5 to 9 p.m. in other months) and lower rates all other hours. Exported energy is credited on the same schedule, but at rates that are 10 to 20% lower. The other owner communities largely have time-invariant rates and compensate exports at or close to the retail rate.

The **medium and high scenarios** assumed all owner communities adopt a rate structure like Fort Collins and that the summer on-peak period shifts later in the day, to 5 to 9 p.m., for all communities. This is due to anticipated high adoption of solar by customers and by Platte River. This results in reduced demand for energy and ample supply when solar energy is available, followed by higher demand and reduced supply as the sun sets and solar output diminishes and then stops. This will lead to higher energy costs as the sun sets and after the sun is down.

The **medium export-rate scenario** assumed the financial value of solar will erode due to higher solar adoption by customers, Platte River and other utilities in the region; low energy prices when solar is plentiful, followed by high prices when solar is absent. Achieving greater value from the solar energy will require that it be shifted in time, from peak solar hours to hours just after the sun sets, which can be achieved through increased deployment and use of energy storage (whether distributed or utility-scale). Modifying the retail rate to compensate exported solar at the wholesale rate will better reflect the value solar alone brings to the system, and at the same time provide value to customers who adopt and use distributed storage to reduce exports and use more solar energy at the home or business.

The study also assessed the adoption of distributed storage. This is projected to be driven by rates and the rate structure as well as on incentives that could be paid to customers to adopt distributed storage and to enroll distributed storage in a VPP for Platte River to dispatch. The combined impact of changes to net energy metering, export compensation and

VPP incentives, coupled with declines in storage costs, are projected to drive higher adoption of storage with solar – increasing from the low scenario (in which 10% of solar was assumed to include storage) to 50% for the medium-export scenario.

Platte River also constructed a fifth scenario, which starts with the medium scenario and then shifts over a period of about 10 years to the medium export-rate scenario.

Figures 23 and 24 illustrate the forecasted adoption of distributed solar and storage, respectively.

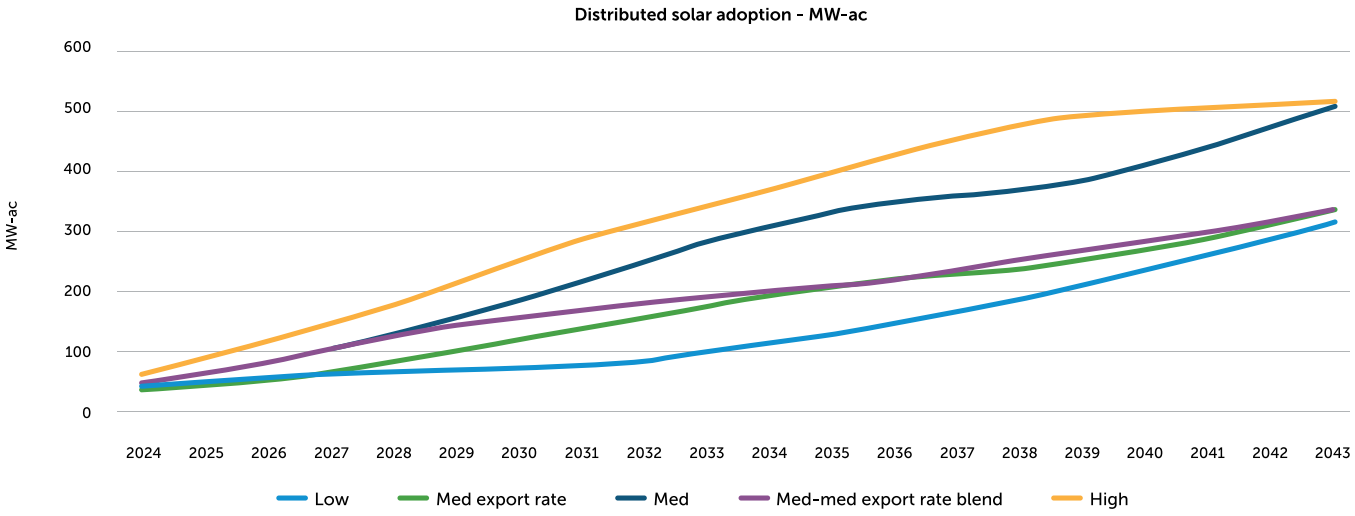


Figure 23. *Distributed solar adoption - MW-ac*

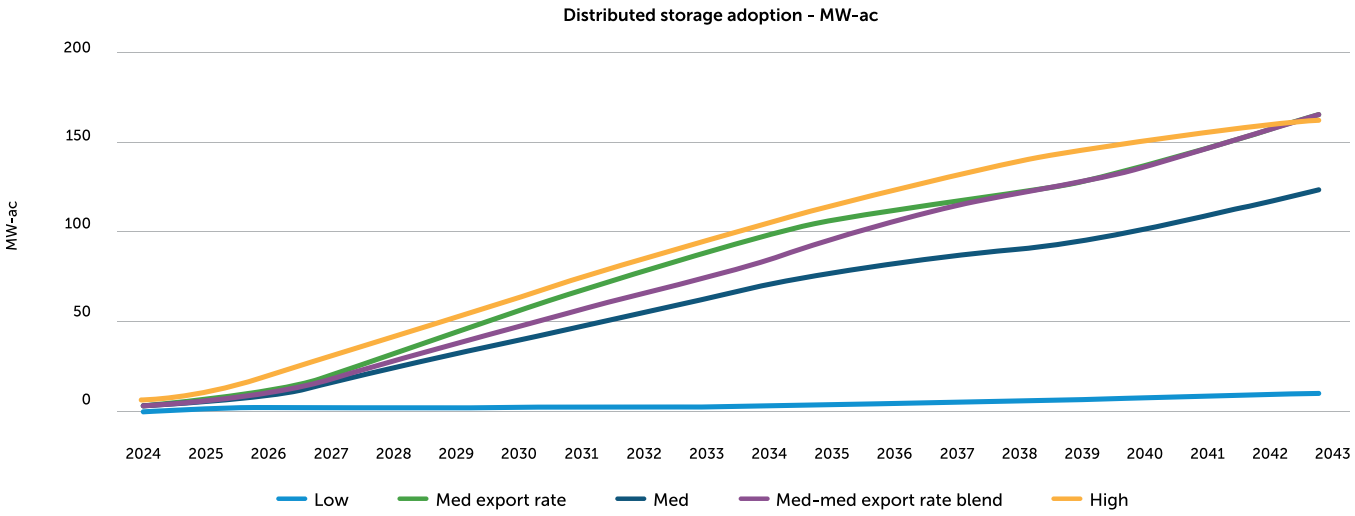


Figure 24. *Distributed storage adoption - MW-ac*

Monitoring and forecasting distributed generation solar and distributed storage adoption. The rise of distributed generation within the owner communities has primarily been driven by individual customers adopting rooftop solar power. Solar energy constitutes around 94% of the existing distributed generation capacity. The remaining capacity is divided among wind (0.02%), cogeneration (4.1%) and hydropower (1%).

Figure 25 illustrates the growth of distributed solar capacity within Platte River's network, fueled by available federal and local incentives, coupled with customers' economics and drive to reduce carbon emissions from electricity generation. As of the end of 2022, estimated distributed solar within Platte River's owner communities totaled 36.3 MW (AC), with 63% from residential solar, 17% from commercial solar, and 20% owned or procured by Platte River or the owner communities.

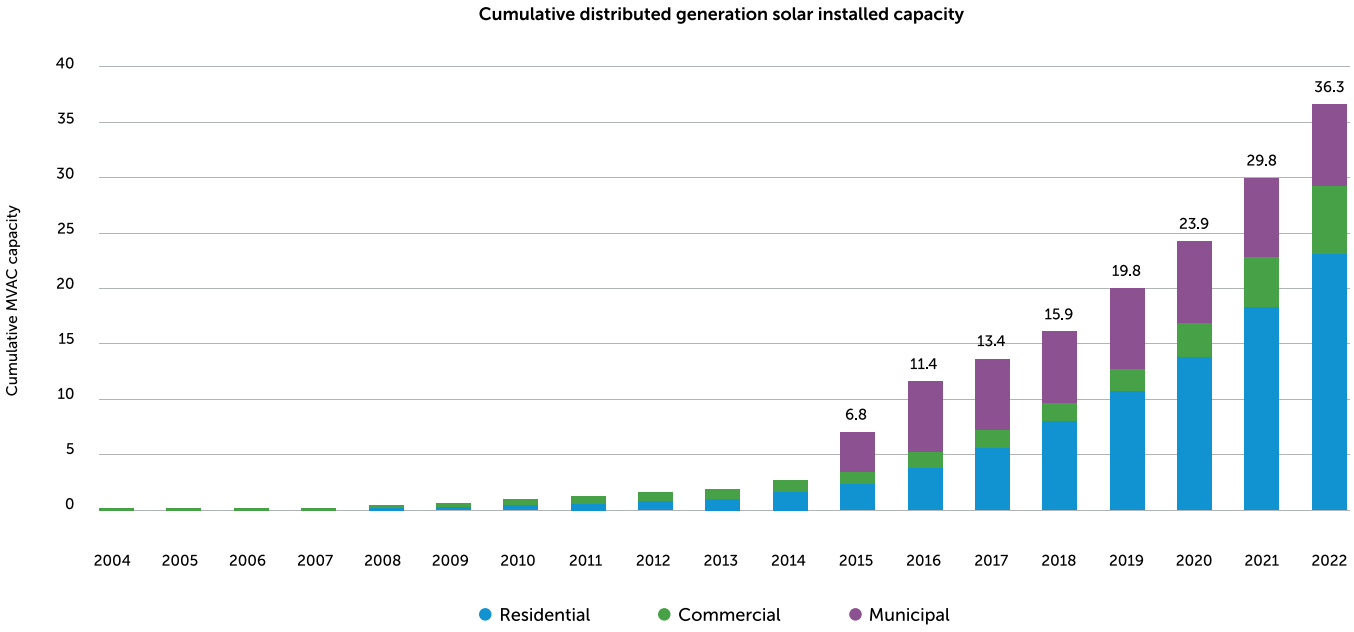


Figure 25. *Cumulative distributed generation solar installed capacity*

Between 2017 and 2022, there has been a notable increase in distributed storage deployment, raising the total capacity to about 1.2 MW in the owner communities. This comprises about 175 systems, averaging a discharge rate of about 7 kW per system. Each year since 2017, there has been an increase in distributed storage system interconnections, with the highest number of installations in 2022. This significant rise highlights the widespread adoption of storage solutions, particularly battery storage, as a versatile tool for providing backup energy and enhancing the operational efficiency of distributed solar systems.

The DER Study evaluated a range of distributed generation solar and distributed storage adoption scenarios to inform the load forecast used for resource planning and to inform DER planning.

Platte River has chosen the blend of the medium and medium-export-rate forecasts. This combination of scenarios represents a gradual change in NEM rates that improves the financial benefit of adopting distributed storage with distributed generation solar. This forecast indicates approximately 155 MW distributed generation solar and 47 MW distributed storage by the end of 2030. This represents 20% annual growth in installed solar capacity and 48% annual growth in storage capacity from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

5.3.7 Flexible DERs and the virtual power plant

As described in previous sections, a VPP is an aggregation of flexible DERs that can be dispatched to support electric system reliability, financial benefits and individual customer benefits. As the name suggests, the VPP can act like a power plant, but it is different in that it is created by thousands of DER devices operating across the electric system. They act in concert, enabled by communication, data collection and management, control and optimization technology.

5.3.7.1 Flexible DER and VPP forecast study results

The DER Study included an assessment of flexible DER that could provide VPP capacity. VPP capacity was evaluated using a multi-step approach that considered the technical, economic and achievable potential of flexible DER technology combined with utility program approaches:

- Technical potential assesses the quantity of flexible DER capacity that theoretically exists in the owner community service territory and how it is expected to grow over time.
- Economic potential considers how much of the technical potential is economic compared to other utility resource options. The study relied on the total resource cost test framework, which compares the marginal costs of a VPP resource for Platte River, the owner communities and their customers to the marginal cost of utility resources.
    - The cost of utility resources included hourly energy costs based on forecasted market energy prices, carbon tax, capacity costs based on four-hour storage and distribution capacity costs based on owner community estimates.
    - The cost of achieving VPP potential included utility program administration costs (excluding incentives) and customer DER technology costs.
    - The cost of achieving VPP potential did not include the cost to the utility of VPP-enabling technology and systems. The need for enabling technology and systems is unaffected by which flexible DER programs Platte River and the owner communities offer.
- Achievable potential considers how much of the economic potential can be realized as a dispatchable VPP capacity at the time of system need and considering customer enrollment rates in VPP program.

The potential study assessed achievable capacity at times of high "net load." This was defined as the load that remains after deducting wind, solar and hydropower. Figure 26 illustrates what this might look like in 2030. Note that while only one day is shown, there are multiple days each summer that would have a similar, though slightly smaller, peak net load. As a result, flexible DER capacity is required many hours throughout the summer. As electrification increases winter loads at a more rapid rate than summer loads, the need for winter dispatchable capacity will grow as well.

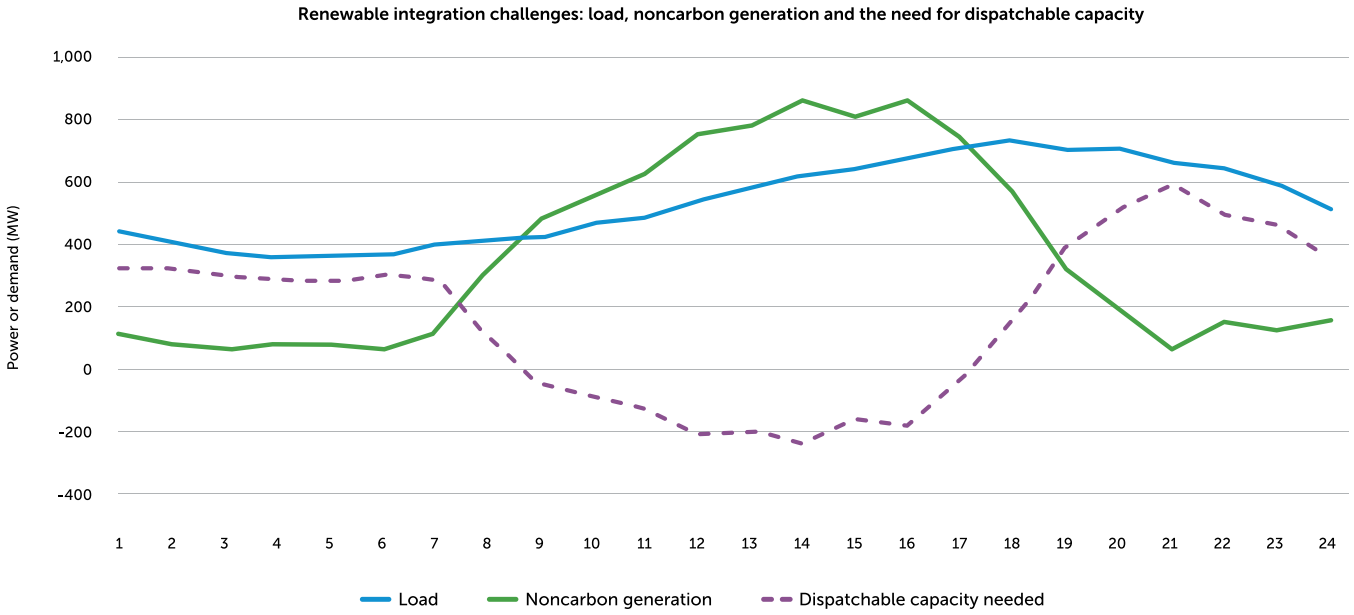


Figure 26. *Renewable integration challenges: load, noncarbon generation and the need for dispatchable capacity*

The DER Study assessed a variety of factors that could drive varying levels of achievable VPP capacity. These were combined in four scenarios as shown in Table 6.



Parameter	Low scenario	Medium scenario	Medium export-rate scenario	High scenario
Time-varying rates	Existing residential TOU rates in Fort Collins only (summer on-peak 2 – 7 p.m.)	New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak)	New residential TOU with solar exports valued at forecasted wholesale energy market rates	New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak)
Program marketing and incentives	Industry-standard marketing and incentives	Industry-standard marketing and incentives	Industry-standard marketing and incentives	Maximum cost-effective marketing and incentives
Efficiency scenario	Low	Low	Low	High
Electric vehicle scenario	Low	Medium	Medium	High
DS solar and storage scenario	Low	Medium	Medium export-rate	High

Table 6. *Primary drivers of achievable VPP capacity*

Within each scenario, various flexible DER approaches were evaluated in an interactive model to determine how they could be combined to provide a sustained reduction in the system net peak, considering the impact of time-varying rates, direct-control programs and each DER's operating characteristics, as summarized in Table 7.



Measure group	Measure sub-group	Characteristics						
		Curtail-ment potential	Event duration (hours)	Pre-charge time	Pre-charge sizing	Rebound time	Rebound sizing (per hour)	Event frequency (per year)
HVAC controls	Smart thermostats	[75%, 33%]	Up to 2 h	1 h	40%	2 h	30%	20
EV charging	EV smart chargers	100%	4 h +	N/A	N/A	6 h	17%	300+
	Vehicle-to-grid	100%	4 h +	N/A	N/A	6 h	17%	300+
Water heating	Electric water heaters	100%	Up to 4 h	2 h	17%	4 h	17%	15
Other loading flexibility	Large C&I curtailment	25%	Up to 4 h	N/A	N/A	N/A	N/A	15

Table 7. *Flexible DER operating characteristics – load*

Measure group	Measure sub-group	Characteristics					
		Size (kW)	Curtail-ment potential	Round trip efficiency	Typical event duration (hours)	Typical rebound / pre-charge time	Typical event frequency (per year)
Storage	Battery storage - residential	3.3	33%	85%	4 h	4 h	300+
	Battery storage – small commercial	5	100%	85%	4 h	4 h	300+
	Battery storage – large commercial	50	100%	85%	4 h	4 h	300+

Table 8. *Flexible DER operating characteristics – storage*

- For residential, it is assumed 33% of the battery is available for flexible DER program, with the remainder used for customer resiliency.
- For commercial batteries, 100% is assumed available for flexible DER, as batteries are typically used for peak load management, and backup generators are used for resiliency.



As illustrated in tables 7 and 8, the flexibility of EVs and battery storage is apparent, with both having the ability to be dispatched on a near-daily basis, 300 times annually. This provides potential for a highly flexible, available resource that can be used to balance variable noncarbon generation. Flexibility of other DERs, such as HVAC control, large commercial and industrial curtailment and water heater control will be limited due to impacts on comfort and productivity.

Figures 27 and 28 summarize the resulting achievable capacity for each of the cases, as well as the annual costs in 2030 and 2040. Program costs are strictly incentives and program administration. They do not include VPP system costs. Growth from 2030 to 2040 was driven largely by increasing adoption of battery storage and EVs.

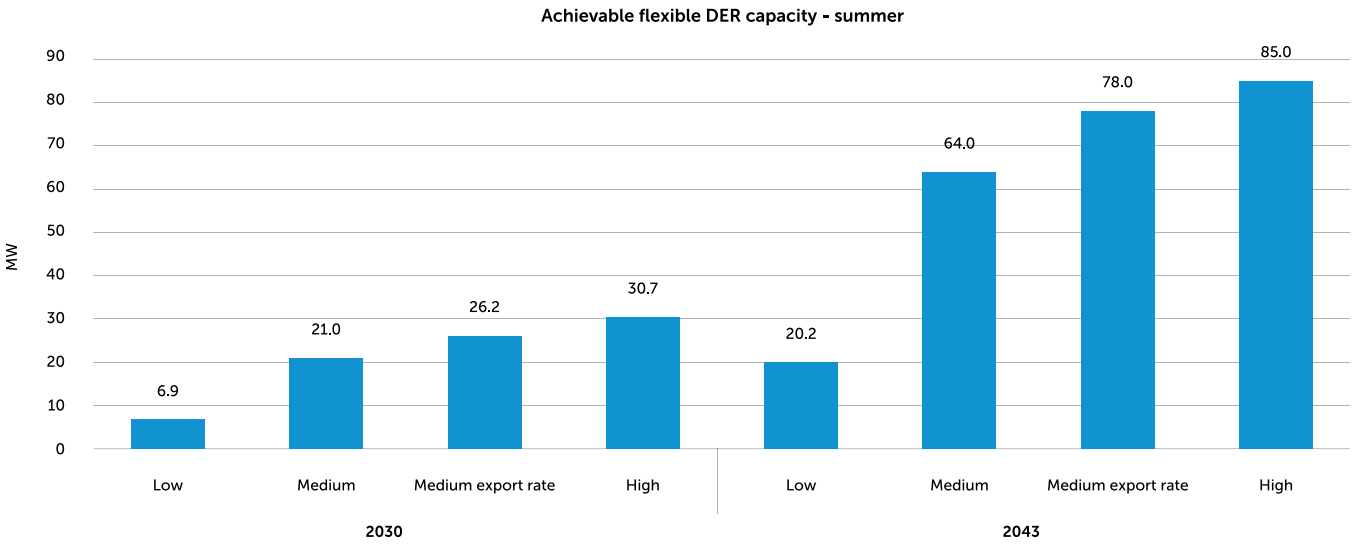


Figure 27. *Achievable flexible DER capacity - summer*

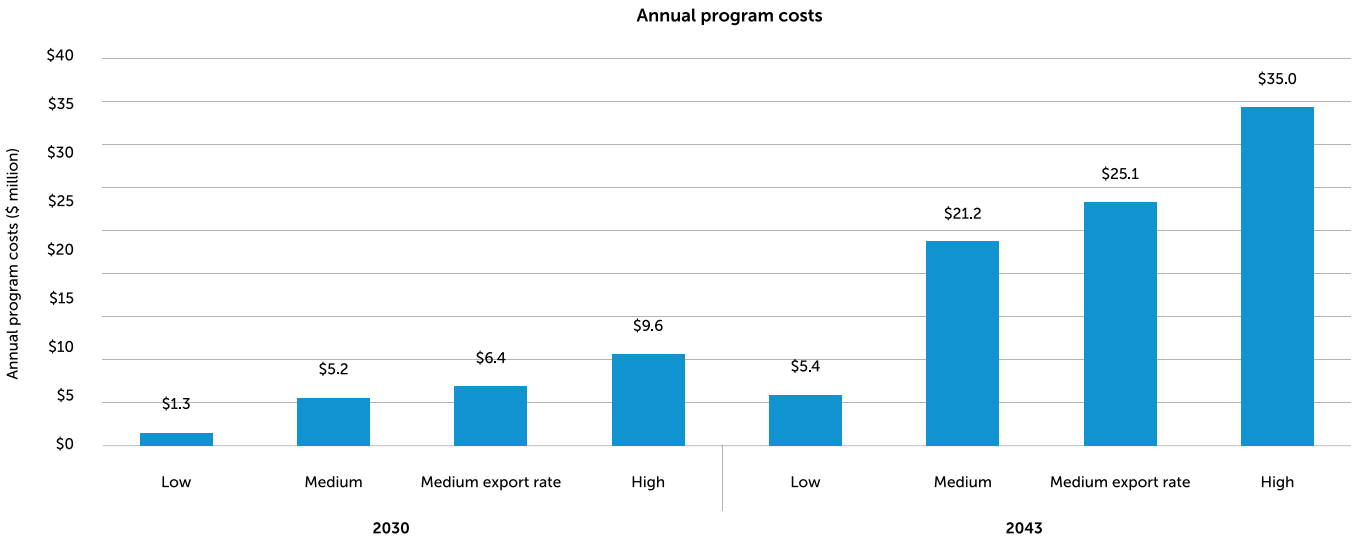


Figure 28. *Annual program costs*

Key takeaways from the DER Study include:

- Summer peak load reductions range from 6.9 MW to 30.7 MW across the different scenarios in 2030.
- The commercial sector is forecasted to have the greatest potential for the low scenario while the residential sector overtakes commercial in the medium and high cases, due to increasing adoption of EVs and distributed storage.
- For the residential sector, battery storage is expected to be by far the most prominent measure in all scenarios except the low one, followed by smart EV chargers and AC smart thermostats in the summer and electric resistance smart thermostats in the winter.
- The commercial demand response potential is primarily driven by large commercial and industrial opportunities, followed by battery storage and water heating.

Develop and implement VPP customer programs. Customers who have flexible DERs and are willing to enroll them in the VPP provide the engine for the VPP's operation. Therefore, a major focus of Platte River and the owner communities is to develop customer programs that support customer enrollment and ongoing participation.

Customer programs must support Platte River's pillars of providing reliable, environmentally responsible and financially sustainable energy, while also providing benefits to participating customers. The DER Study has identified the following opportunities for flexible DERs that can participate in the VPP:

- **Distributed storage management.** Distributed storage is expected to grow significantly, often paired with distributed generation solar.
- **EV charge management (including vehicle-to-grid when available)**. EV

adoption is expected to grow significantly, providing a large and highly flexible load for the VPP. Vehicle-to-grid is also anticipated to grow, with the potential of providing additional storage to the grid.

- **Large commercial and industrial customer custom demand response.** These customers are likely to have large and sometimes unique DER opportunities. Platte River anticipates developing custom approaches to support these projects similar to the custom, pay-for-performance incentives currently offered for efficiency improvements.

- **HVAC demand response.** HVAC demand response programs manipulate electric load for heating and cooling buildings for short periods of time, either through direct control of the heating or cooling system components (for example, compressor load-control switches) or increasingly, through wi-fi enabled thermostats ("smart thermostats").

- **Electric water heater demand response and storage.** Electric water heater demand response takes advantage of the storage that is typically integral to the water heat to allow active heating to be curtailed for brief periods.

Taken together, these customer resources are anticipated to provide a VPP capable of dispatching 32 MW of capacity by 2030 and 93 MW by 2040. To improve the availability of this capacity, Platte River anticipates enrolling more DER capacity than these values indicate. This is to account for limitations on the flexibility of DERs to consistently provide capacity during the evening peak while respecting customer restrictions on Platte River's and the owner communities' use of their flexible DERs. As a result, the enrolled capacity of customer resources may reach an estimated 71 MW by 2030 and 204 MW by 2040. As experience is gained operating the VPP, it is possible that other uses for the enrolled capacity may emerge.

In addition to the customer resources, the VPP is anticipated to include other flexible DERs developed by Platte River and the owner communities. Platte River is in developing plans for 20 MW of distribution-scale storage to be located within the owner communities. This is expected to bring the total achievable VPP capacity to about 52 MW by 2030 and 113 MW by 2040.

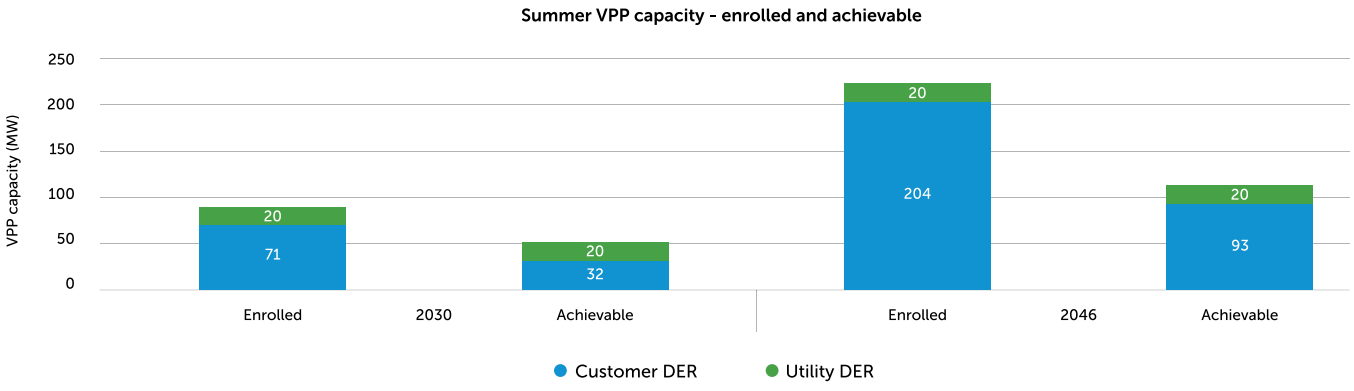


Figure 29. *Summer VPP capacity - enrolled and achievable*



Achieving a VPP of this magnitude requires a high level of customer participation. The enrolled capacity is projected to include 50,000 DER devices by 2030 and close to 100,000 devices by 2040, drawn from the owner communities' customer base of about 172,000 customers. To achieve this high level of participation, Platte River will collaborate with the owner communities to support customers on their DER journeys. This includes engaging customers as they evaluate their DER options and consider enrollment in the VPP. It is also expected to include providing incentives for enrollment and ongoing participation based on the system benefits their DERs can provide. In addition, Platte River and the owner communities will need to engage with the local, regional and some national market actors in the manufacturing, distribution, sales, installation, and operation of DERs.

Platte River issued an RFP in May 2024 to identify firms experienced in providing VPP customer program deployment to provide a rapid, cost-effective, and customer-focused portfolio of VPP programs.

5.3.8 Summary of selected scenarios for DER and VPP potential

Platte River evaluated a range of DER potential scenarios, ranging from low to high. Table 9 summarizes the scenarios selected for each type of DER and describes the reason the scenario was selected.

DER type	Selected scenario	Description
Energy efficiency	Low	Low scenario is most consistent with current participation levels, even as Efficiency Works offers some of the highest efficiency incentives in the state.
Building electrification	Medium	Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification.
Transportation electrification	Medium	Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification.
Distributed generation and storage	Medium-medium export rate	A hybrid scenario starting with medium and shifting to medium export rate was used to reflect current adoption trends and anticipated shifts in net metering policy to favor storing excess solar rather than exporting it.
Virtual power plant / flexible DERs	Hybrid – see description	A hybrid scenario was defined in part by the DER adoption scenarios described above. In addition, EVs that the study assumed would respond to time-varying rates were instead reclassified as being under direct load management to provide greater responsiveness to varying system conditions. The result is that the selected VPP potential is close in magnitude to the high scenario.

Table 9. *Summary and logic for selected scenarios*

5.4 Load forecast with DER (final) 2024-2043

Section 5.2 of this chapter covered load forecast before considering the impact of DERs. In section 5.3, we covered different DERs and saw how much energy and peak demand they contribute (like distributed solar or demand response) and require from the system (like EVs and building electrification). This section discusses the energy and peak demand contribution of each DER and the composite load forecast including the contributions from all the DERs. The composite load forecast, including energy and peak demand, was used in the Plexos model to develop a supply-side portfolio.

5.4.1 Energy contributions of DER

5.4.1.1 Distributed generation

Figure 30 shows the energy contribution from distributed generation, primarily distributed solar. This is shown as negative because it represents the reduction in customer energy needs from Platte River's supply. The bars show energy in gigawatt-hours (GWh) and the solid line shows percent reduction in total Platte River energy. By 2030, distributed generation energy is expected to reduce base energy by 6% and by the end of planning horizon in 2043, it is expected to reduce the predicted base energy by about 13%. Distributed solar produces more energy in summer and less energy in winter but these are annualized values.

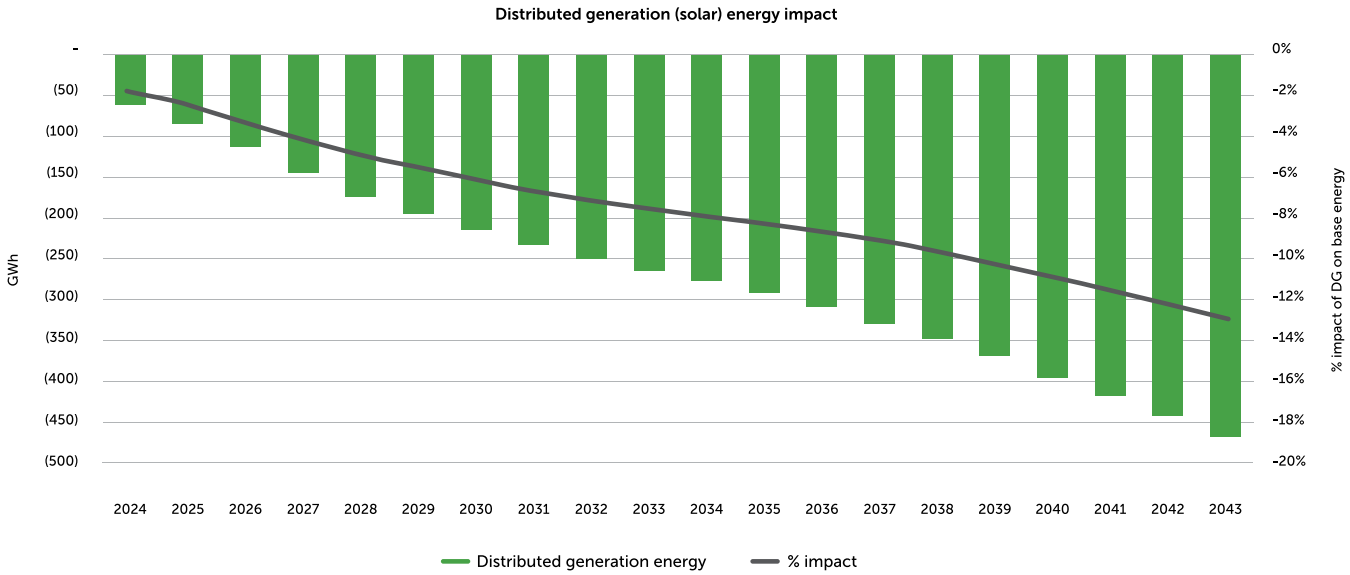


Figure 30. *Distributed generation (solar) energy impact*

5.4.1.2 Building electrification

As illustrated in Figure 31, building electrification (mostly consisting of heating load) starts from a very small level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows the percent increase in the base energy forecast. By 2030, building electrification is expected to increase base energy by 3% and by the end of the planning horizon in 2043, it is expected to add about 19% to the predicted base energy. Because it is heating load, most of the building electrification energy requirements will be in winter, but we show annual values in the chart.

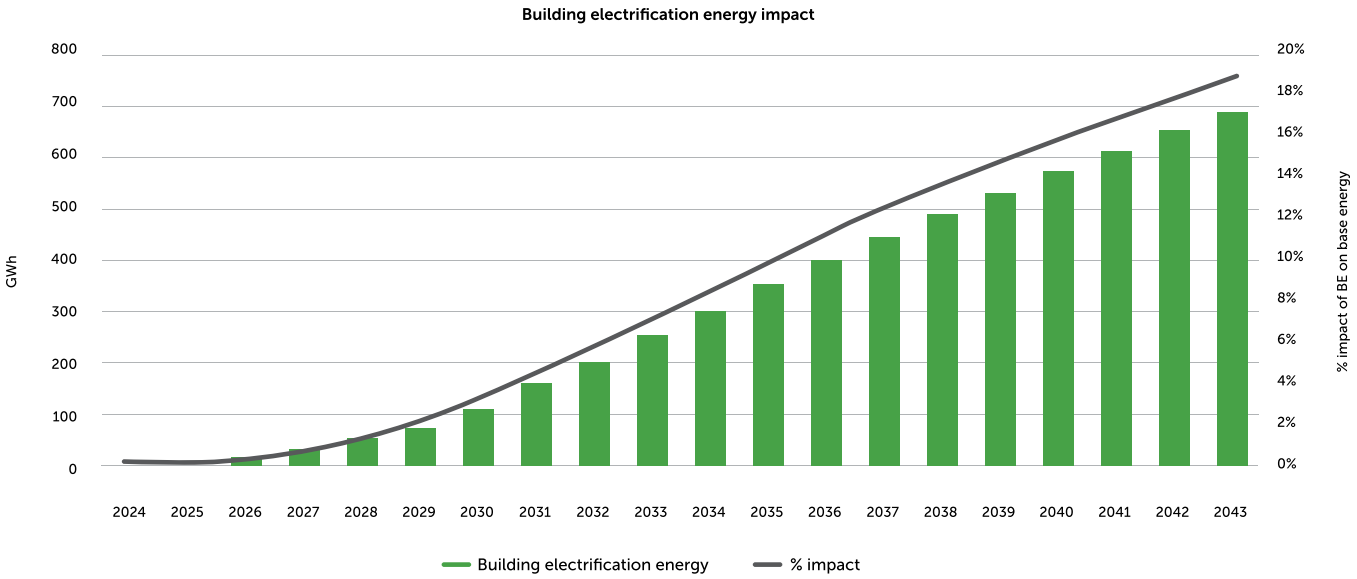


Figure 31. *Building electrification energy impact*

5.4.1.3 Electric vehicles

As illustrated in Figure 32, EV load starts from a very low level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows percent increase in the base energy forecast. By 2030, EV is expected to increase base energy by 5% and by the end of the planning horizon in 2043, it is expected to add about 23% to the predicted base energy. These are annual values. EV load is evenly distributed across the year. A portion of the EV load is flexible and exact charging time can be managed by the utility to more opportune times.

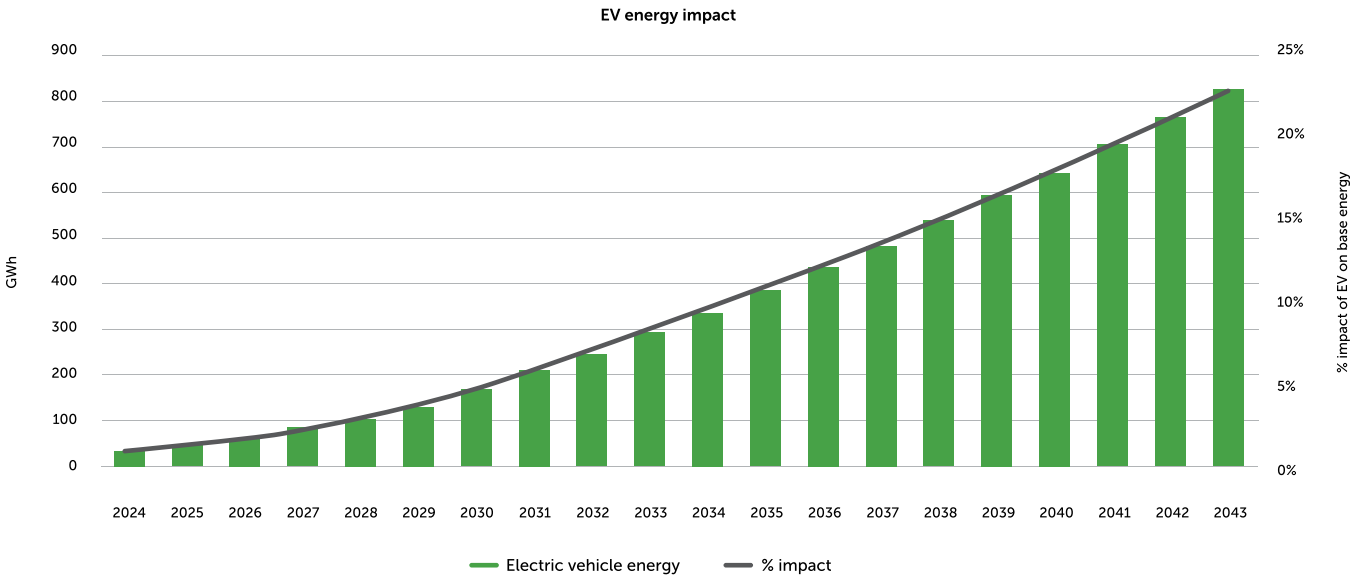


Figure 32. *EV energy impact*

5.4.2 Capacity contribution of DER

5.4.2.1 Distributed generation

Figure 33 shows the summer peak capacity contribution from distributed generation. This is shown as negative because this is the reduction in customer peak demand due to the rooftop solar. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, distributed generation is expected to reduce summer peak by 2% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 3.4%. Although the absolute megawatt addition of rooftop solar is large, its impact on the summer peak is small due to low Effective Load Carrying Capability (ELCC) value of distributed solar (like utility scale solar). Basically, the incremental contribution of solar to reduce summer peak becomes negligible to zero as more solar is added and the peak hour moves closer to the sunset.

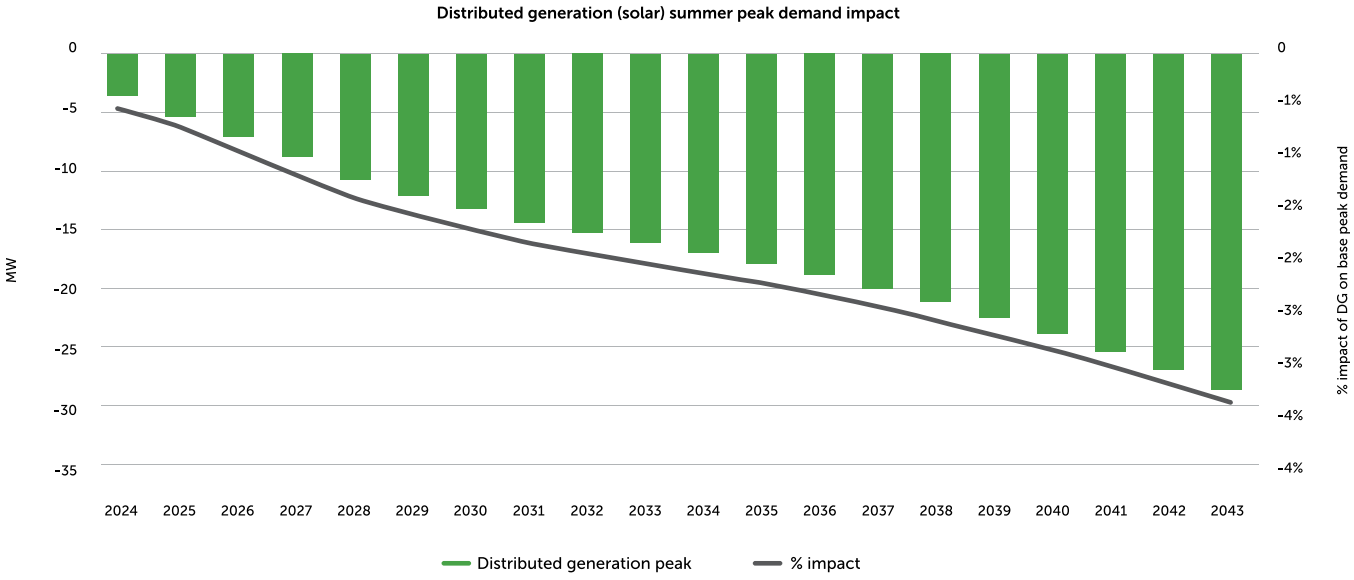


Figure 33. *Distributed generation (solar) summer peak demand impact*

5.4.2.2 Demand response

Figure 34 shows the summer peak capacity contribution from demand response or flexible resources such as home battery storage and EV charging load. This is shown as negative because it represents the reduction in overall customer peak demand. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, demand response is expected to reduce summer peak by 5% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 9%.

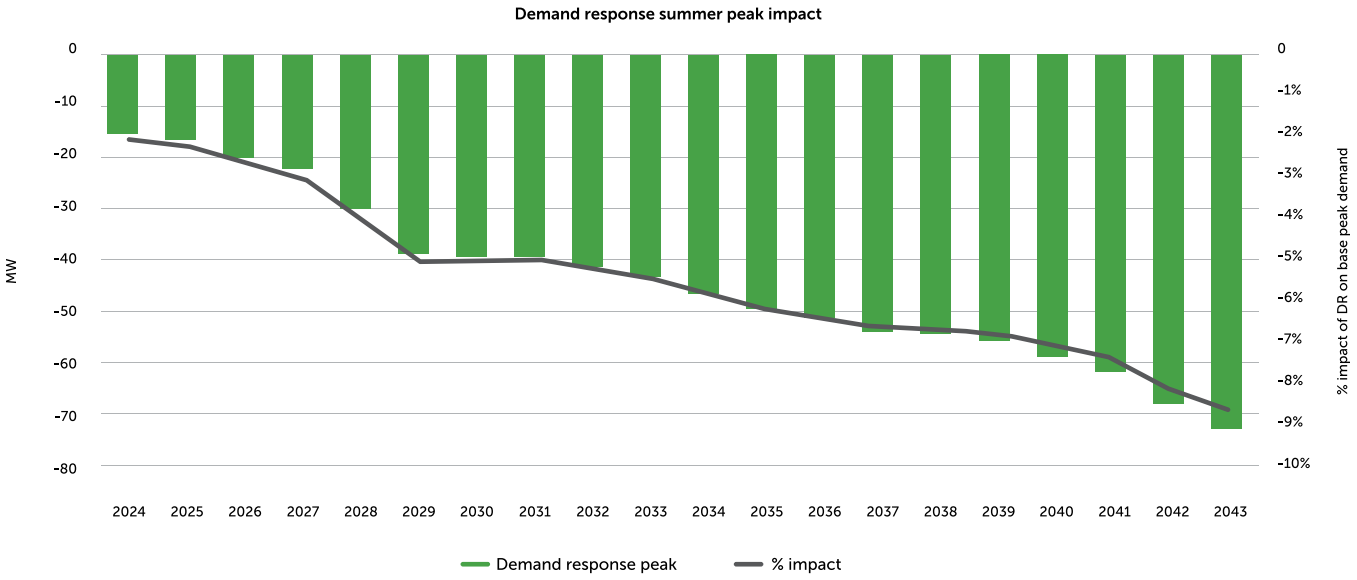


Figure 34. *Demand response summer peak impact*

5.4.2.3 Building electrification

As illustrated in Figure 35, building electrification starts from a very low level but is expected to grow rapidly in the next decade. Most building electrification contribution is from heating systems in colder months, so the impact on summer peak demand is fairly small, mainly coming from electric cooking and water heating. The bars show summer peak hour building electrification load in megawatts and the solid line shows percent increase in the base peak demand. By 2030, building electrification is expected to increase summer base peak by about 1% and by the end of the planning horizon in 2043, it adds about 3% to the predicted base summer peak demand.

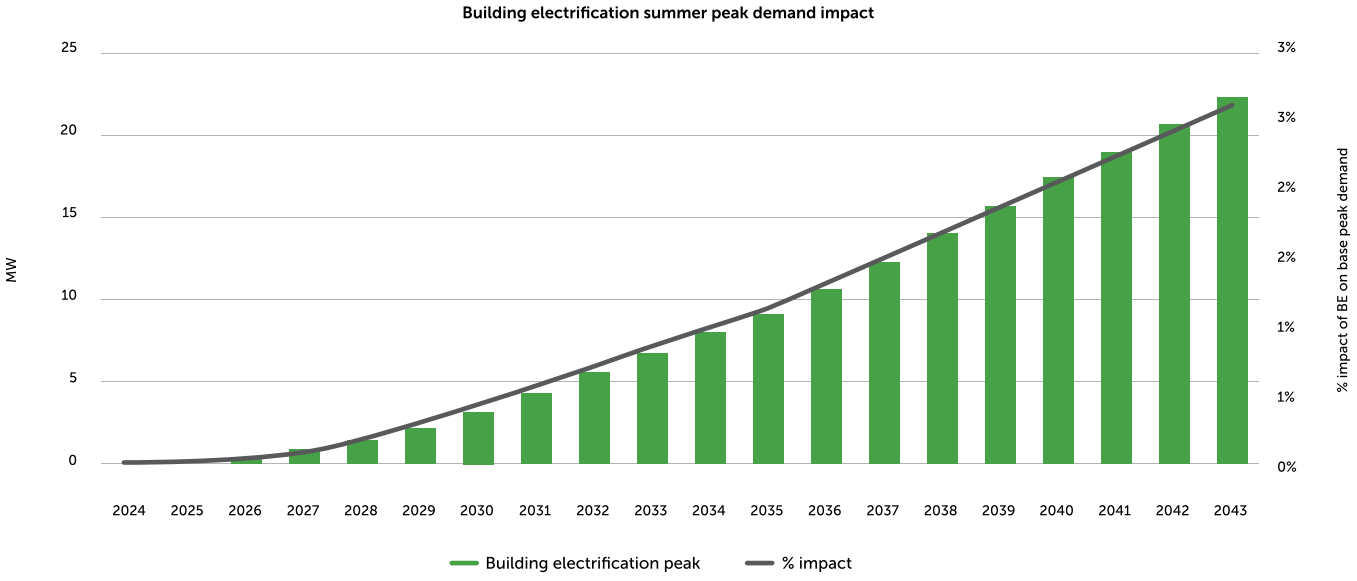


Figure 35. *Building electrification summer peak demand impact*

5.4.2.4 Electric vehicles

As illustrated in Figure 36, electric vehicle load starts from a very low level but is expected to grow rapidly in the next decade. This figure shows the portion of the EV load that is inflexible and cannot be managed or moved away from the summer peak hour. The bars show summer peak capacity in megawatts and the solid line shows percent increase in the summer base peak demand forecast. By 2030, EV is expected to increase summer base peak demand by 3% and by the end of the planning horizon in 2043, it adds about 15% to the predicted base summer peak demand. It is important to note that most EV load is flexible, and its exact charging time can be managed by the utility to lower summer peak demand. Contribution from the flexible EV charging load is not included in the chart below because we assume it will be controlled at the time of summer peak hour and moved to a later, lower-demand hour.

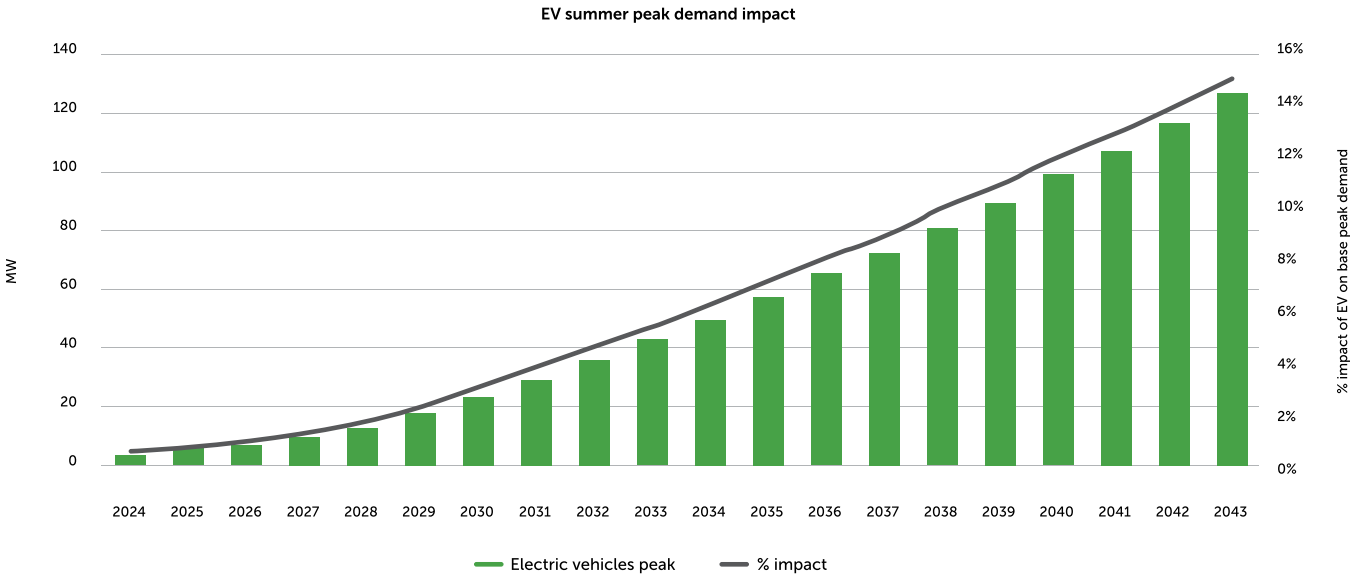


Figure 36. *EV summer peak demand impact*

5.4.3 Composite load with all DER contributions

Collectively, DERs decrease electric consumption and load growth in early years, due to the presence of distributed generation resources like rooftop solar and demand response programs, offsetting additional load created by electric vehicles and building electrification. However, as adoption of electric vehicles and building electrification increase, the additional load outpaces growth in distributed generation, resulting in higher load growth. The combined DER impact trend is similar for annual energy and summer peak demand but the percent impact varies. Figure 37 shows composite annual energy requirements and the combined percent impact of DERs.

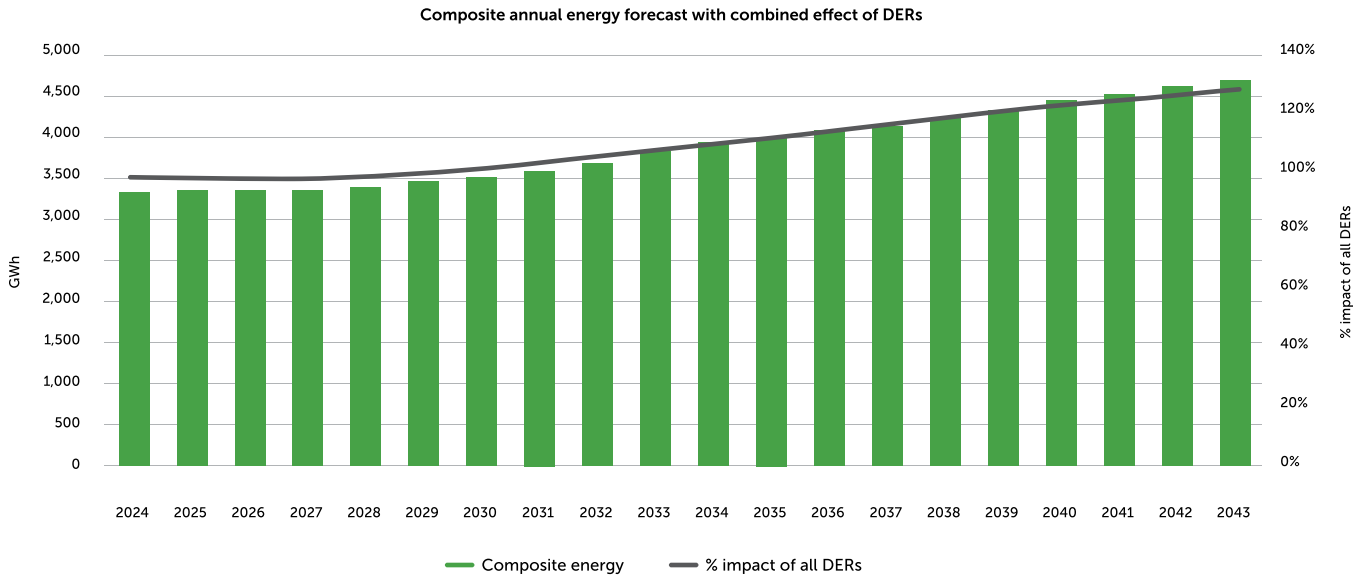


Figure 37. *Composite annual energy forecast with combined effect of DERs*

The green bars in Figure 37 show composite annual energy in gigawatt hours that Platte River's supply system must produce, and the solid black line shows the combined impact of all DERs as a percent. The combined effect of DERs reduces the annual energy need through 2029 and increases it afterwards, due to rapid increase in building electrification and EV load, reaching an almost 29% increase by 2043.

Figure 38 shows composite summer peak requirement and the combined percent impact of DERs. The green bars show composite summer peak demand in megawatts that Platte River's supply system must provide, and the solid black line shows the combined impact of all DERs. The combined effect of DERs reduces the summer peak demand through 2035 and increases it after, due to rapid increase in building electrification and EV load, reaching an almost 6% increase by 2043. The combined percent impact of DERs on summer peak demand is much lower than the percent impact on annual energy consumption because the two major DERs, EV and building electrification, do not increase the summer peak load as much as they increase annual energy consumption.

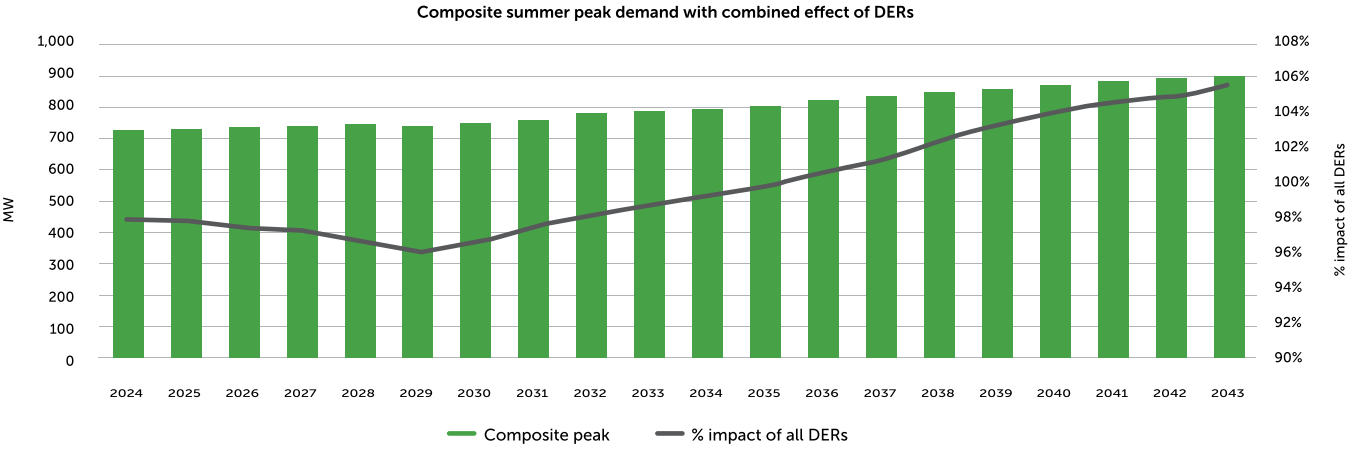


Figure 38. *Composite summer peak demand with combined effect of DERs*



06 Supply-side assumptions

This section reviews assumed supply-side resources available to serve projected demand. These assumptions include commodity fuel prices, resource costs and their future trajectory, as well as assumptions about how Platte River interacts with other power suppliers in our region. The study period spans 20 years starting Jan. 1, 2021, largely because the typical life of investments for new generating capacity is 20-30 years.

6.1 Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power, carbon dioxide (CO2), nitrogen oxides, sulfur dioxide (SO2), and mercury cost projections. Platte River projected coal prices based on unique coal supply plans for its coal-fired generation fleet. The following subsections discuss these commodity price projections in more detail.





6.1.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition to the base case pricing, Siemens also provided high and low gas price projections the planning team used to develop sensitivity cases. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market, such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 39.

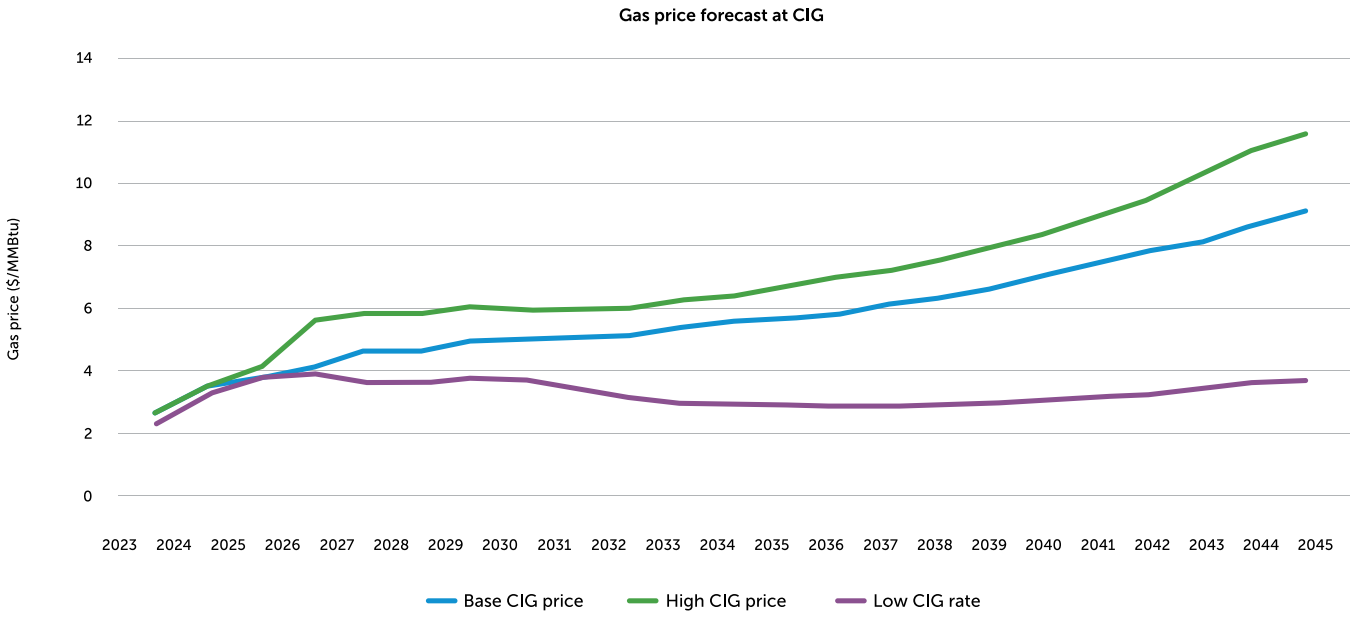


Figure 39. *Gas price forecast at CIG*

In addition to the above gas commodity prices, Platte River also pays transportation for natural gas delivered to the Rawhide site. Charges begin at $1.05/MMBtu for 2024, based on actual expenses, and increase at the assumed inflation rate.

Analysis assumes additional gas-related cost for gas pipeline reservation to improve the reliability of gas supplies after coal retirements. Actual gas supply cost varies depending on consumption levels, but an average cost to firm gas supply ranges from $35/kw-yr to $50/kw-yr for different gas units. These costs begin in 2030 and end in 2040, when the models assume the units switch to 100% green hydrogen. To improve fuel supply reliability, we will analyze options for firming up gas supplies, such as on-site storage or constructing an additional pipeline to the Rawhide plant site.

6.1.2 Green hydrogen prices

Green hydrogen as a noncarbon-emitting fuel for traditional gas turbines has potential in the future, as technological and economical barriers for storing and transporting hydrogen diminish. Based on the recommendations from Black & Veatch, Platte River assumed a 50% blend of hydrogen with natural gas in 2035 and use of 100% hydrogen in 2040. Future hydrogen pricing is uncertain; IRP modeling assumed 2035 hydrogen prices five times the prices of natural gas by 2035, decreasing to three times of natural gas by 2045. Hydrogen prices can be expressed in $/MMBtu or $/kg units. Price projections are shown in Figure 40.

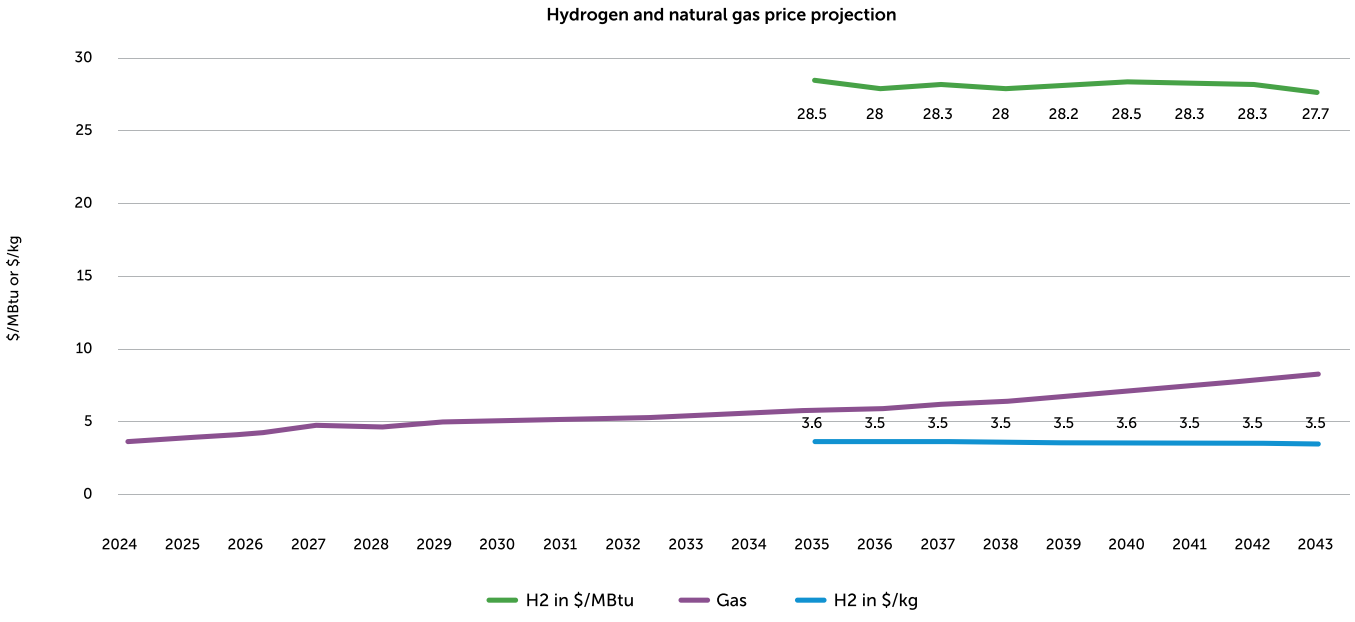


Figure 40. *Hydrogen and natural gas price projection*

6.1.3 Coal prices

Each coal plant in Platte River's portfolio operates with a unique coal supply arrangement. This means that price forecasts for Rawhide Unit 1 and the two Craig units are developed separately, as discussed below.

Rawhide receives coal from the Powder River Basin by rail and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier and near-term coal market assessments and indices. As locked-in quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens's forecast for Powder River Basin coal. By 2027, the price forecast is based entirely on the forecasted commodity price from Siemens. The commodity price is adjusted to reflect mine-specific pricing. It includes additional costs for required dust suppressants and taxes passed through by the mine. Transportation expenses, based on the current rail rates projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a "cash cost" basis, with no transportation costs incurred. Figure 41 illustrates the delivered coal prices for Platte River coal plants.

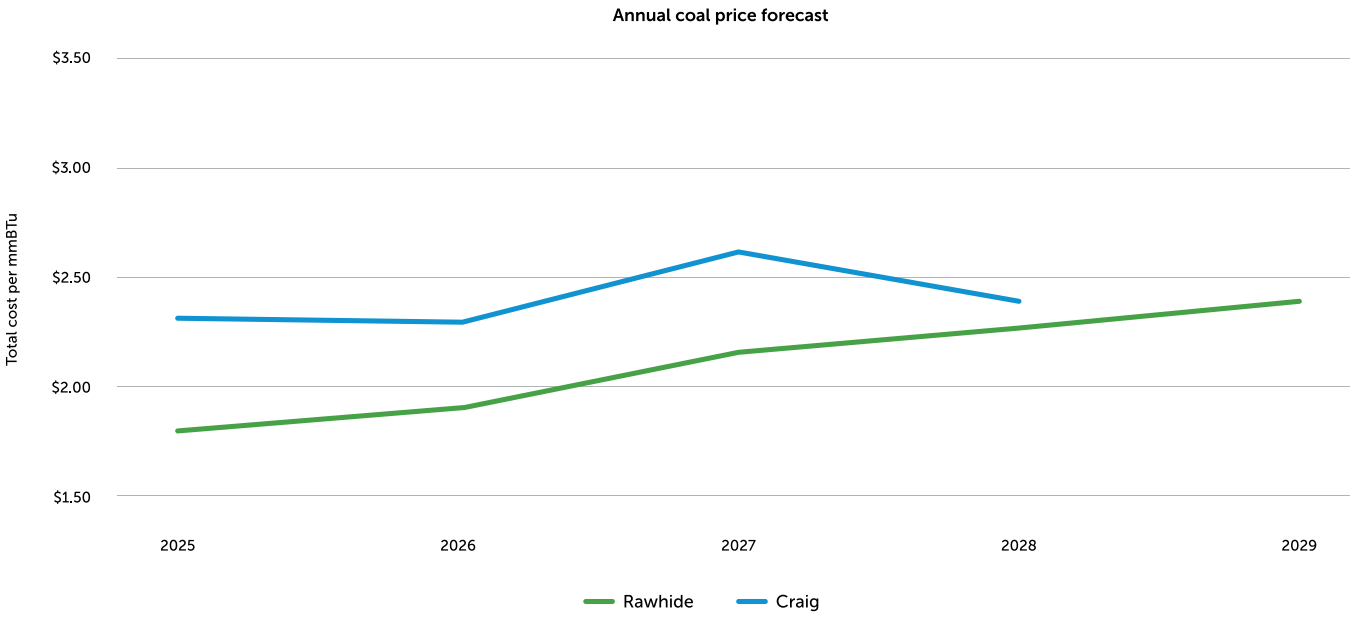


Figure 41. *Annual coal price forecast*

6.1.4 Regional power prices

Platte River's resources are dispatched in real time with resources from other utilities in the WEIS market to maximize economic exchange of power across the market. In addition to the real-time market, Platte River transacts with neighboring utilities bilaterally, selling excess power and buying power when needed. To simulate these bilateral transactions with neighboring utilities, resource planning models a regional market where Platte River can buy or sell when economical. Siemens has provided hourly future prices for Colorado area and these hourly prices are used in our simulations. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River's marginal cost of production and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Net revenues from market transactions reduce the overall cost of providing power to Platte River's owner communities.

With more renewable resources on the regional grid, renewable energy becomes a bigger driver of power prices. Siemens predicts that average annual power prices will remain relatively stable over the 20-year planning horizon. However, daytime prices (labeled as "on-peak solar" prices in Figure 42) will decline as more solar generation is added.

Figure 42 shows our current forecast for on-peak and off-peak power prices, including solar and non-solar hours. The model defines on-peak hours as Monday-Saturday from 6 a.m. to 10 p.m., with on-peak solar 8 a.m. to 5 p.m. every day and on-peak non-solar 5 p.m. to 10 p.m. Monday-Saturday. Off peak hours are 11 p.m. to 5 a.m. Monday-Saturday and all day Sunday. As shown in Figure 42, on-peak non-solar prices (representing the evening hours) stay the highest and on-peak solar, which reflect the day and time when solar is plentiful, are the lowest prices.

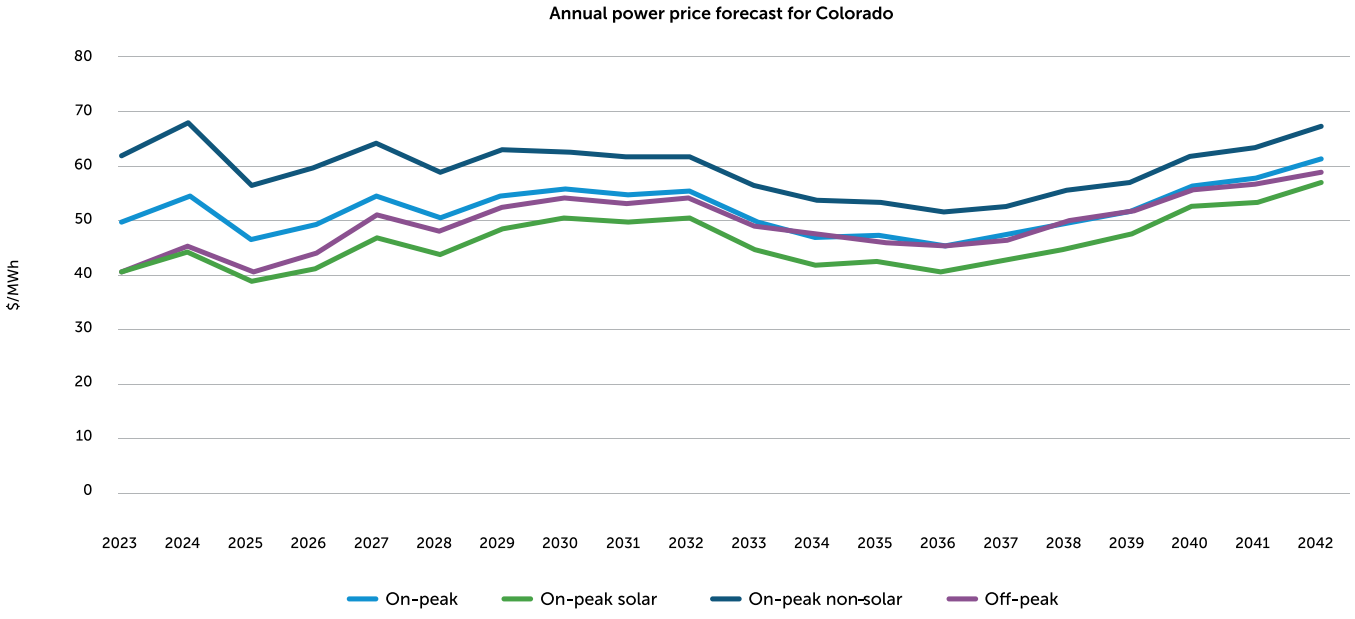


Figure 42. *Annual power price forecast for Colorado*

For the 2024 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped correlate relationships between market prices and energy production from the intermittent wind and solar resources. Siemens also provided the natural gas and emission prices forecasts, which were appropriately correlated to an hourly level in the IRP assumptions to ensure internal consistency among various projections.

6.1.5 Carbon taxes embedded in projected energy prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation. A carbon tax will discourage carbon emissions.

Platte River also evaluated portfolio outcomes using a social cost of carbon. The social cost of carbon simulates total direct and indirect (such as healthcare or extreme weather events) cost to the society from continued CO2 emissions. The social cost of carbon projection was based on the guidance of the Colorado Air Quality Control Commission, which valued the social cost of carbon at $68 per short ton in 2020 with an escalation rate of 2.5%, as shown in Figure 43.

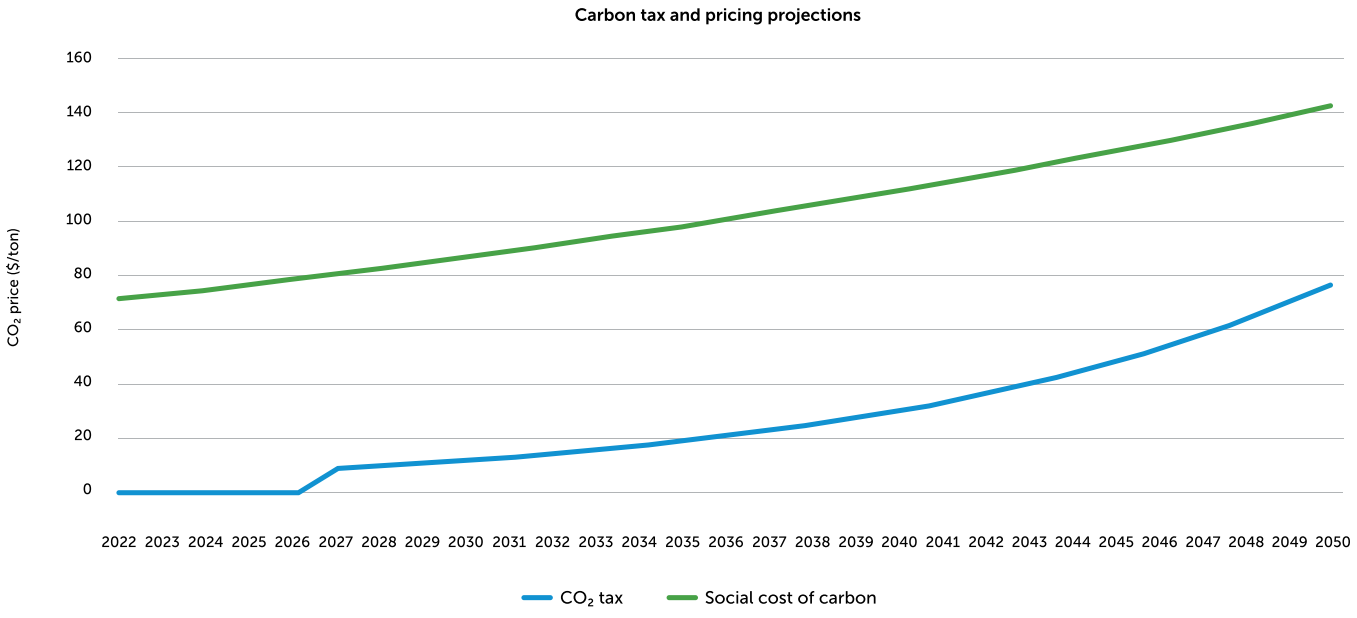


Figure 43. *Carbon tax and pricing projections*

6.2 Regional import/export limits

Platte River joined the WEIS market in April 2023, where Platte River's generation resources are jointly dispatched along with generation resources of other market participants to minimize dispatch costs for all market participants. When it joins SPP RTO West, Platte River will serve its load with a combination of owned resources and lower-cost resources from other market participants, implying real-time power sales and purchases with other RTO members. In addition, Platte River will continue bilateral transactions with regional entities, marketing excess energy through short- and long-term transactions. For IRP modeling, analysts assumed purchases or sales up to 150 MW in any hour. The 150 MW import/export limit means that market transaction volume remains realistic and that Platte River builds enough reliable energy generation to meet customers' needs and planning reserve margin requirements.

6.3 Supply-side generation resources

This section discusses all power generation resources Platte River considered to meet its customers' future electricity needs, beginning with our existing resources followed by committed resources. We then discuss additional future resources and the screening process to select candidate resources. A detailed discussion follows concerning the resources (both renewable and traditional) that Platte River is evaluating for future investment.

6.3.1 Platte River's existing resources

Platte River's existing supply-side resources consist of power plants, PPAs and community solar generation facilities. Distributed and community-owned solar were modeled as supply-side resources even though they may have unique contracts with retail load or with an owner community's distribution utility. For modeling purposes, they function as resources that serve community load. Tables 10-15 list Platte River's existing resources.

Coal generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Nominal retirement / contract expiration
Rawhide Unit 1	280	280	1984	2029
Craig Unit 1	77	77	1980	2025
Craig Unit 2	74	74	1979	2028

Table 10. *Platte River's existing coal resources*

Natural gas (simple-cycle CTs) generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Rawhide Unit A	65	65	2002
Rawhide Unit B	65	65	2002
Rawhide Unit C	65	65	2002
Rawhide Unit D	65	65	2004
Rawhide Unit F	128	128	2008

Table 11. *Platte River's existing natural gas resources*

Contracted wind resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Medicine Bow	6	1	1998
Silver Sage[11]	12	2	2009
Spring Canyon I[12]	32	5	2014
Spring Canyon II	28	6	2014
Roundhouse	225	39	2020

Table 12. *Platte River's contracted wind resources*

Contracted hydropower[13] resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Loveland Area Project	30	30	1973
Colorado River Storage Project	60	48	1973

Table 13. *Platte River's contracted hydropower resources*

Contracted solar resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Commercial solar power purchase program	4	2	Approved 2013
Fort Collins community solar	1	0.4	2015
Foothills Solar (Platte River share)	0.5	0.2	2016
Rawhide Flats	30	17	2016
Rawhide Prairie	22	12	2020

Table 14. *Platte River's contracted solar resources*

Contracted storage resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Rawhide Prairie Battery	1 MW x 2 hours	1	2020

Table 15. *Platte River's contracted storage resources*

[11] Silver Sage wind has been sold through 2029, when its PPA with Platte River expires. It does not return as a resource.

[12] Both Spring Canyon resources were sold in 2020 through 2030. They will return to Platte River in June 2030 and serve Platte River customers for the remaining term of their contract (through 2039).

[13] Estimated effective capacity due to persistent drought conditions throughout the West.

6.3.2 Committed or expected resources

This category includes resources for which either a final contract has been signed or negotiations are ongoing. These resources are treated like existing resources. These resources are included in modeling as assumed available and not subject to change through the optimization and resource selection process. These resources are shown in Table 16.

Committed resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Current status
Solar				
Black Hollow	150	31	2025	PPA signed
New solar	150	24	2026	Negotiations ongoing
Storage				
Community battery	25 MW x 4 hours	18	2026	Negotiations ongoing

Table 16. *Committed resources*

6.3.3 Future candidate resources

Platte River selected future candidate generation resources by reviewing data from credible public sources, its consultants and its own market intelligence as detailed below. This section provides an overview of data sources, selection process and details of the selected resources.

6.3.3.1 U.S. Energy Information Administration

The EIA publishes cost and performance of new generation every year in its annual energy outlook report. The EIA report[14] is comprehensive and covers state of the art in traditional, low-carbon and renewable power generation technologies. We selected the following technologies from this report for further evaluation:

- Onshore wind
- Solar photovoltaic
- Battery storage
- Aeroderivative combustion turbine
- Reciprocating internal combustion engine
- Carbon sequestration
- Modular nuclear
- Geothermal

Planning staff screened out the following technologies from this report, as they are not suitable for Platte River's future power supply portfolio.



- Coal with or without carbon sequestration
- Combined cycle with or without carbon sequestration
- Large nuclear
- Offshore wind
- Biomass
- Solar thermal
- Conventional hydro
- Fuel cells

6.3.3.2 Black & Veatch consulting support

In addition to the resources considered from the EIA report, Platte River engaged Black & Veatch[15] to assess the landscape of low- and no-carbon fuels, energy storage and dispatchable power generation technologies. The Black & Veatch report assessed the availability of these technologies for 2028 commercial operation. For technologies not available for 2028, they estimated their future costs and commercial availability in the next decade. Black & Veatch reviewed the following options:

- **Biofuels.** The study concluded biofuels for power generation are not a viable option at Rawhide due to limited fuel availability and significant modifications required in the equipment to burn this fuel. Biofuels are better suited for transportation applications, rather than large power generation.

- **Hydrogen** – both green and blue. Green hydrogen is produced by an electrolyzer using renewable electricity, while blue hydrogen is produced from natural gas and the CO2 produced in the process is sequestered and stored in the ground. Hydrogen can be used as fuel in traditional power generation machines like CTs with some modifications. But there are significant technoeconomic challenges to store and transport hydrogen. The study concluded that green hydrogen could be a viable option for Platte River starting in the middle of the next decade.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[15] Results from the generation technology screening by Black & Veatch are accessible on Platte River's IRP microsite at prpa.org/2024irp/information.

- **Renewable natural gas.** Renewable natural gas is produced mostly at landfill or biowaste locations. The study concluded that renewable natural gas for power generation at the Rawhide site is not a viable option due to limited fuel availability. This fuel is better suited for small power generation at or near locations where the fuel is produced, such as landfill or wastewater treatment sites. Another possible use of renewable natural gas is for transportation, like the City of Longmont using renewable natural gas from its wastewater facility in the waste services truck fleet, displacing the use of diesel fuel. In some cases, renewable natural gas can be refined enough to meet the pipeline quality natural gas standard and can be pumped back into the gas network.

- **Ammonia.** Since transporting hydrogen over long distances is technologically and economically challenging (because hydrogen is a very light-weight molecule), industry is considering converting hydrogen into ammonia and then transporting it. At the destination, ammonia can be used directly in power generation or converted back to hydrogen and then used. The study concluded ammonia for power generation is not a viable option. It is better suited for transportation applications, rather than large-scale power generation.

- **Carbon capture and sequestration.** Carbon capture and sequestration technology was considered for removing CO2 from the existing combustion turbine units at the Rawhide site. The study concluded carbon capture and sequestration is not a viable option at Rawhide due to high cost of CO2 removal in peaking units (like those at Platte River, where combustion turbines are expected to run less than 20% of the time), and lack of known places to sequester CO2. Carbon capture and sequestration technology is a better option for baseload applications, where the generation source is running continuously and where the large capital cost can be spread over numerous tons of removed CO2. Additionally, carbon capture and sequestration technology is in the early commercial stages of development, with few proven and successful applications for power generation.

- **Long duration energy storage.** The study concluded that long-duration energy storage is an emerging technology, but not ready for commercial operation in 2028. This technology has potential and may become commercially available by the middle of the next decade. Platte River decided to plan for a 10 MW pilot long-duration energy storage project by 2030 and assume the technology would be available for commercial applications by 2035.

- **Flexible and low CO2 emitting thermal power generation.** In addition to the low- or no carbon emitting power generation options discussed above, the study reviewed various traditional combustion turbine and reciprocating internal combustion engine technologies that are flexible, reliable, efficient and hydrogen-capable. Three key future dispatchable technology requirements will be reliability, flexibility, and the ability to provide power for at least one week during dark calms. Because low or no-carbon options were not commercially available, the study recommended using gas-fired combustion turbines or reciprocating

internal combustion engines for commercial operation in 2028 and progressively converting to green hydrogen when it is economically available in large quantities. Combustion turbine and reciprocating internal combustion engine vendors claim that these machines will be capable of burning about 30% hydrogen by 2028.

6.3.3.3 Platte River's own market intelligence

Plate River's portfolio integration team monitors markets and collects information informally and formally through requests for information and requests for proposals. This engagement informs Platte River of the latest technology and pricing trends in the area. EIA, Annual Technology Book (ATB) or consultants can provide market trends and average prices, but the real prices for our area are available only through engagement with developers and vendors. Platte River conducted a solar and storage RFP in 2022 and started a wind RFP in 2023. These market interactions were valuable for collecting information about the projects being developed in our region—their costs, locations, schedules and technologies. This information was used to input costs of renewable and storage technologies in IRP modeling.

6.3.3.4 NREL's Annual Technology Book

NREL provides cost, efficiency and technology improvement trends of renewable and storage technologies in the ATB every year. We used the data in the 2022 ATB for this IRP, as it was the latest available in the spring of 2023 when staff finalized assumptions.

After a detailed review of all the sources mentioned above and internal deliberations, Platte River decided the following:

- For wind, solar and four-hour storage costs, we used our own market intelligence data for early year prices where data was available from multiple vendors.
- After the first three years, we used cost escalation and efficiency improvement rates proposed by the ATB.
- Actual cost data used for each technology is shown in the following sections.

For dispatchable resources, Platte River relied on the recommendations of Black & Veatch. Platte River decided the best option is to use highly flexible, state-of-the-art, hydrogen-capable aeroderivative combustion turbine technology. These machines will initially use natural gas fuel and by 2035 may start using 50% green hydrogen blend and by 2040 may use 100% green hydrogen. The process of selecting aeroderivative technology is discussed in section 6.3.7.

6.3.4 New wind resources

While wind resource availability within Platte River's service territory is limited, wind is abundant to the north and the southeast. Most likely, our future wind will come from southeast Wyoming or eastern Colorado. We have assumed that the southeast Wyoming wind will be delivered to Platte River through existing transmission capacity that will become available after retirement of Craig coal generation.



Eastern Colorado wind would be delivered through a neighboring transmission system at a cost of $6/MWh in 2023 and escalating with inflation. Because the existing transmission infrastructure in southeast Wyoming is limited, only 200 MW of wind is expected to be procured without incremental transmission cost. Any future wind will include a transmission charge or new transmission infrastructure at an assumed cost of $6/MWh.

New wind resources are assumed to be procured under PPAs for 100 to 200 MW blocks. PPA payments compensate the developer or the owner for capital costs (depreciation and returns), financing costs, interest during construction, taxes (sales, property, and income) and ongoing operating and maintenance costs. PPA prices for wind are based on recent quotes from project developers in the region. We assumed future wind prices will escalate based on the 2022 ATB future wind cost curves.

Southeast Wyoming wind is assumed to have an average annual capacity factor of 42.5%, while the eastern Colorado wind was modeled with a 45% capacity factor.

Wind projects (existing or new) carry ancillary service charges through 2025. Beyond 2025, we assume those costs cease with entry into a regional market. The combined cost of wind ancillary services in 2024 were modeled at $1.24/kw-mo.

Figure 44 shows wind costs for the two locations along with solar costs. As mentioned earlier, PPA prices are generally fixed for their terms (typically 20-30 years). Figure 44 assumes that for 2026, the southeast Wyoming wind PPA price will be fixed at $35/MWh for the PPA term, while for the wind PPA signed in 2030, it will cost $33.65/MWh for the life of the project.

6.3.5 New solar resources

New solar resources were considered as 50 MW block sizes priced at a 30-year levelized PPA payment, including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Platte River received solar price data based on recent RFPs and negotiations with developers. These prices were escalated with NREL's 2022 ATB solar cost projections.

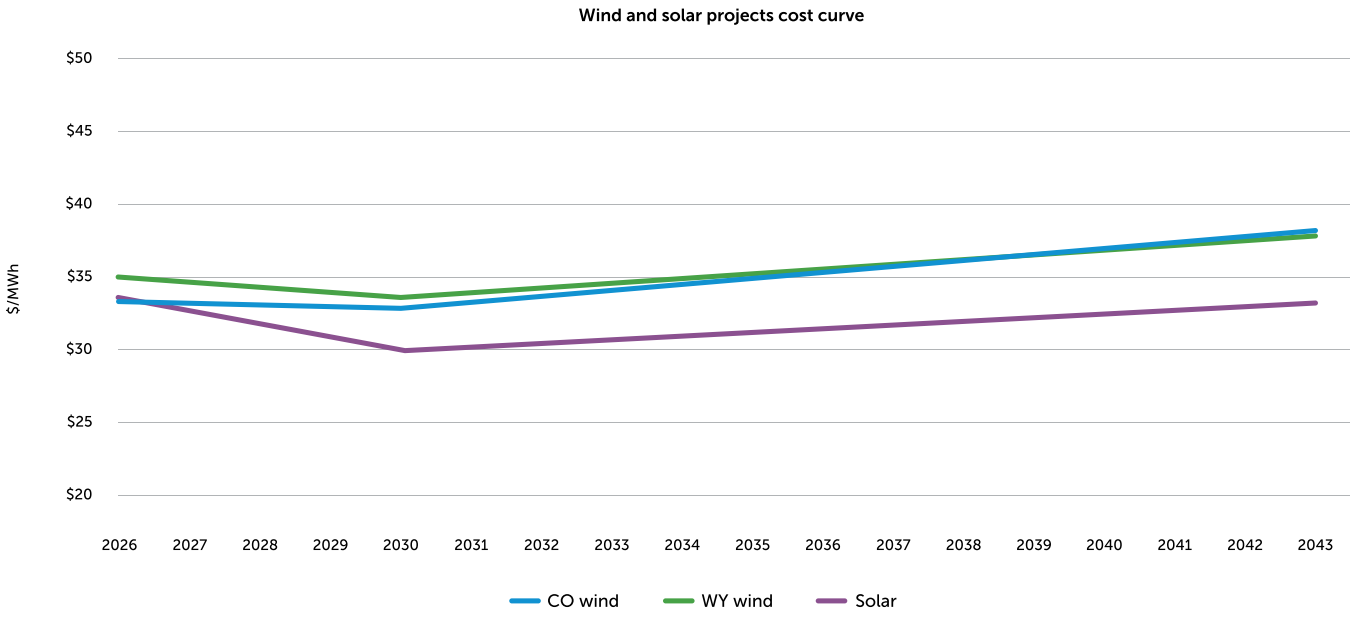


Figure 44. *Wind and solar projects cost curve*

Platte River assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Solar ancillary service costs in 2024 were assumed at $0.09/kw-mo.

6.3.6 New storage resources

Energy storage is the keystone in a deeply decarbonized power supply portfolio. A 100% renewable power supply portfolio using wind and solar as the main source of energy will need energy storage from a few seconds to several days to complement supply intermittency. Platte River considered a variety of different commercially available battery storage technology options, including lithium-ion batteries for four-hour storage duration, flow batteries for 10-hour storage duration and long-duration energy storage batteries for 100-hour storage duration. These battery types will provide different services to support the grid while complementing renewable intermittency.

Four-hour lithium-ion battery technology is mature and commercially available. We assumed 200 MWh of storage per 50-MW four-hour battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Four-hour batteries were assumed to have an 85% round trip storage efficiency. The economic life of a four-hour battery was modeled to be 20 years. Like wind and solar, 2024 prices for four-hour battery storage were based on the recent RFP and vendor negotiations. Future prices escalate based on the 2022 ATB. See the cost projections in Figure 45.

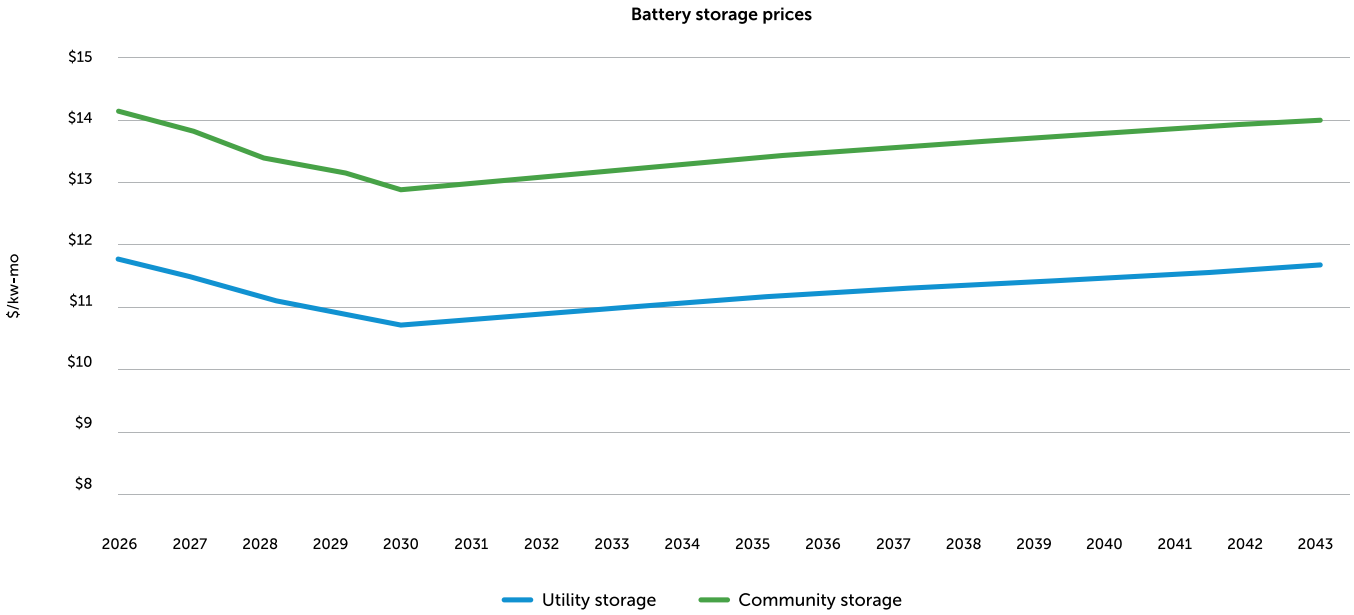


Figure 45. *Battery storage prices*

Ten-hour flow batteries are an emerging technology with no existing commercial installations as of 2023. We worked with a vendor to get cost, efficiency, and performance details. Based on the data provided by the vendor, this technology was not found to be economical during our early technology screening and minimal cost portfolio development process. Therefore, this technology was not considered as a resource in the IRP. However, this technology has potential to become part of the future power supply portfolio. As the technology matures, Platte River will consider it.

Long-duration energy storage is critical for supplying power during extended dark calm periods. Like flow batteries, this technology is also under development with no existing commercial installations as of 2023. Platte River analyzed the cost, efficiency, and performance details of long-duration energy storage. When fully developed and commercialized, long-duration energy storage will reduce the need for fossil generation to provide backup power and reliability in a renewable portfolio. Platte River plans to integrate a 10 MW pilot unit before 2030. For IRP modeling, we assumed that the technology will be commercially available by 2035. The current capital cost of this technology is high, and the round-trip efficiency is low. We assumed cost reduction and performance improvements over time as the technology matures and finds commercial applications.

6.3.7 New dispatchable thermal generation resources

As mentioned earlier, after a thorough review of all the options for no- or low-carbon fuels, and for dispatchable generation technologies, Black & Veatch recommended Platte River use natural gas-fired generation for 2028 commercial operation and then convert to green hydrogen fuel when it is commercially available. Platte River and Black & Veatch looked at 50+ options and screened down to the seven listed in Table 17 for detailed assessment.

Characteristic	Unit	LM2500	LM600	LMS100	RICE	7F CC conver-sion	LM600 CC	SGT800
Unit size	MW	28	40	90	17	17-116	31-44	55
Heart rate	btu/kWh	9,875	9,649	8,820	8,510	6,646	7,087	9,707
Cost per MW	$M/MW	$1.8	$1.7	$1.2	$1.7	$2.2	$2.3	$1.4

Table 17. *Screened dispatchable technologies*

LM2500, LM6000 and LMS100 are aeroderivative CTs manufactured by General Electric. RICE is reciprocating internal combustion engine. The next two were combined cycle options; converting the existing 7F CT at Rawhide station or install 4 LM6000 CTs with combined cycles. Finally, SGT800 is a combination of frame and aeroderivative technologies manufactured by Siemens.

After analyzing the levelized cost of energy and reviewing operational characteristics of the seven technologies, a smaller group of four featured in Table 18 was selected for more detailed assessment. These four technologies were further analyzed in detail for characteristics like reliability, emissions, economic value, operational flexibility, fuel versatility, constructability and market performance. During this detailed evaluation, higher weights were assigned to the factors aligned with Platte River's three pillars of reliability, environmental responsibility and financial sustainability. This analysis concluded that aeroderivative technology was the best option for Platte River. The LM6000 technology was selected as the presumed technology for inclusion in the supply portfolio.

Qualification	Weight	Option 1	Option 2	Option 3	Option 4
Reliability	30%	1.52	2.52	2.7	1.51
Emissions	25%	0.7	2.41	2.34	1.69
Costs	20%	1.55	1.47	1.55	2
Operational flexibility	10%	0.9	0.91	0.88	0.8
Fuel versatility	5%	0.05	0.36	0.36	0.42
Constructability	5%	0.45	0.45	0.45	0.35
Market performance	5%	0.4	0.5	0.45	0.45
Total weighted score	**100%**	**5.57**	**8.62**	**8.72**	**7.21**

Table 18. *Results of detailed screening of four selected technologies*

07 IRP design



7.1 Studies

The following studies support this IRP. All studies are available on the IRP microsite.

- PRM and ELCC study by Astrape Consulting
- Beneficial electrification forecast by Apex Analytics
- Distributed energy resources forecast and potential study by Dunsky
- Extreme weather events and dark calm analysis by ACES
- Independent review of dispatchable capacity needs by Black & Veatch
- Generation technology screening by Black & Veatch

Additionally, this IRP uses fundamental market analysis of supply and demand in the region provided by Siemens, and a locational marginal pricing assessment by ACES.

7.2 Objectives

The objective of this IRP is to continue Platte River's journey toward achieving the goals of the RDP by developing a roadmap to meet the owner communities' needs for reliable, environmentally responsible and financially sustainable energy and services using a diverse power supply portfolio.

7.3 Planning for a reliable future power supply

Power supply reliability is a key responsibility of a utility. It is a foundational pillar for Platte River's planning and operations. Platte River plans to join a full organized energy market in 2026, which will take over transmission planning and some operational responsibilities. In a market, a load-serving entity like Platte River is required to bring enough resources to reliably serve its load according to the reliability criteria enacted by the market operator. Markets allow a wider access to improve economics and reliability under varying weather and operating conditions, but they do so by relying on the resources contributed by each market participant. This chapter covers reliability modeling in the IRP and the development of different power supply portfolios to cover a wide range of future possibilities.





7.3.1 Power supply reliability

As society's dependence on electricity increases, power supply reliability is becoming more critical. Electric reliability is not only the foundation for commerce; our security and safety depend on it. This critical dependence became tragically clear when Texas power outages during Winter Storm Uri caused 246[16] deaths and billions of dollars in economic losses.

Power supply reliability is the ability of a power system to keep the lights on under changing supply and demand conditions. Electric utilities must plan, design, construct and operate an electric supply system for reliability of supply.

There are a few terms used under the broad umbrella of reliability:

- Adequacy is a measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, considering scheduled and unscheduled outages of system components.
- Security is the ability of the power system to withstand disturbances.

[16] Texas winter storm: 246 Texans' deaths classified as winter-storm related (kxan.com).

[17] https://www.energy.gov/articles/economic-benefits-increasing-electric-grid-resilience-weather-outages



- Resilience is the ability to quickly adapt and recover from a disruption, with minimal impact.

Historically, threats to power supply reliability included equipment failure (at the distribution, transmission, or generation level) or extreme weather like hurricanes, floods, snowstorms and heat storms. More than 90% of the power supply interruptions or reliability events can be attributed to breakdowns in the distribution system.[17]

Distribution system interruptions are typically localized and affect a small number of customers. Reliability events that stem from interruptions on the generation or transmission system, or lack of generation, are broader reaching and potentially more consequential. With increased reliance on wind and solar generation in the future, an additional threat to reliability will be low or no production from these intermittent resources for extended periods.

In our IRP process, Platte River focuses on reliable, environmentally responsible and lowest reasonable cost power supply portfolios. Some of the major variables that drive power supply reliability in our planning process are:

- Occasional generation equipment failures
- Load forecast uncertainty
- Variability of hourly wind and solar generation patterns
- Occasional extreme weather (such as heat or cold waves)
- Extended periods of low or no renewable generation

After an extensive review of hourly generation profiles of solar and wind, we found that there are certain times when there is very little or no renewable generation for extended periods. We call these incidents dark calms. We have found that dark calm events occur frequently and can last from a day to as long as seven days.

While our definitions of reliability and related concepts are general, over the years the power industry has developed specific metrics and methods to plan for a reliable supply portfolio as discussed in the next section. A starting point for developing a reliable power supply is a resource adequacy study. This study simulates a future power supply portfolio under varying conditions of power supply and power demand to assess its reliability.

7.3.2 Planning for a reliable future portfolio

7.3.2.1 Reliability metrics for planning

The North American Electric Reliability Corporation, the regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, defines requirements for resource adequacy in Standard BAL-502-RFC-02.[18] This standard requires utilities to "calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1." This metric is also referred to as Loss of Load Expectation (LOLE) of 0.1 per year or LOLE of one day in 10 years, or sometimes, as "One Day in Ten Years" (ODTY). This metric has been widely used in planning studies since the early days of modern power systems.[19]

This metric has traditionally guided investment in generation to provide reliability accepted as the optimal target. Historically, ODTY or 0.1 day LOLE per year has required utilities to maintain a 10-15% PRM. PRM is defined as the percent additional firm capacity relative to the peak demand in a future year. Specifically,

$$\text{PRM} = \frac{\text{Firm capacity - peak demand}}{\text{Peak demand}}$$

Historically, PRM covered planned or unplanned outages (equipment breakdowns) and load forecast error due to weather and economic growth uncertainty. Following the retirement of dispatchable coal generation (which provides



firm capacity) over the past decade, and with the introduction of intermittent renewable generation resources, the structure of power supply portfolios is rapidly changing.

LOLE of 0.1 day per year is still the dominant metric in the power industry, but some alternatives are being proposed and debated.[20] The main criticism of 0.1 day LOLE per year metric is that this probabilistic calculation does not adequately measure the depth (how much power was lost, or how many customers lost power), breadth (how long power was lost) and the frequency (how often power was lost).

In a recent report,[21] EPRI summarized the existing and proposed metrics, arguing that a single metric such as ODTY may conceal some risks and may not be able to sufficiently capture



the future challenges to the power grid from:

- Rapid decarbonization of power supply with the retirement of dispatchable resources and adoption of intermittent renewables.
- Adoption of electrification in transportation and heating.
- Adoption of DERs with wider customer involvement.
- Climate change and extreme weather events.

With the introduction of renewable generation, the concept of planning for the "Peak Hour" of the year is giving way to planning for every hour in the year. The hour when the system experiences peak demand is less important than the load net of renewables. For example, Figure 46 from New York ISO[22] shows that typically they experience peak demand between 3-4 p.m. in July, but, due to solar generation, the net peak demand is lower and shifts to 5-6 p.m.

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

[19] https://www.astrape.com/wp-content/uploads/2024/01/EISPC_The_Economic_Ramifications_of_Resource_Adequacy_White_Paper.pdf

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-telos-and-gridlab.pdf

[21] https://www.epri.com/research/products/000000003002023230

[22] https://www.nyiso.com/-/shaving-peaks-with-the-sun

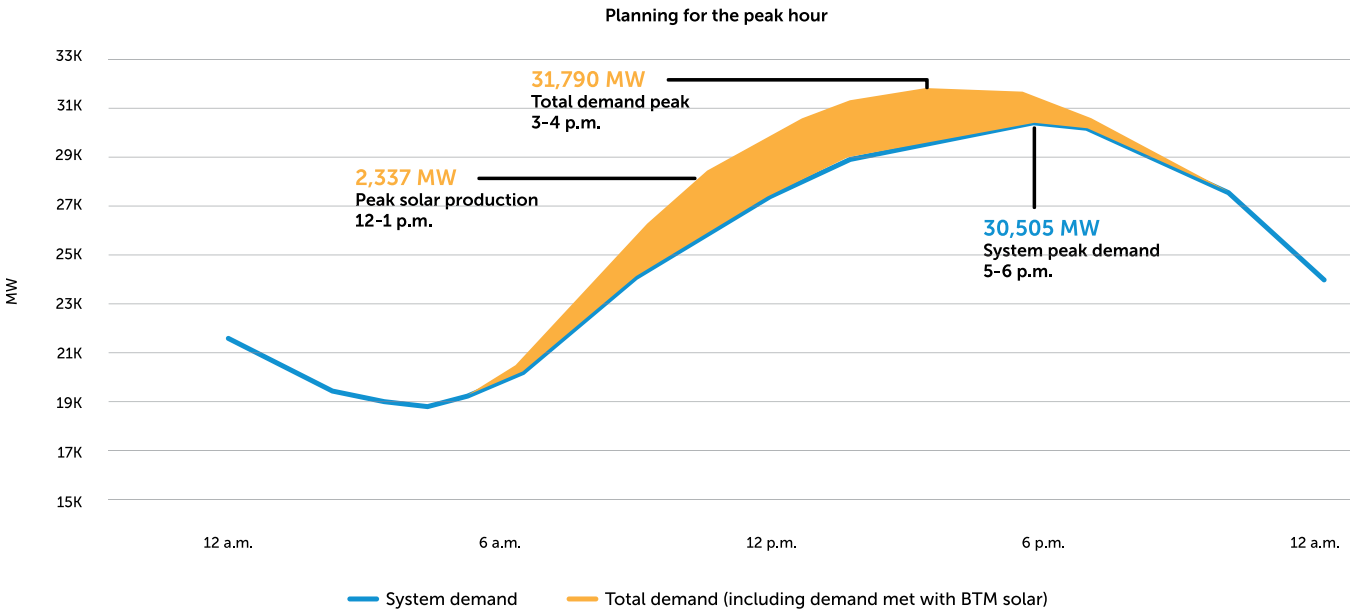


Figure 46. *Planning for the peak hour*

Other parts of the country experience similar phenomena. Wind generation may shift the net peak demand to different hours. In fact, the Western Electricity Coordination Council (WECC), the entity responsible for reliability of the electric grid in 13 western states (including Colorado), is proposing to estimate resource adequacy for every hour, targeting an hourly LOLE of 0.002%.[23]

7.3.2.2 Platte River PRM for future planning

For the 2020 IRP, Platte River used a 15% PRM as its reliability metric. With the changing portfolio mix in the region[24] and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy[25] study for this 2024 IRP. This study computed PRM and ELCC[26] of intermittent renewable resources, small amounts of energy battery storage and DERs. The study focused on the year 2030 and modeled the Platte River supply portfolio, along with other utilities in Colorado. The study assumed these utilities will develop the power supply portfolios projected in their respective IRPs and will be part of a functioning market. The study concluded that all Colorado utilities, including Platte River, would need a PRM of 19.9%. This value, though higher

[23] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default

[24] Platte River has filed a voluntary clean energy plan committing to reduce its 2030 CO2 emissions by at least 80% from 2005 levels.

[25] https://www.prpa.org/wp-content/uploads/2023/11/2024IRP-PRM-and-ELCC-study-by-Astrape.pdf

[26] ELCC of a resource is the measurement of that resource's ability to produce energy at the time of peak demand.

[27] https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

than the 2020 IRP PRM of 15%, aligns with the WECC-recommended Planning Reserve Margin Index or Variability Margin Index in its 2023 Western Assessment of Resource Adequacy[27] report. Power markets like the Midcontinent Independent System Operator (MISO) and SPP are also looking at higher PRMs than previously recommended due to coal retirements and more intermittent energy integration.

Astrape's proposed PRM of 19.9% for 2030 incorporates its analysis of Colorado, utilities including Xcel Colorado, Colorado Spring Utilities and Black Hills Colorado, using their modeling platform Strategic Energy & Valuation Model, which is also used by major U.S. utilities and several regional power pools. Astrape modeled major uncertainties like weather by using 42 years of historical data for hourly wind, solar and load shapes, three to five days of dark calms, five scenarios of future load forecast error and 300 scenarios of generation availability, for a total of 63,000 simulation scenarios for each hour of the year 2030. This comprehensive analysis produced the relationship between LOLE and PRM as shown in Figure 47.

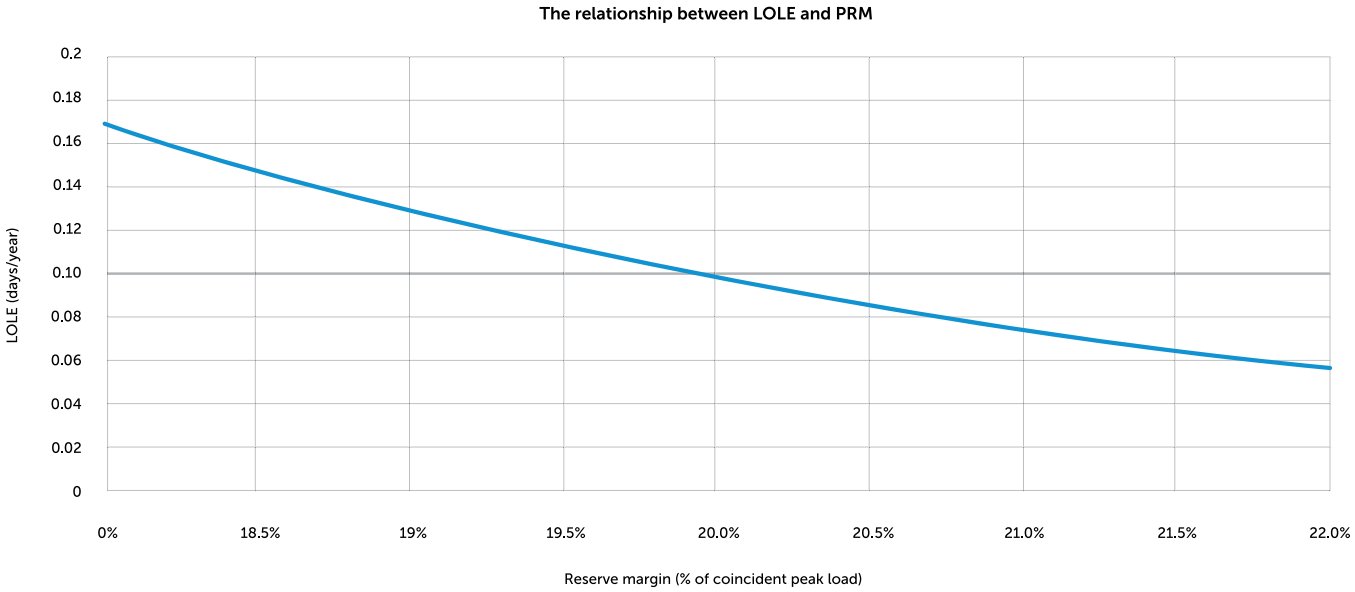


Figure 47. *The relationship between LOLE and PRM*

At 0.1 day LOLE per year, the PRM is 19.9%. If we were to build a more reliable system with a LOLE of 0.06, or one outage every 16 years, we will need a PRM of 21.8%. On the other hand, a LOLE of 0.16, with an expected outage every six years, would require a PRM of 18.4%. Essentially, the more spare capacity we have, the less likely we are to face a supply shortage or LOLE.

As mentioned earlier, EPRI recommends not relying on one metric. Utilities and other entities are considering many metrics. In addition to the PRM, we used Loss of Load Hours (LOLH) in our IRP modeling. LOLH measures the average duration of outages. We used LOLH 0.2 during reliability testing of our portfolios.

7.3.2.3 ELCC values for renewables and limited energy resources

The ELCC of a renewable or energy-limited resource measures its expected contribution to peak demand. For example, 100 MW from a coal or gas fired plant can provide 100 MW at the time of peak. When running at full load, it will reduce the peak load by 100 MW. The ELCC of this resource is 100 MW or 100%.

But 100 MW of wind, solar or four-hour storage may or may not be able to provide 100 MW at system peak. This means its ELCC will be lower than the nameplate capacity. This can be seen for solar generation in the example shown in Figure 48. It shows hypothetical hourly load and solar generation forecast for a summer day in 2030 for Platte River's system.

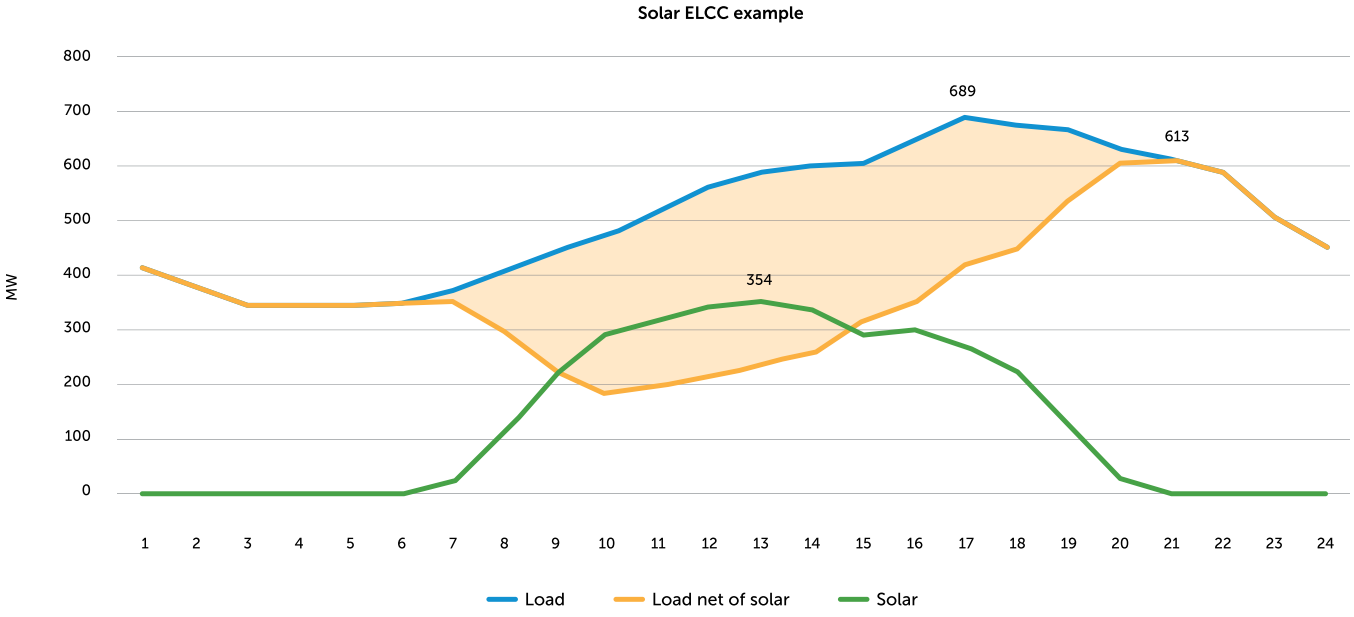


Figure 48. *Solar ELCC example*

The blue line shows hourly load for 24 hours across the day. The peak load during the day is 689 MW at hour 17 or 5 p.m. The green line shows solar generation. It starts around 6 a.m., peaks at 354 MW at 1 p.m. and drops to zero by 9 p.m. The orange line shows hourly load net of solar generation. Solar generation reduces the load by the shaded area. The orange line shows that the peak hour of the load has shifted from 5 p.m. to 9 p.m. and is 613 MW. So, the solar generation has reduced the peak demand by 76 MW (689 minus 613). While the maximum solar generation is 354, the nameplate of installed capacity of solar is 507 MW in this example. For this day, solar ELCC is 76/507=15%. In other words, installed capacity of 507 MW reduces the peak demand by 76 MW. Put another way, the effect solar had on the peak is that it reduced peak by 76 MW.

As we install more solar, its impact on reducing peak will be zero, because the peak demand hour has already moved to 9 p.m., after sunset when solar stops producing. In that case, the incremental ELCC of solar after 507 MW is zero. This example shows just one hypothetical day. In reality, ELCC calculations are computed after thousands of simulations under different load and weather conditions.

ELCC of wind and other resources follows the same declining pattern with more resource additions. As more wind is added, the incremental contribution of the next wind project to reduce peak demand continues to decline. Figure 49 shows the ELCC values of solar, wind and four-hour storage through time as computed by Astrape, which we used for this IRP. As utilities in Colorado add more of these resources over time, their ELCC contributions diminish.

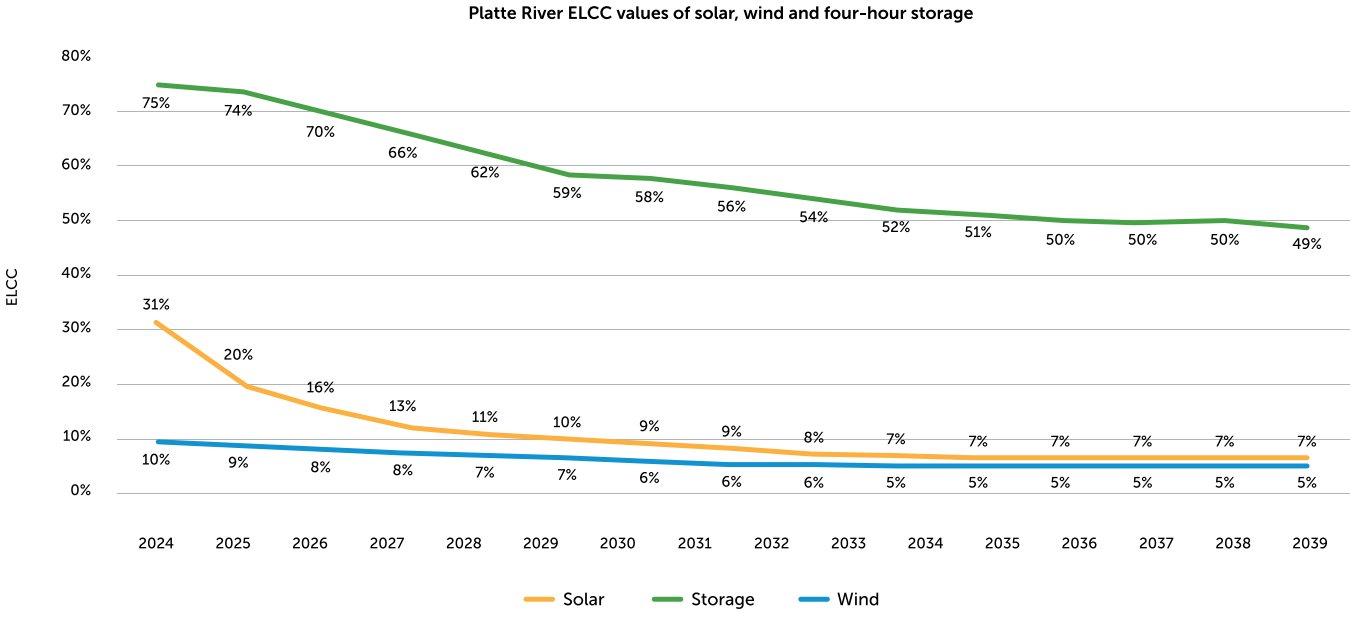


Figure 49. *Platte River ELCC values of solar, wind and four-hour storage*

Table 19 shows ELCC values of longer duration battery storage and some DER technologies, as computed by Astrape and used by Platte River in this IRP. The installation of more resources of the same type reduces that resource type's ELCC. For example, the ELCC of distributed solar is 8.5% if Colorado utilities install 500 MW. It drops to 5.8% with 4,000 MW installed.

Technology	Penetration (MW)	Average ELCC (%)	Marginal ELCC (%)
8-hour batteries	500	92.7%	91.6%
8-hour batteries	1,000	90.5%	84.4%
8-hour batteries	1,500	87.0%	75.6%
100-hour batteries	500	92.7%	91.6%
100-hour batteries	1,000	91.9%	90.8%
100-hour batteries	1,500	91.4%	90.0%
Distributed generation solar	500	8.5%	7.9%
Distributed generation solar	1,000	8.0%	7.2%
Distributed generation solar	2,000	7.2%	5.8%
Distributed generation solar	4,000	5.8%	2.9%
Beneficial electrification	100	6.9%	7.4%
Beneficial electrification	200	7.3%	8.2%
Beneficial electrification	300	7.8%	9.0%
Electric vehicles	100	32.0%	33.6%
Electric vehicles	200	33.8%	37.3%
Electric vehicles	300	35.7%	41.0%
Demand response	100	92.3%	87.3%
Demand response	200	87.1%	77.8%
Demand response	300	82.6%	70.4%

Table 19. *ELCC values of long-duration energy storage and DERs*

7.3.2.4 Extreme weather and dark calm modeling

Winter Storm Uri, which brought blackouts to Texas and stressed power supply across a much wider area, also impacted power supply in our area. Due to extremely cold weather for many days, demand for electricity continued to rise. Additionally, there was very little renewable generation for almost 80 hours during Feb. 12-16, 2021, as shown in Figure 50.

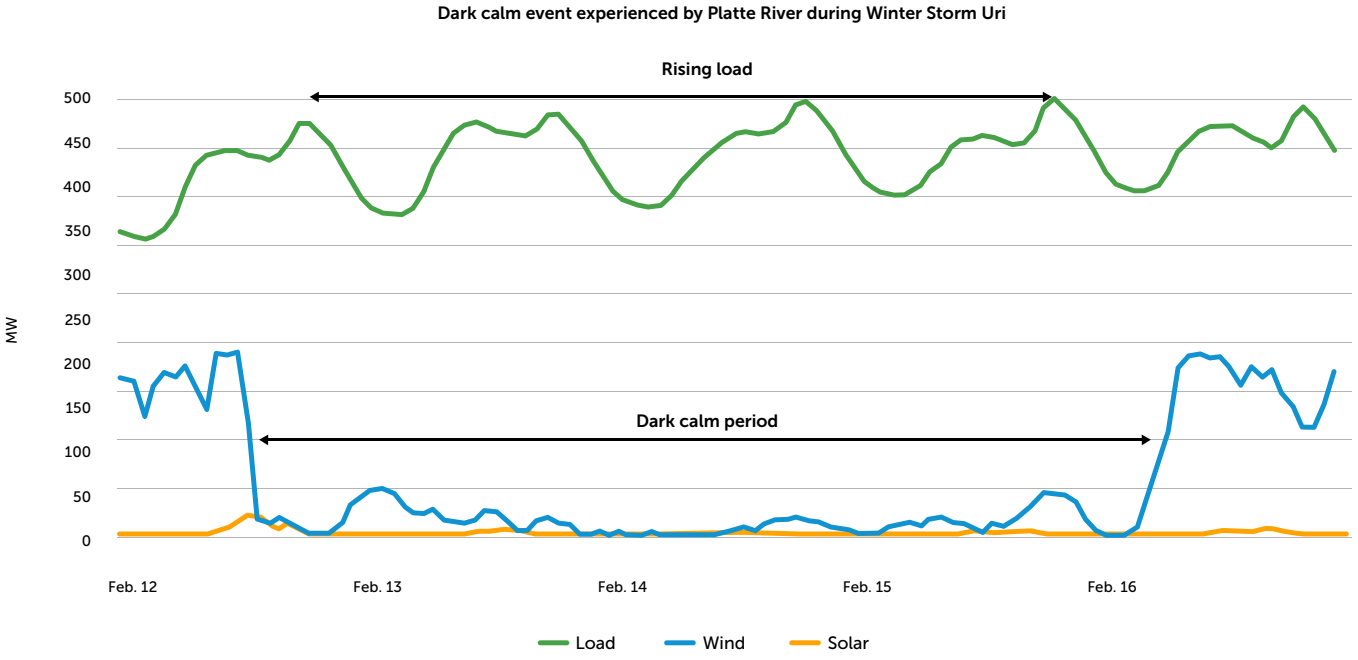


Figure 50. *Dark calm event experienced by Platte River during Winter Storm Uri*

During this 2021 dark calm, Platte River was able to serve its customers' load reliably because dispatchable coal resources were available. But after coal units retire in 2030, we may experience similar or even more severe dark calms. A fundamental requirement of an IRP is to develop supply portfolios that will be reliable under varying conditions of weather, previously experienced or not. This led us to hire ACES to conduct a study on extreme weather and dark calm events.[28]

ACES reviewed hourly weather profiles for 70 locations west of Mississippi for the past five decades (1973-2019) to estimate the frequency, duration and depth of extreme weather and dark calm events. Since these events are uncommon, ACES reviewed weather data across a wide region and over a long period of time to enhance confidence in the findings. Figure 51 shows locations of the airports where data was collected.

[28] https://www.prpa.org/wp-content/uploads/2023/04/2024IRP-Extreme-weather-events-and-Dark-Calm-Analysis-by-ACES.pdf In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).



Figure 51. *Locations of extreme weather events*

7.3.2.5 Extreme weather events

The study found the following durations and frequencies of heat and cold waves:

Heat wave summary – west region						
Number of hours	48	72	96	120	144	168
Events per year	0.47	0.02	0.09	0.04	0.021	0.043

Table 20. *Heat wave summary - west region*

This means every other year, there is a heat wave lasting two days and every 11th year, there is a heat wave lasting four days.

Cold wave summary – west region													
Number of hours	48	72	96	120	144	168	192	216	240	264	288	312	336
Events per year	4.9	1.7	0.9	0.4	0.17	0.08	0	0	0	0	0	0	0

Table 21. *Cold wave summary - west region*

This data shows cold waves are more common with five two-day events every year and a weeklong event almost every 12th year.

The study also found that load, power and gas prices rise during these extreme events and noted these increases during winter storms Uri and Elliot and the 2020 summer heat wave in the Pacific Northwest. Because our focus with extreme weather modeling is on reliability, we assessed how extreme weather impacts load only. The study found that during these events, on average, the load could increase by about 10% relative to the normal load for that time of year. So, for reliability assessments during extreme weather, we increased the hourly load by 10%.

7.3.2.6 Dark calm events

Frequency and duration of dark calm events was assessed for the MISO North , covering parts of Illinois, Indiana, Wisconsin and Michigan; MISO Central, covering parts of Minnesota, Iowa and North Dakota; and the Northwest portion of the Electric Reliability Council of Texas (ERCOT. Table 22 shows the frequency and duration of different levels of dark calm events.



Dark calm events by location				
% of full output	48 hours	72 hours	96 hours	120 hours
MISO Central				
5%	3.0	1.25	0.5	0.25
10%	11.2	5.6	2.4	2.0
15%	6.2	11.4	3.8	4.8
MISO North				
5%	1.0	1.0	0.67	0.0
10%	5.0	1.75	0.5	1.0
15%	2.2	3.0	1.2	2.0
Northwest ERCOT				
10%	3.8	1.0	0.2	0.2
15%	3.2	3.4	3.0	1.2

Table 22. *Dark calm events by location*

As shown in Table 22, a dark calm event in MISO Central, where the output of renewable drops to 5% of total generation occurs:

- Three times during the year for two days every year
- Once per year for three consecutive days
- Every other year for four consecutive days
- Every four years for five consecutive days

Dark calm events where output of renewables drops to 10% of total generation are more frequent than events where renewable generation is only 5% of total generation. Dark calm events are less intense and less frequent in MISO North and Northwest ERCOT.

In the Plexos model, we averaged the two 5% rows for MISO Central and MISO North. Multiplying the probability of an event's occurrence with its duration yields the expected outage hours in a given year for that event. For example, as illustrated in Table 23, an average of two events with a duration of 48 hours means any given year would expect a total of 96 dark calm hours because the events last two days.

Since the events are non-additive, we sum all the expected hours to find the total expected dark calm hours in a year. In this case, an average year would see a total of 248 hours of dark calm spread across events of different durations.

Dark calm duration (hours)	48	72	96	120	Total dark calm hours
Average # of dark calm events across all regions (5% of full output)	2.000	1.125	0.585	0.125	
Expected dark calm hours per year	96	81	56.16	15	**248.16**

Table 23. *Dark calm event duration and frequency*

7.3.2.7 Transmission planning

Platte River conducts annual transmission assessment studies to plan for a system that adequately supports both short and long-term load obligations to the owner communities. The studies use transmission network modeling software and integrate forecasted owner community loads, existing and planned generation, and loads and generation from neighboring utilities.

Short-term studies evaluate system needs under the current transmission network configuration, integrating projected short-term load and generation forecasts. Evaluating long-term transmission needs includes forecasting long-term load and generation forecasts with both the current transmission system and planned transmission additions.

The study objectives are for the transmission system to perform reliably during extreme contingency situations, heavy or light load conditions and fault events. If a study identifies network deficiencies, further analysis follows to determine network expansion options to mitigate those deficiencies. Transmission studies are conducted during annual internal assessment activities, along with collaborative studies with regional transmission planning committees.

7.3.3 Need for new resources

As explained in chapter 5, we forecast our future energy needs as annual peak demand (maximum demand in any hour) and total annual energy for every hour of the year. For supply-side planning, we adjust these values with DER contribution from our customers. The net peak demand and energy demand are what Platte River needs to plan for through this IRP process. As discussed earlier in this chapter, Platte River plans to meet its future peak demand with 19.9% PRM to protect supply reliability. We also discussed that renewable and energy limited resources contribute less ELCC capacity toward the peak demand than their maximum or nameplate capacity.

Figure 52 shows the capacity requirements and capacity contributions from the existing and committed resources.

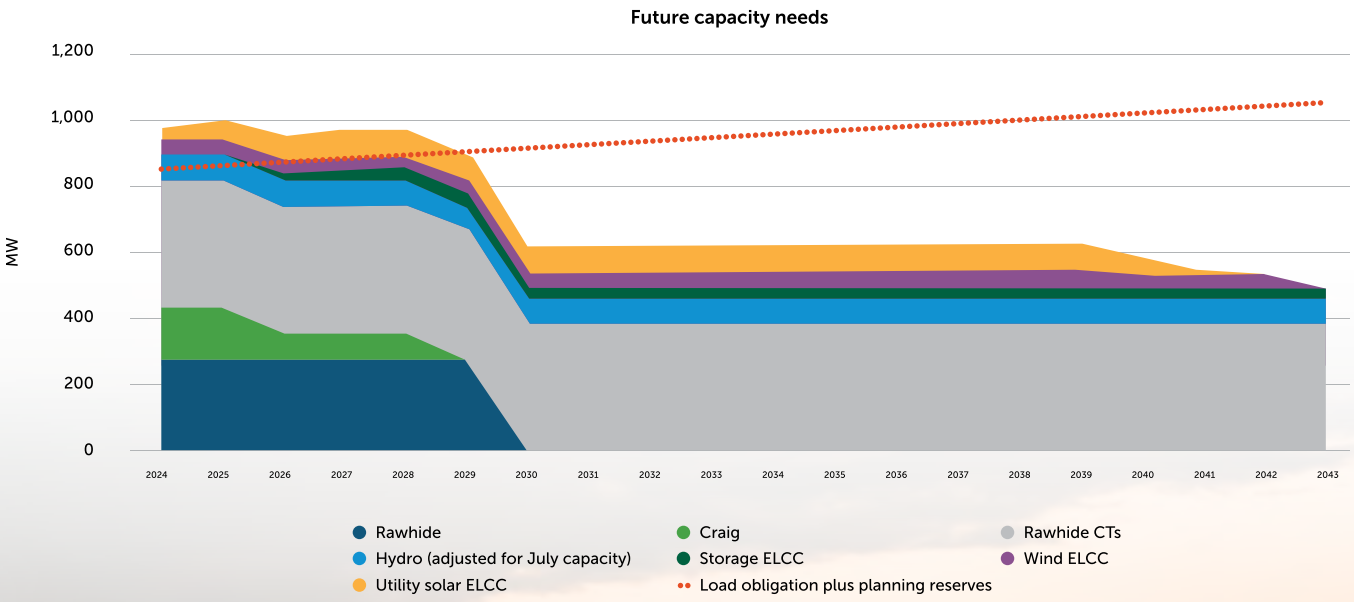


Figure 52. *Future capacity needs*



The dotted red line shows capacity requirements, while the area chart shows the capacity available. By 2029, following the retirements of Craig coal units, Platte River would need to build some new capacity, and by 2030, with the retirement of Rawhide coal plant, the additional capacity requirement rises to about 200 MW. The gap continues to expand as our load continues to increase and when our existing wind and solar PPAs reach their maturation dates. The IRP process offers recommendations to fill this gap with the lowest cost, least-emitting reliable resources.

Figure 53 shows similar chart depicting the energy deficit that will need to be filled in this IRP. Note small changes in renewable energy from year to year are due to projected changes in excess or "dumped" renewable generation.

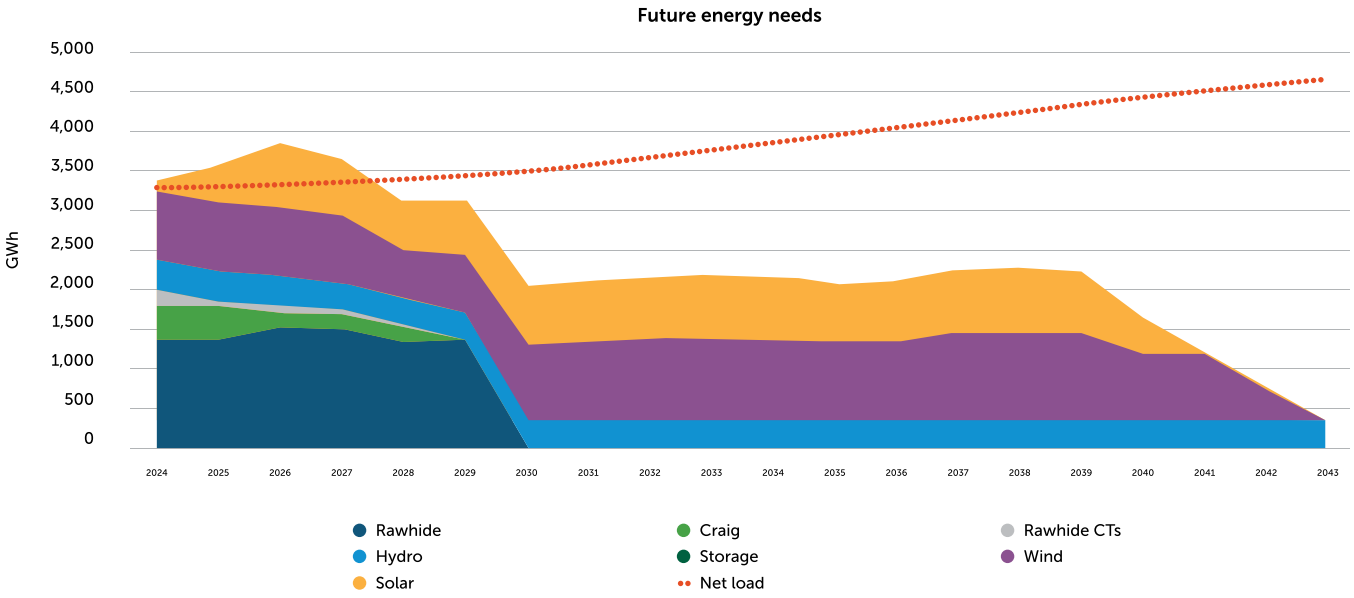


Figure 53. *Future energy needs*

Although capacity and energy gaps appear in 2030, Platte River plans to bring new resources online before 2030. This would give us time to test the availability and reliability of our new portfolio before retiring the last coal plant by the end of 2029.

7.4 Future portfolios

The portfolios selected for this IRP are designed to capture the range of potential paths available to Platte River as it transforms its generation portfolio and strives to meet the RDP goal. Reliability is the only firm constraint common to all portfolios. Other financial, operational and environmental metrics are optimized within the unique constraints of each portfolio.

Due to PRM requirements and to support reliability during dark calm events, Platte River keeps its existing combustion turbines in all portfolios. All portfolios emit some CO2 in 2030 because dispatchable noncarbon options will not be available by 2030, so thermal units are dispatched to balance the system during shortages. Portfolios that build new dispatchable thermal generation assume a blend 50% green hydrogen fuel by 2035 to reduce CO2 emissions. All dispatchable thermal generation is assumed to switch to 100% green hydrogen by 2040 and reach zero CO2 emissions. No new dispatchable thermal generation is allowed after 2030 and the IRP assumes long-duration energy storage becomes available in 2035. All portfolios assumed that future electricity prices would also include carbon taxes. Below is a brief description of all the portfolios.

7.4.1 No new carbon

In this portfolio, Platte River cannot add new thermal generation. Wind, solar and four-hour storage are the only new resource additions available until 2035, when long-duration energy storage is assumed to also become available. This portfolio is designed to test the feasibility of relying on the existing combustion turbines to maintain reliability, without adding new thermal generation.

7.4.2 Minimal new carbon

This portfolio is built to add minimal amount of new thermal generation. It adds only 80 MW of new dispatchable thermal generation.

7.4.3 Carbon-imposed cost

This portfolio is built with the cost of carbon assigned to the dispatch cost of all thermal units. This additional cost, assigning a dollar value to the externalities associated with emitting CO2, disincentivizes the construction and use of carbon-emitting resources unless it is more cost effective than other options after accounting for the social cost of carbon. Specifically, this is a least-cost portfolio where the assumed cost carbon emissions have been internalized into the optimization process.

7.4.4 Optimal new carbon

This portfolio is a balance between the additional new carbon and carbon-imposed cost portfolios in terms of reliability and cost, building 200 MW of new thermal generation. This portfolio is optimal to support reliability in all conditions, as dark calm and extreme weather events continue to become more severe, as they have in the recent past.

7.4.5 Additional new carbon

This portfolio is the result of a least-cost optimization. The model builds the lowest-cost portfolio that meets reliability standards, but adds no additional constraints to guide resource selection or operation.

7.5 Methodology

Developing future power supply portfolios is a multi-step, iterative process. Figure 54 illustrates the initial steps and the subsequent iteration through the remaining steps.

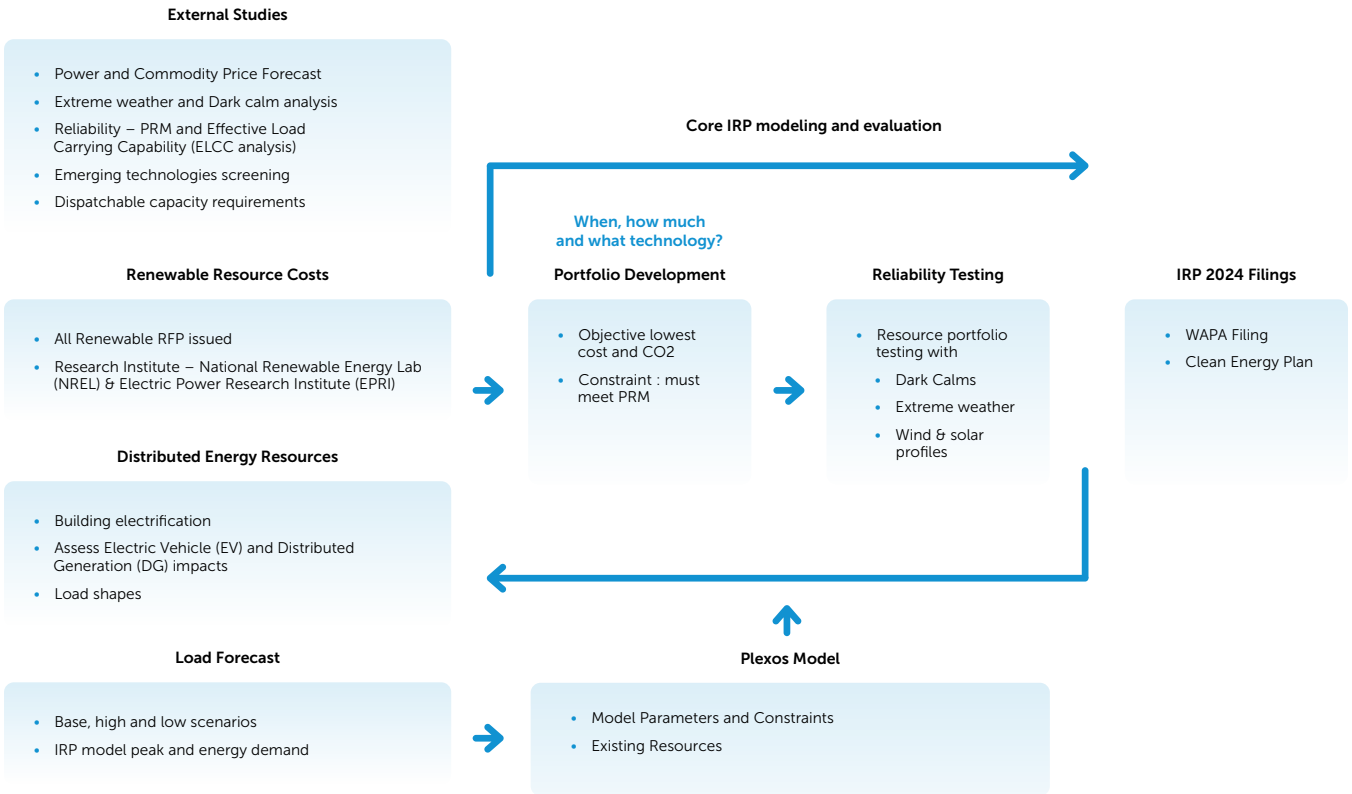


Figure 54. *IRP process*



7.5.1 Multi-step portfolio selection methodology

Data collection and review: Gather data on existing resources, including their performance and their expected operational lives; develop power and fuel price forecasts; review existing and potential future environmental regulations. These results provide a first step in understanding the planning landscape for the IRP.

Demand forecasting: Estimate future electricity demand, considering factors such as population growth, economic trends and technological advancements to project the energy needs over the planning horizon.

DER forecasting: Forecast new sources of demand, such as beneficial electrification and electric vehicles as well as additional demand-side resources, including customer-sited storage, rooftop solar, demand response and other programs.

Technology assessment: Evaluate the performance, costs, and environmental impacts of various energy technologies, including renewable energy sources, dispatchable thermal resources and energy storage. Based on the results of this high-level evaluation, Platte River can eliminate some technologies from consideration.

Stakeholder engagement: Collect feedback from a broad range of stakeholders. Community members, local businesses and advocacy



organizations are invited to offer their ideas and raise any concerns they have with the IRP process. This collaborative approach helps portfolios reflect the range of interests and priorities in the communities we serve.

7.5.2 Portfolio iterations

Optimization modeling: Use Plexos to develop and evaluate different portfolios of energy resources. Each portfolio is the result of a unique mix of inputs and constraints designed to test different aspects of the planning criteria, such as financial sustainability or environmental responsibility.

Reliability testing: Conduct reliability testing to identify uncertainties and potential challenges associated with different resource options. With high penetration of variable generation, the most critical risk tests quantify the system's exposure to dark calms or extreme weather. Platte River also reviews potential challenges associated with excessive energy length (too much energy produced compared to load) in a region expected to add substantial amounts of renewable energy in the future.

Sensitivity analysis: Explore how different external factors, such as fuel and market prices or emissions, might influence the performance of the portfolios. This helps develop plans that should be resilient under a range of future outcomes.

7.6 Reliability testing of portfolios

Because reliability is a foundational pillar, we first make sure each candidate portfolio is sufficiently reliable. As a starting point, a least-cost portfolio is developed to fill the capacity and energy gaps identified above while meeting the PRM requirement for every year of the planning horizon. Meeting the annual PRM requirement while applying the ELCC to energy-limited resources is useful, but does not test or guarantee reliability during extreme weather events or dark calms. So we conducted additional reliability testing through the Monte Carlo functionality in Plexos to understand how the portfolios might behave under stress conditions. Using the data from the extreme weather report supplied by ACES and historical weather data from Vaisala, we modeled different system conditions with the following variables:

1. **Weather:** Wind and solar profiles reflecting conditions from 1997-2019 (hourly profiles for 24 years), drawn with equal probability across the suite of simulations. In our runs, with 504 iterations, each weather year was experienced 21 times.

2. **Thermal unit outages:** The software randomly draws the timing of thermal unit outages. The duration of outages is also hypothetical, but the software does align the random outages with the known long-term forced outage rate over the course of many draws.

3. **Load forecast error:** Each iteration simulated a potential deviation from the near-term load forecast. This represents a shift in load drivers, such as population changes or economic indicators, over the one-to-four-year horizon, which is too short for the utility to respond to. The system, as built, would need to cover these near-term divergences before new resources could be brought online in response. For this IRP, Table 24 summarizes the potential load forecast error outcomes.

LFE	Probability
-4%	7.26%
-2%	24.10%
0%	37.28%
2%	24.10%
4%	7.26%

Table 24. *Potential load forecast error outcomes*

4. **Dark calm events:** Based on observed historical events, the model simulated weather events with impacts on both load and weather-dependent generation. These events could last between one and five days, with a two-day event being the most common. Often, dark calm events occur with extreme weather events. In any year, the system would expect to experience a total of 248 hours of extreme weather conditions distributed across several events. As with thermal outages, specific years could experience higher or lower than average dark calm outages with the long-term average converging to the expected value over may iterations. Across all 504 iterations of our reliability modeling, the dark calm hours in a year varied from a low of 119 hours to a high of 458 hours. Specific details on the impact to wind, solar and load are described below.

    a. **Load:** Load is modeled to increase by 10% during the event, which is consistent with data seen in other regions during extreme weather events. This is primarily driven by increased heating load during winter storms while cooling load is expected to increase during heat dome events in the summer. This increase captures the load already embedded in the load forecast.

    b. **Building heating:** During extreme winter storms, some new load from heat pumps is expected to shift to much less efficient electrical resistance heating as temperatures drop below their operating ranges. This increase in load is captured individually and is quantified by the consultant who supplied the beneficial electrification forecast.

    c. **Solar:** During the winter months, solar generation during a dark calm averages 5% of its nameplate. These generators can experience a variety of issues including snow cover or icing, overcast skies or debris or dust buildup due to high winds. In the summer months, solar output during a dark calm event averages 10% because summer outages are often caused by extended overcast weather.

    d. **Wind:** During the winter months, wind generation during a dark calm averages 5% of its nameplate. This reduced production is primarily due to blade icing, but overspeed (wind too strong to safely operate turbines) also drives some outages. In the summer months, output during a dark calm event also averages 5%, as summer wind droughts, especially during heat dome events, are common.

7.7 Modeling tool

Platte River used the Plexos simulation and modeling tool for the 2024 IRP. Plexos is an economic dispatch and capacity expansion model developed by Energy Exemplar (www.energyexemplar.com).



08 IRP study results

This chapter presents the modeling results for each portfolio, with comparisons of their most important metrics including cost, CO2 emission reductions and renewable energy penetration—metrics that align with Platte River's foundational pillars of financial sustainability and environmental responsibility. As noted previously, every portfolio considered in this IRP meets our reliability criteria (another foundational pillar).

8.1 Summary of five portfolios

Every portfolio assumed a common starting point of existing resources plus new, near-term resource additions from recently signed agreements and solicitations under development. These are considered "committed" resources and the IRP process considers them "given," just like existing resources. These near-term additions represent Platte River's best estimate of solicitation results. In the current environment, project timelines, pricing and size are uncertain and subject to change. Platte River remains flexible and will adjust future capacity acquisitions to compensate for changes to current acquisitions.



8.1.1 Load forecast with DER assumptions

Customer load and DER projections for all the portfolios are similar. Therefore, the various portfolios primarily represent different supply-side options. Load forecast and DER projections are discussed in detail in chapter 5. Figures 37 and 38 in Chapter 5 show annual peak and energy forecasts and DER impact through the planning period. Figures 55 and 56 illustrate annual peak and energy forecasts for quick reference.

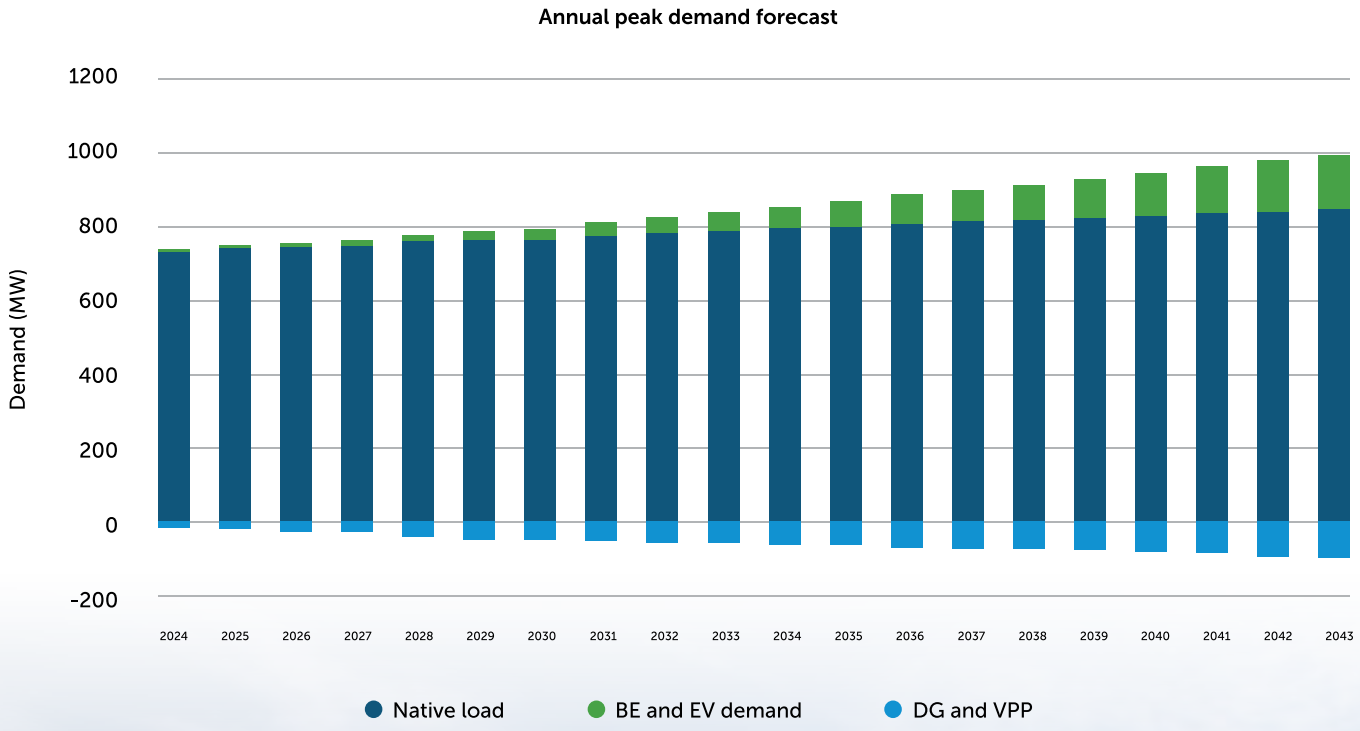


Figure 55. *Annual peak demand forecast*



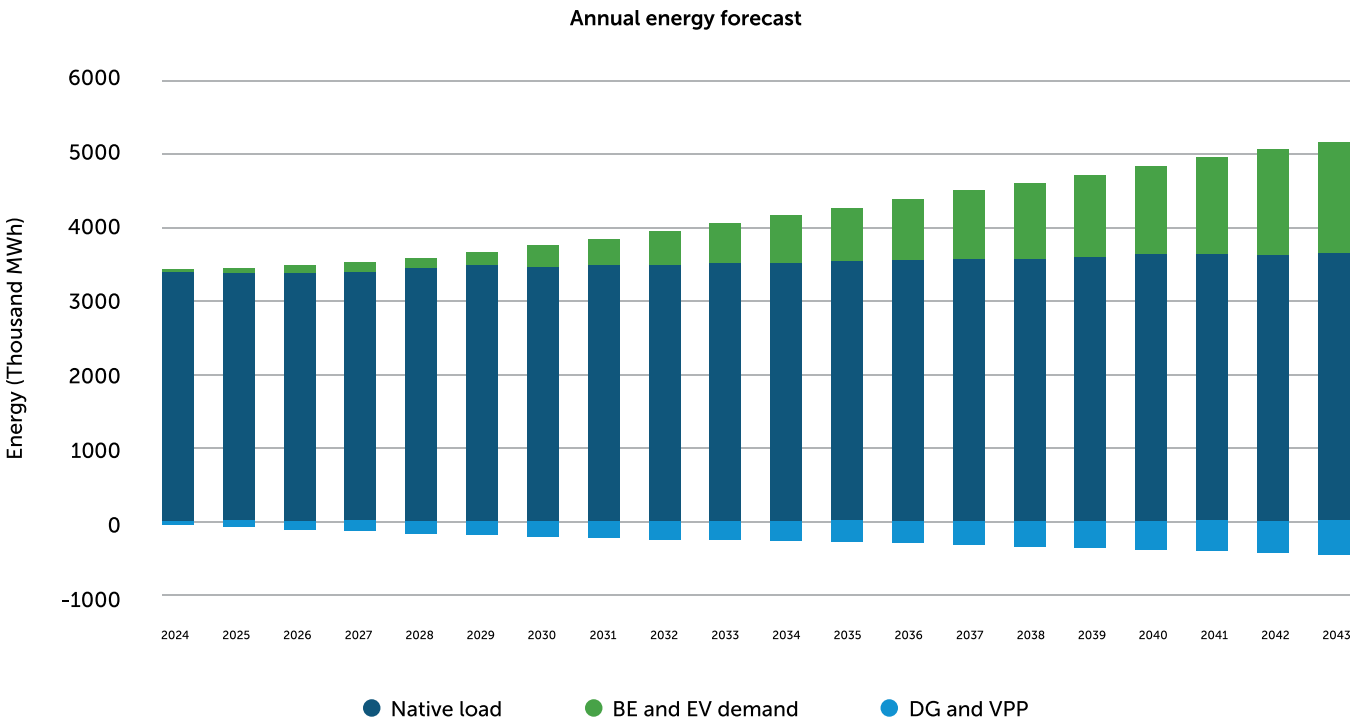


Figure 56. *Annual energy forecast*

Figures 55 and 56 illustrate that DERs are projected to grow much faster than the base load. Distributed generation, which is largely rooftop solar, reduces base peak load by 7% in 2030 and 10% by 2040. The growth of building beneficial electrification and EVs is even faster. Together, these add about 8% to the annual energy demand by 2030 and 34% by 2040.

Table 25 summarizes the utility-scale resources common to all portfolios before Platte River developed and optimized its expansion plans. As described in earlier sections, there are also DER resources embedded in every portfolio that are not subject to optimization during the modeling process.

	Existing resources MWs	Near-term solicitation MWs	Total MWs
Wind	231	250	481
Solar	52	300	352
Battery energy storage systems	1	50	51
Long-duration storage	0	10	10

Table 25. *Existing and committed resources*



Additionally, the following assumptions are common to all the portfolios:

- No new thermal generation is constructed after 2030 and all subsequent resource additions will be noncarbon-emitting resources.
- Long-duration energy storage technology is available from 2035 onwards.
- New thermal generation uses a fuel blend containing 50% green hydrogen from 2035 onwards.
- All thermal generation uses 100% green hydrogen fuel from 2040 onwards, eliminating CO2 emissions.

The portfolios developed in this IRP cover a broad range of potential pathways Platte River might consider as it decarbonizes its power supply portfolio. We are committed to completely retire coal generation by the end of 2029 so the expansion plans include aggressively adding renewable energy. Each portfolio adds 600-800 MW of new renewable energy capacity, although the mix between wind and solar may be different in each portfolio as the optimization seeks to minimize cost while meeting reliability metrics.

Platte River also models additional thermal units and storage to complement its renewable energy acquisitions and comply with reliability criteria. The main differences between the portfolios are the choices about adding thermal resources and storage.

Table 26 summarizes the resources added during the resource acquisition period, as well as the final buildout at the end of the planning horizon in 2043. Note the solar and wind energy additions closely converge by 2043, with only a 100 MW capacity spread between the highest and lowest additions. This is because all portfolios depend heavily on renewable energy, with thermal energy largely acting as a reliability backstop.

	No new carbon	Minimal new carbon	Carbon-imposed cost	Optimal new carbon	Additional new carbon (lowest cost)
2024-2029 incremental additions (MWs)					
Wind	300	300	400	400	300
Solar	450	500	350	300	300
Four-hour storage	2,850	1,050	275	175	100
Long-duration storage	10	10	10	10	10
Dispatchable thermal	0	80	160	200	240
Final 2043 Portfolio (MWs)					
Wind	885	885	985	885	985
Solar	600	600	550	600	450
Four-hour storage	2,850	1,100	400	275	175
Long-duration storage	10	160	10	160	110
Dispatchable thermal	0	80	160	200	280

Table 26. *Summary of five portfolios*

Additional detailed tables are provided in the following section for each portfolio, showing annual capacity additions by each category, further divided into new and existing resources.

8.2 Individual portfolio details

In this section we describe notable features of each portfolio and show the 20-year projections for each by year and by resource type.

8.2.1 No new carbon portfolio

This portfolio does not add any new thermal generation but continues to operate the existing natural gas CTs at Rawhide. To serve its future energy and reliability needs, Platte River adds an incremental 300 MW of wind and 450 MW of solar. To maintain reliability, the portfolio relies on four-hour battery storage with a total addition of 2,850 MW by 2029.

The substantial buildout of four-hour storage in the early years eliminates the need for additional storage during the planning period. Table 27 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	450	450	450	450	500	500	500	500	500	550	600	700	550	450	550	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	400	400	400	400	400	400	560	660	660	885
Storage 4-hr	2	2	27	52	1452	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2850	2850	2850	2850
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**3457**	**4806**	**4607**	**4628**	**4698**	**4716**	**4827**	**4843**	**4861**	**4929**	**4997**	**5117**	**5088**	**5090**	**5186**	**5263**

Table 27. *No new carbon portfolio annual resource additions (in MW)*

8.2.2 Minimal new carbon portfolio

This portfolio allows only 80 MW of new thermal generation. Due to this constraint, this portfolio requires a substantial amount of four-hour storage by 2030, as much as 1,050 MW. This portfolio also adds 300 MW of wind and 500 MW of solar by 2030. This is the most additional solar among all the portfolios, complementing the four-hour storage needed to cover daily peaks. After 2030, more wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 28 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	450	500	500	500	500	500	550	550	600	700	700	750	600	500	600	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	300	400	400	400	400	400	560	660	660	885
Storage 4-hr	2	2	27	52	552	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1050	1050	1075	1100
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	60	60	60	110	110	110
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2637**	**3136**	**2937**	**2958**	**2978**	**2996**	**3057**	**3173**	**3241**	**3359**	**3427**	**3497**	**3468**	**3520**	**3641**	**3693**

Table 28. *Minimal new carbon portfolio annual resource additions (in MW)*

8.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO2 for society. Due to the increased cost for CO2 emissions, this portfolio limits the addition of new dispatchable thermal units to 160 MW and favors four-hour battery storage, with 275 MW of new capacity. As with other plans, wind and solar are the primary energy sources, with 400 MW of new wind and 350 MW of new solar by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 29 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	350	350	350	400	450	450	450	450	450	450	500	450	450	500	550
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	400	400	460	400	400	400	400	500	500	500	600	600	660	760	760	985
Storage 4-hr	2	2	27	52	127	277	277	302	327	352	377	377	377	377	377	377	375	375	375	400
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	160	160	160
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2242**	**2391**	**2192**	**2238**	**2333**	**2426**	**2462**	**2628**	**2646**	**2664**	**2782**	**2852**	**2873**	**3025**	**3071**	**3173**

Table 29. *Carbon-imposed cost portfolio annual resource additions (in MW)*

8.2.4 Optimal new carbon portfolio

This portfolio adds 200 MW of new dispatchable thermal resources and 175 MW of new battery storage as it balances capacity support across both thermal and batteries. Like the carbon-imposed cost portfolio, this portfolio adds 400 MW of wind but slightly less solar, with 300 MW of new capacity by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 30 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	300	300	300	300	300	400	400	400	400	400	450	450	450	550	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	400	400	460	400	400	400	400	500	500	500	600	600	660	660	660	885
Storage 4-hr	2	2	27	52	102	177	177	202	227	252	252	252	252	252	252	252	250	250	250	275
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	160	160	160
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2257**	**2281**	**2082**	**2128**	**2173**	**2216**	**2327**	**2493**	**2511**	**2529**	**2647**	**2717**	**2788**	**2840**	**2936**	**3038**

Table 30. *Optimal new carbon portfolio annual resource additions (in MW)*

8.2.5 Additional new carbon portfolio

The primary objective of this portfolio is to minimize costs. To do so, this portfolio relies on 240 MW of new dispatchable thermal resources to provide firm capacity. Renewables still supply most of the energy, with 300 MW of new wind and 300 MW of new solar by 2030. To help manage the renewable energy, this portfolio adds 100 MW of storage. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 31 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240	240	280	280	280
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	300	300	300	300	300	300	350	350	350	350	400	400	350	400	450
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	500	500	500	600	600	600	660	760	760	985
Storage 4-hr	2	2	27	52	52	102	102	102	127	152	152	152	152	152	152	152	150	150	150	175
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	110	110	110
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2147**	**2146**	**1947**	**1968**	**2013**	**2056**	**2267**	**2383**	**2401**	**2519**	**2537**	**2607**	**2678**	**2770**	**2816**	**2918**

Table 31. *Additional new carbon portfolio annual resource additions (in MW)*

8.3 Comparative analysis of portfolios

8.3.1 Portfolio costs

As part of "least-cost" resource planning and optimization, the Plexos model captured relevant incremental costs associated with building, acquiring and operating the power supply portfolios over the 20-year planning horizon. Platte River excluded other costs from the model, like depreciation of existing transmission and generation infrastructure, cost of DERs and administrative and general costs. While these additional costs are important, they are not relevant to the capacity expansion planning process. The cost comparison presented here is not a rate forecast because it does not capture the full revenue requirement needed to set rates. Figure 57 compares the annual cost of all five portfolios.

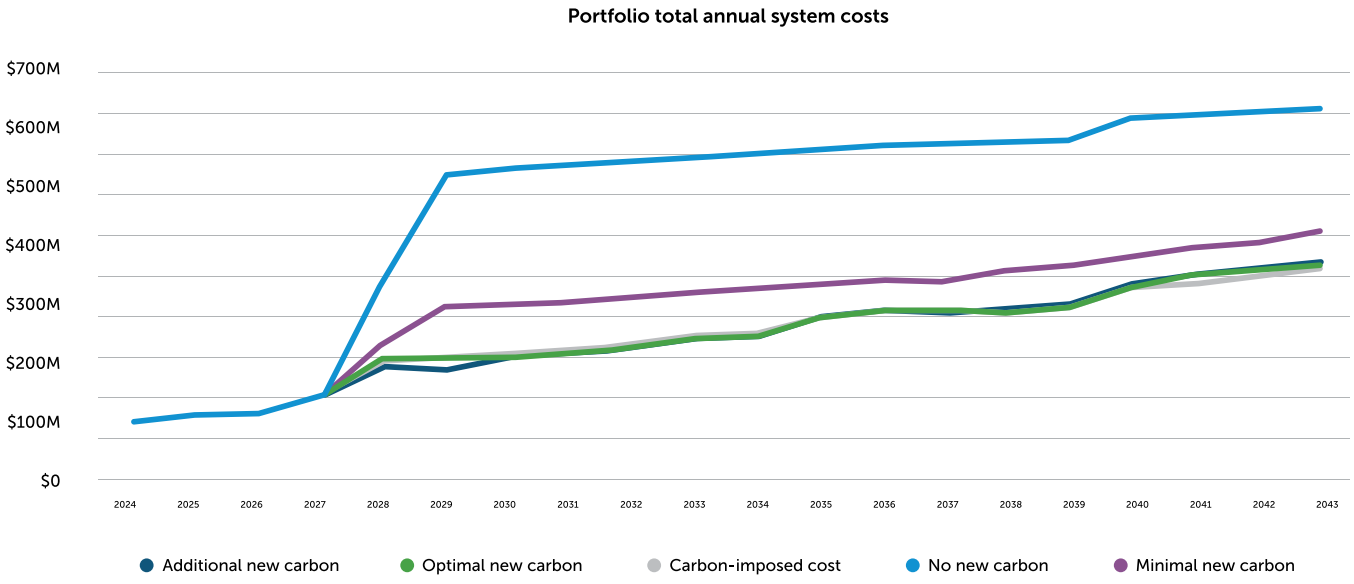


Figure 57. *Portfolio total annual system costs*

The no new carbon portfolio stands out as significantly more expensive, with the large buildout of four-hour storage starting in 2027. Annual costs exceed $500 million per year by 2028 and continue an upward trend. The minimal new carbon portfolio is also noticeably more expensive than others, again due to the large battery buildout, with annual costs exceeding $300 million by 2029. The remaining portfolios' costs are similar, with some annual deviations due to small changes in resource size and timing. Looking at the present value of the total portfolio cost in Table 32, costs for the carbon-imposed cost, optimal new carbon and additional new carbon portfolios are within 1%

of each other. But the minimal new carbon portfolio is about 20% more expensive than the three lower-cost portfolios (on a net present value basis), while the no new carbon portfolio is almost twice as expensive, costing an extra $2.6 billion over the planning horizon.

20-year net present value ($000)	
No new carbon	$5,344,991
Minimal new carbon	$3,372,202
Carbon-imposed cost	$2,779,024
Optimal new carbon	$2,772,407
Additional new carbon	$2,761,036

Table 32. *Portfolio net present value cost comparison*

As noted previously in this report, the portfolios rely on different technologies to supply differing services. Cost, energy and capacity breakouts in Table 33 highlight the complementary roles of renewable energy and thermal units in the optimal new carbon portfolio. In this case, when looking at the net present value of costs from 2030 through 2043, thermal units account for about 29% of the total cost while supplying almost 58% of the firm capacity and only about 7% of the energy. In contrast, noncarbon resources account for nearly 49% of the cost while contributing just over 91% of the energy but only about 23% of the firm capacity. The thermal resources are more cost-efficient at contributing capacity while noncarbon resources are more cost-efficient at contributing energy. A reliable and low-cost portfolio needs an optimal combination of both capacity and energy. While battery storage does not generate energy, it shifts the renewable production to omitted renewable production hours, thereby contributing to capacity needs and supporting renewable energy integration.



	% of cost	% of generation	% of capacity
Thermal	29.2%	6.9%	57.9%
Noncarbon	48.8%	91.5%	23.1%
Battery storage	15.1%	0.0%	19.0%
Purchases	6.9%	1.6%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**

Table 33. *Optimal new carbon portfolio: cost, energy and capacity contribution breakout*

8.3.2 Portfolio CO2 emissions

Lowering CO2 emissions is a primary metric driving portfolio development and selection. While there are many ways to quantify a portfolio's emissions, this IRP uses the methodology developed in conjunction with Colorado's Clean Energy Plan (CEP)[29] rules.

Under this methodology, stack emissions from the portfolio are adjusted to reflect additional emissions associated with energy purchases while energy sales assign the associated CO2 to the counterparty buying energy. This netting prevents companies from avoiding emissions by outsourcing generation to an outside counterparty and helps Colorado measure total CO2 emissions due to electricity production and consumption within the state. This methodology also avoids penalizing companies for supplying energy to other utilities. This methodology is a good match for a future market where energy is entirely sold into and purchased from the market without regard to how individual companies balance load and generation. Figure 58 shows annual percent reduction of CO2 emissions for each portfolio relative to Platte River's 2005 baseline emissions.

[29] In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).

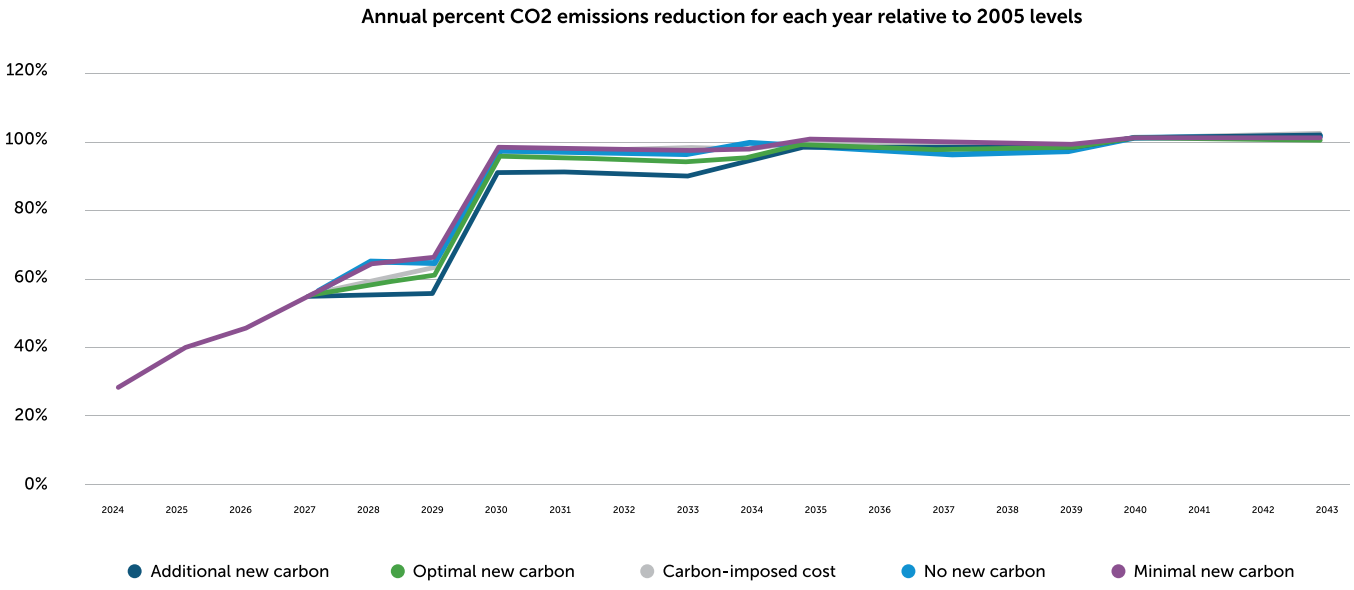


Figure 58. *Annual percent CO2 emissions reduction for each year relative to 2005 levels*

Starting in 2025, Platte River makes substantial progress to reduce CO2 emissions due to the renewable energy additions and phased coal retirements. By 2027, we expect all five portfolios to achieve a 55% CO2 reduction. By 2030, the additional new carbon portfolio achieves a 91% reduction, while the remaining portfolios have reductions greater than 95%. After 2035, when the remaining thermal units should begin partially burning green hydrogen, the average carbon reduction for all five portfolios is 99%. This rises to 100% when we assume that all thermal units will transition to 100% hydrogen fuels in 2040, eliminating CO2 emissions.

All portfolios comply with:

- The framework in SB23-198 requiring Platte River to model at least one plan that can demonstrate 46% CO2 reduction (from 2005 levels) by 2027 and one plan that reduces carbon further than its filed CEP; and

- Platte River's voluntary CEP showing its plan to achieve at least 80% CO2 reduction (from 2005 levels) by 2030.

In addition to CO2 emissions reductions, emissions from other pollutants, including volatile organic compounds, carbon monoxide and nitrogen oxides, will also decrease with the coal plant retirements. We assume the new dispatchable generation will use the best available control technologies to maintain compliance with state laws and minimize environmental impact on water resources and air quality.

8.4 Recommendation

8.4.1 Optimal new carbon portfolio



Planning is a dynamic process, and the IRP is snapshot in time. The 2024 IRP presents a possible future based on the best information available in the summer of 2023. The five portfolios presented in this chapter cover a wide range of future paths. All five portfolios provide reliable electricity supplies during the planning horizon under our assumed set of conditions and variables. But our assumed conditions will probably change. In fact, they will almost certainly change in the long run because we are living amid rapid transition. While all five portfolios provide hypothetical options to meet load requirements and reduce carbon emissions, we must select one that:

- Presents a path towards meeting our RDP and state goals.
- Meets Platte River's three pillars of reliability, financial sustainability and environmental responsibility.
- Presents a path where the actions taken in early years will not unnecessarily limit future options or intensify risks.

The following section highlights the key merits of each portfolio and provides a recommendation.

The **no new carbon portfolio** does not add any new CO2 emitting sources, but it is the most expensive due to heavy reliance on four-hour storage batteries. It builds 2,850 MW of new batteries, almost three times our expected peak demand in 2030. Consequently, it costs about twice as much as some other portfolios. As a not-for-profit entity, Platte River must pass these higher costs to the owner communities, causing significant rate shock.

The no new carbon portfolio does not offer the least CO2-emitting path, as it relies heavily on existing dispatchable generation to complement renewable generation. This portfolio fails the financial sustainability test and is not as effective in reducing CO2 emissions post-2030 as other portfolios. Due to heavy reliance on four-hour battery storage, this portfolio may be unreliable in a dark calm event that spans more days than we have modeled. This portfolio does not present a plausible future path.

The **minimal new carbon portfolio** builds 80 MW of new thermal generation and 1,050 MW of new storage batteries, almost 50% more than



the expected peak demand in 2030. This portfolio emits the least CO2 but is more than 20% more costly than the optimal new carbon portfolio. Just like the no new carbon portfolio, due to heavy reliance on four-hour storage batteries, this portfolio may be unreliable in a dark calm that spans multiple days. Because it does not meet Platte River's requirements for reliability or financial sustainability, this portfolio does not present a workable future path.

The **carbon-imposed cost portfolio** builds 160 MW of new thermal generation and presents a workable path. While this portfolio is reliable for the historically experienced weather uncertainties, it may not be reliable if weather events continue to become more extreme as they have in the recent past.

The **optimal new carbon portfolio** builds 200 MW of new efficient thermal generation and presents a viable path. This portfolio presents a balance between the additional new carbon and carbon-imposed cost portfolios in both cost and the amount of new thermal generation. This portfolio better supports reliability if weather events continue to become more extreme, as they have in the recent past. This is our recommended portfolio.

The **additional new carbon portfolio** builds 240 MW of new efficient and flexible thermal generation. It is the lowest-cost portfolio but emits more CO2 than some other portfolios that also meet reliability and financial sustainability pillars. This portfolio presents a workable future path.

The carbon-imposed cost, optimal new carbon and additional new carbon portfolios are potentially workable options. There are important differences among the three. After careful consideration, Platte River recommends the optimal new carbon portfolio because it optimally balances the organization's three foundational pillars, offers more flexible and lower-risk early decisions, has the robustness to withstand changes in assumptions and helps advance the 100% noncarbon energy goal of the RDP.

The recommended portfolio is a possible path for the future and not a firm plan. Platte River will further refine this path during implementation, incorporating market conditions, technology evolution, availability, and cost and timing of new resources. This plan will evolve as needed to align with our board's direction and our owner communities' wishes. Staff will continue to refine this portfolio with new data, assumptions, and market conditions. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining its three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

8.5 Risk assessment and sensitivity analysis

Platte River developed all five portfolios using several assumptions, assessments and forecasts about commodity prices, customer load growth, costs of renewables, DER adoption rates, market evolution, technology evolution, and other inputs. But these inputs are unlikely to occur exactly as assumed, requiring us to adapt. In this section, we outline the risks our plan faces, summarize our sensitivity analyses and provide options to adjust the plans for key risks. As time passes and newer information is available, we will modify our plans.

8.5.1 IRP risks and barriers

As Platte River moves forward with this IRP implementation, we must consider two types of risks. First, there are execution risks that complicate portfolio implementation. These risks tend to be very specific to the composition of the portfolio, driven by large, complex external factors (such as global supply chains) and are difficult to hedge because they are unique and difficult to forecast. We discuss these risks in detail below.

8.5.1.1 Execution risks

- **Cost escalation** – As discussed in section 3.4.3, renewable costs continue to escalate dramatically. Platte River uses the latest market data to develop plans, but costs continue to rise, and new generation may be more expensive than anticipated. Renewable energy seems to carry the highest exposure due to both high market demand and complex, immature supply chains. Thermal generation has seen moderate escalation and other resource additions could be impacted by trade policies. Platte River must be prepared to adjust to the best portfolio mix to reflect evolving cost considerations.





- **Siting complications** – Individual projects have unique siting challenges. Platte River must address community concerns about the impact of a project itself or its transmission connections. Local regulation can also shift rapidly and require project modifications that often add costs. Projects may also encounter unexpected geological, hydrological or environmental conditions.

- **Technology evolution** – Our proposed portfolios assume a specific timeline of technology readiness. This forecast is based on our best estimates, but technology development is beyond Platte River's control. If specific storage technologies fail to mature or hydrogen is not available at the required volumes, the portfolio would need to be reoptimized to accommodate this new reality. More specifically, we assumed long-duration energy storage and green hydrogen will be available and economically viable for commercial deployment in 2035 to help continue to decarbonize Platte River's resource mix . If these technologies are not available at the projected dates or are available sooner, our decarbonization schedule will change accordingly.

- **DER adoption rates** – Platte River is proactively working with its owner communities to forecast and incentivize customer-sited resources. Like other technology forecasts, the exact trajectory of deployment of many new and emerging technologies is uncertain. Rooftop solar, electric vehicles, beneficial building electrification and battery storage systems



all impact both the energy mix and flexibility of the system. If there are unforeseen breakthroughs or complications, Platte River will need to adjust its resource mix in response.

8.5.1.2 Operational risks

There are operational risks that can occur in each plan once they are executed. It is easier to understand and quantify these operational risks with specific model runs. Their impact on portfolio viability is still significant and uncertain, but it is easier to evaluate the quantifiable tradeoffs.

- **Fuel and market price risk** – Portfolios are developed using the best estimates of future fuel and energy market prices. Past volatility suggests the potential for future volatility. Sensitivity runs modeling gas and power prices help establish each portfolio's susceptibility to this input and the consequences of future deviations from the expected value.

- **Regulatory risk on carbon accounting and emissions** – There continues to be a range of opinions on how carbon emissions will be regulated. The presence or absence of a carbon tax can impact the economics of a portfolio. Again, a sensitivity analysis can help quantify the financial impacts of a carbon tax.

- **Market evolution** – The implementation of a western energy market will impact different resources in different ways. Transmission congestion may erode the economics of remotely sited resources, while a robust energy market may impact price levels and volatility. If multiple utilities add renewable resources and transmission constraints emerge in moving power out of our region, there is a risk that excess renewable generation will depress market prices. This risk is more difficult to quantify than other operational risks, but Platte River continues to explore the potential range of impacts as the market develops.

The risks described above can impact a portfolio in different ways. One way to analyze their impacts is to conduct sensitivity analyses, where we change a driver or variable and measure the resulting impact on the portfolio. Section 8.5.2 discusses these analyses.

Because these risks and assumptions can change simultaneously, the combined effect can be large and drive us to change the portfolio mix. In section 8.5.3, we assess the combined risk of renewable cost increases and market price changes and review potential portfolio modifications to reduce this risk.

8.5.2 Sensitivity analyses

To understand the robustness of the modeled portfolios, the IRP process tests the portfolios under assumptions different from the base assumptions. In a sensitivity analysis, a single assumption or input is changed (gas prices, for example) and the portfolio is re-evaluated. Portfolios with stronger responses to the new assumption or input show greater risk. This analysis provides a deeper understanding of the tradeoff between cost and risk. For this IRP, Platte River performed sensitivity analyses on two main inputs: natural gas prices and renewable energy prices.

8.5.2.1 Natural gas prices

Natural gas prices can impact a portfolio in two ways. First, the price of this fuel directly influences regional market prices, which impacts the volume and cost or revenue of imports and exports to and from the Platte River system. Second, the portfolios continue to consume modest amounts of natural gas in the future, so changes in price directly impact the economics of the thermal generation. In this analysis, gas prices were tested at both higher and lower levels than the base assumption used in the portfolio development. Siemens, the supplier of the base gas price forecast, also supplied the high and low gas price trajectories, seen in Figure 39 earlier in this document, as well as associated market prices for each sensitivity.

8.5.2.2 High gas prices

Under this sensitivity, gas prices are 20% higher on average from 2030 to 2040. On a net present value basis, the portfolios' costs change very little, indicating the relatively small role of gas in future portfolios. On the low side, there is a 0.3% savings for the minimal new carbon portfolio while the additional new carbon portfolio has a cost increase of 1.4%. In general, higher gas prices increase the system operating cost due to higher fuel expenditures, but these increases are partially offset by higher sale revenues from higher market prices. Portfolios with more gas generation will see a net increase in cost, while portfolios with more must-sell renewable energy will benefit from the attractive market prices and see a slight savings.



8.5.2.3 Low gas prices

For this sensitivity, gas prices remain relatively flat starting in 2026. While the base case and high-price sensitivity show average escalation rates of 4.45% and 5.71% respectively through 2043, the low-price curve has a net gain of 0.2% by 2043, with a small decline during the 2030s. As expected, the results are the opposite of the high gas price sensitivity. Since this sensitivity sees a larger change to gas prices, with an average decrease of 54% relative to the base assumption, the change in net present value is more noticeable than in the high gas price sensitivity. The additional new carbon portfolio sees a cost savings of 5.1% and the optimal new carbon portfolio sees a savings of 3.6%. The minimal new carbon and no new carbon portfolios see modest savings of 0.6% and 0.8%, respectively.

8.5.2.4 Renewable energy prices

As discussed in section 3.4.3, renewable energy projects have seen significant cost increases in recent years.

In addition to the cost drivers of the projects themselves (including supply chain issues and competition for renewable resources), a second source of uncertainty around the cost of new renewable energy comes from Platte River's expected market participation. There is some possibility that the market will fail to launch as planned, or will launch with a different mix of participants, which would leave some projects exposed to higher transmission costs than might otherwise be expected in a market. Assuming the market does move forward as planned, there is still substantial uncertainty around the additional costs of transmission congestion, both under the existing portfolio and as regional portfolios evolve with more renewable energy concentrated at the optimal sites. Without a market, or with a market that is more congested than expected, the delivered cost of our renewable energy would rise.

For these reasons, Platte River ran a sensitivity analysis on renewable energy prices. We evaluated price increases for new wind and solar projects under each portfolio. Table 34 compares the base assumption to the higher price sensitivity for selected years. We did not test prices for energy storage and thermal generation because Platte River has not seen similar price volatility in those markets and their transmission congestion risk is much lower.



Wind cost (including transmission costs)			Solar cost	
	Base	High sensitivity	Base	High sensitivity
2030	32.85 $/MWh	40.99 $/MWh	30.01 $/MWh	40.37 $/MWh
2035	34.82 $/MWh	43.75 $/MWh	31.22 $/MWh	41.99 $/MWh
2040	36.87 $/MWh	46.67 $/MWh	32.43 $/MWh	43.62 $/MWh

Table 34. *Renewable PPA prices*

Because each portfolio adds a similar amount of renewable energy, the results across the portfolios are reasonably close. On a net present value basis, the smallest change is a $181 million increase for the additional new carbon portfolio, while the largest increase is $198 million for the carbon-imposed cost portfolio. The optimal new carbon portfolio has a cost increase of $190 million, which is about a 7% increase if renewable energy prices reach the level projected in the sensitivity.

The last two columns of Table 35 illustrate how the relative difference among portfolio costs changes from the base case to the sensitivity case. These intra portfolio cost comparisons are shown relative to the lowest cost portfolio referred to as the additional new carbon portfolio (labeled as "ANC" in the table below). For the base case runs, the cost of the no new carbon portfolio is 93.6% higher relative to the additional new carbon portfolio, while the sensitivity case is 88.0% higher. There is very little change in the relative cost differences for the remaining portfolios.

	Base and sensitivity comparison			Intra portfolio cost comparison	
Portfolio	Base case	Sensitivity: high RE	% change	Base case: % diff vs. ANC	Sensitivity: % diff vs. ANC
No new carbon	$5,344,991	5,531,559	3.5%	93.6%	88.0%
Minimal new carbon	$3,372,202	3,559,856	5.6%	22.1%	21.0%
Carbon-imposed cost	$2,779,024	2,976,911	7.1%	0.7%	1.2%
Optimal new carbon	$2,772,407	2,962,228	6.8%	0.4%	0.7%
Additional new carbon	$2,761,036	2,941,920	6.6%	0.0%	0.0%

Table 35. *Renewable PPA prices*

8.5.2.5 Sensitivity analysis summary

While uncertainty about some model inputs is unavoidable, quantifying the impacts of those uncertainties can help manage the risks associated with them. Table 36 compares the net present value costs across the base case assumptions and the sensitivities described above.

Net present values	Base	High gas and power	Low gas and power	High renewable energy prices
No new carbon	$5,344,991	$5,343,332	$5,304,721	$5,531,559
Minimal new carbon	$3,372,202	$3,363,500	$3,352,897	$3,559,856
Carbon-imposed cost	$2,779,024	$2,783,634	$2,724,507	$2,976,911
Optimal new carbon	$2,772,407	$2,794,671	$2,672,710	$2,962,228
Additional new carbon	$2,761,036	$2,800,210	$2,620,375	$2,941,920

Table 36. *Net present value cost comparison with gas prices and renewable prices*

At a high level, the no new carbon portfolio and the minimal new carbon portfolio are uncompetitive in every case. Table 37 converts the net present value costs into rankings for the base case and each sensitivity, with the result that the no new carbon portfolio is last under every assumption tested and the minimal new carbon portfolio is fourth under every assumption tested.

Net present value rankings	Base	High gas and power	Low gas and power	High renewable energy prices	Average
No new carbon	5	5	5	5	5.0
Minimal new carbon	4	4	4	4	4.0
Carbon-imposed cost	3	1	3	3	2.5
Optimal new carbon	2	2	2	2	2.0
Additional new carbon	1	3	1	1	1.5

Table 37. *Portfolio ranking with sensitivity analysis*

The top three portfolios are more competitive, and their relative value depends on the future trajectory of prices and the impacts of CO2 emissions. The optimal new carbon portfolio proves to be robust, with a second-place ranking in every run. This portfolio is, on average, only 0.9% more expensive than the best portfolio in any given sensitivity (including the base case). While some portfolios may perform better in a specific set of circumstances, the optimal new carbon portfolio performs well across the range of outcomes and proves to be a cost-effective and robust solution.

8.5.3 Excess renewable and market participation risk

With a substantial increase in intermittent renewable resources, Platte River faces an increasing risk from the mismatch in timing between customer demand and when renewable generation is available. Some of the mismatch can be managed with energy storage, but it would be impractical to balance the entire renewable energy portfolio using current battery storage technology. When there is insufficient renewable energy, Platte River can purchase energy from the market, withdraw stored energy, or rely on thermal generation to fill the gap. When there is too much energy, Platte River will store the excess (after meeting its load) and must sell any additional renewable energy into the market or curtail the resource.

Starting in 2030, Platte River anticipates having about 10% to 35% surplus energy on an annual basis. Of that excess, about 75% is expected to be sold, while the remainder will be curtailed due to limited energy demand and constrained transmission systems.

Because renewable energy contracts are structured as take-or-pay, Platte River must pay the full price of the PPA whether we take delivery of the energy or not. In this context, Platte River will sell excess renewable energy into the market if the market price is greater than $0 but will incur a loss if the market price is below the PPA price. Therefore, the economic value of the surplus renewable energy depends on the cost of the PPA relative to the market price of the energy at the time of the excess energy.

Given that the entire region is adding wind and solar resources, we anticipate market prices to be lowest when we have surplus renewable energy. Figure 59 illustrates the average expected monthly power prices in 2031 and monthly excess renewable energy as a percentage of the total monthly energy required by Platte River customers.

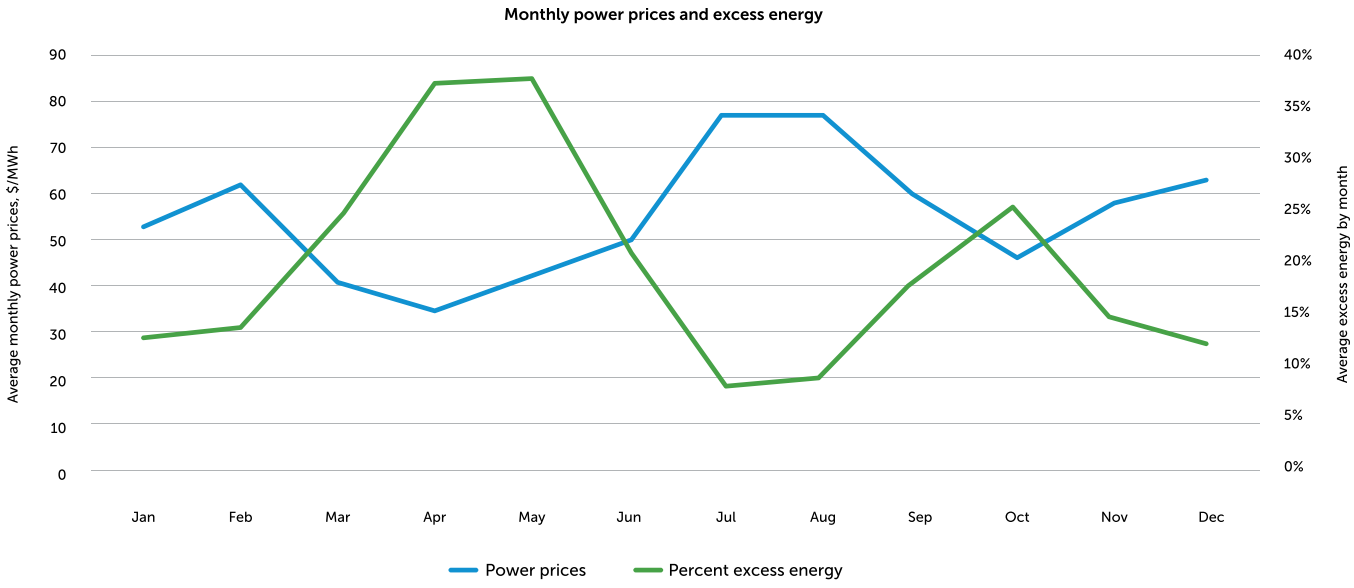


Figure 59. *Monthly power prices and excess energy*

The blue line shows average monthly prices, while the green line shows excess energy as a percent. The average prices are lowest in April and May, when the excess energy is above 35% of Platte River's needs. Excess energy is relatively low in higher-priced months of summer and winter.

To better understand the supply-demand balance and assess energy risk, Platte River staff analyzed expected hourly operations during the year 2031 using 24 historical hourly weather patterns for the recommended portfolio, which called for adding 400 MW of new wind by 2030. The diversity of weather data allows a broader quantification of the risk across multiple weather years, rather than relying on a single representative year.

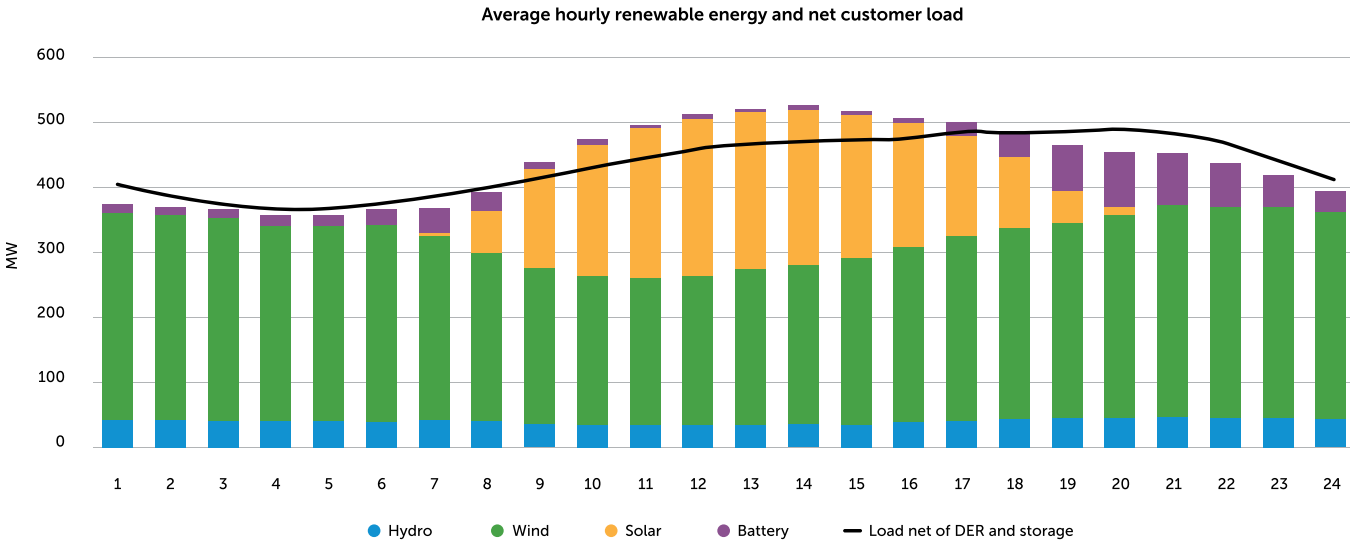


Figure 60. *Average hourly renewable energy and net customer load*

Figure 60 summarizes the average excess megawatts by hour of day and month of the year. During the day, we have excess energy in midday when solar output is high. However, during the morning and evening hours, when the load is ramping up, the Platte River system needs dispatchable capacity and market access.

Balancing this excess renewable energy with the need for sufficient energy during high demand is one of the primary tasks of this IRP. Platte River developed the recommended portfolio with 400 MW of new wind, with the wind power purchase price around $32/MWh, and market prices in the 2030s around $50/MWh, making excess energy revenue positive. However, if market prices continue to drop with the addition of renewable resources in the region and demand for renewable energy continuing to rise, the cost of renewable energy will increase. In this scenario, the risk is not only the limited value from excess renewable energy but also market price volatility.

Platte River will need to consider these risks before fully implementing the recommended plan. This exposure to factors outside Platte River's control makes managing the portfolio's risk a critical part of the execution phase. Platte River will continue to monitor commodity prices (like gas), market power price forecasts, and the cost of renewable energy to refine and rebalance the plan as necessary to meet our financial sustainability pillar. If necessary, we can adjust the renewable mix or storage capacity to mitigate risk if it is cost-effective.





09 Action plan

Platte River will continue to work toward the RDP goal over the next five years. Platte River plans to retire coal generation, add more renewable generation, add energy storage, add a VPP, join a full organized energy market and add efficient dispatchable thermal generation to complement renewable intermittency.
We expect to carry out the following specific activities.



9.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Contract for new 107 MW solar from the 2022 solar RFP	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution Operational risks (section 7.5.1.2) • Market evolution
	Contract for new 250 MW wind from the 2023 wind RFP	2024	
	Begin commercial operation of 150 MW Black Hollow Solar project	2025	
	Begin commercial operation of a 130 MW solar project	2027	
Dispatchable capacity (reliability)	Contract to add up to 20 MW of distributed energy storage from 2021 solar and storage RFP	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	Issue RFP for four-hour battery energy storage system	2024	
	Review results from all-dispatchable-resource RFP	2024	
	Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include: • Apply for air and land use permits • Identify actions related to ordering some long lead time equipment, especially related to power transmission • Develop initial project design and enlist engineering, procurement and construction contractor	2024	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Dispatchable capacity (reliability)	Issue RFP for systems and services to support development of a VPP that can provide dispatchable capacity for Platte River and the owner communities	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	Issue RFP for dispatchable thermal resource development if the 2024 all dispatchable resource RFP does not result in an acceptable project	2025	
	With our owner's engineer and contractor, complete plant design for new resource and balance of plant services	2025	
	Complete battery energy storage system agreements	2025	
	Issue RFP for additional energy storage system	2025	
	Plan VPP systems design and architecture	2025	
	Start work on a demonstration project for long-duration energy storage system	2025	
	Build VPP systems, system integrations and develop key functionality	2026	
	Begin commercial operation of up to 25 MW of distributed energy storage from 2021 solar RFP	2026	
	Launch VPP with 7 MW dispatchable capacity	2027	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Customer programs	Plan and develop VPP customer programs	2025	Execution risks (section 7.5.1.1) • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Market evolution VPP system integration Third-party DER device aggregators
	Launch VPP customer programs	2026	
Community engagement	Continue public education campaign to engage communities, customers in the energy transition	2024-2028	
	Support renewable energy project acquisitions and engage communities through groundbreaking events, ribbon-cutting ceremonies	2025-2028	
Transmission	Complete construction and energize the 230-kV interconnection switching station (Severance substation) to interconnect new renewable resources	2025	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications Operational risks (section 7.5.1.2) • Market evolution
Markets	Begin training staff to prepare for SPP RTO West market entry	2024	Operational risks (section 7.5.1.2) • Market evolution System integration Market tariff and resource adequacy
	Screen and select market interface software	2024	
	Begin testing operations in SPP RTO West	2025	
	Join SPP RTO West market operations on April 1	2026	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Other enabling activities	Finalize and file a just transition plan with the state of Colorado for workers affected by Rawhide Unit 1's closure	2024	Interest rates
	Working alongside other owners, retire Craig Unit 1 (of which Platte River owns a 77 MW share)	2025	
	Initiate 2028 IRP process	2026	
	Issue bonds to fund capital investments	2025-2026	
	Continue 2028 IRP process including: • Receive studies from external consultants • Execute community engagement activities to educate public, collect stakeholder feedback • Conduct modeling and analyze portfolios • Compile draft report	2027	

9.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Begin commercial operation of new wind generation	2028	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution Operational risks (section 7.5.1.2) • Market evolution
Dispatchable capacity (reliability)	Testing, commissioning, and operation of new dispatchable thermal resource	2028	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	Begin commercial operation of energy storage systems (for which RFP was issued in 2025)	2028	
	Grow VPP dispatchable capacity to 15 MW and develop market dispatch capabilities	2029	
	Grow VPP dispatchable capacity to 24 MW and develop distribution dispatch capabilities	2029	
	Develop a mobile app to help customers and distribution utilities connect with Platte River's system	2028-2030	
Community engagement	Support mobile app deployment with communications and community activations	2028-2030	
	Continue public education campaign to engage communities, customers in the energy transition	2028-2030	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Other enabling activities	Implement the Just Transition Plan	2024-2030	
	Working alongside other owners, retire Craig Unit 2 (of which Platte River owns a 74 MW share)	2028	
	Seek approval from Platte River Board for 2028 IRP; file with WAPA	2028	
	Retire Rawhide Unit 1 by December 31	2029	

10 Appendices





Appendix A: IRP checklist for WAPA

Document section	Requirement	Included in this IRP	Section number
IRP design, IRP study results **Power markets** **Energy efficiency** **DER integration, flexible DERs and the virtual power plant** **IRP portfolios**	Does the IRP evaluate the full range of alternatives for new energy resources, including: • new generating capacity? • power purchases? • energy conservation and efficiency? • cogeneration and district heating/cooling applications? • renewable energy resources?	✓	6.3.3, 6.3.4, 6.3.5, 6.3.6, 6.3.7 7.1, 7.4, 8.2, 8.3 4.1.5, 6.3.4, 6.3.5, 5.3.2 5.3.1 7.4, 8.2, 8.3
Planning for a reliable future power supply	Does the IRP provide adequate and reliable service to the customer's electric consumers?	✓	7.3
IRP design, IRP study results	Does the IRP take into account the necessary features for system operation?	✓	4.2.1, 7.3, 8.5
DER integration, flexible DERs and the virtual power plant	Does the IRP take into account the ability to verify energy savings achieved through energy efficiency?	✓	5.3
DER integration, flexible DERs and the virtual power plant	Does the IRP take into account the projected durability of such savings measured over time?	✓	5.3
Load forecast methodology and data	Does the IRP treat demand and supply resources on a consistent and integrated basis?	✓	5.3, 5.4.1, 5.4.2
Planning for a reliable future power supply	Does the IRP consider electrical energy resource needs?	✓	7.3
Energy and capacity planning, DER integration, flexible DERs and the virtual power plant, supply side generation resources, IRP portfolios	Does the IRP identify and compare resource options?	✓	4.1.2, 5.3, 6.3, 7.4, 7.5

Document section	Requirement	Included in this IRP	Section number
Comparative analysis of portfolios, portfolio recommendation, risk assessment and sensitivity analysis	Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options?	✓	8.3, 8.4, 8.5
Action plan	Does the IRP include an action plan describing specific actions the customer will take to implement the IRP?	✓	9
Action plan	Does the IRP list the time period that the action plan covers?	✓	9
Action plan	Does the IRP include an action plan summary consisting of: • Actions the customer expects to take in accomplishing the goals identified in the IRP? • Milestones to evaluate accomplishment of those actions during implementation? • Estimated energy and capacity benefits for each action planned?	✓	9
Portfolio CO2 emissions	Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts?	✓	8.3.2 with additional text from environmental
Portfolio CO2 emissions	Does the IRP include a qualitative analysis of environmental effects in a summary format?	✓	8.3.2
Stakeholder engagement process	Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP?	✓	3.7

Document section	Requirement	Included in this IRP	Section number
Stakeholder engagement process	Does the IRP include a brief description of public involvement activities?	✓	3.7
Board resolution to approve the 2024 IRP	Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met?	✓	Appendix C
Board resolution to approve the 2024 IRP	Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body?	✓	Appendix C
Electricity demand	Does the IRP contain a statement that the customer conducted load forecasting, including specific data?	✓	5.1-5.4
Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios	Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met?	✓	7.3.2.2, 8.3.2, 5.3
Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios	Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation?	✓	7.3.2.2, 8.3, 5.3
	Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA?	N/A	

Appendix B: 2024 Just Transition Plan

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

2024 JUST TRANSITION PLAN



BACKGROUND

Platte River Power Authority (Platte River) is a not-for-profit, community-owned public power generation and transmission utility that provides safe, reliable, environmentally responsible and financially sustainable energy and services to the communities of Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their distribution utility customers. Platte River owns and operates Rawhide Energy Station (Rawhide), located roughly ten miles north of Wellington, Colorado. Rawhide consists of one 280 megawatt (MW) capacity coal fired boiler (Unit 1) and five natural gas-fired combustion turbines with a combined 388 MW capacity (Units A, B, C, D and F) that support peak power demand. Additionally, Rawhide also has 52 MW of solar and a 2 MW-hour battery storage system.

Platte River, like other Colorado utilities, is transforming how it generates and delivers energy. In 2018, Platte River's board of directors (the board) approved the Resource Diversification Policy (RDP), which directed Platte River to proactively work toward achieving a 100% noncarbon energy mix by 2030 while maintaining Platte River's three foundational pillars of providing reliable, environmentally responsible and financially sustainable electricity and services. A significant milestone on the journey to 100% noncarbon energy is its commitment to retire Unit 1 by the end of 2029. This commitment is reflected in its current Integrated Resource Plan (2024 IRP) and in its Clean Energy Plan, which was submitted to the state of Colorado in 2022. This commitment is also included in Resolution 08-24 which formally announces Unit 1's accelerated retirement as part of the 2024 IRP. With Platte River's commitment to retiring Unit 1, the utility will submit this document – Platte River's Just Transition Plan – to the Colorado Office of Just Transition within 30 days of Platte River's board of directors approving Resolution 08-24 and the 2024 IRP.

Platte River is not just transforming its energy mix. Embracing the future will require Platte River to change and adapt as an organization. Platte River entered the Southwest Power Pool (SPP) Western Energy Imbalance Service market in 2023 and will enter SPP's Regional Transmission Organization –West (RTO–West) in April 2026, which is one of the key advancements identified to further the RDP. To support entering RTO–West, Platte River is initiating a strategic workforce analysis to identify the necessary changes to its people, processes, and technologies.

Platte River's board passed Resolution 08-2020 (Workforce Resolution) in 2020, when Platte River announced Unit 1's retirement. The Workforce Resolution planned six principles that Platte River is committed to follow when implementing its transition plan. These principles are:

- Transparency
- Workforce Planning
- Workforce Opportunities
- Workforce Training
- Retention Strategies
- Transition Support

Platte River, through its Workforce Resolution and Just Transition Plan, will continue to demonstrate its unwavering commitment to support and retain employees who wish to remain with the organization through Unit 1's retirement and its transition to a clean energy future.

PLATTE RIVER AT A GLANCE

Platte River Power Authority is a not-for-profit, community-owned public power utility that generates and delivers safe, reliable, environmentally responsible and financially sustainable energy and services to Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their utility customers.

Headquarters

Fort Collins, Colorado

General manager/CEO

Jason Frisbie

Began operations

1973

Staff

268

2023 peak demand of owner communities

680 MW

2023 deliveries of energy

4,506,208 MWh

2023 deliveries of energy to owner communities

3,161,533 MWh

Transmission system

Platte River has equipment in 27 substations, 263 miles of wholly owned and operated high-voltage lines, and 522 miles of high-voltage lines jointly owned with other utilities.

PLATTE RIVER POWER AUTHORITY'S 2024 JUST TRANSITION PLAN

As required by House Bill 19-1314 and to further its commitment to Unit 1's retirement and the 100% noncarbon goal of its RDP, Platte River submits this Just Transition Plan to the Colorado Office of Just Transition. Platte River views this Just Transition Plan as a living document and anticipates that it will revise both the Just Transition Plan and its IRP as Unit 1's Dec. 31, 2029 retirement date nears. Platte River's Just Transition Plan follows the six principles of its Workforce Resolution and supports its ongoing commitment to retain employees through the energy transition and to avoid involuntary separations (layoffs) due to Unit 1's retirement.






MARKET
09
22



PRINCIPLE 1: TRANSPARENCY

Platte River management will make every effort to communicate impacts proactively and transparently to employees as decisions are made, including the timelines of planned events.

To implement this principle, Platte River consistently updates both Rawhide and Headquarters staff on the transition plan, including at plant and business meetings and through updates to Platte River's board. Platte River also discusses the upcoming transition, including its commitment to retain employees after Unit 1's retirement, with external candidates as part of the interview and hiring process. Platte River offers RTO–West training to the whole organization and will provide the results of its upcoming gap analysis to internal stakeholders so that each department can evaluate the changes to people, processes, and technology that will be needed in 2026 and beyond. Platte River also plans to provide this Just Transition Plan and the 2024 IRP to all employees through multiple channels and opportunities for employee to submit questions, concerns, and feedback on Platte River's transition.

Platte River's Just Transition Plan is led by a cross-functional team including representatives from power generation, operations, human resources, communications, and legal affairs and is sponsored by Platte River's Chief Operating Officer – Generation, Transmission and Markets. This cross-functional team currently plans additional outreach and communication to staff on workforce planning and workforce transition to accompany the Just Transition Plan and 2024 IRP. The cross-functional team is guided by the RDP, the Workforce Resolution and Platte River's Strategic Plan as it deploys Platte River's strategic workforce planning tools to further those goals and establish ongoing dialogue on how to best meet them in a just and transparent way.

PRINCIPLE 2: WORKFORCE PLANNING

Platte River management will continue to evaluate and identify workforce needs and to communicate its needs to staff.

To implement this principle, Platte River's leadership, partnering with its human resources department, is currently using strategic planning, data modeling, and other workforce planning tools to anticipate Platte River's future workforce needs. While this modeling is an imperfect science, Platte River is committed to using the best tools and data available, and to continually updating its models as Unit 1's retirement nears and Platte River's future needs become clearer.

It is important to note that Platte River is growing as an organization, even as Unit 1 retires. It will need additional staff in many functional areas to meet the RDP and the Strategic Plan, including in power marketing, power delivery, compliance, information technology, and substation maintenance. Platte River has determined how future vacancies will provide opportunities to transition Rawhide employees to other positions in the organization.

Platte River's internal modeling also shows that its workforce transition will largely be driven by natural attrition and retirement, not through layoffs. Many current Platte River employees have more than 25 years of service. Historically, Platte River attrition has been low amongst its longest-tenured employees, a trend that it anticipates may change as more staff members reach retirement age. Platte River, like other employers, has experienced increased attrition and volatility amongst its newer employees, a trend that it anticipates will not change between now and 2029.

Figure 1 and Figure 2 show the general trends that Platte River has modeled and observed in attrition by years of service, both for the organization as a whole and for Rawhide.

Figure 1: Platte River Attrition by Years of Service

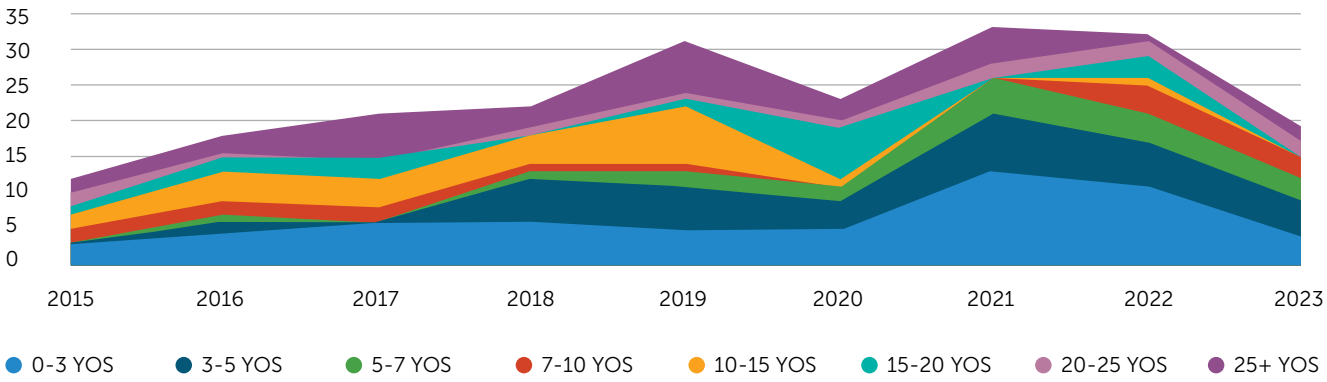


Figure 2: Rawhide Attrition by Years of Service

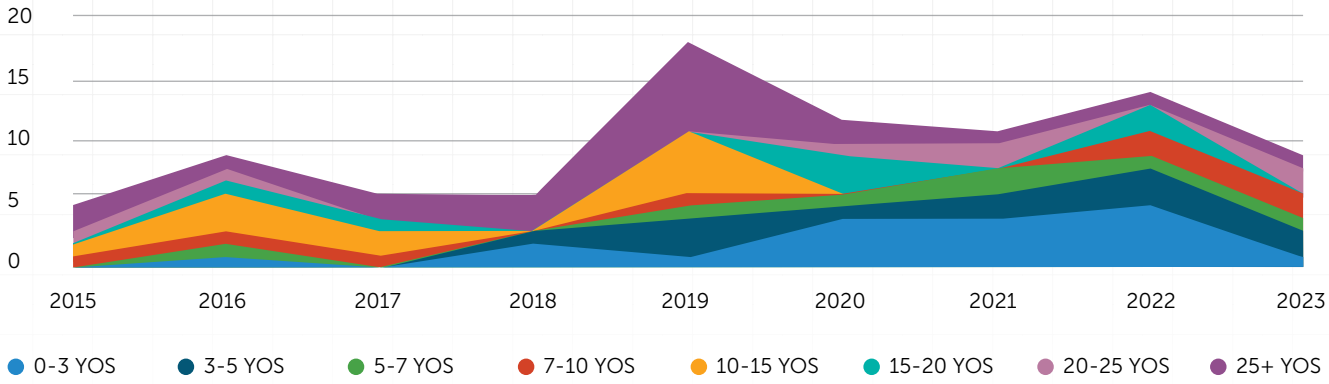


Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for natural attrition show that it will be understaffed at Rawhide in the latter part of the decade (for example, from 2027 to 2029).

Figure 3: Platte River Attrition by Reason

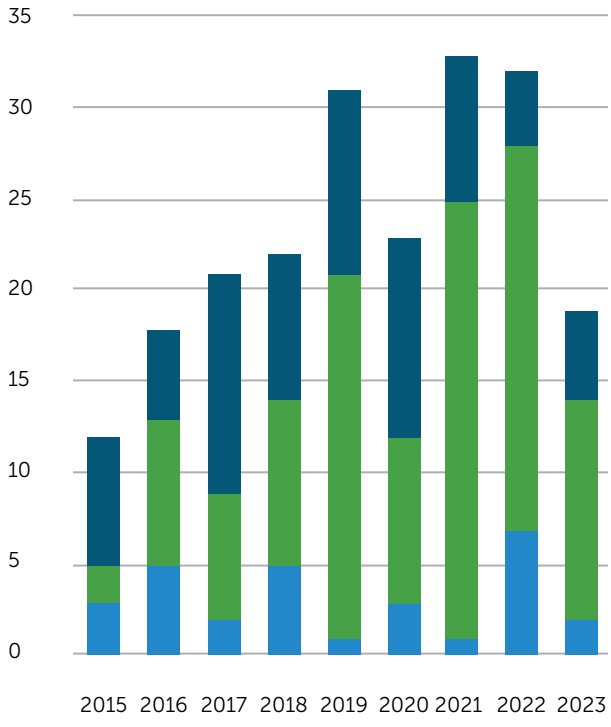
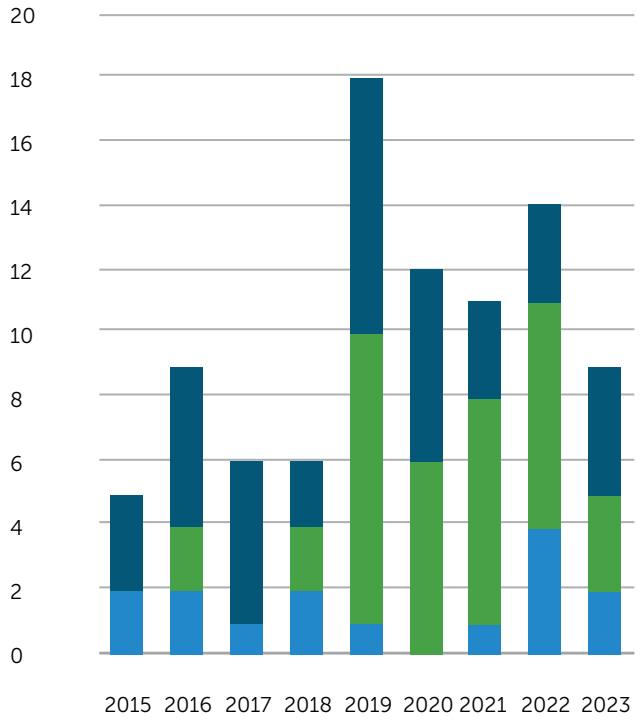
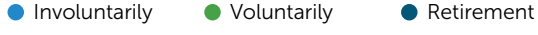


Figure 4: Rawhide Attrition by Reason





Platte River projects that it will need to transition approximately 25-30 Rawhide employees at Unit 1's retirement if it backfills vacancies that arise due to retirements or other natural attrition. See Table 1. But Platte River may also fill in for natural attrition with contract labor as Unit 1's retirement date nears. Platte River will be able to better estimate the exact number of employees to transition in future years, as it clarifies the number of employees needed to support the remaining generation at Rawhide and its other departments.

Table 1. Projected headcount and the number of employees to transition to Rawhide

Department	Current headcount As of Jan. 1, 2024	Target headcount At retirement Dec. 2029	Target headcount Post 2030	Employees to transition
Plant operations	31	22	10-15	7-12
Mechanical maintenance	14	8	6	2
Instrumentation and electrical	12	12	4	8
Fuel handling / facilities	12	5	4	1
Engineering	10	7	2	5
Lab	2	2	2	0
CAD	1	1	0	1

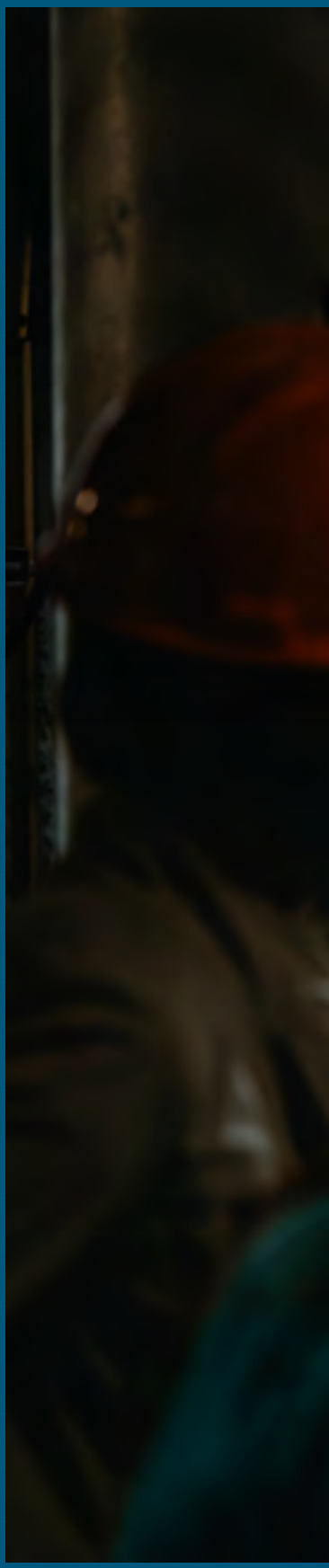
Current headcount
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

Target headcount (at retirement)
This is the estimated number of employees needed to safely operate Rawhide Unit 1 and the existing combustion turbines.

Target headcount (post-2030)
This represents the number of employees that it estimates are needed to run the existing gas combustion turbines at Rawhide after Unit 1 retires. These estimates may be updated in future filings.

Employees to transition
This number represents employees whose existing jobs may be eliminated due to Unit 1's retirement. Therefore, this is the number of employees to retrain, transfer within other business areas, or otherwise transition as part of the Just Transition Plan.

Platte River is committed to finding opportunities for each of these employees to remain with the organization, if desired. Platte River intends to honor its promise that no employees will be laid off or involuntarily separated solely due to Unit 1's retirement and the energy transition. How Platte River intends to meet this commitment is discussed further in the principles below.




ANGER

PRINCIPLE 3: WORKFORCE OPPORTUNITIES





Platte River management will prioritize internal staff for workforce opportunities where Rawhide employees have relevant qualifications and experience.

To implement this principle, Platte River is identifying growth opportunities and projected work for existing employees to transition at Rawhide and at Headquarters. The main areas where Platte River sees these opportunities are:

- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

Each of these areas is anticipated to grow between now and 2029 due to the energy transition and Platte River's entry into RTO–West. Platte River encourages high-performing employees to reach out to their supervisors (either as part of a scheduled performance discussion or at other times) to discuss potential transition plans and opportunities. Platte River advertises all vacancies to internal employees and seeks to prioritize internal applicants for many of its open positions.

Platte River plans additional formal efforts in the upcoming years to highlight potential growth opportunities within the organization and support employee advancement and retention. These efforts include an internal "career fair" (expected in 2026) to showcase potential opportunities within the organization and to further the dialogue between departments that may lose staff and departments that need additional employees. Platte River also plans a "shadowing" program between Rawhide and headquarters so that Rawhide employees may learn more about headquarters positions that may be available, and the knowledge, skills, or abilities needed for those roles.

No later than year end 2028, Platte River plans to start formal interviews with employees to have more in-depth discussions about their goals and determine how they may align with future roles. These formal interviews will also help Platte River determine what training, education, or other support might be needed to successfully transition employees into future growth roles.

PRINCIPLE 4: WORKFORCE TRAINING



Platte River management will provide workforce training for Rawhide employees when appropriate to allow them to successfully transition into new roles.

To implement this principle, Platte River will use the career fair, shadowing, and interview programs described above to engage with employees on how Platte River can best help employees meet their career goals. Platte River intends to capture and analyze information learned through annual employee evaluation processes and other discussions to identify employment trends and skill gaps and to formalize training programs that are specific to the identified skill needs post-2029.

Platte River understands that training and education may be a large component of the workforce transition, particularly for employees contemplating career changes. Platte River currently has a tuition reimbursement program for employees who want to increase skills. This program is already in use with a current Rawhide employee taking courses in information technology. Platte River anticipates this program will grow significantly as it identifies skill gaps and helps employees chart career paths. Platte River is working with its staff to increase transferable skills (like computer literacy) in its current workforce. Platte River will also explore partnerships with local educational institutions in northern Colorado and southern Wyoming.These partnerships may include formal training programs tailored to the Rawhide transition or a continuation of the current tuition reimbursement program, depending on employee and Platte River needs.







PRINCIPLE 5: RETENTION STRATEGIES

Platte River management will evaluate, design, and implement employee retention strategies to ensure Rawhide Unit 1 continues to provide safe, reliable and financially responsible energy to its owner communities until its closure date.

Platte River is committed to implementing this principle for transitioning Rawhide employees. But employee retention is not just a concern as part of the energy transition or the Just Transition Plan. Platte River seeks to be a leading employer to drive retention for all employees, at both Rawhide and headquarters, and has made many recent changes to its compensation and total employee rewards programs to support employee retention. These changes include industry-leading total rewards and compensation packages, such as:

- Platte River family leave program (providing 12 weeks fully paid family leave),
- Platte River's compensation philosophy is inclusive of a compensation study which uses a market-leading pay above the 50th percentile in 2024,
- Platte River's employee-focused benefits program, and
- Hybrid and remote work available for certain roles.

Platte River is exploring other options for retention at Rawhide up to transition, including retention bonus programs and incentives for advance retirement planning in the years leading up to Unit 1's closure. Platte River will work with its employees to evaluate and carefully implement these strategies in a way that supports the goals of continued operational excellence at Rawhide, an orderly and well planned closure, and employee transition to new roles.



PRINCIPLE 6: TRANSITION SUPPORT



For those employees whose paths lead away from Platte River, Platte River management will seek to ease their transitions with placement support and incentives, where appropriate.

When discussing this principle, it is important to reiterate that current projections show few, if any, non-voluntary transitions due to the retirement of Rawhide Unit 1. As discussed in the first five principles, above, Platte River is committed to retaining its workforce and anticipates finding roles for Rawhide employees who want to transition to new roles after 2029. Platte River does not anticipate layoffs or other mass transitions. Platte River's Just Transition Plan supports an individualized and career-focused approach for each employee affected by Unit 1's closure.

Should any non-voluntary transitions be needed in the future due to Unit 1's retirement, Platte River is committed to supporting those employees as it supports those who transition voluntarily. Efforts will be deployed through career path discussions and ongoing training and education opportunities like those provided to employees transitioning to internal Platte River roles. Platte River also provides an employee assistance program, which is available to current employees contemplating career changes and transitions. This program may include counseling support as well as legal or financial advice to assist employees in making life changes.

CONCLUSION

Platte River is committed to a just transition and to retaining its staff and culture of operational excellence. This document will be updated as its workforce plans evolve. Platte River will remain committed to the principles outlined by its board and management to demonstrate their unwavering support to the Platte River employees that safely and reliably operate Unit 1, its highest-performing and most cost-effective resource. Platte River looks forward to working with its staff, management, and the Office of Just Transition to responsibly move toward its energy future.





Appendix C: Board resolution for 2024 IRP approval

RESOLUTION NO. 07-24

Background

A. Platte River Power Authority (Platte River) was formed to provide electric generation and transmission services to its owner communities.

B. Platte River is obligated by contract to serve the owner communities' wholesale electrical capacity and energy needs through 2060.

C. Platte River and its owner communities collaborate to conduct supply-side and demand-side planning.

D. Platte River uses integrated resource planning to support its development of a resource portfolio consistent with its three foundational pillars of reliability, environmental responsibility and financial sustainability.

E. In 2018, the board of directors (board) adopted the Resource Diversification Policy, which directs Platte River's general manager/CEO to proactively work toward the goal of reaching a 100% non-carbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

F. By law and to remain eligible for federal hydropower allocations, Platte River must submit a formal integrated resource plan (IRP) to the Western Area Power Administration every five years. Given the challenges of quickly advancing the board's Resource Diversification Policy goals, compounded by rapid evolution of utility technology, the board encouraged staff to accelerate its formal IRP development process. Platte River staff completed and submitted its most recent IRP in 2020, and shared with the board an informal update to the IRP inputs and assumptions in 2022.

G. Platte River staff, collaborating with industry experts, has worked over the past 18 months to develop the 2024 IRP with updated studies, assumptions, technology advancements, and modeling inputs. Platte River supported community engagement through numerous in-person and virtual meetings, cataloguing and responding to stakeholder questions, and a dedicated internet microsite. Staff shared background information for the 2024 IRP with the board in April 2024 and presented a full draft of the 2024 IRP at the May 2024 board meeting.

H. The 2024 IRP reflects existing and potential future resources based on current information, technology and system capabilities and recognizes these and other factors will continue to evolve.

I. Staff recommends selection of the 2024 IRP's optimal new carbon portfolio to establish a new baseline for planning, budgetary and ratemaking purposes.

J. The optimal carbon portfolio in the 2024 IRP provides a path for Platte River to reduce its carbon emissions by more than 90% from 2005 levels while maintaining reliability and financial sustainability, and is therefore consistent with the Resource Diversification Policy and surpasses Colorado legislative goals for greenhouse gas reductions.

K. Staff expects to prepare an updated IRP by 2028, while continuing to communicate transparently and foster public engagement in Platte River's long-term resource planning activities.

L. The board intends that when it approves the Just Transition Plan (Resolution 08-24) for the closure of Rawhide Unit 1, the Just Transition Plan will become part of the 2024 IRP.

Resolution

The board of directors of Platte River Power Authority therefore resolves that:

1. The 2024 IRP, as contained in the July 2024 meeting packet, is approved, and
2. Staff's recommendation to select the optimal new carbon portfolio as Platte River's new baseline for planning, budgetary and ratemaking purposes is accepted, and
3. When the board approves Platte River's Just Transition Plan for Rawhide Unit 1, the Just Transition Plan becomes part of the 2024 IRP.

AS WITNESS, I have signed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this 25 day of July 2024.

Secretary

Adopted: July 25, 2024
Vote: 6-0

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

www.prpa.org

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit FF: PRPA, *Craig Units 1&2 (Yampa Project)* (2026)

Craig units 1 & 2 (Yampa Project)



Fuel type: coal
Net capacity: 151 MW
Commercial operation: Unit 1—1980; Unit 2—1979
Operations: baseload

Operations

- Platte River's ownership of Craig 1 and 2 is 18%
- Operated by Tri-State Generation and Transmission
- Co-owners include Tri-State Generation and Transmission, Salt River Project, PacifiCorp and Xcel Energy
- Craig Unit 1 to be removed from Platte River's mix by Dec. 31, 2025
- Craig Unit 2 to be removed from Platte River's mix by Sept. 30, 2028

Financials

- Platte River's second-lowest operating cost resource
- Fuel prices are based on production costs and not subject to market price volatility
- No debt service
- Fuel cost volatility mitigated by management of mine production levels and costs through an ownership share of Trapper Mine (27.14%), located adjacent to Craig units 1 and 2

Environmental

- Upgraded technology to reduce sulfur and particulate emissions
- Maintains full compliance with strict environmental laws and regulations

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit GG: PacifiCorp, *Utah Integrated Resource Plan Volume I* (Mar. 31, 2025)





UTAH 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.

For more information, contact:
PacifiCorp Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
irp@pacificorp.com
www.pacificorp.com

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CHAPTER 13 – UTAH ACTION PLAN

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



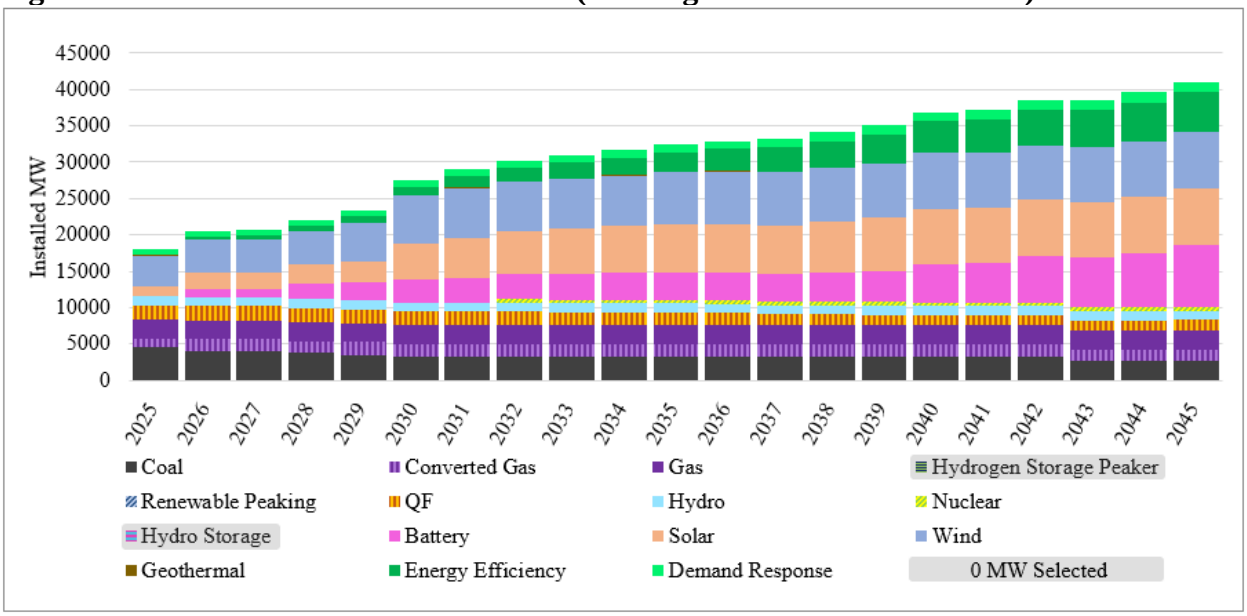
Preferred Portfolio Highlights

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.

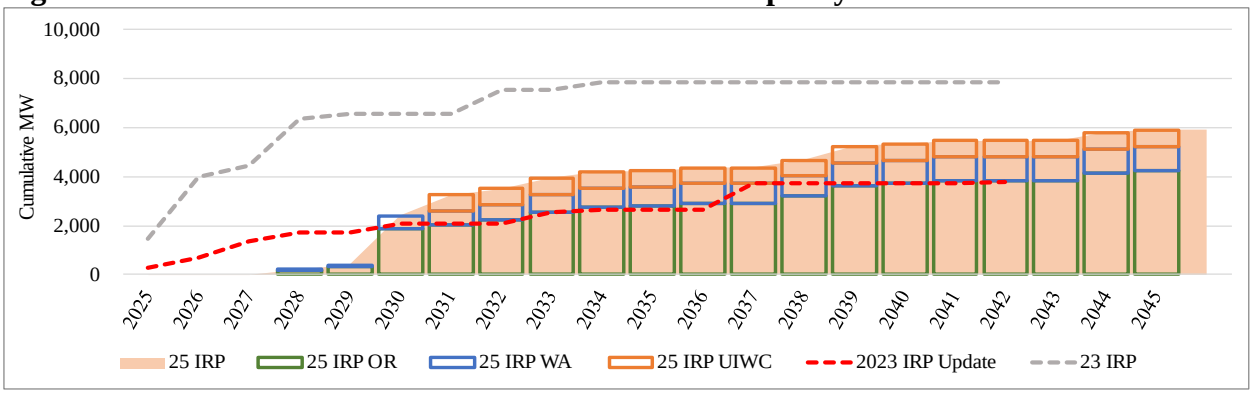
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

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.

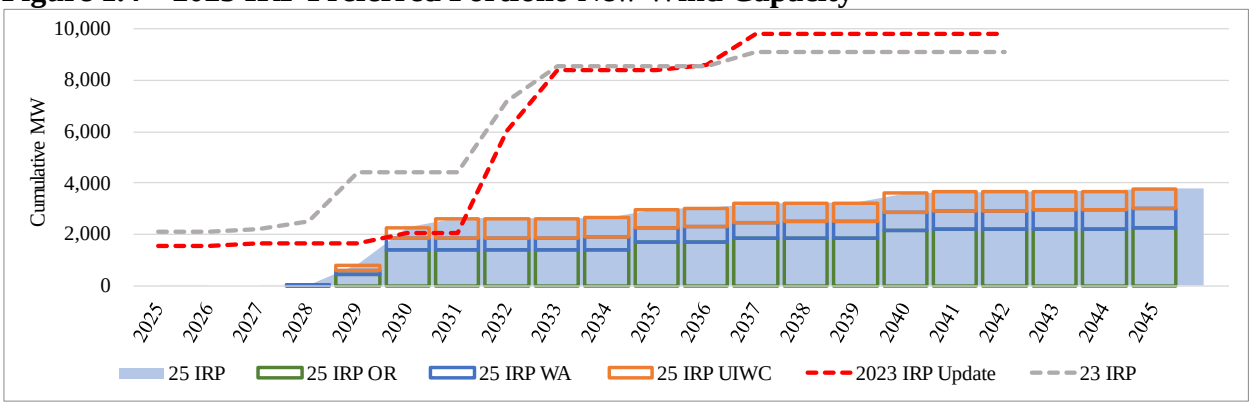
Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity



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.

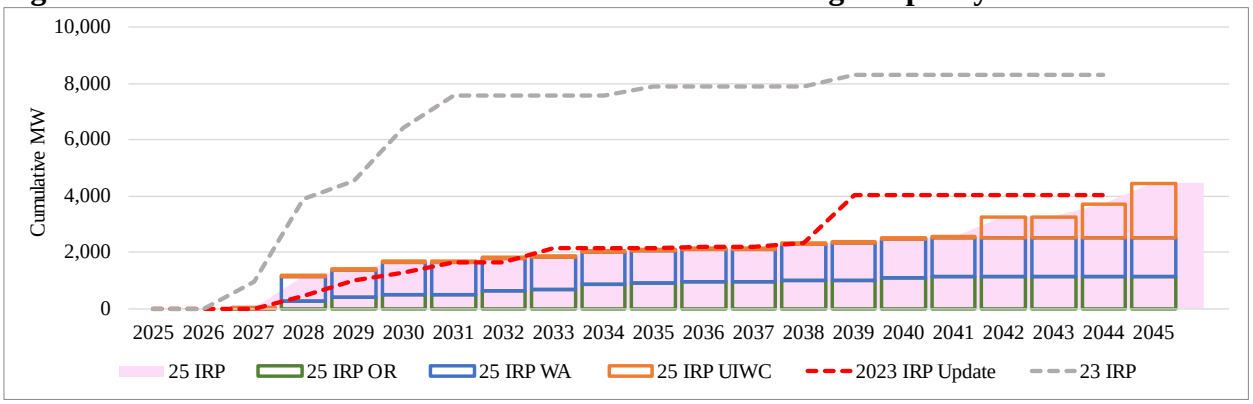
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

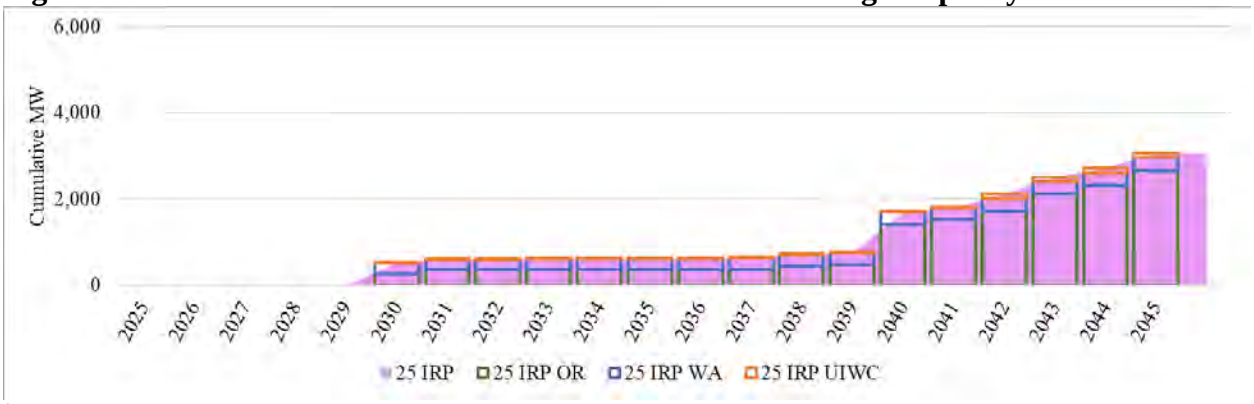
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred 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]

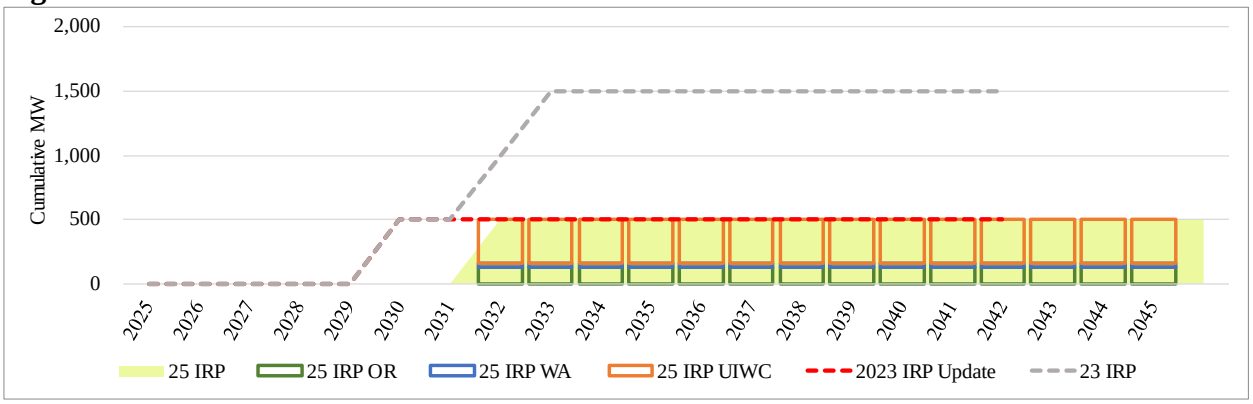


[1]The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

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.

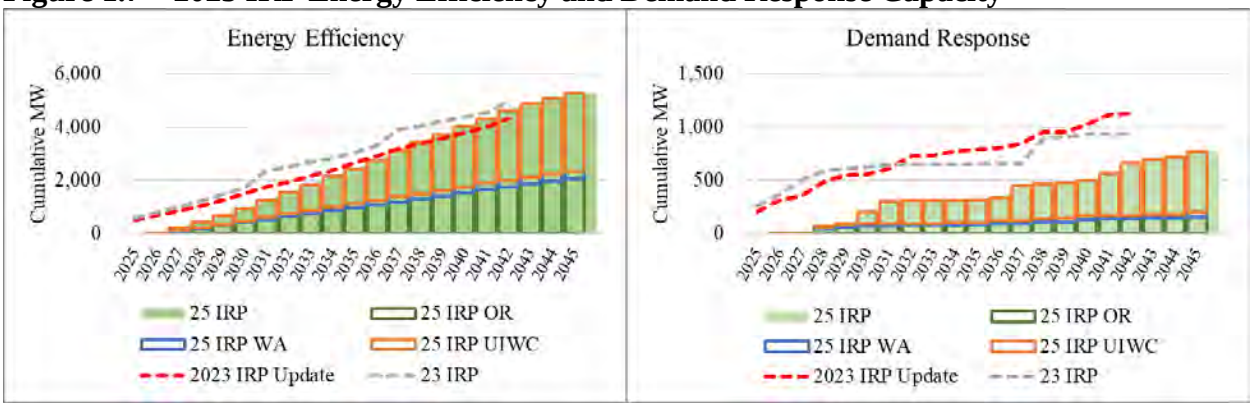
PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 12.3 percent

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

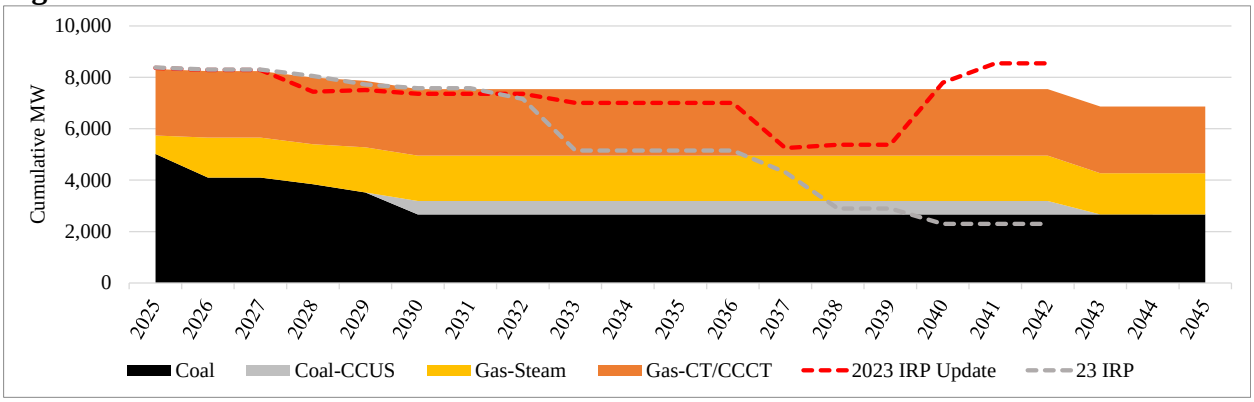


Coal and Gas Exits, Retirements, and Gas Conversions

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)

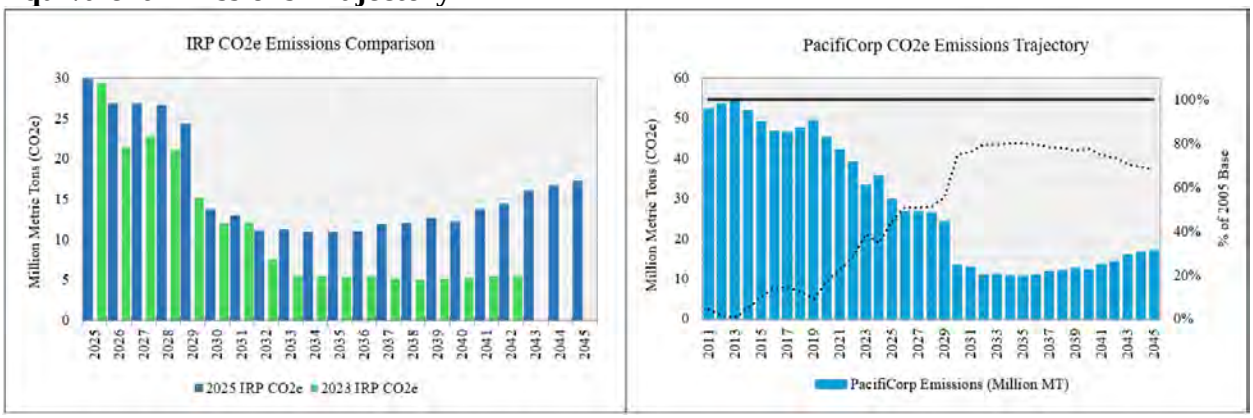
Carbon Dioxide Emissions

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*

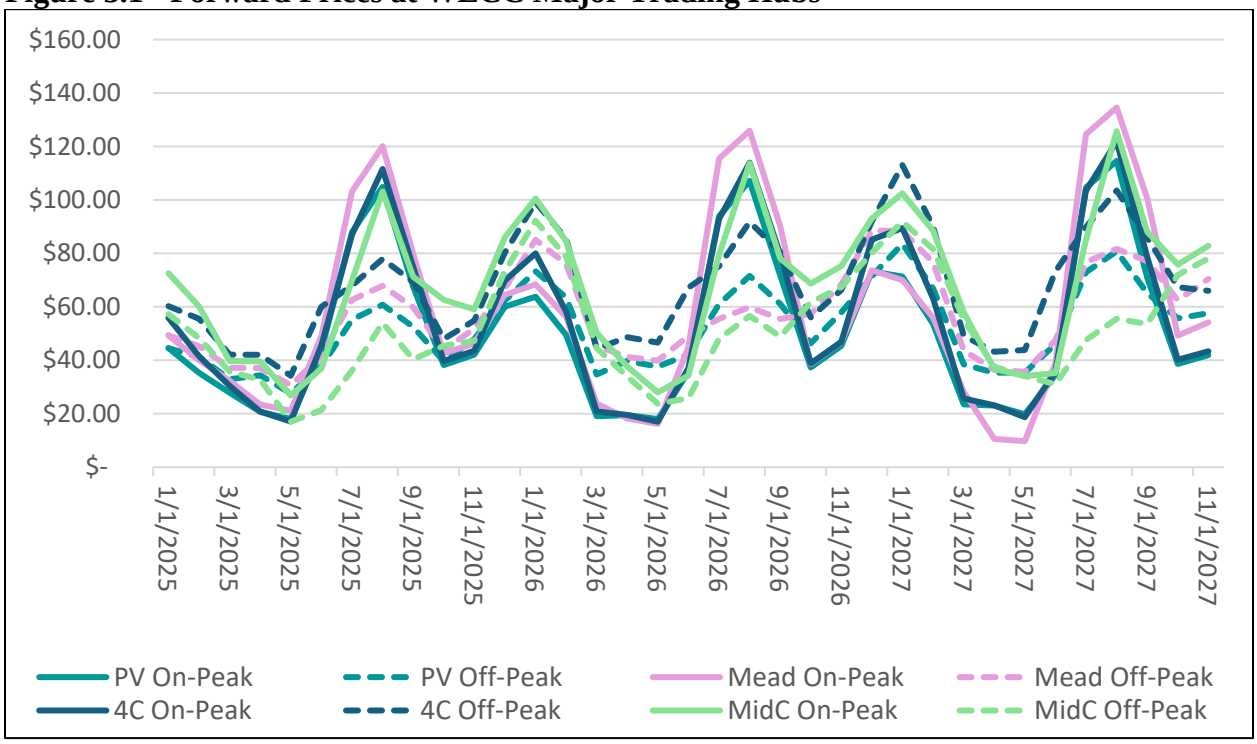
Source: SNL

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

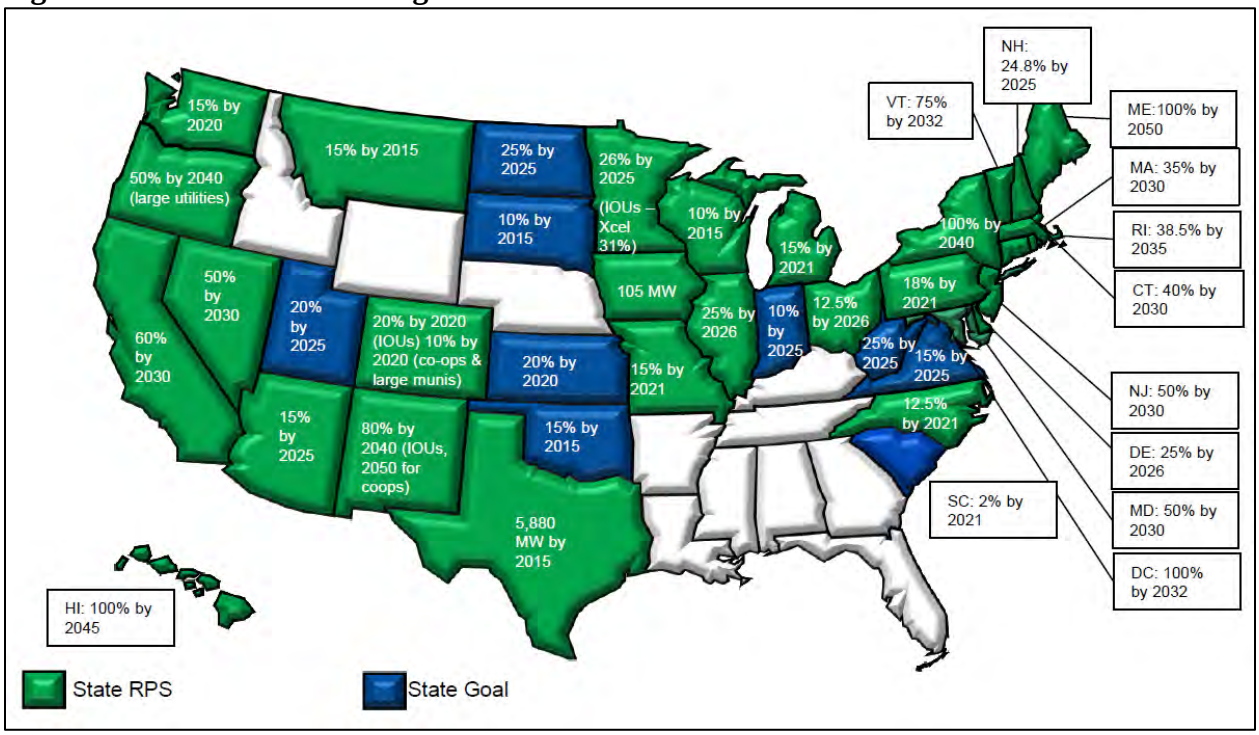
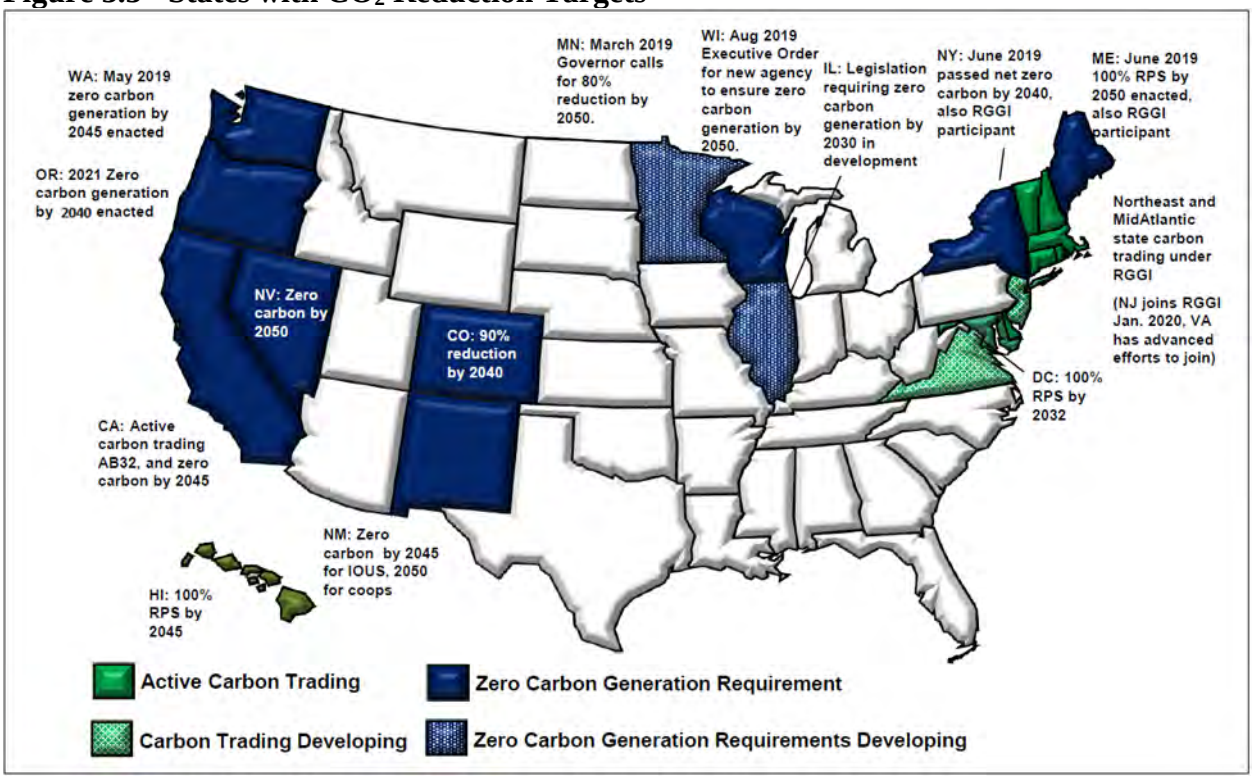
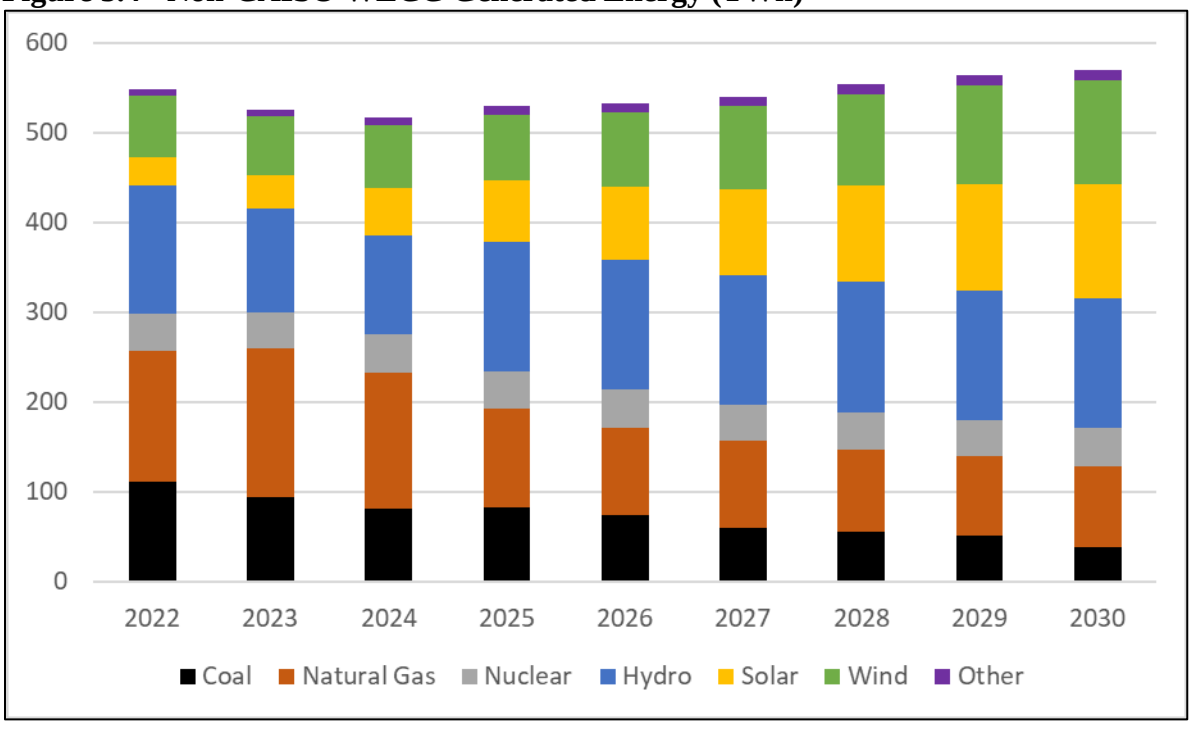


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

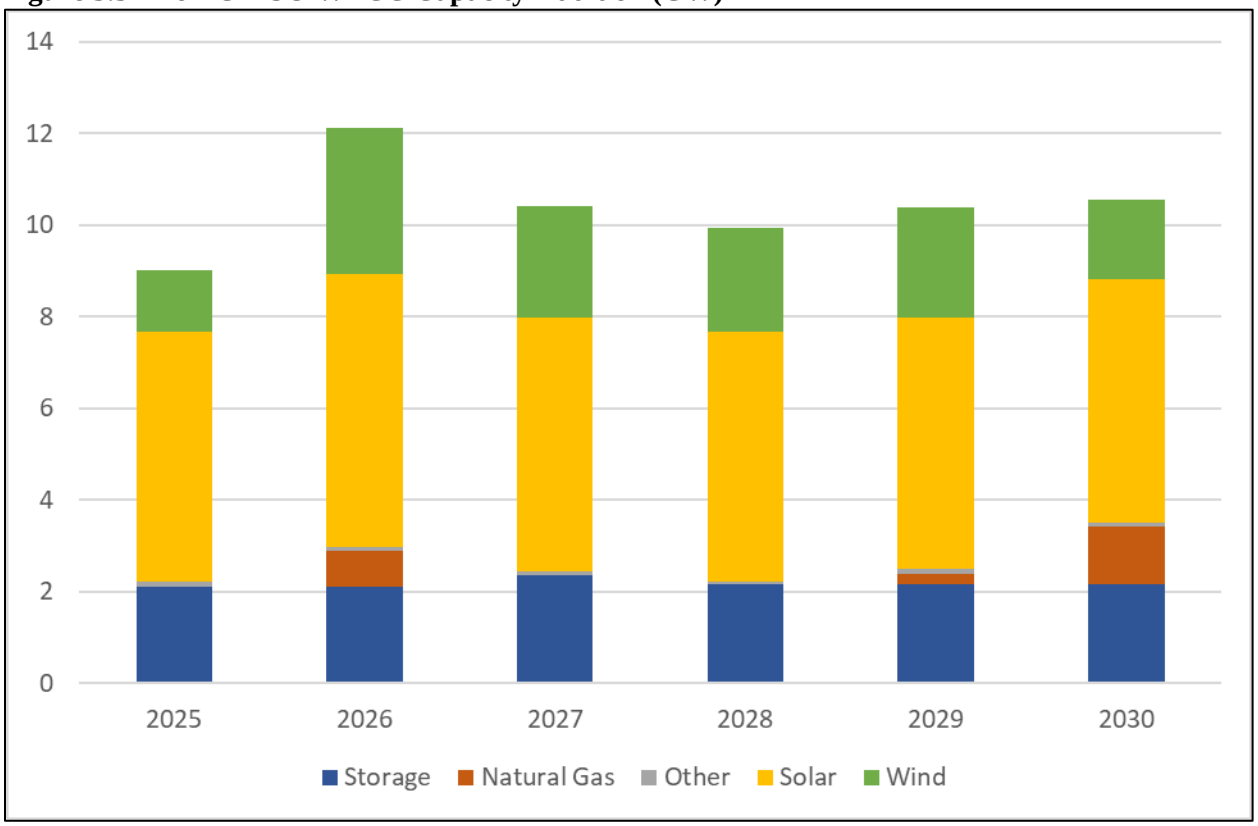
Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)



Source: IHS Markit, SNL, Siemens PTI

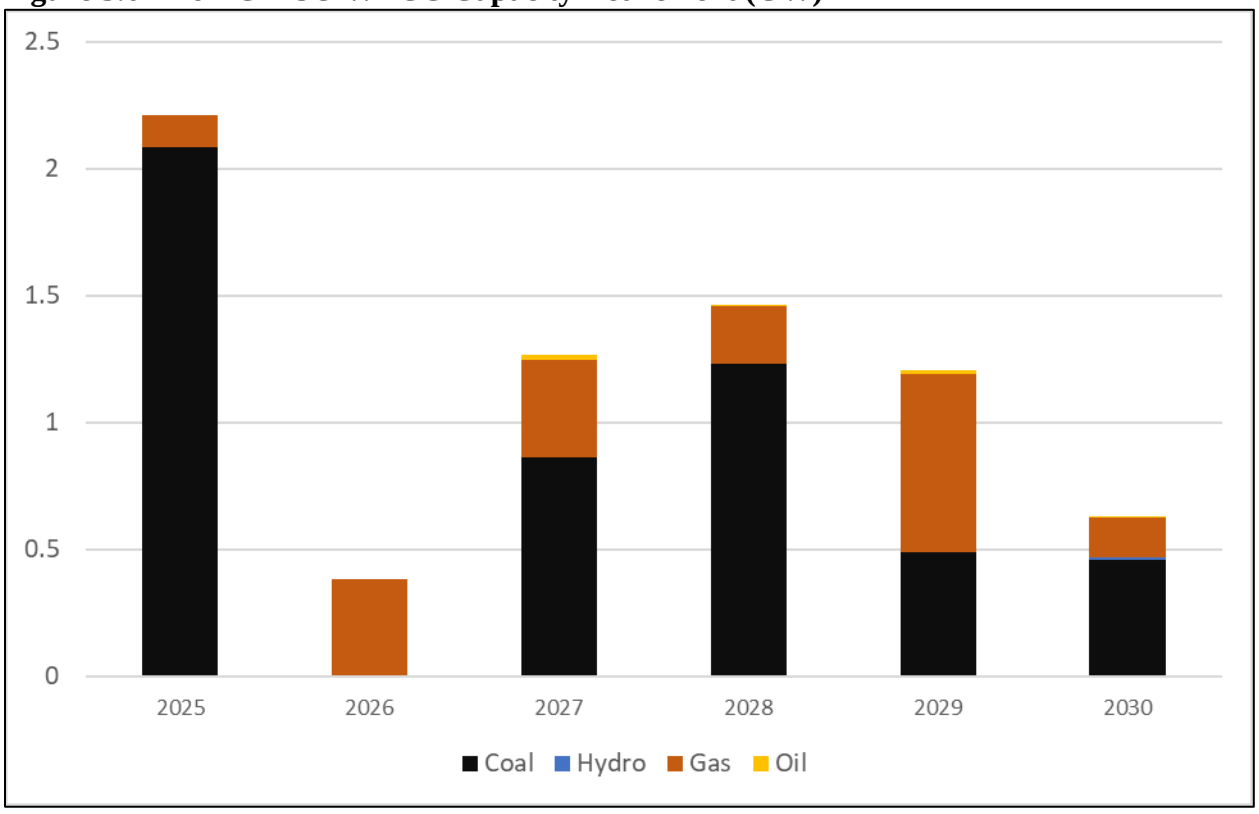
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage 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

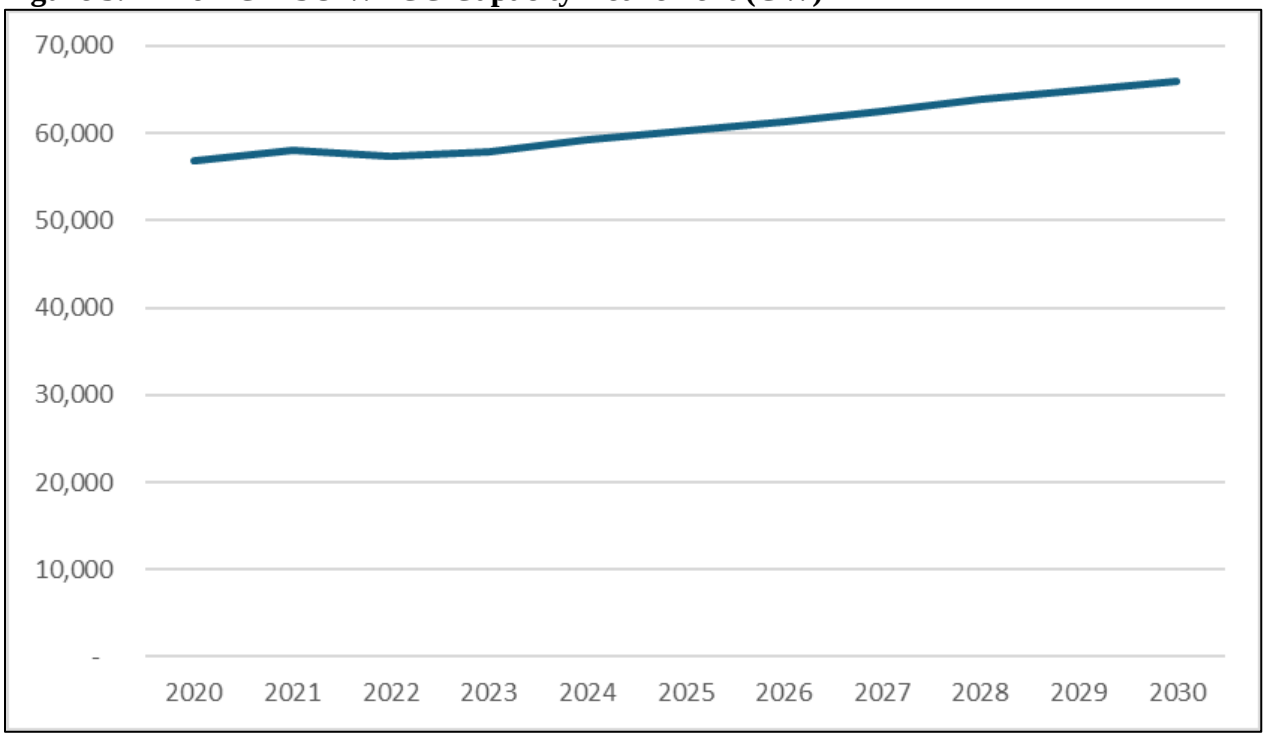
Emissions and Environment

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

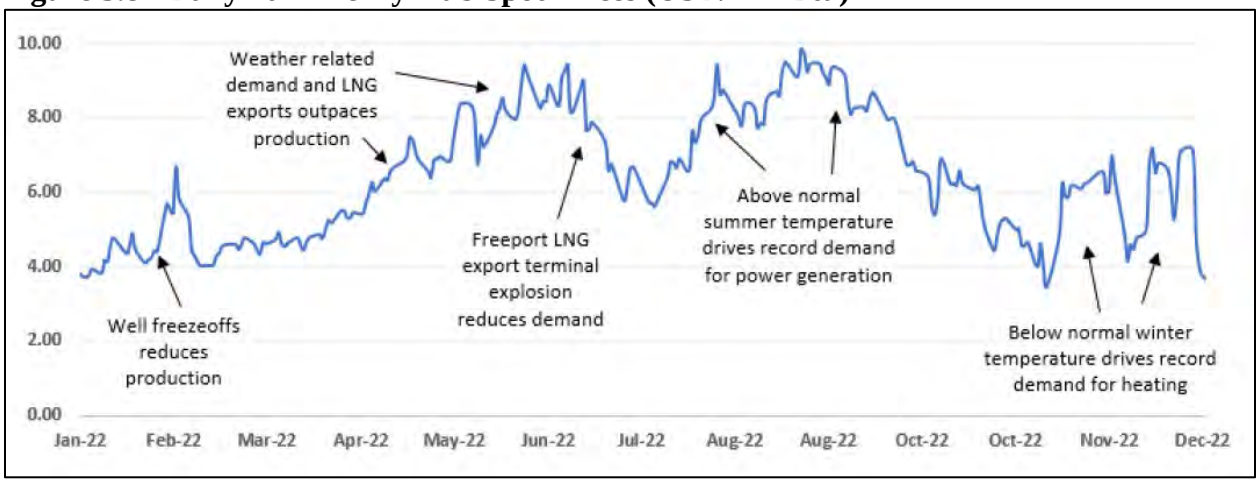
2022 Summary

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.

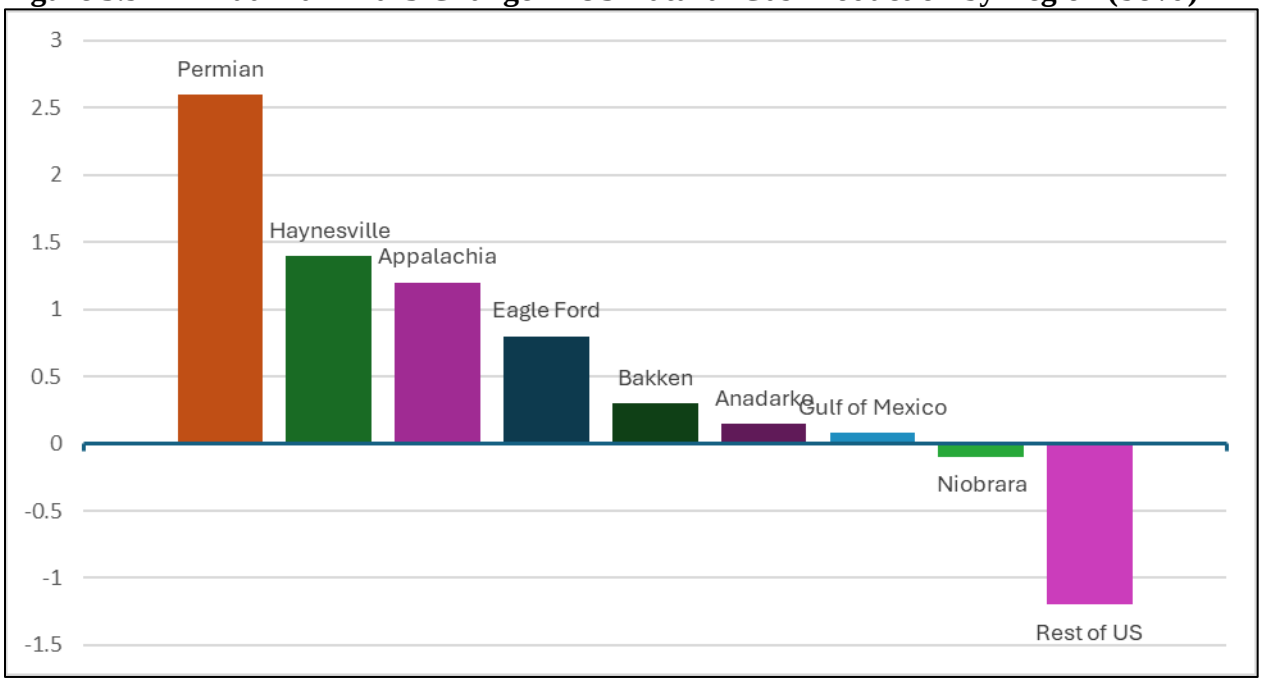
However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased

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.

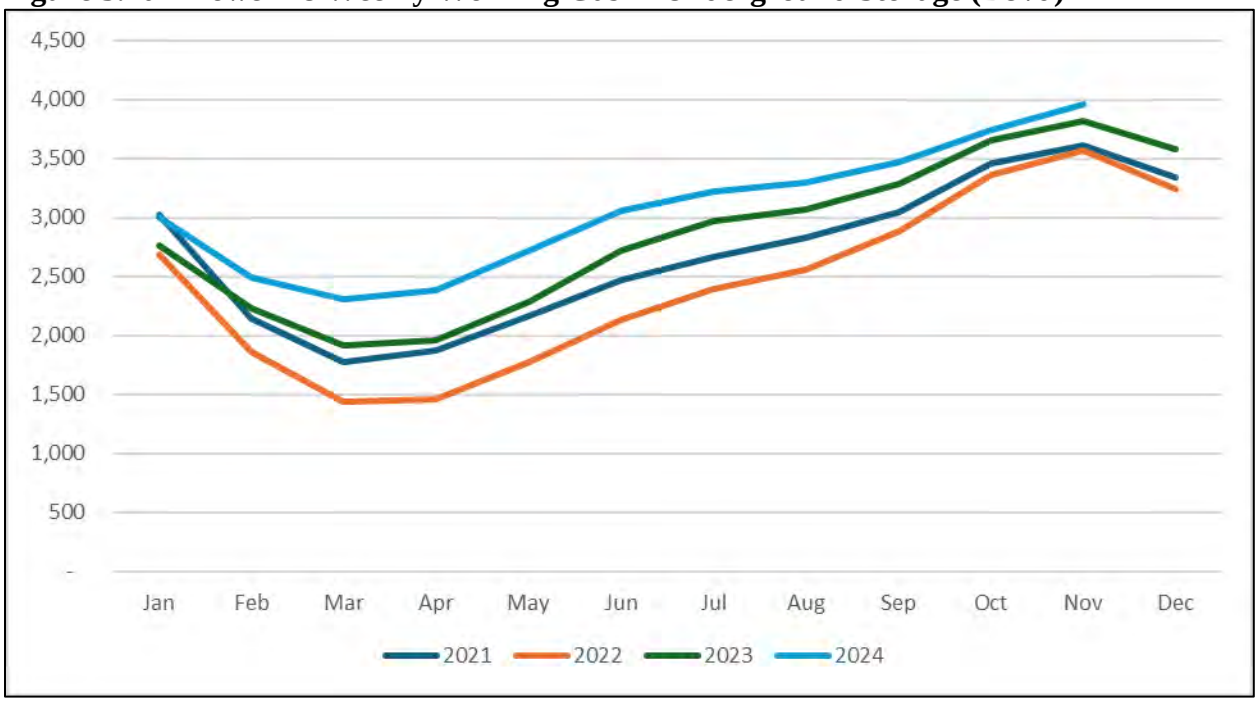
Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



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

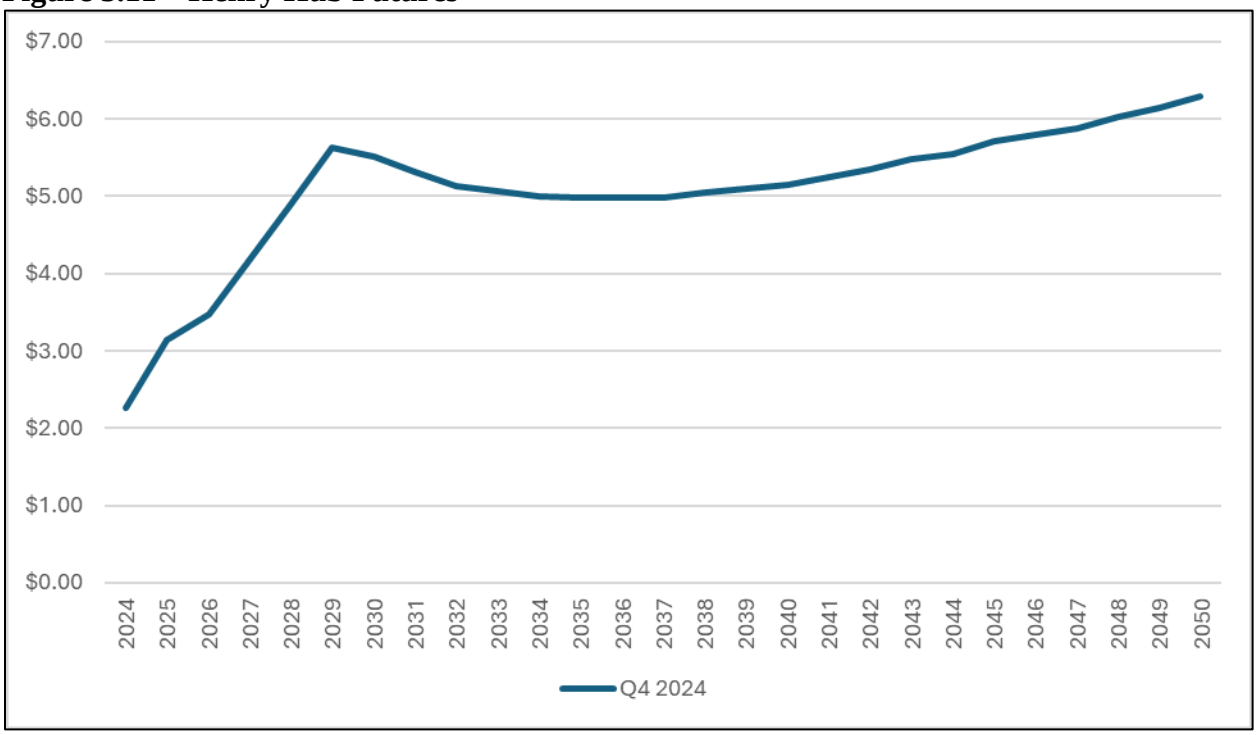
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts 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.

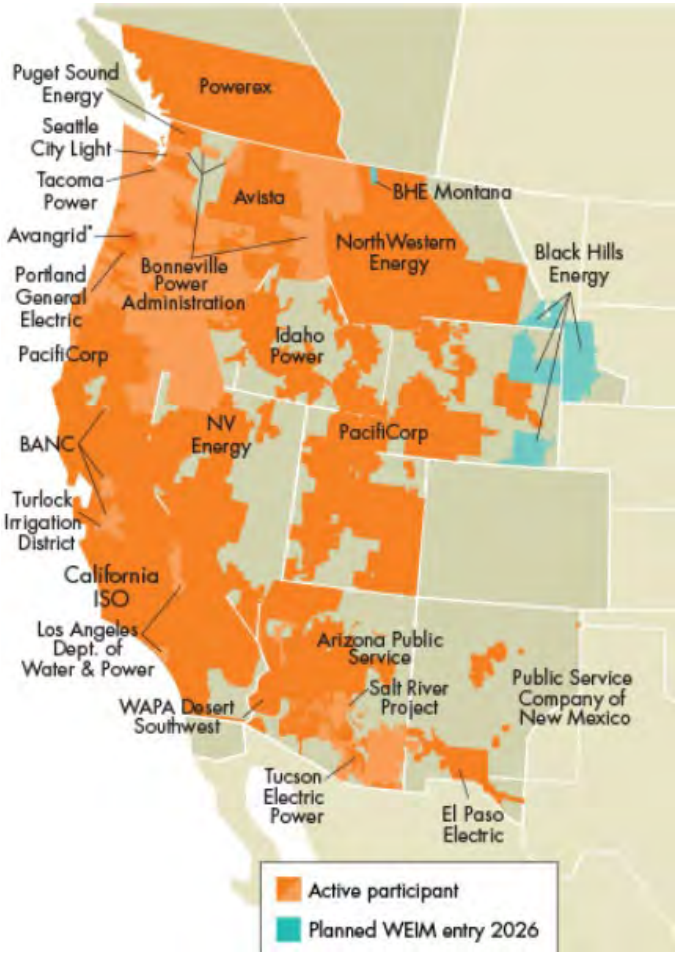
Electricity Market Development Update

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.

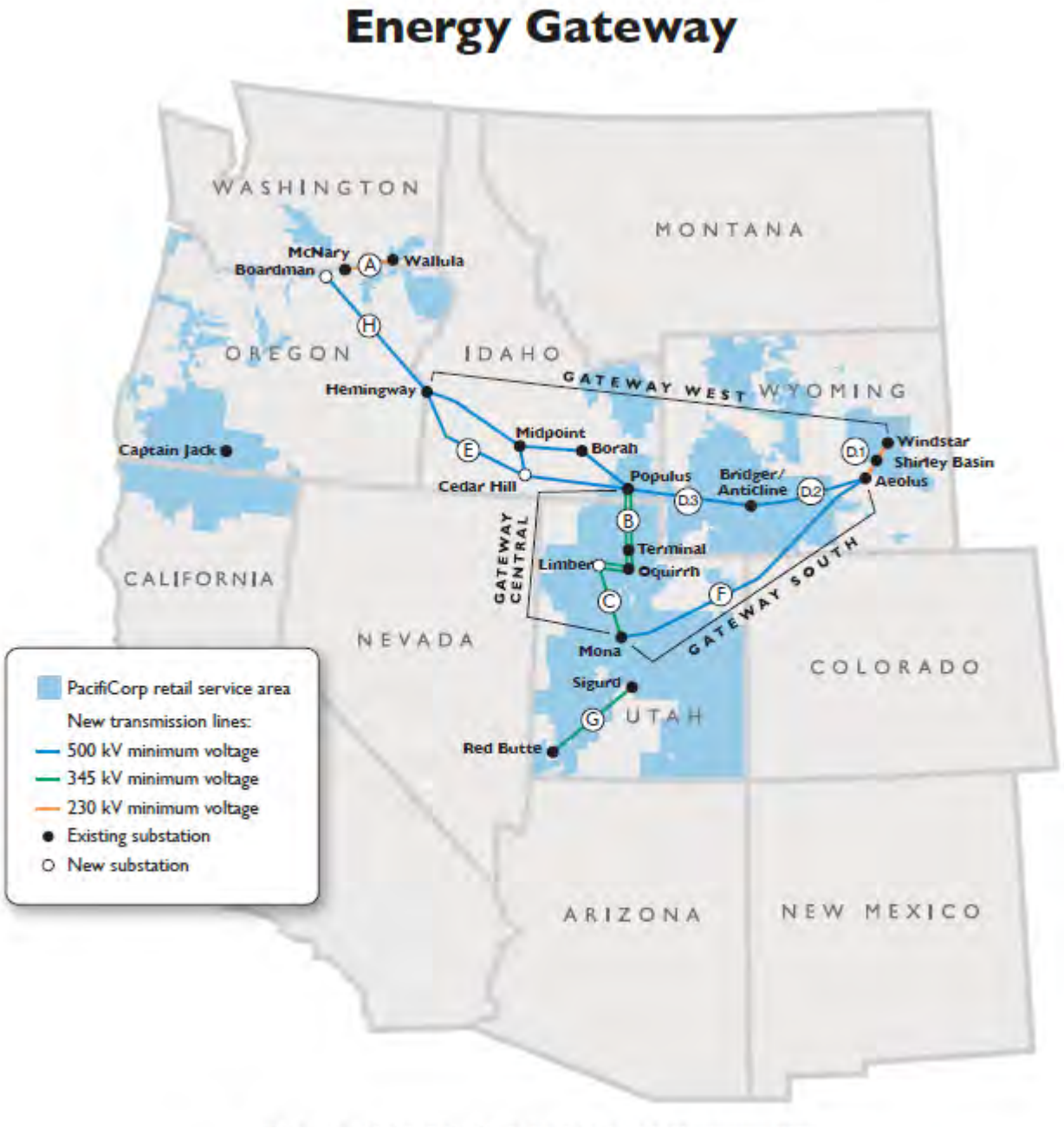
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 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

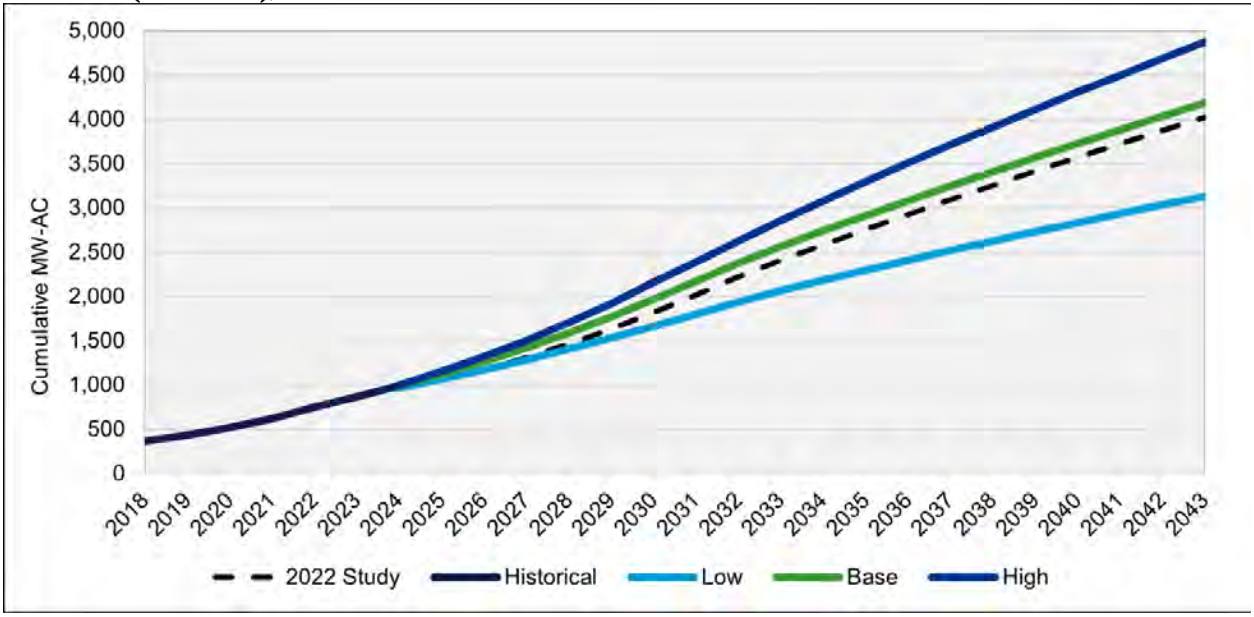
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each 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.

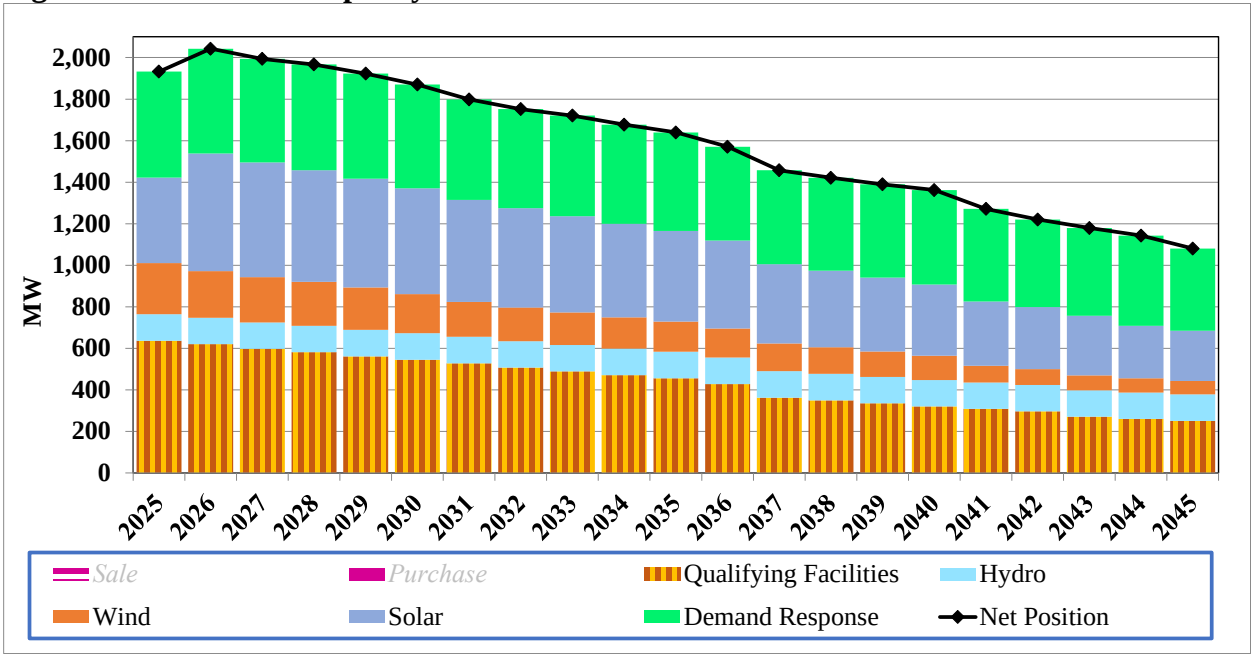
Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



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

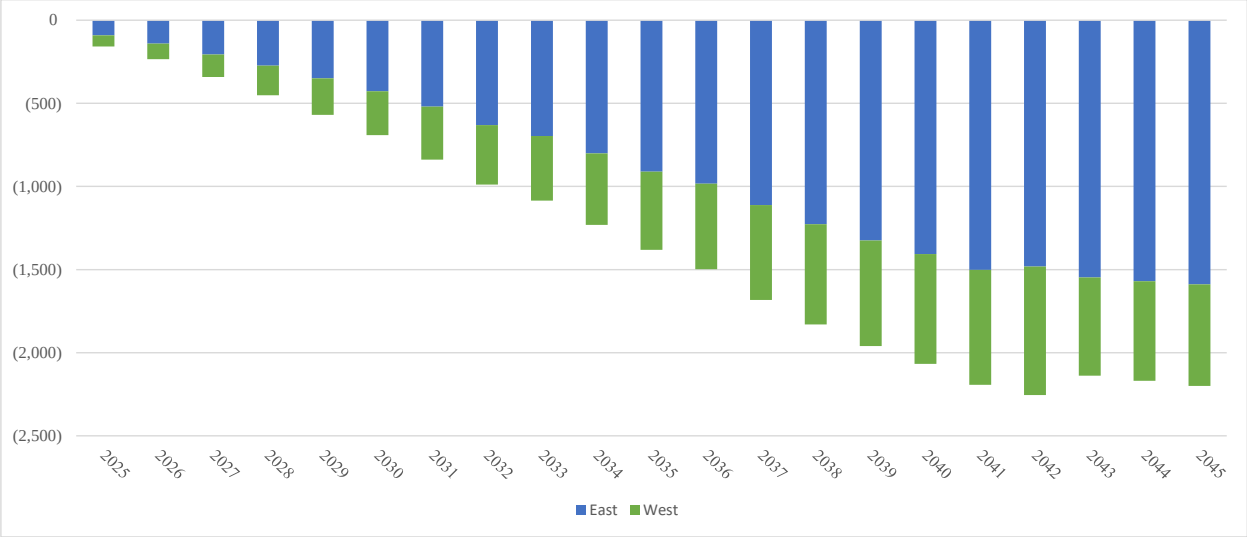
The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system

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

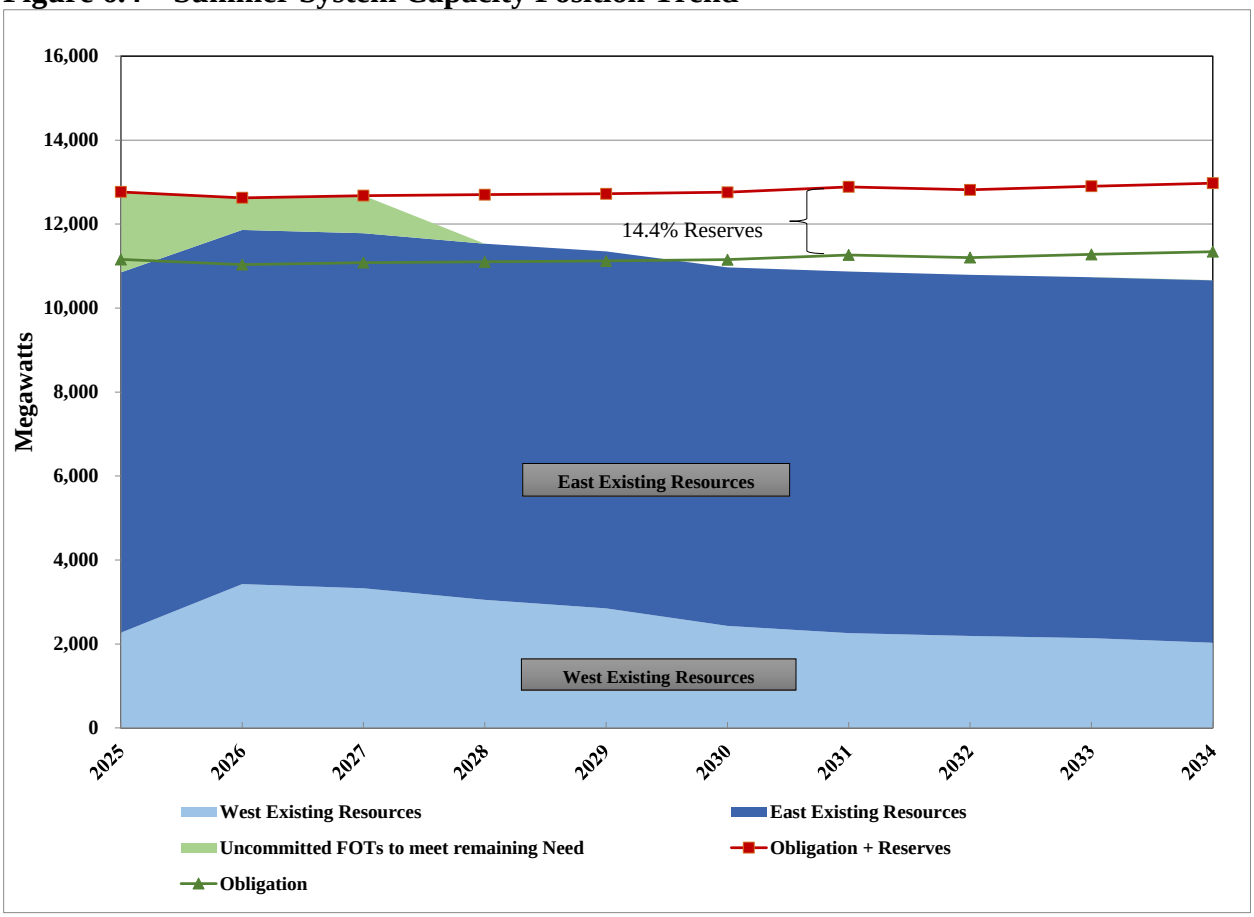


Figure 6.5 – Winter System Capacity Position Trend

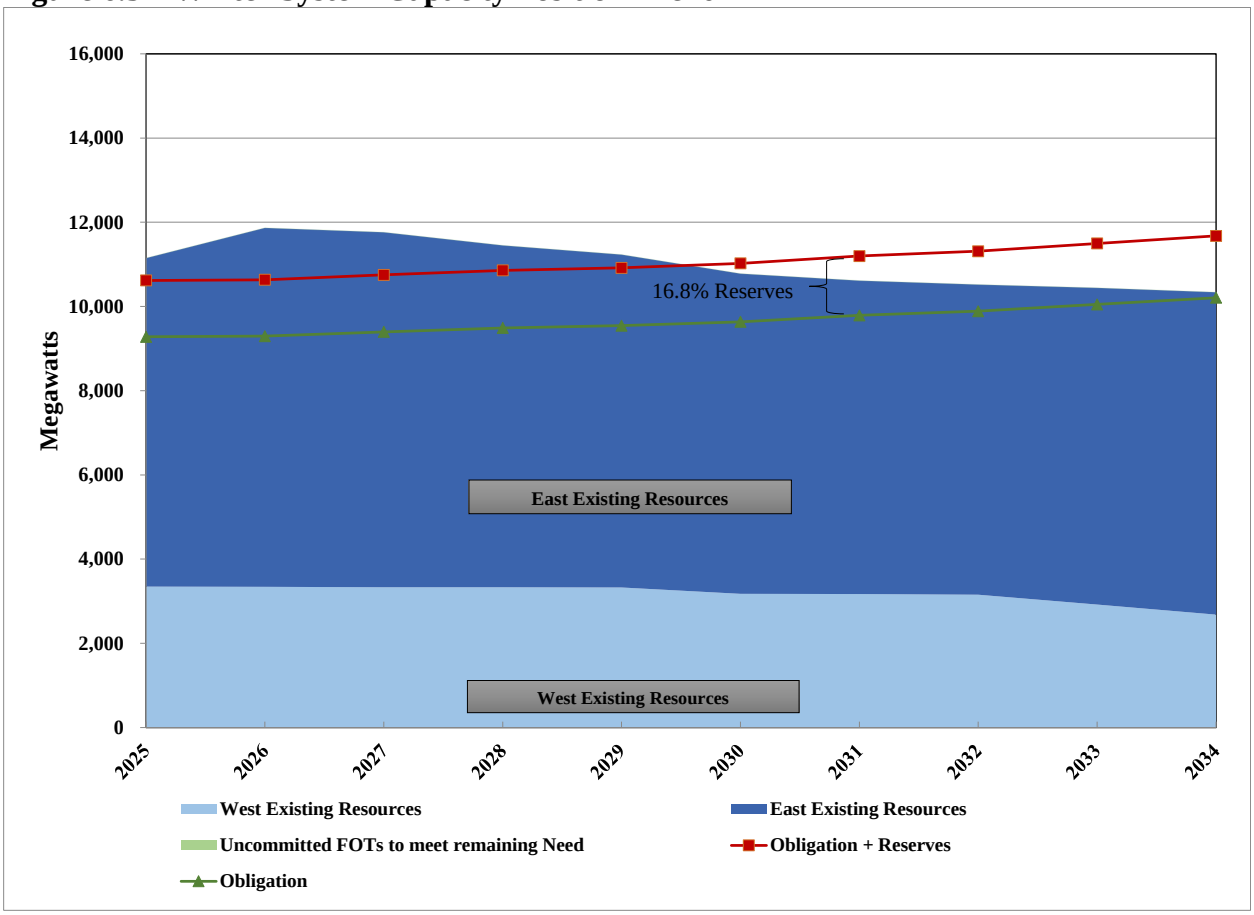


Figure 6.6 – East Summer Capacity Position Trend

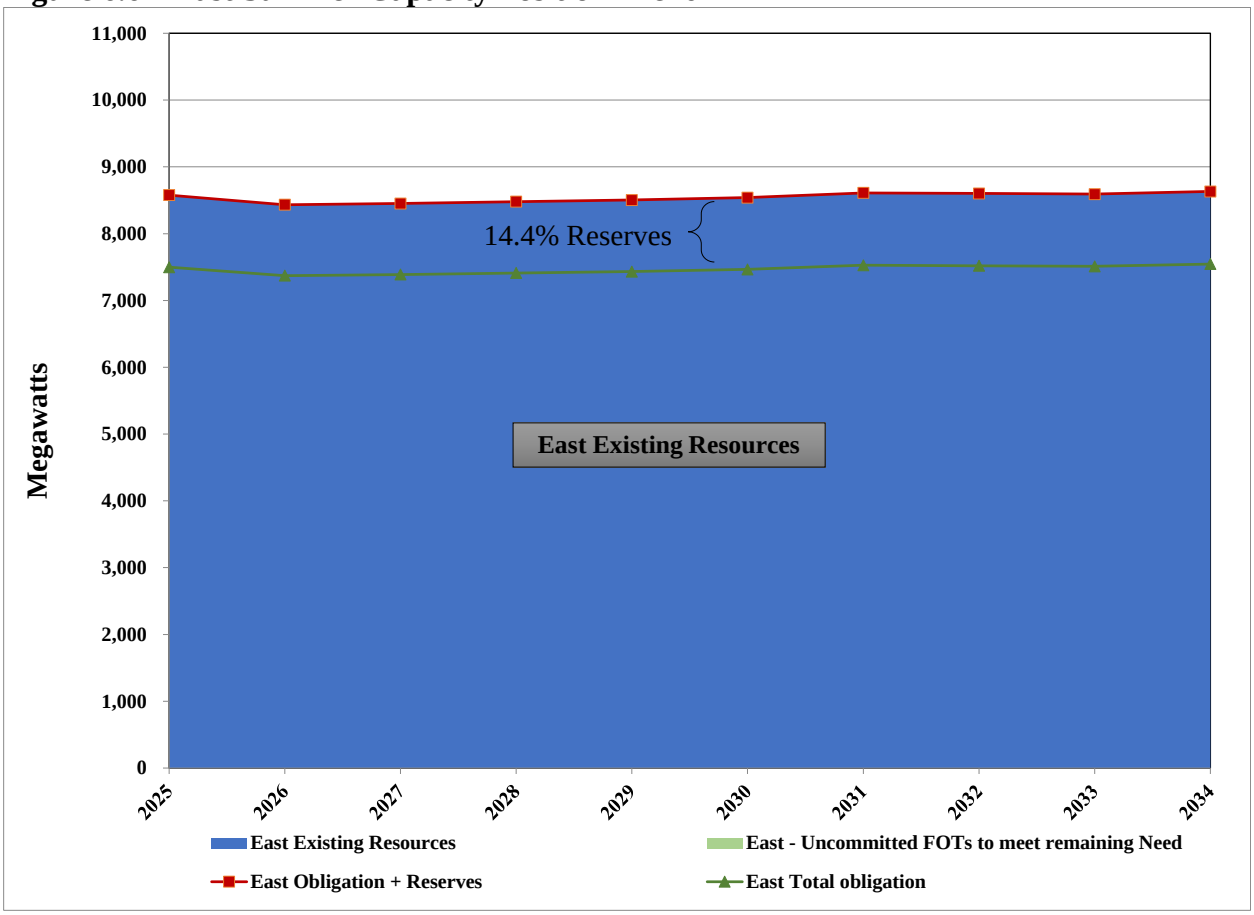
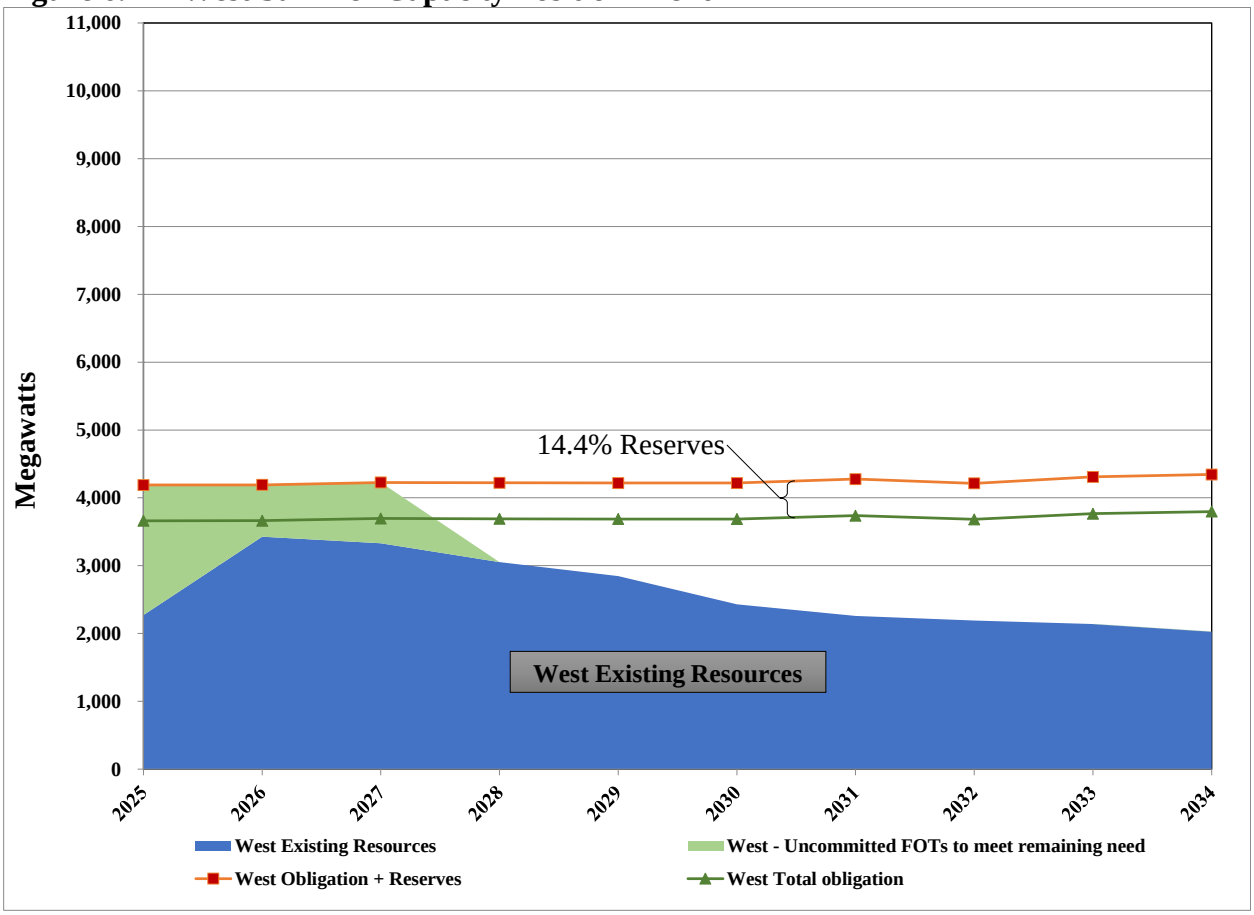


Figure 6.7 – West Summer Capacity Position Trend



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 ($/kW-Yr)	Gas Transport ($/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$)

	Variable O&M					Credits		
Resource Description	Levelized Fuel ($/MWh)	O&M ($/MWh)	Capitalized Premium	O&M Capitalized ($/MWh)	Total Resource Cost ($/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

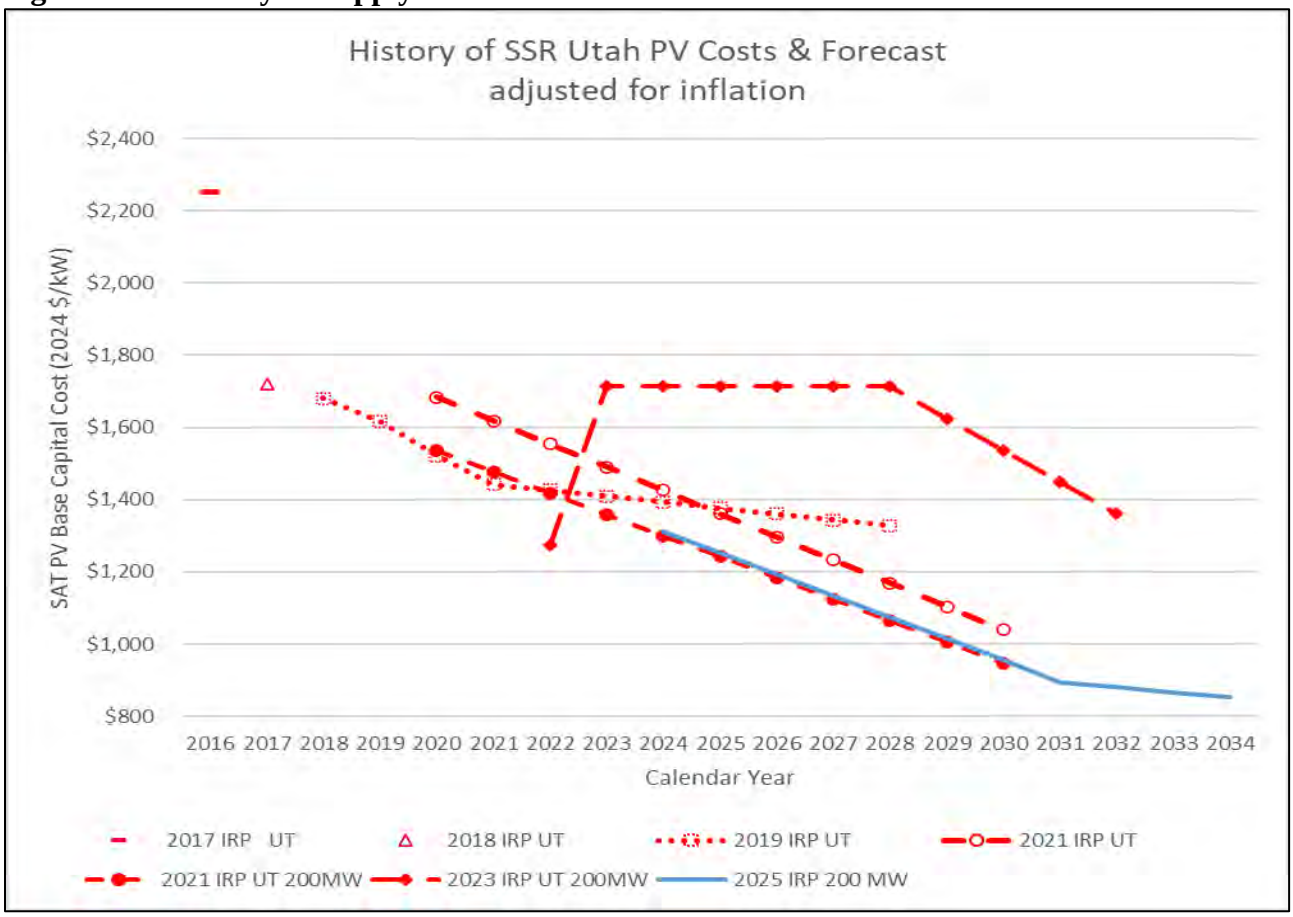
Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options 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).

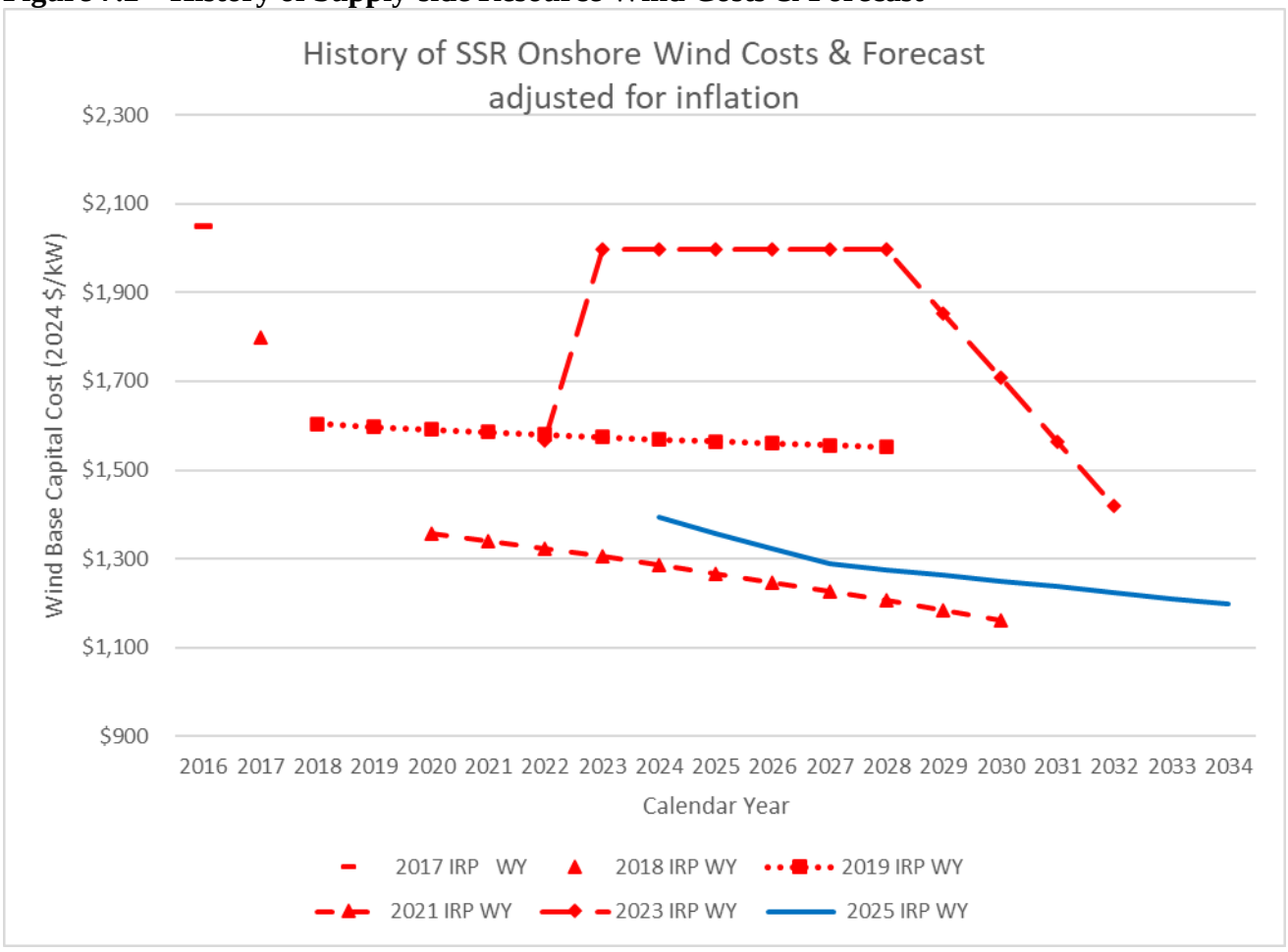
Figure 7.1 – History of Supply-side Resource PV Cost & Forecast



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.

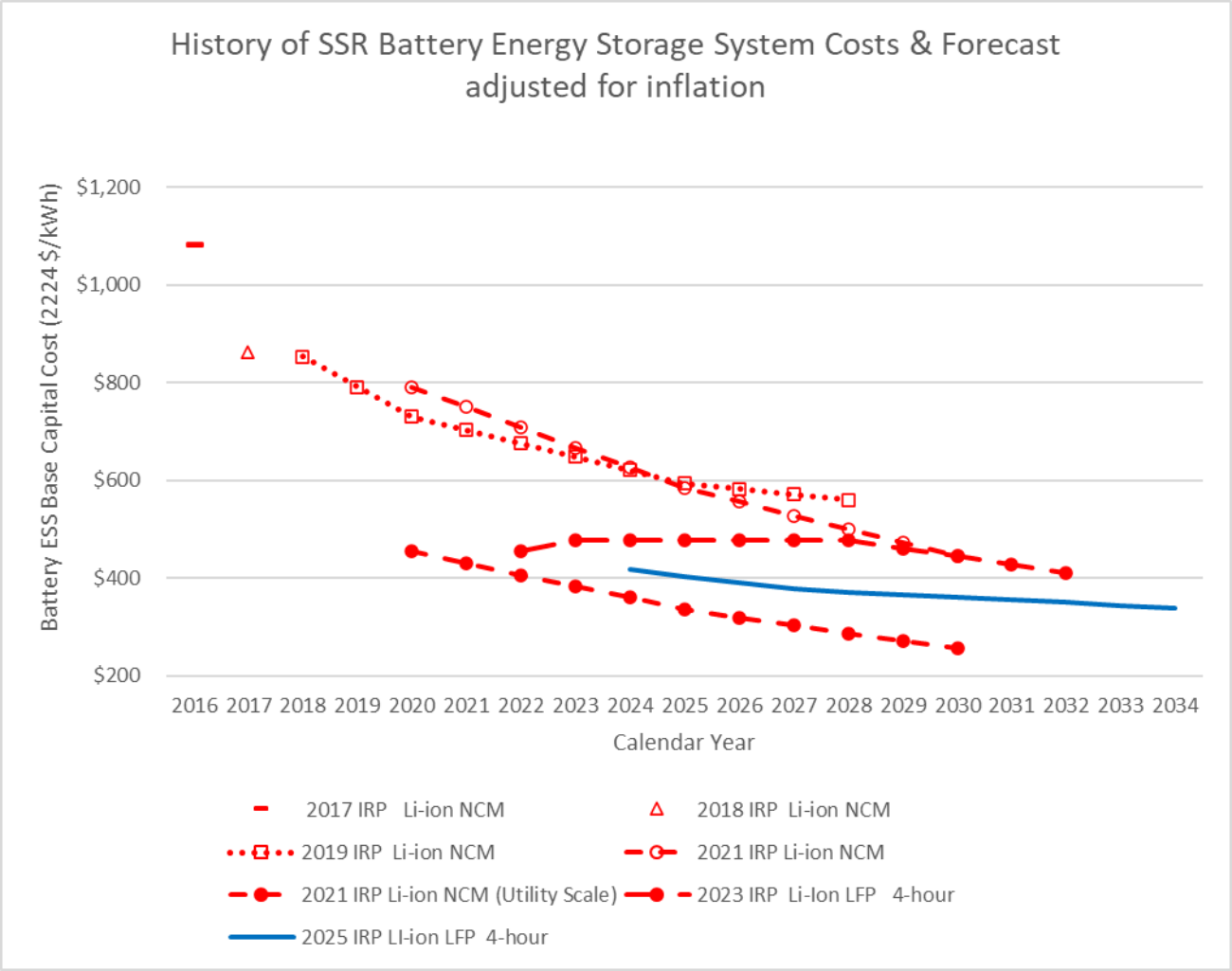
Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast



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.

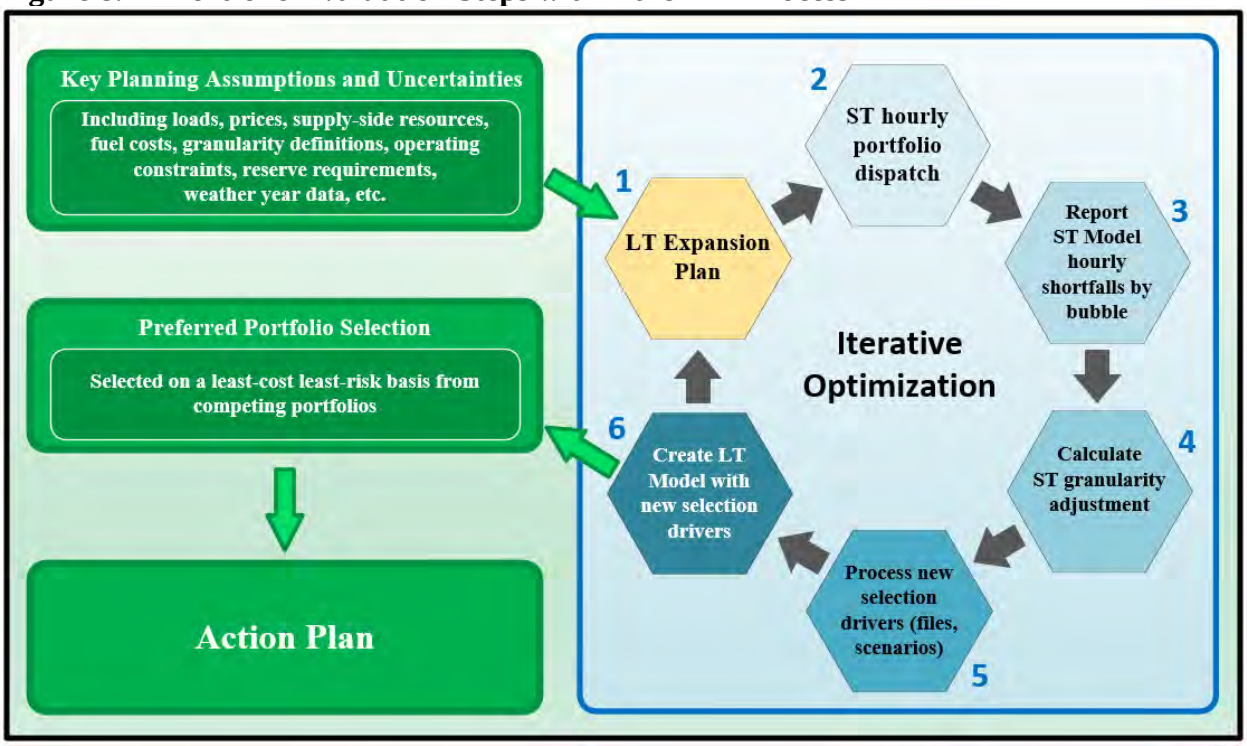
Modeling and Evaluation Steps

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.

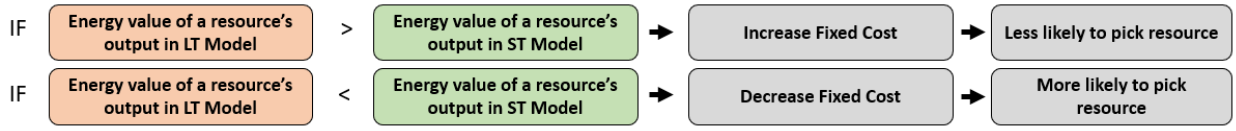
This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

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.

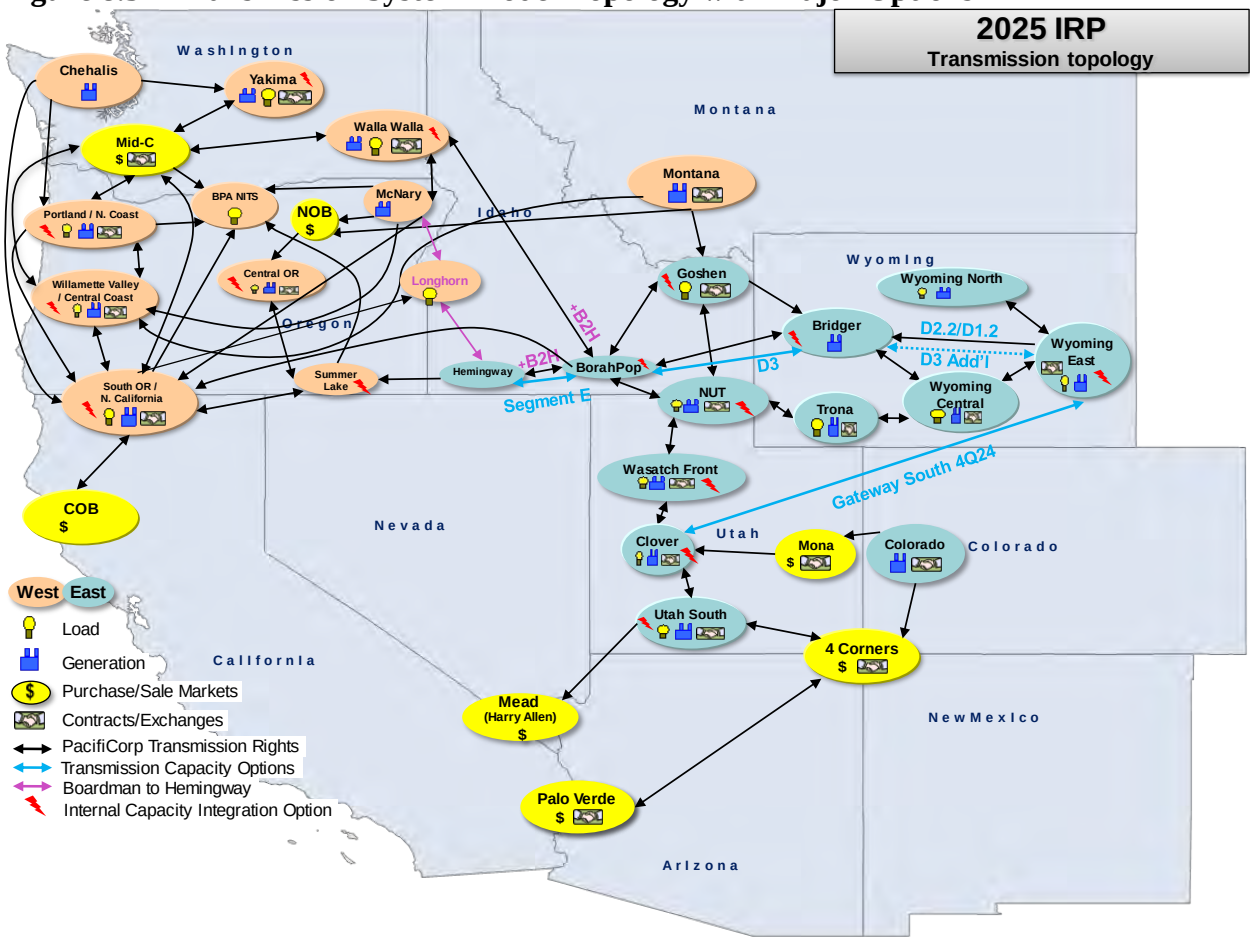
Key modeling elements and inputs for the LT capacity expansion model include the following:

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).

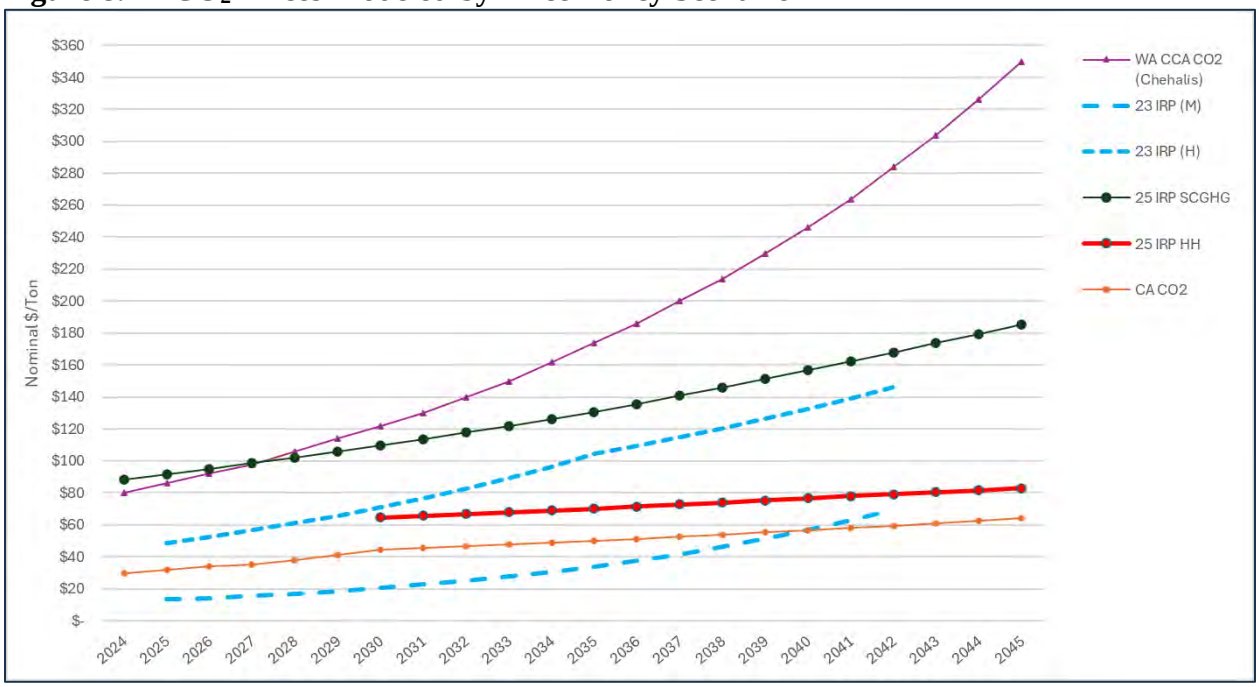
In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.[17] This is in addition to the assumed federal CO_2 policy represented in the 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

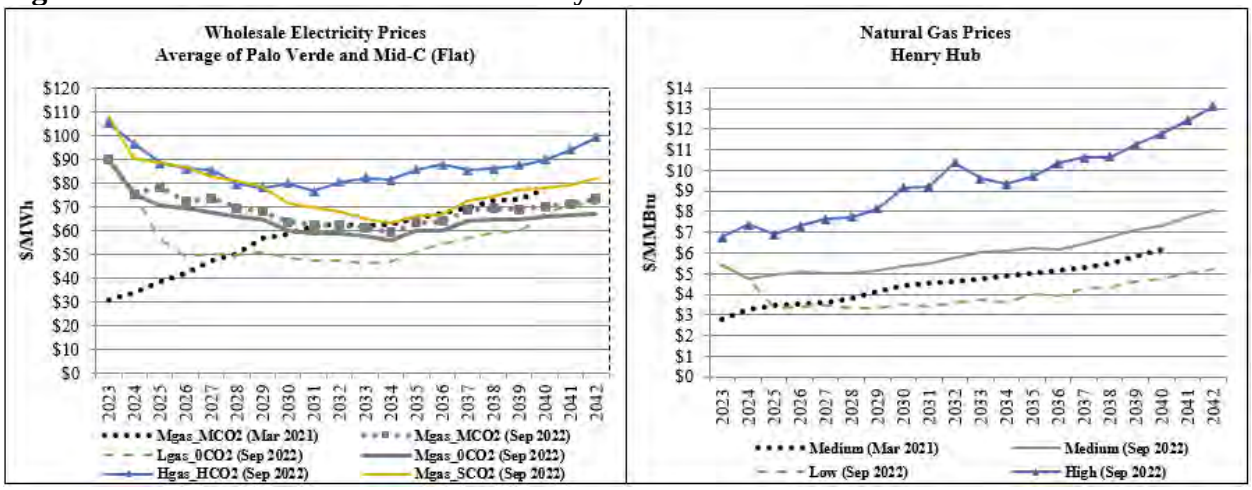
[19] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[20] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

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.

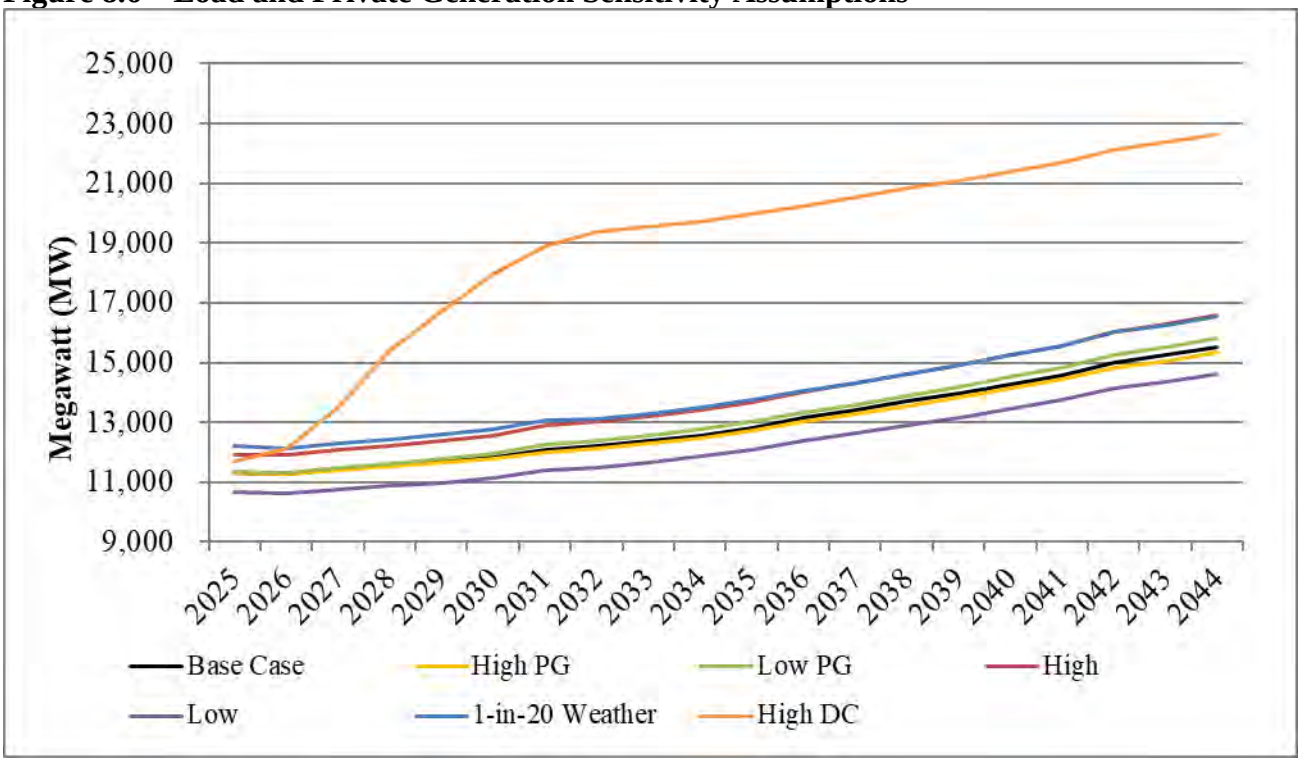
Table 8.7 – Sensitivity Case Definitions

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

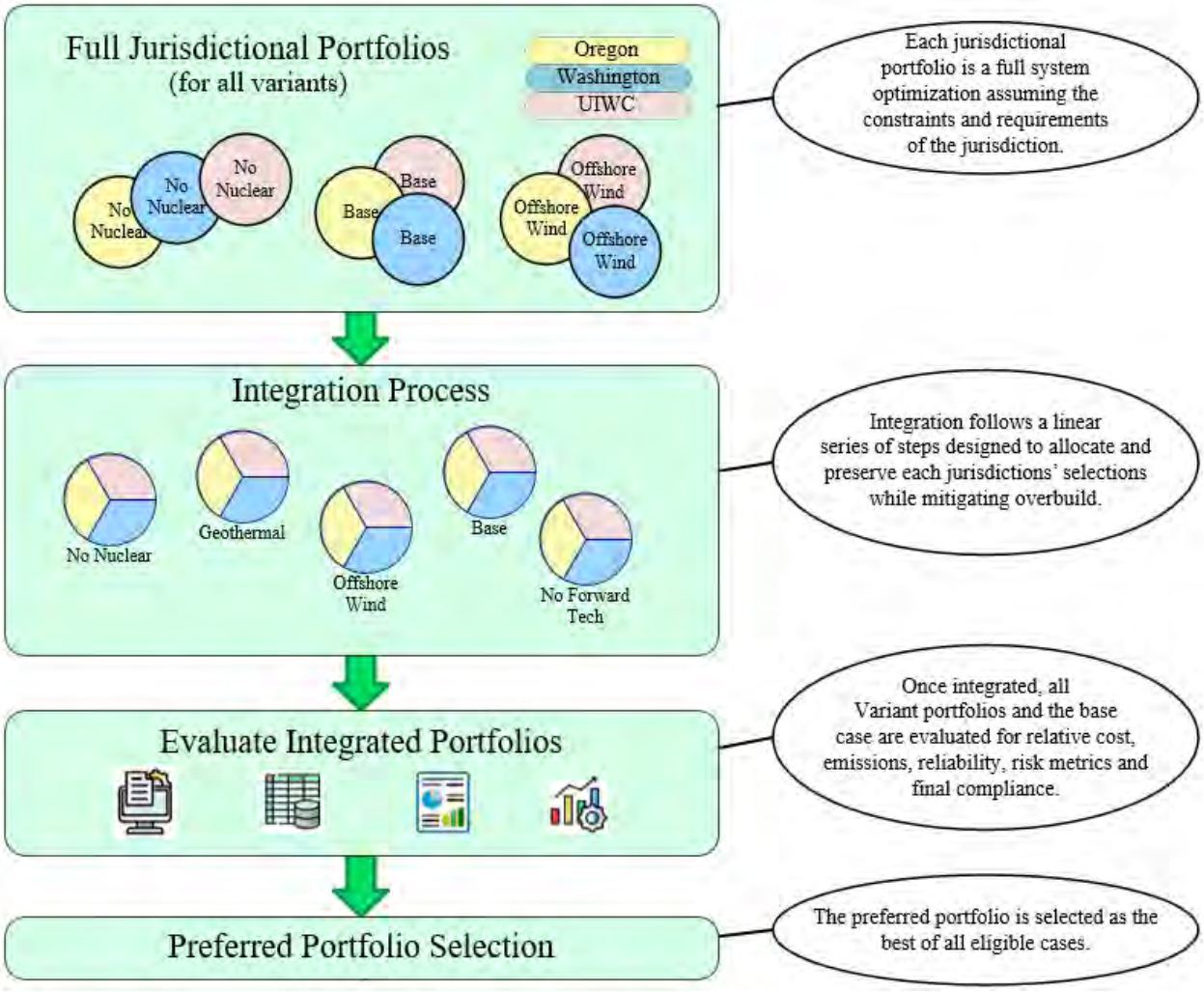
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis 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

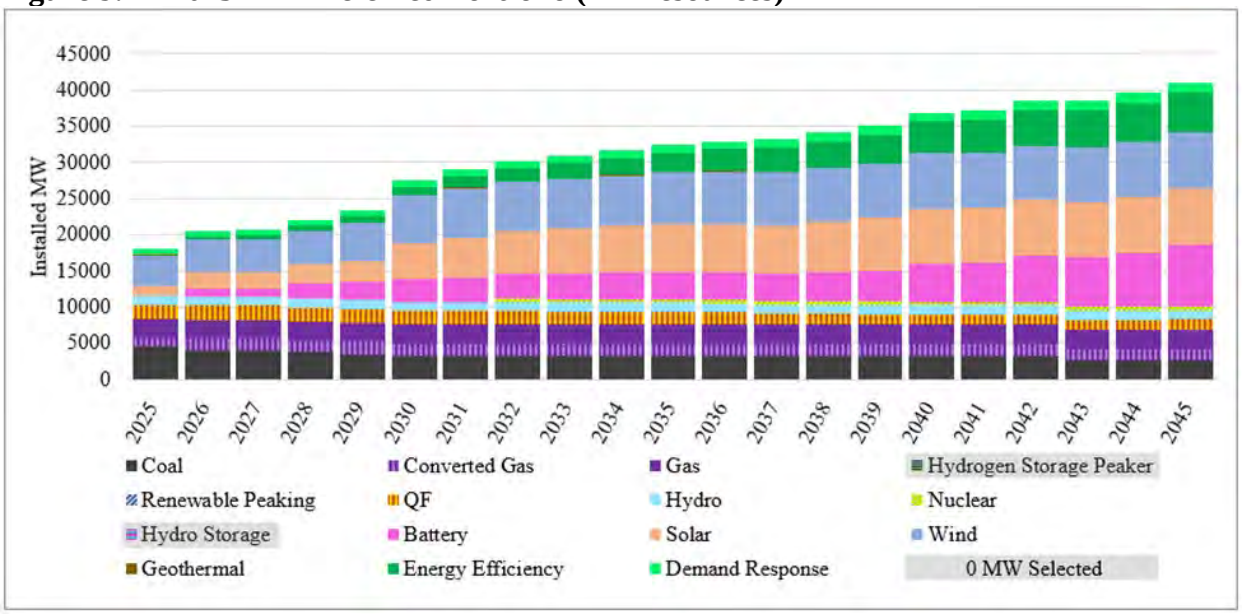
Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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**			

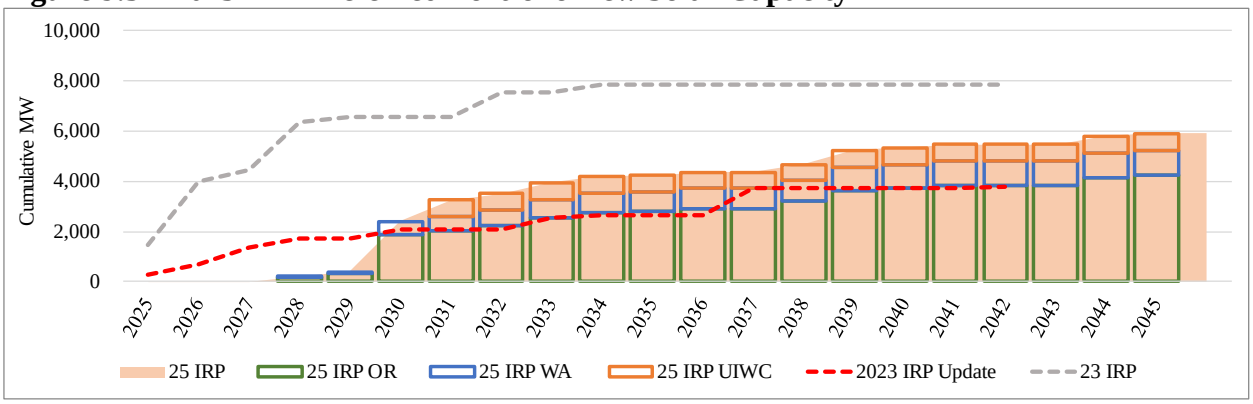
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource 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.

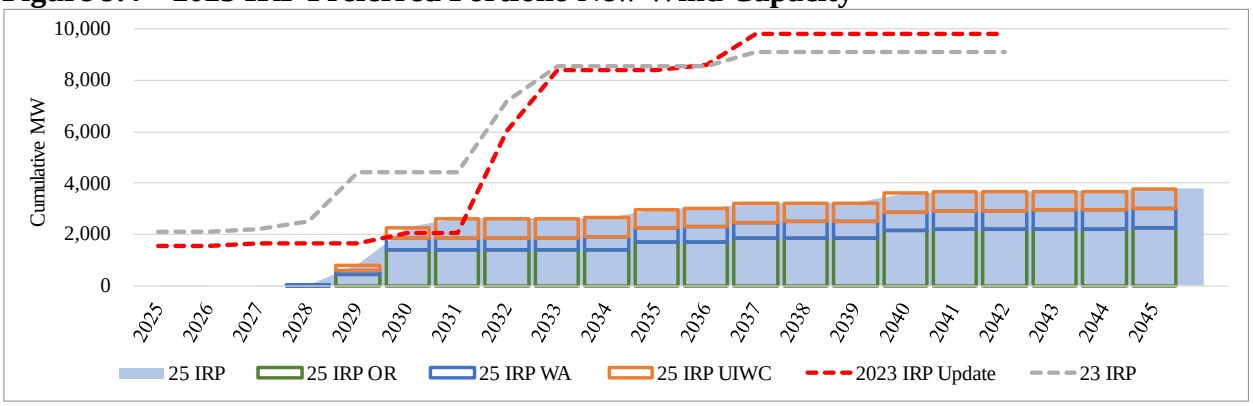
Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity



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.

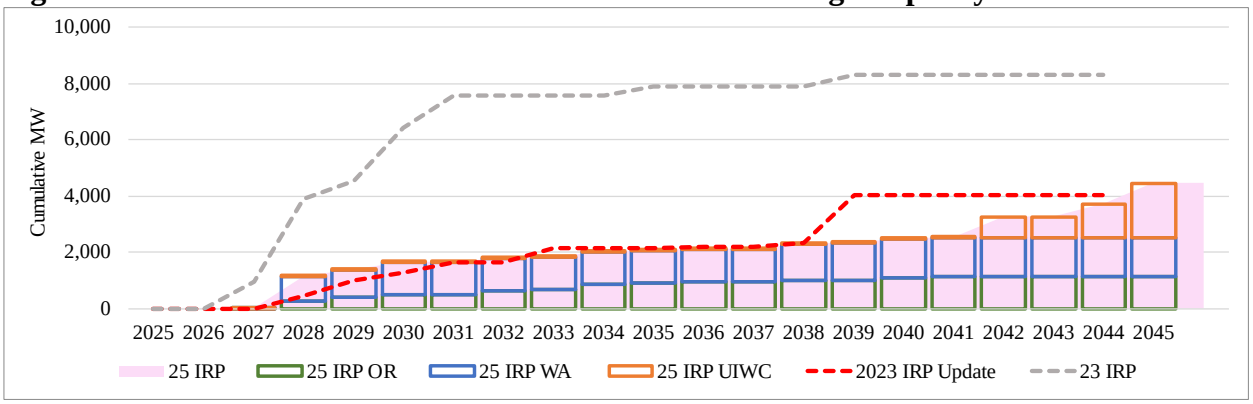
Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

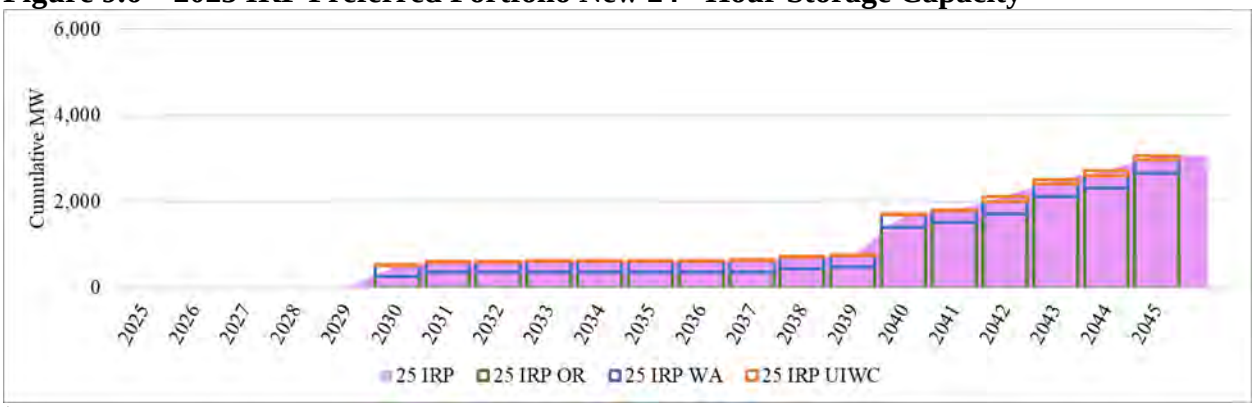
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 9.5 and 9.X. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio 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]

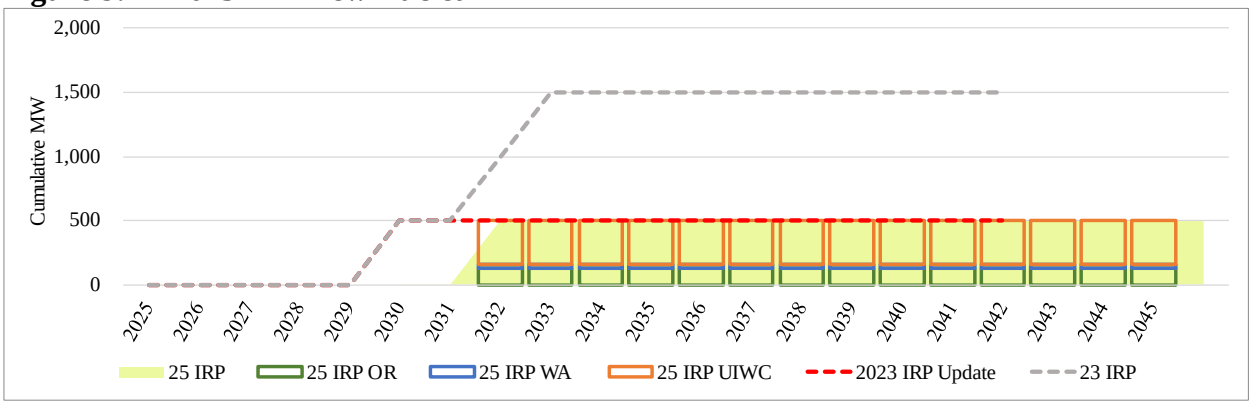


[1]The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

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]



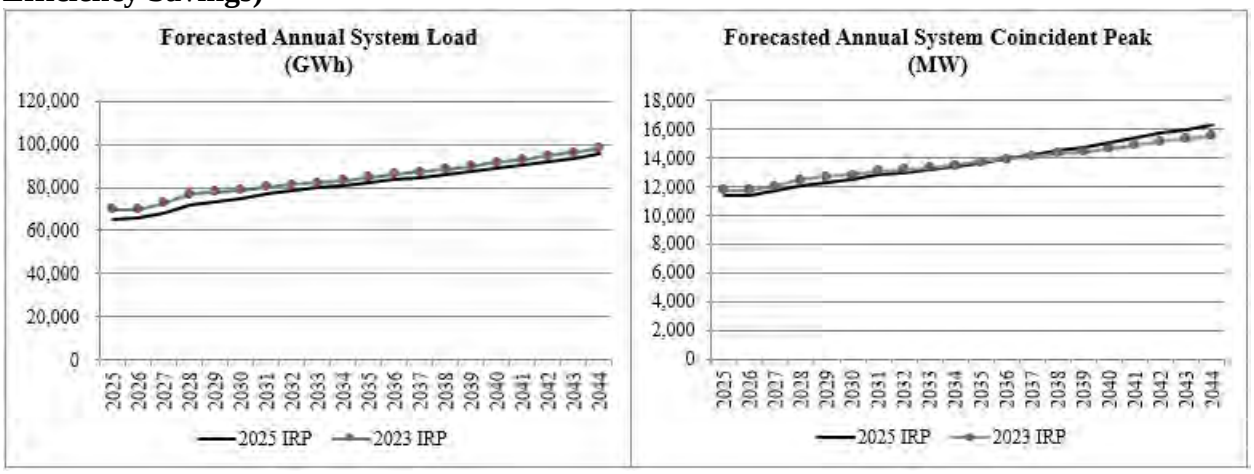
[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

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)

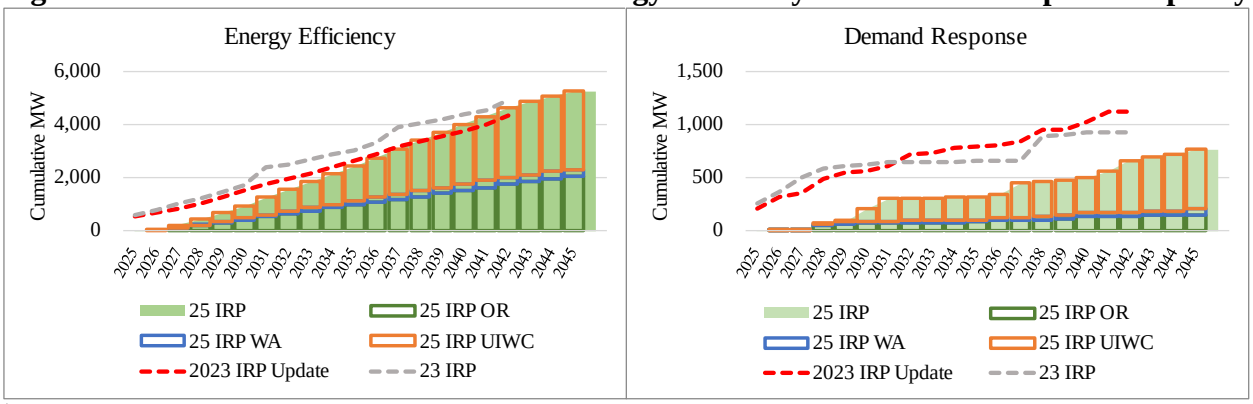


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 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

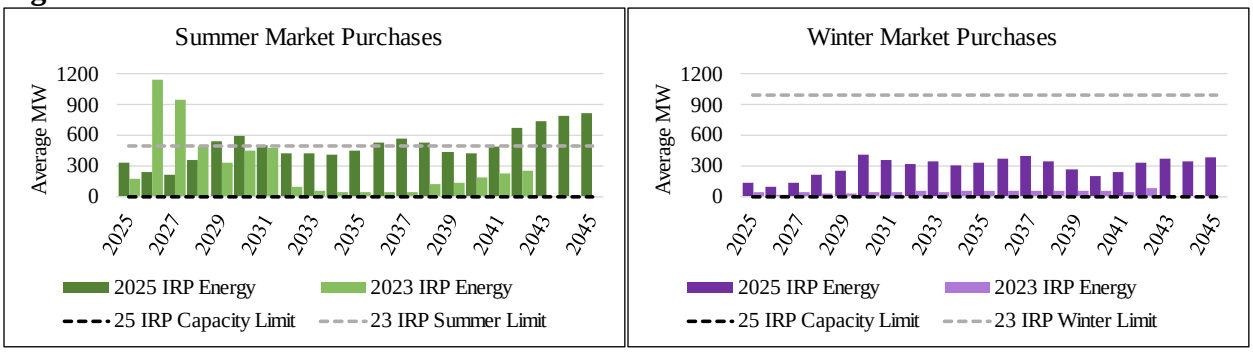
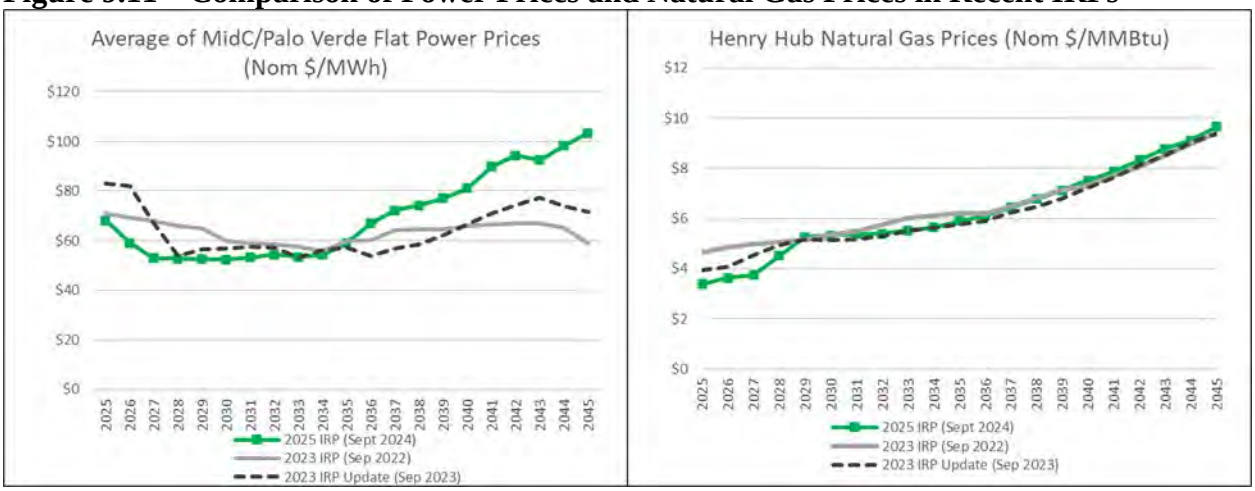


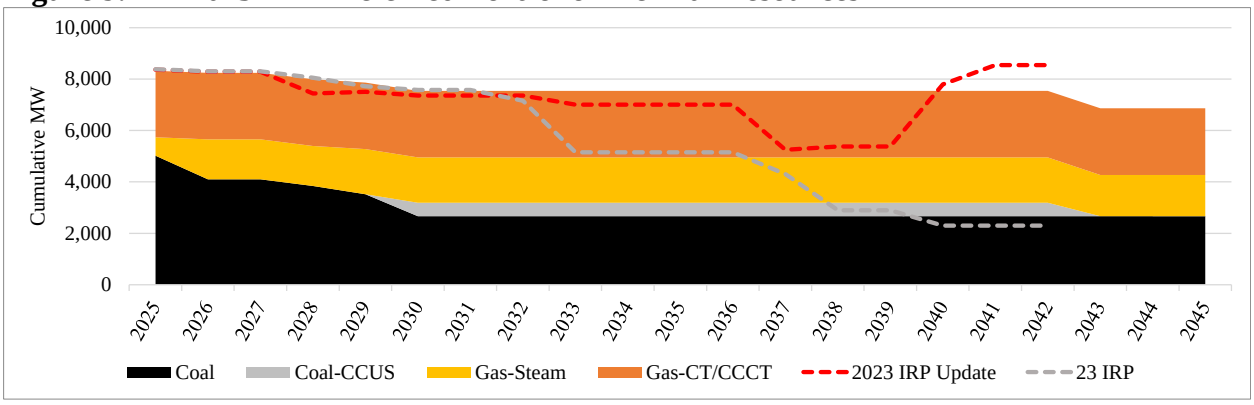
Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



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-

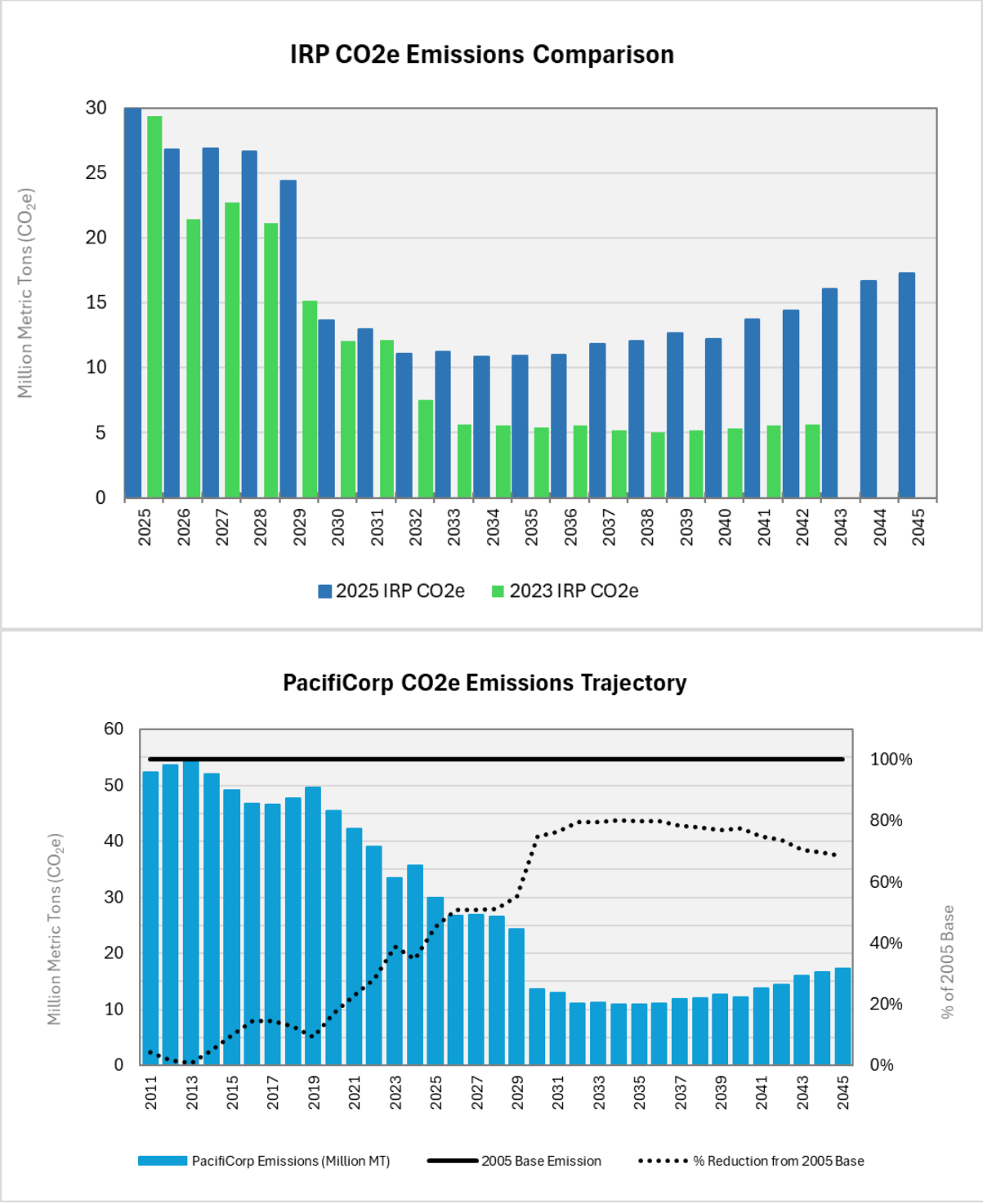
[6] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

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

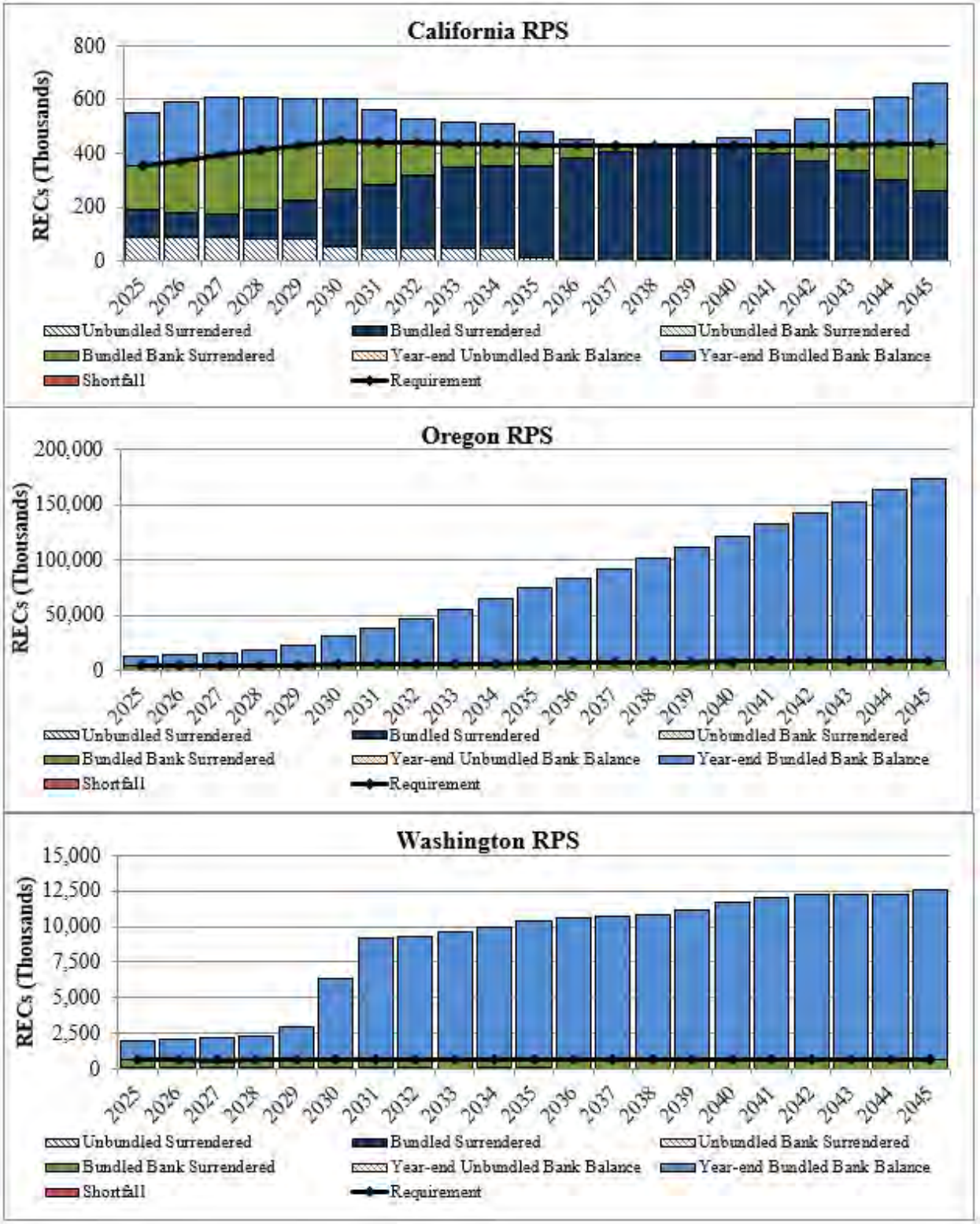
Figure 9.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective 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

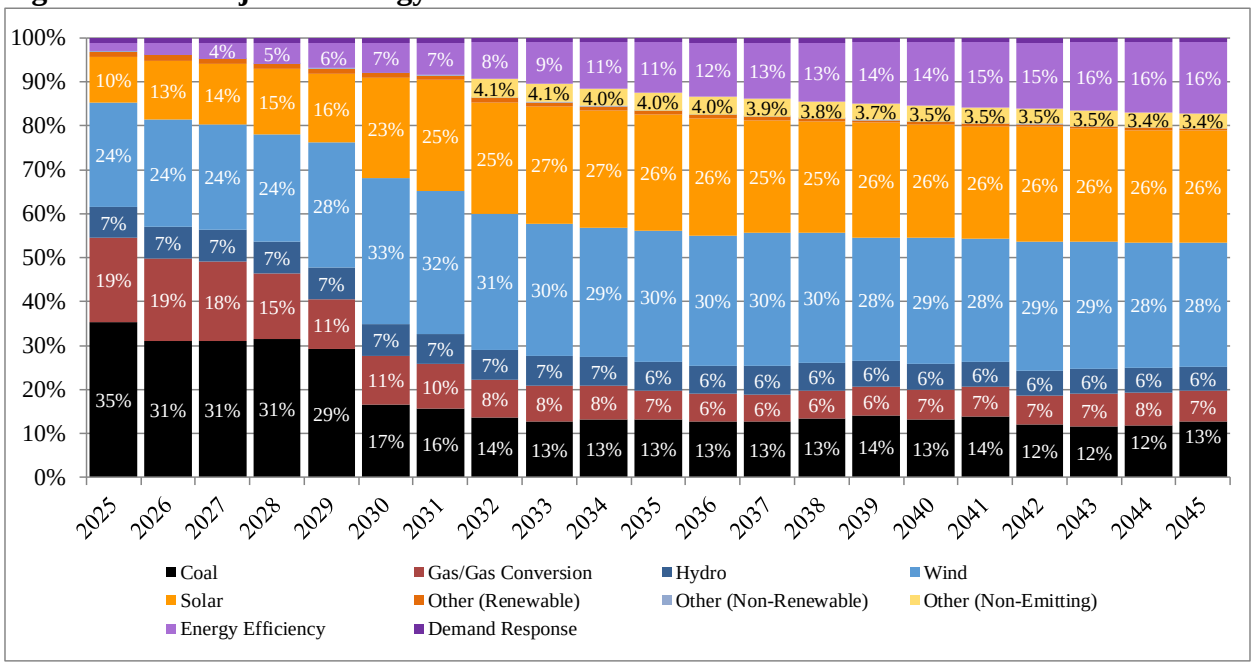
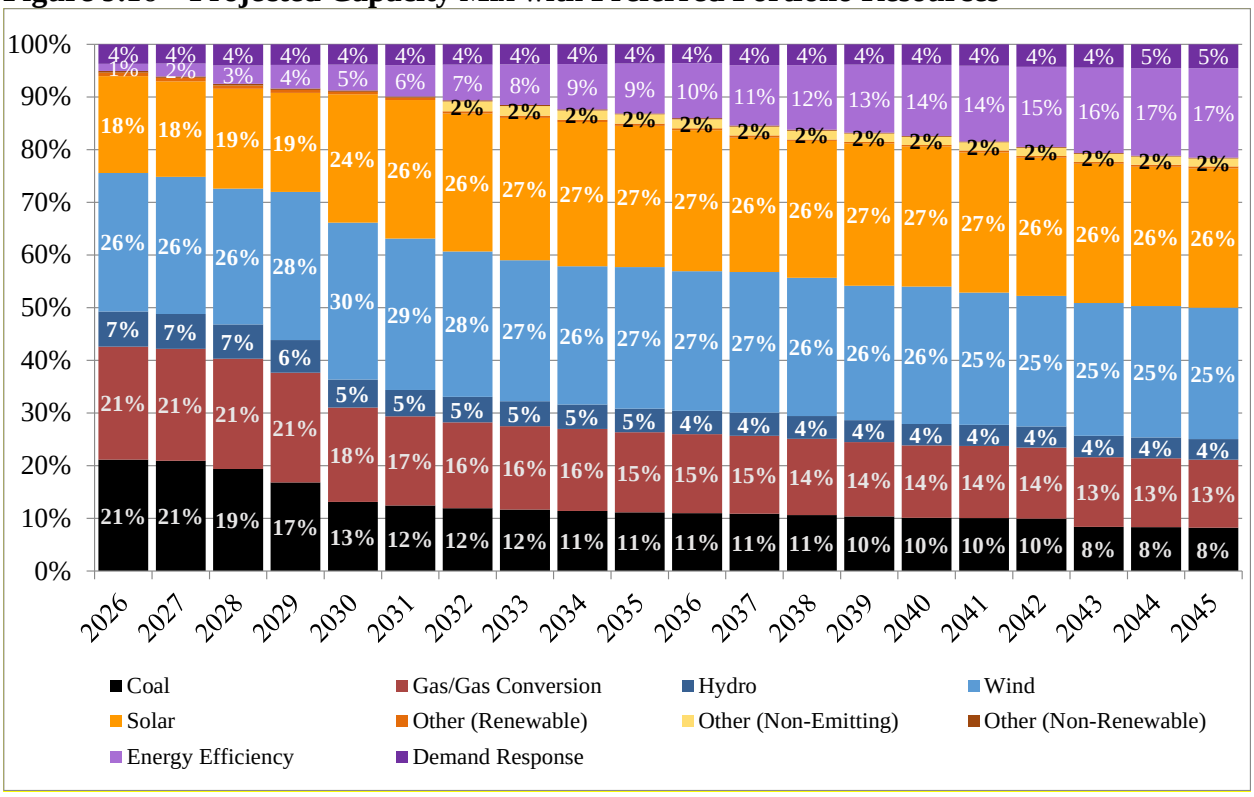


Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources



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

Case - HH	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	31,498	$0	1	174,521	444	2
Integrated Base MN	34,498	$3,000	8	232,976	58,900	13
Integrated No CCS MN	35,762	$4,264	11	219,378	45,302	12
Integrated No Nuclear MN	35,275	$3,777	10	202,255	28,178	10
Integrated No Coal Post 2032 MN	33,052	$1,553	4	179,879	5,803	4
Integrated Offshore Wind MN	45,727	$14,228	13	194,780	20,703	8
Integrated No Future Tech MN	35,902	$4,404	12	207,187	33,110	11
Integrated Geothermal MN	35,247	$3,749	9	189,861	15,785	7
Integrated Hunter Retire MN	31,973	$475	3	179,948	5,871	5
Integrated Base MR	31,796	$297	2	180,431	6,355	6
Integrated No CCS MR	33,110	$1,612	5	178,538	4,461	3
Integrated Base LN	33,995	$2,496	6	201,609	27,532	9
Integrated Base SC	34,207	$2,709	7	174,077	0	1

Table 9.37 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario.

Table 9.37 – Integrated Portfolios Under Medium Gas/ Social Cost of 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

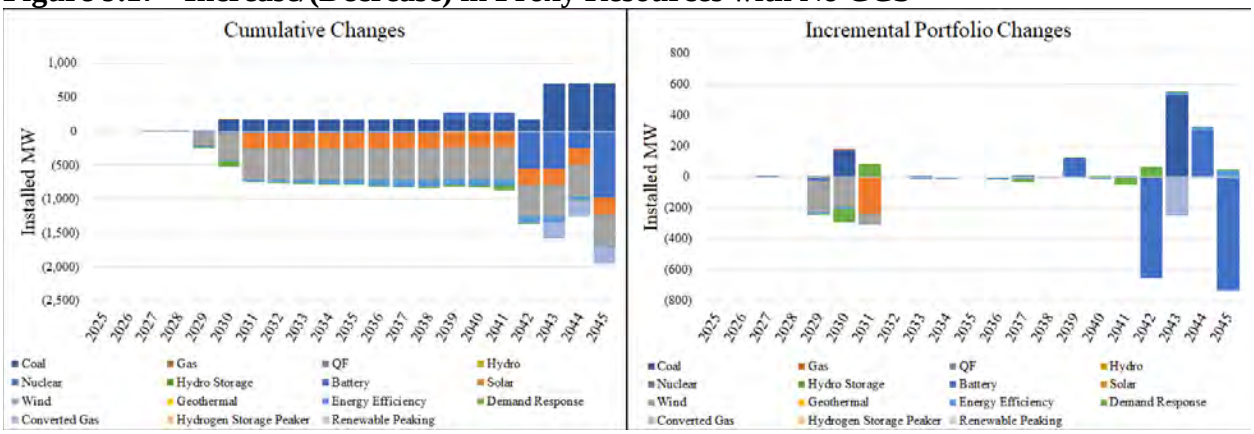
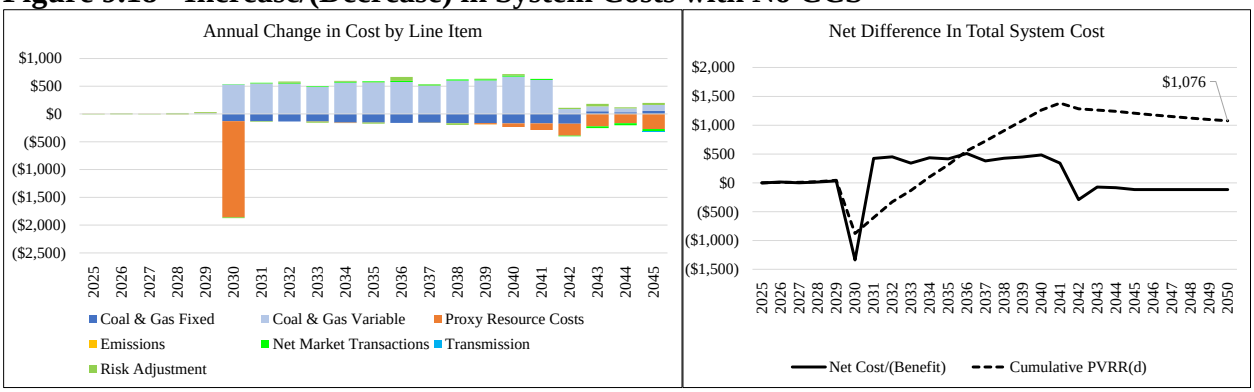


Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

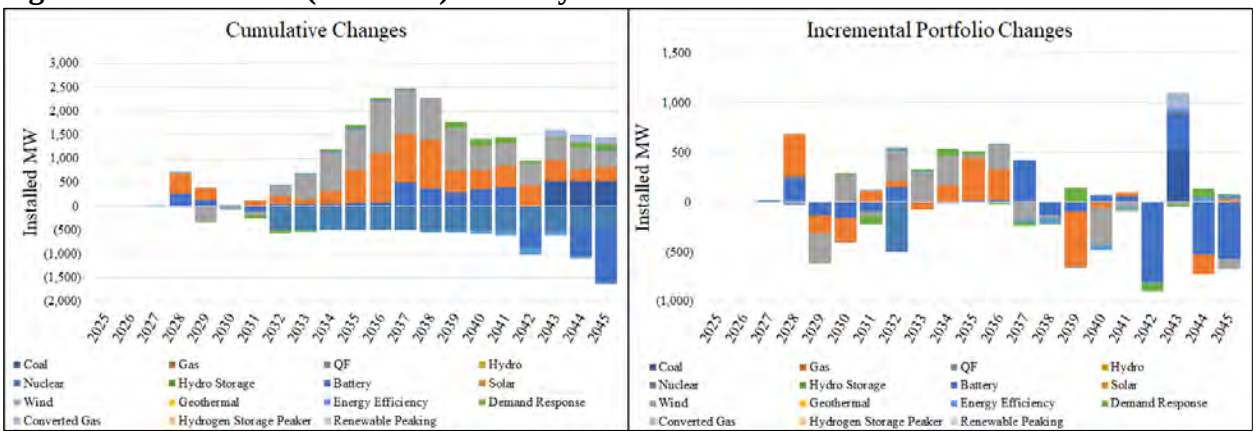
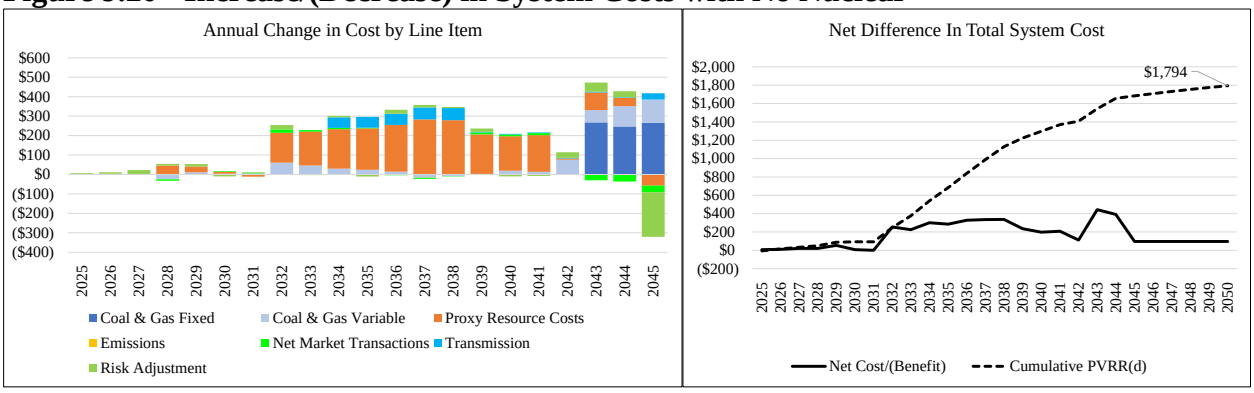


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid 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

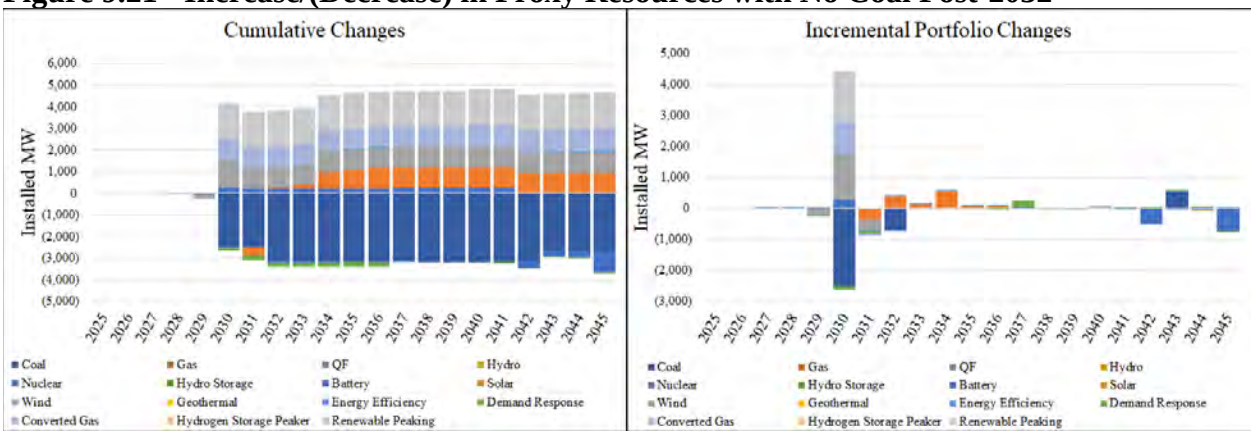
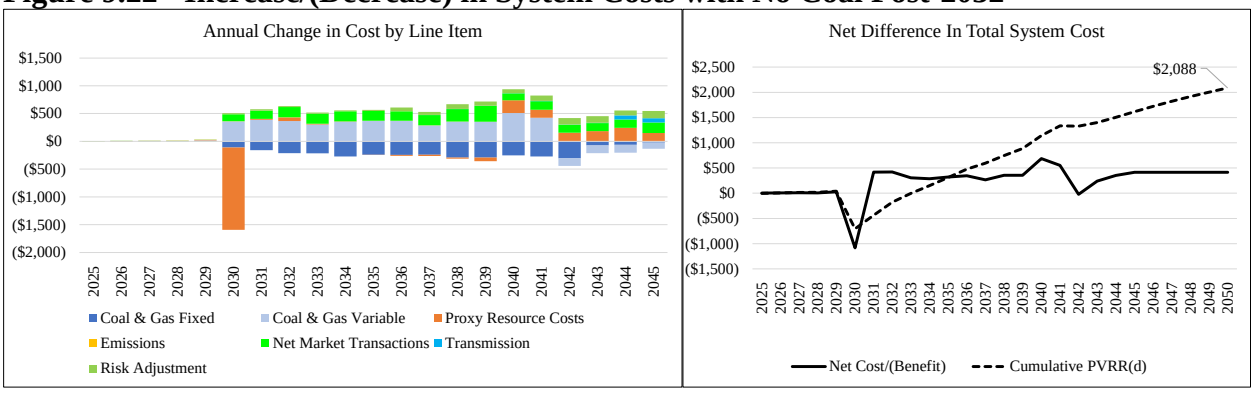


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the 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

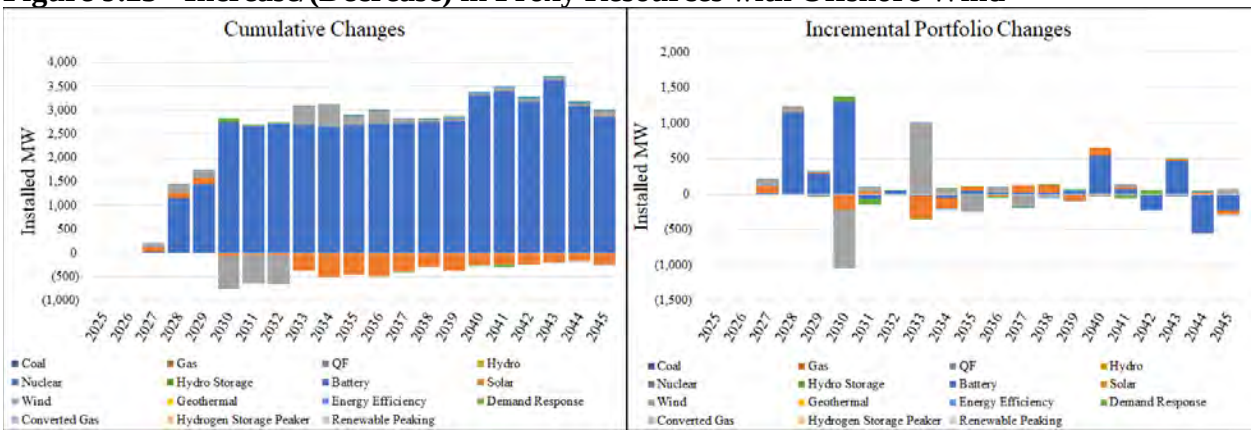
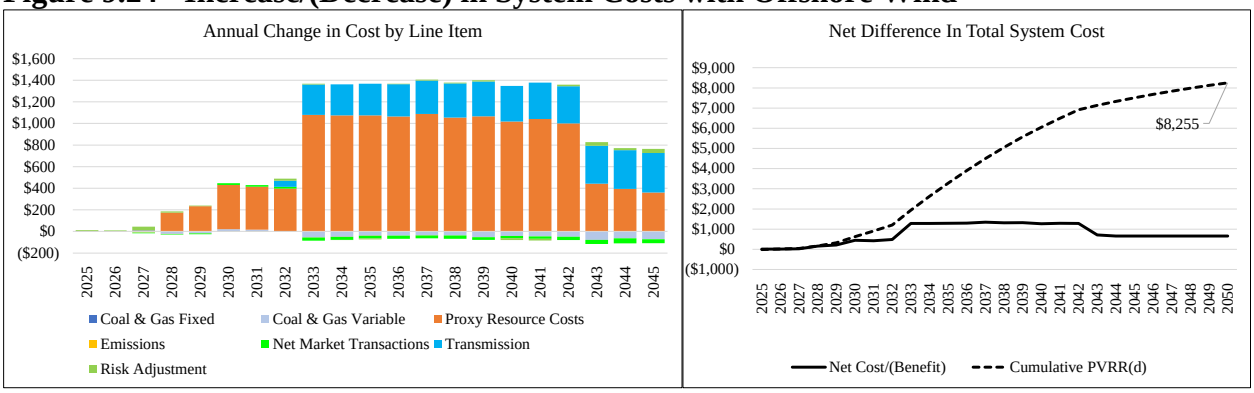


Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total 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

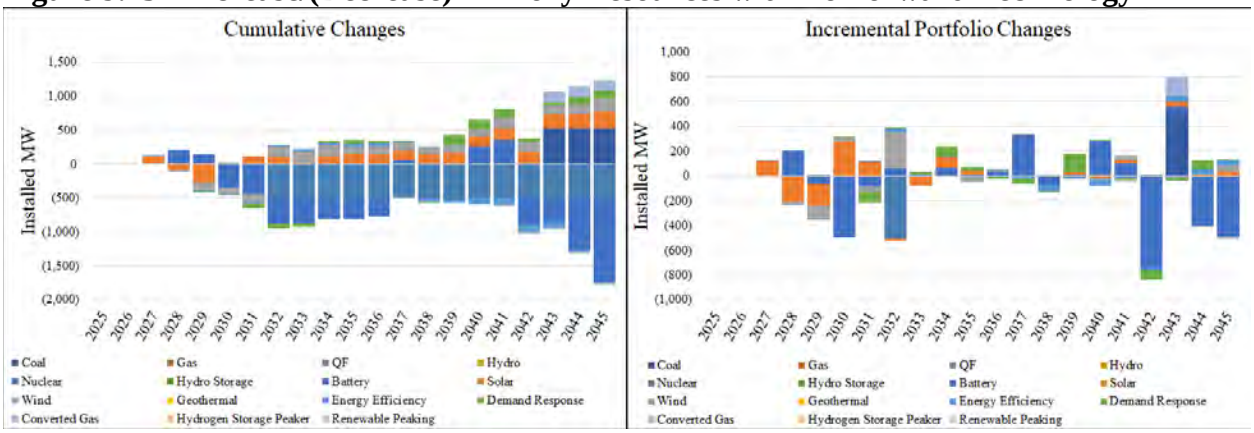
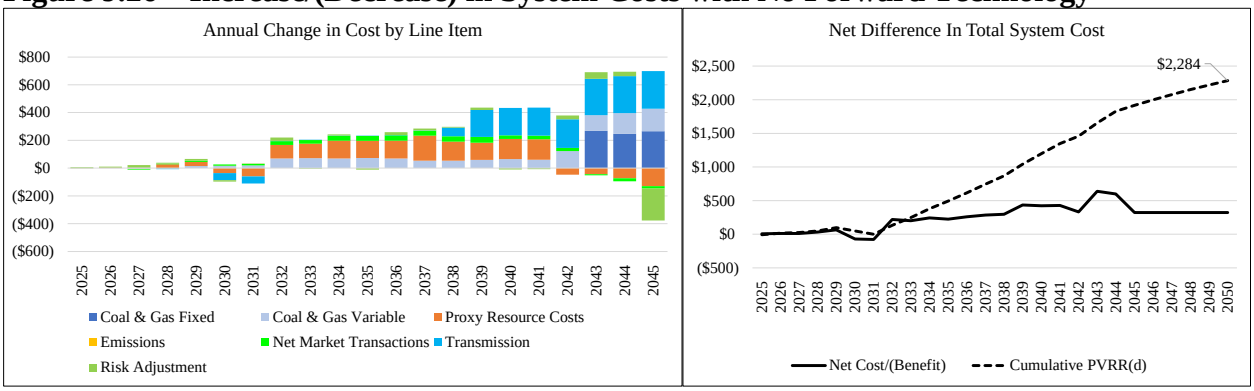


Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the 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

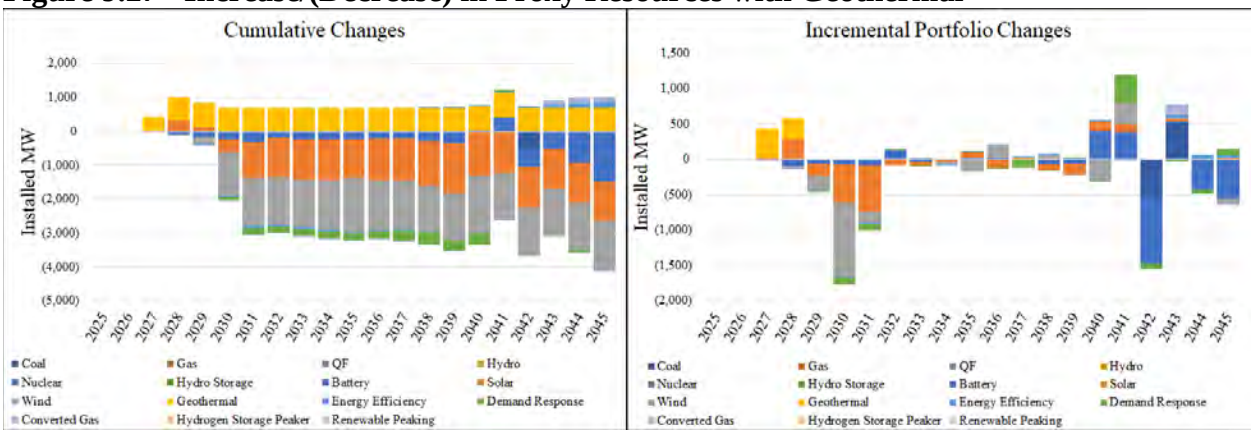
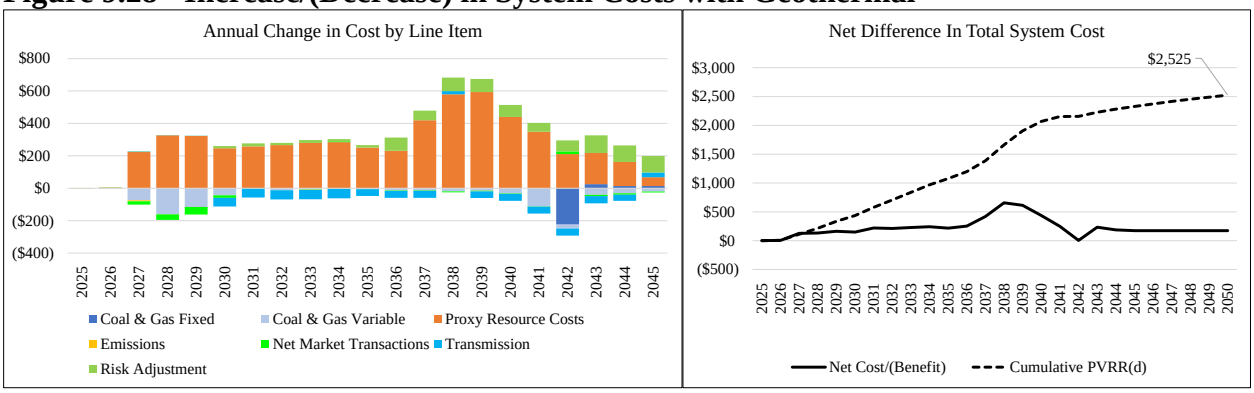


Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total 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

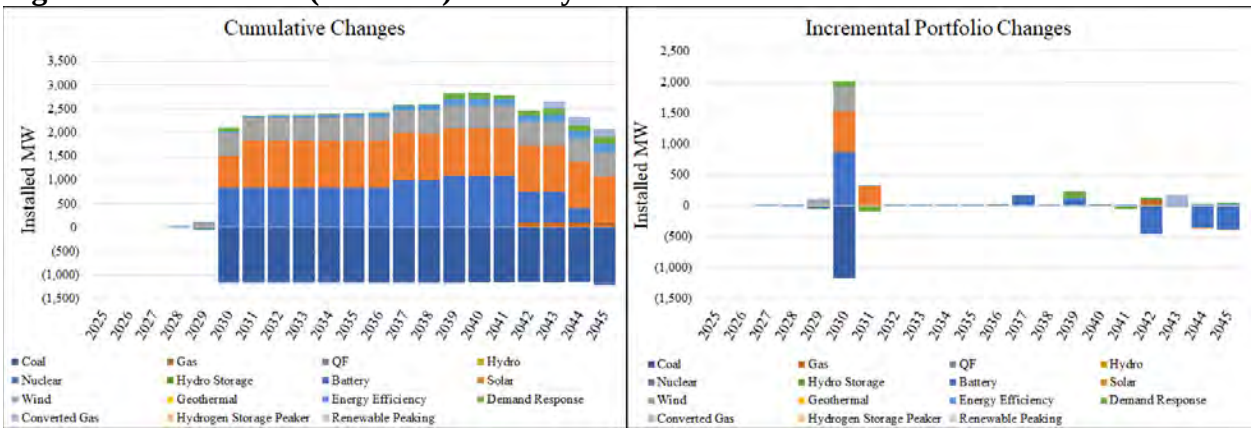
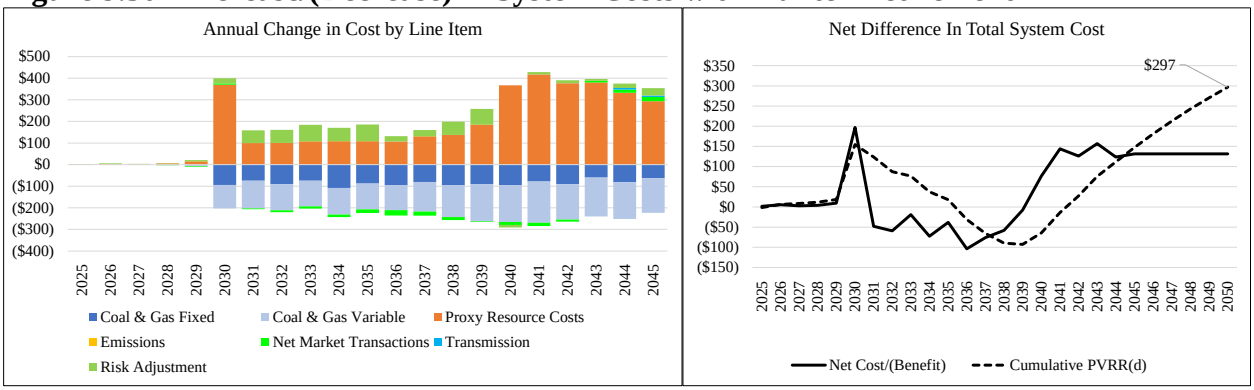


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

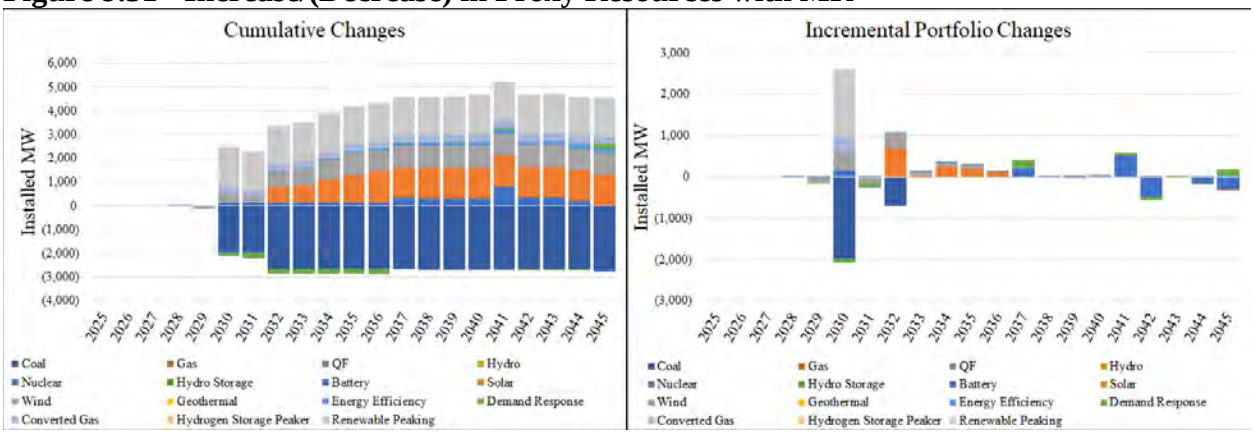
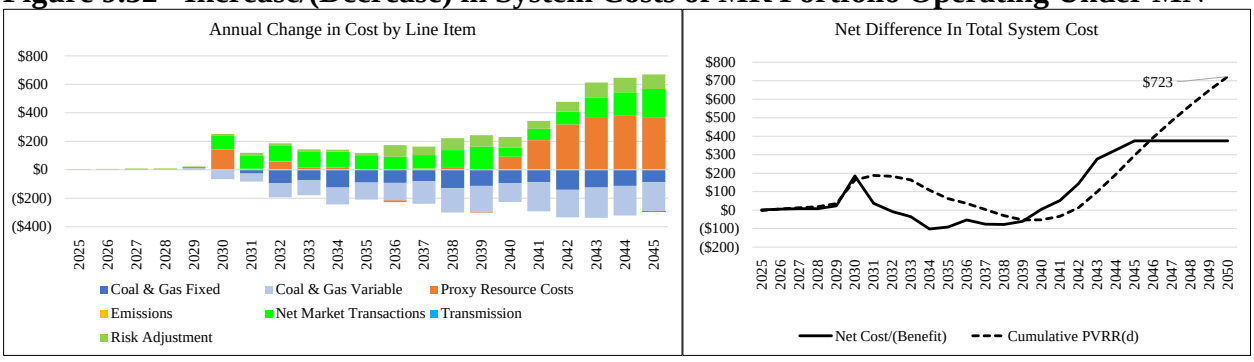


Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

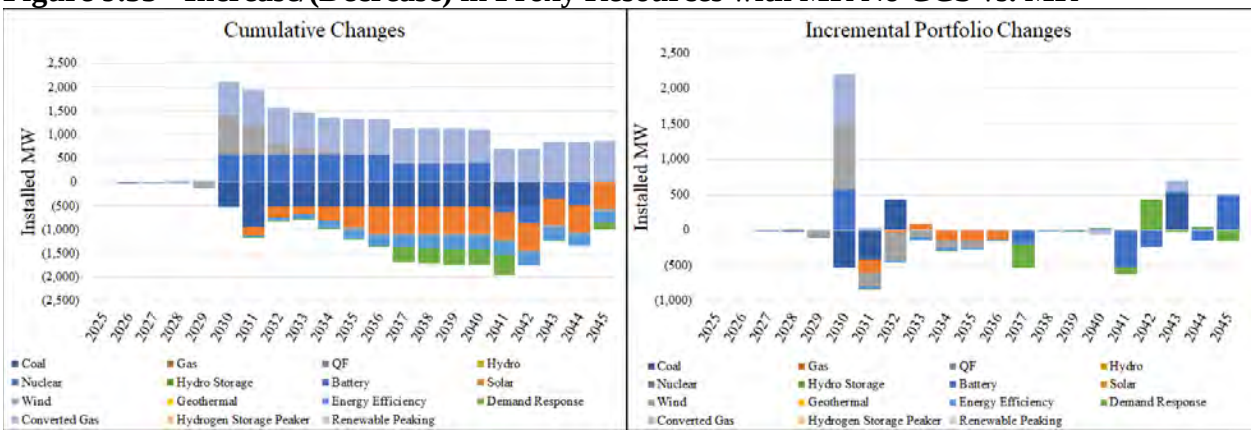
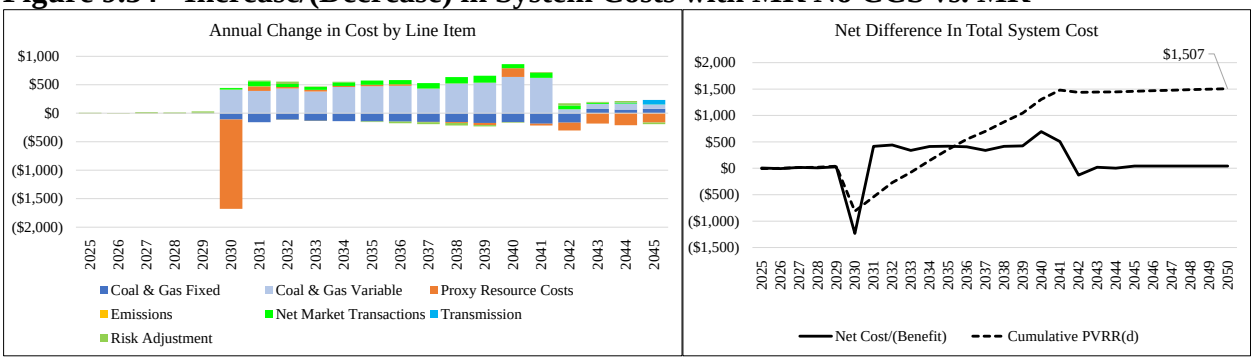


Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

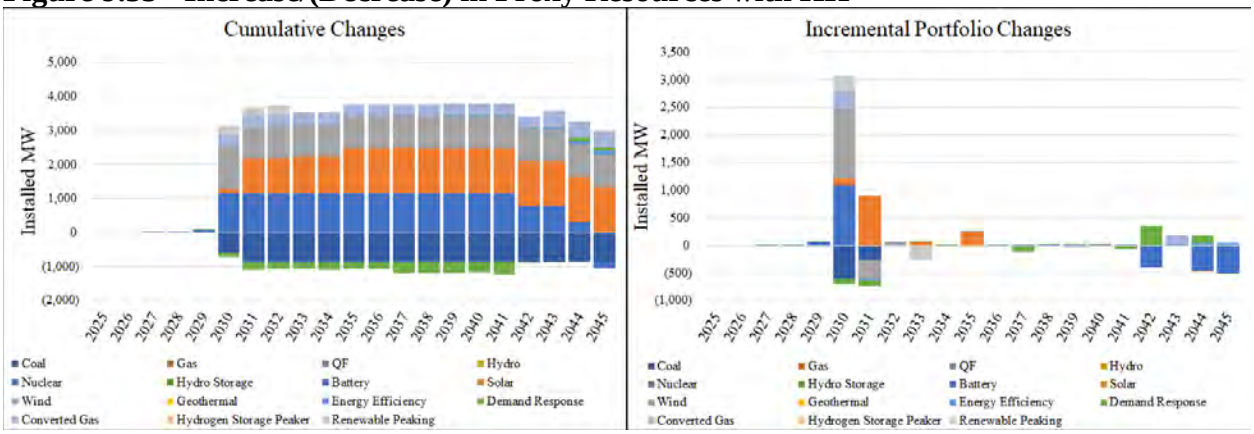
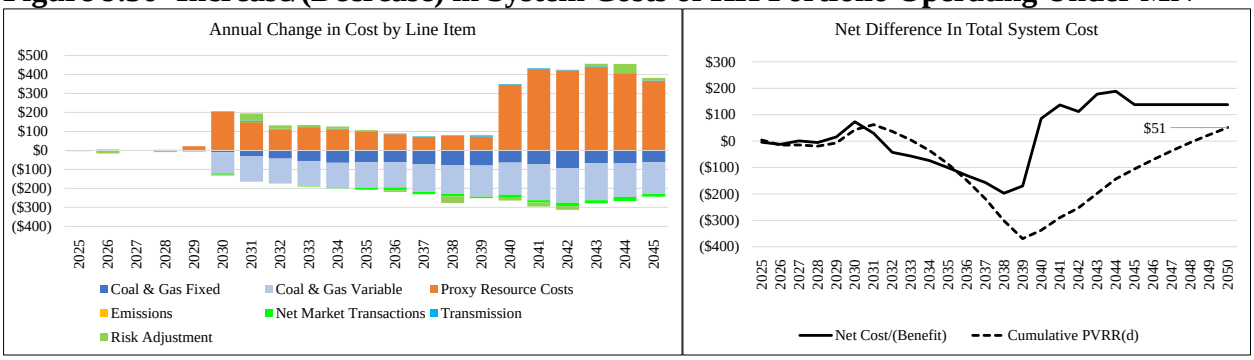


Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

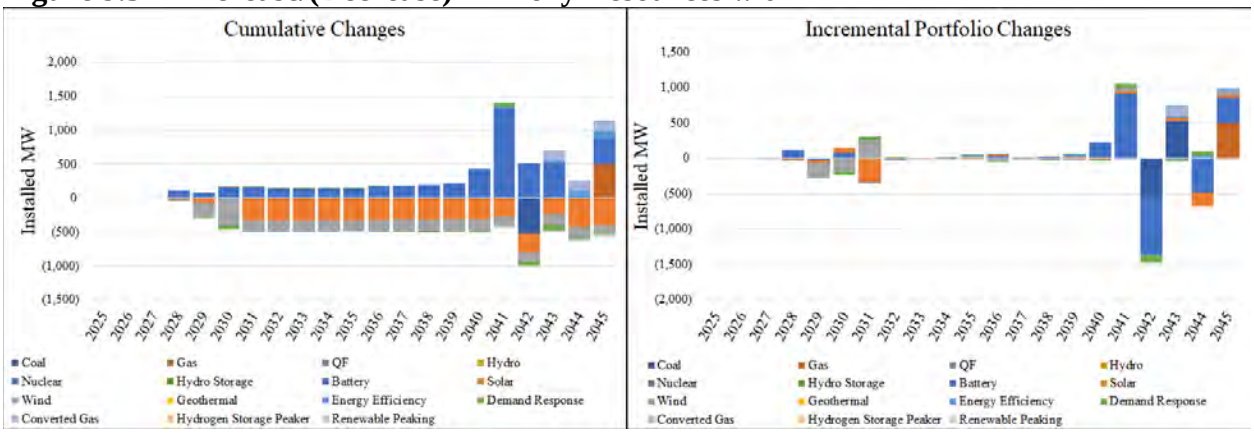
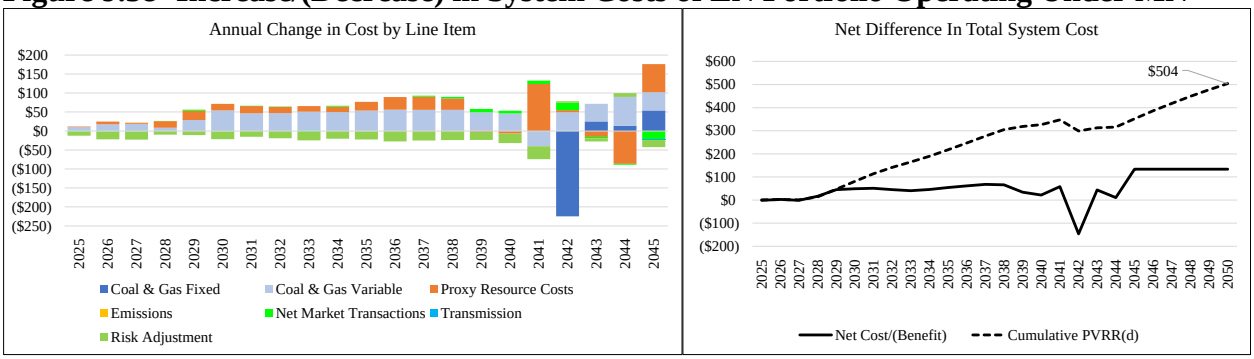


Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

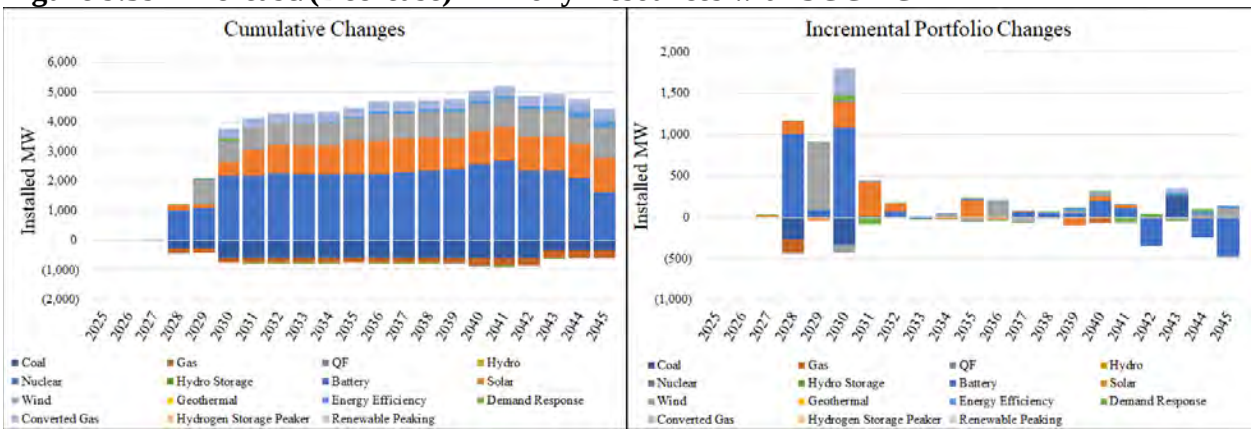
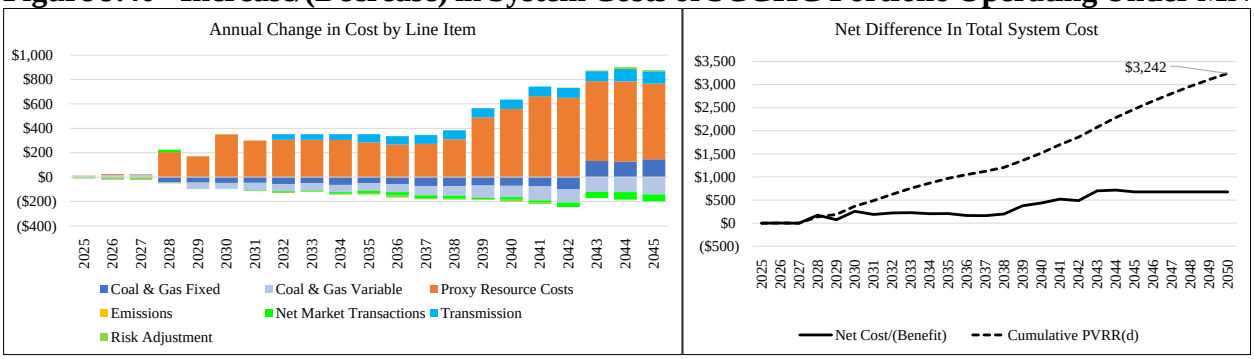


Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

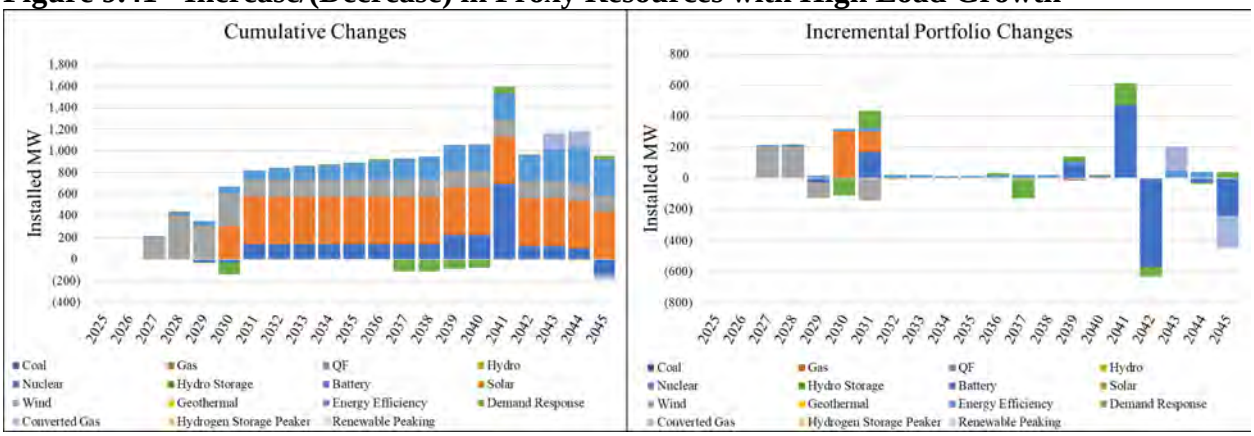
High Load Growth

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

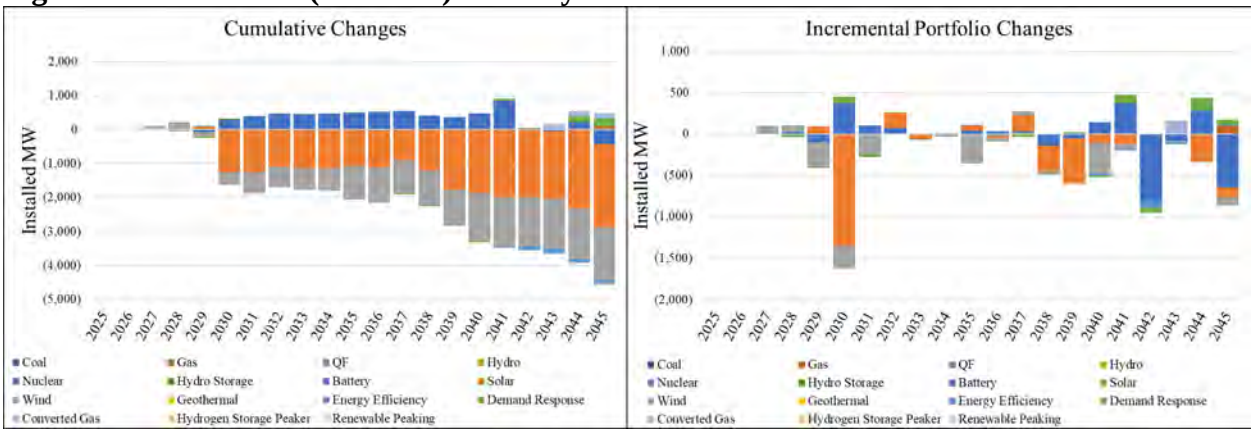


Low Load Growth

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



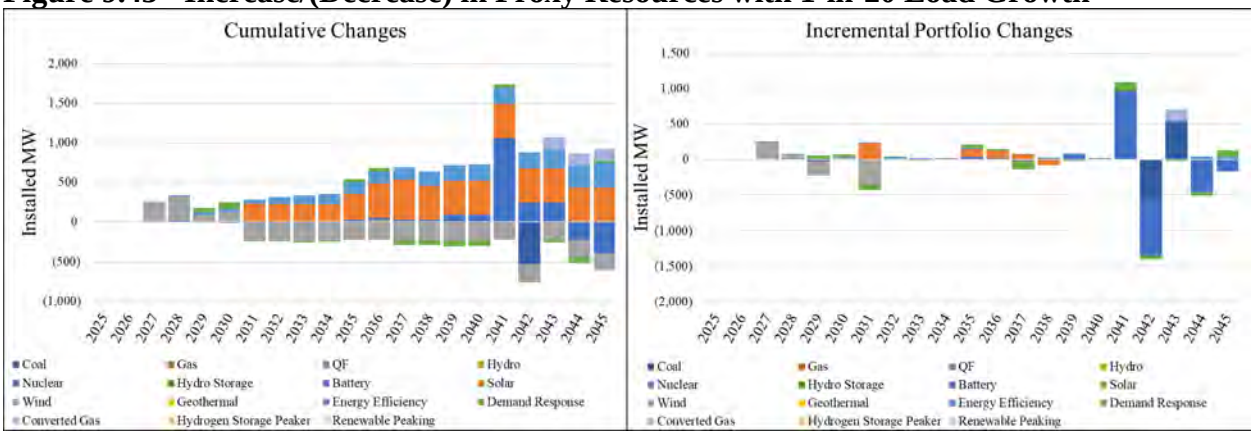
1-in-20 Peak Load Growth

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

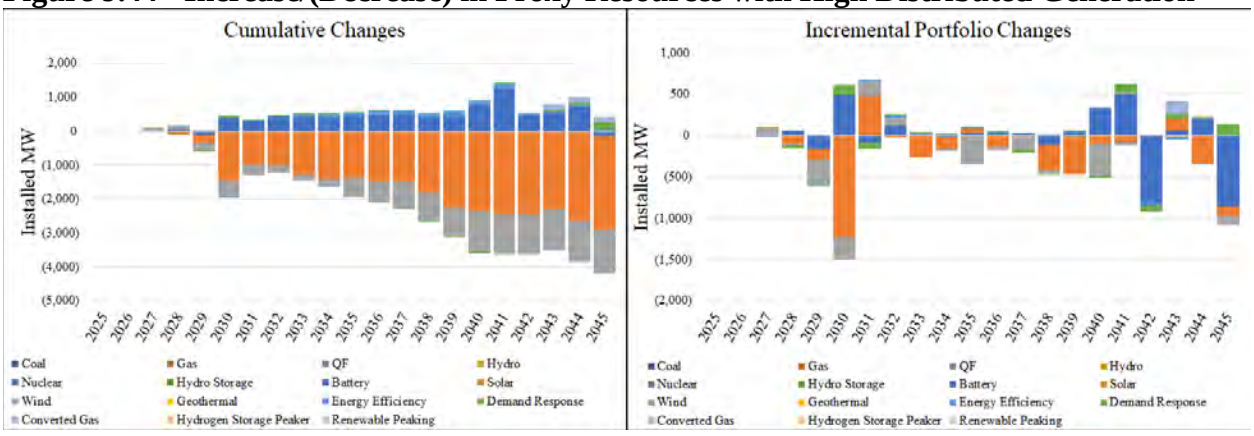


High Distributed Generation Growth

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

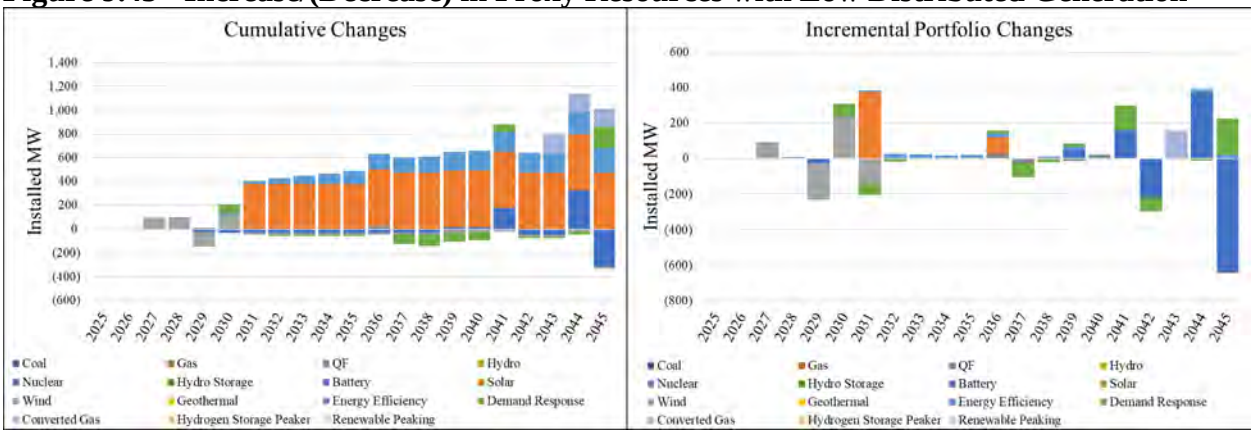


Low Distributed Generation Growth

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

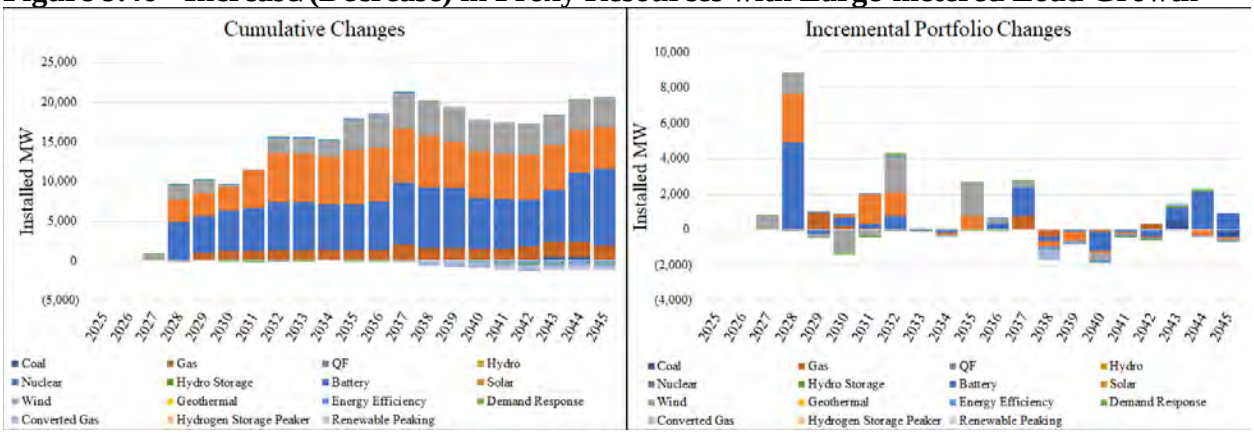
The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the 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



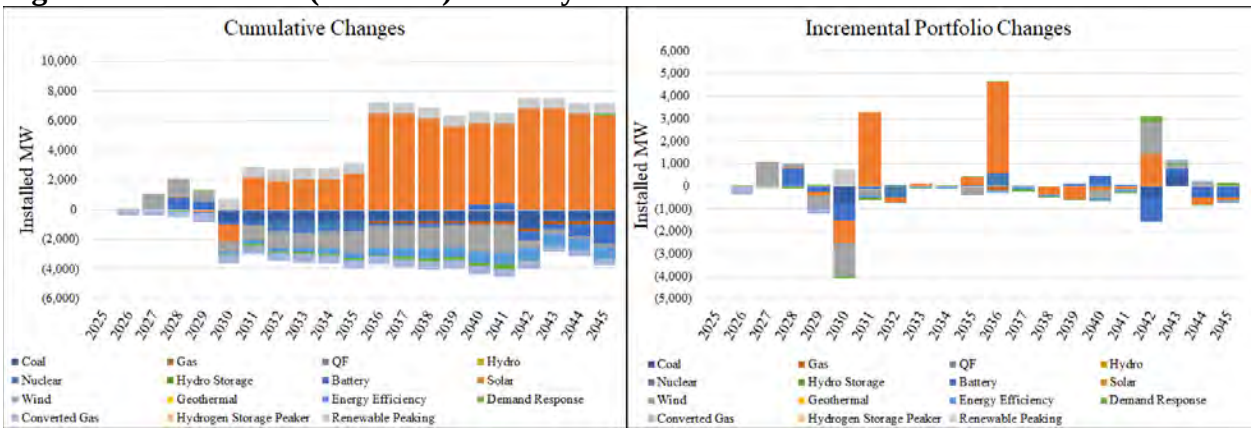
Low-Cost Renewables

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

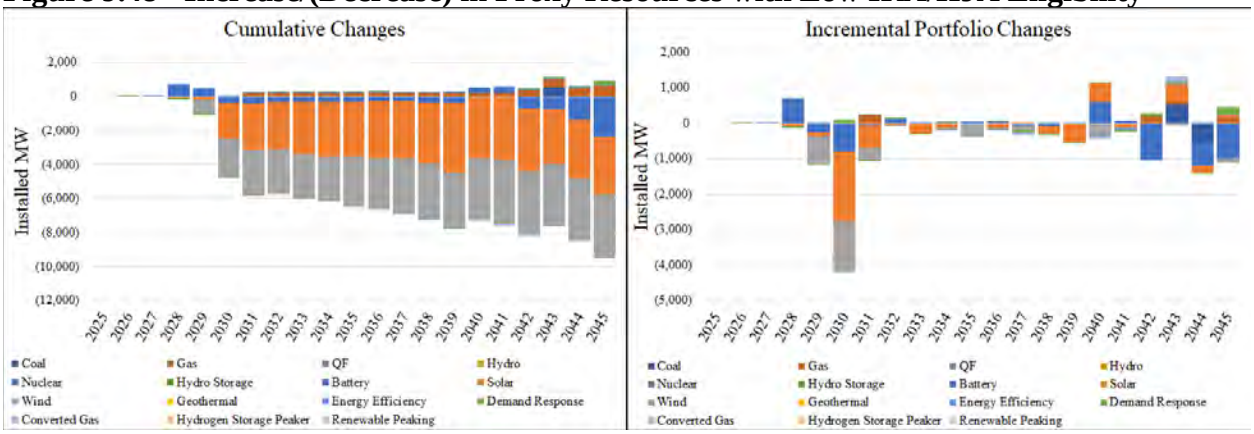


Low IRA/IIJA Eligibility

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

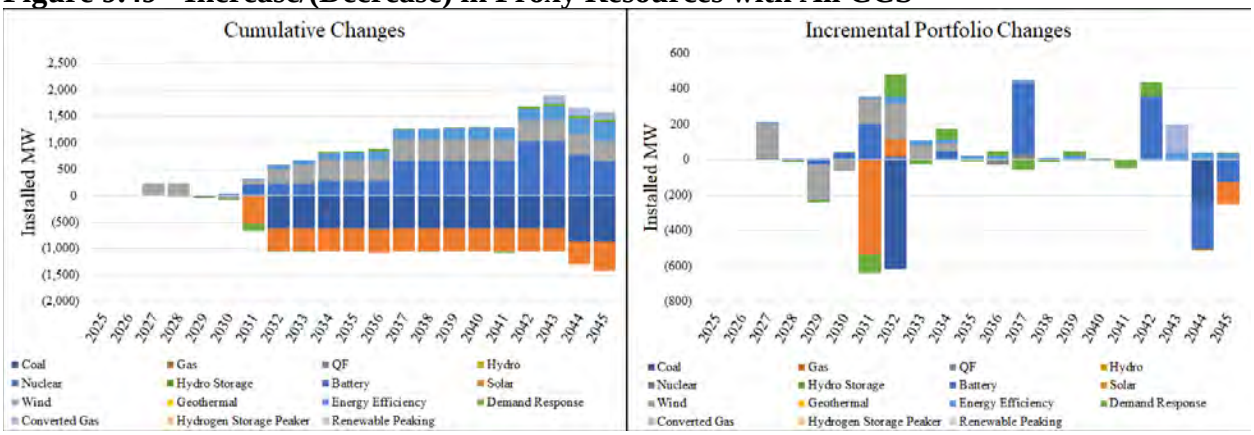


All CCS

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

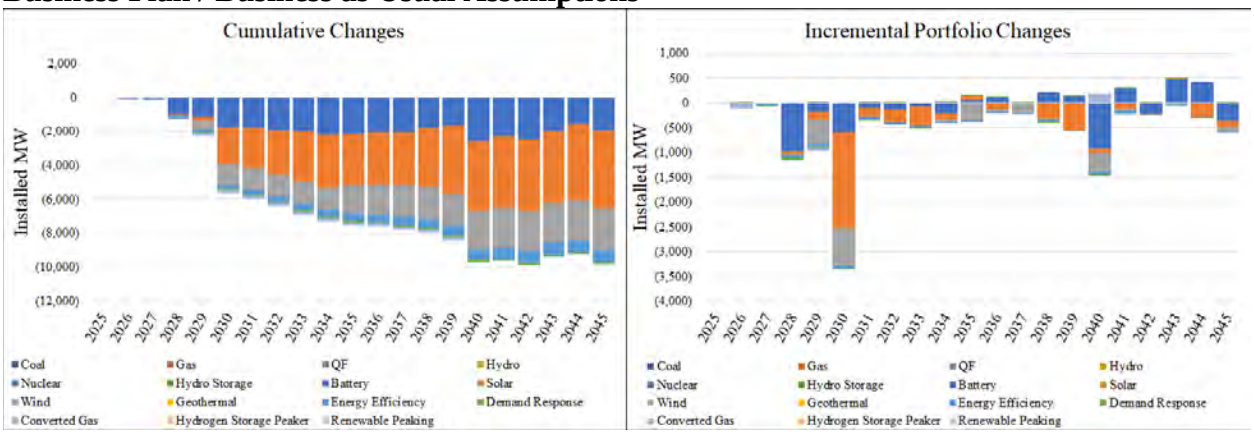


Business as Usual/Business Plan

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.

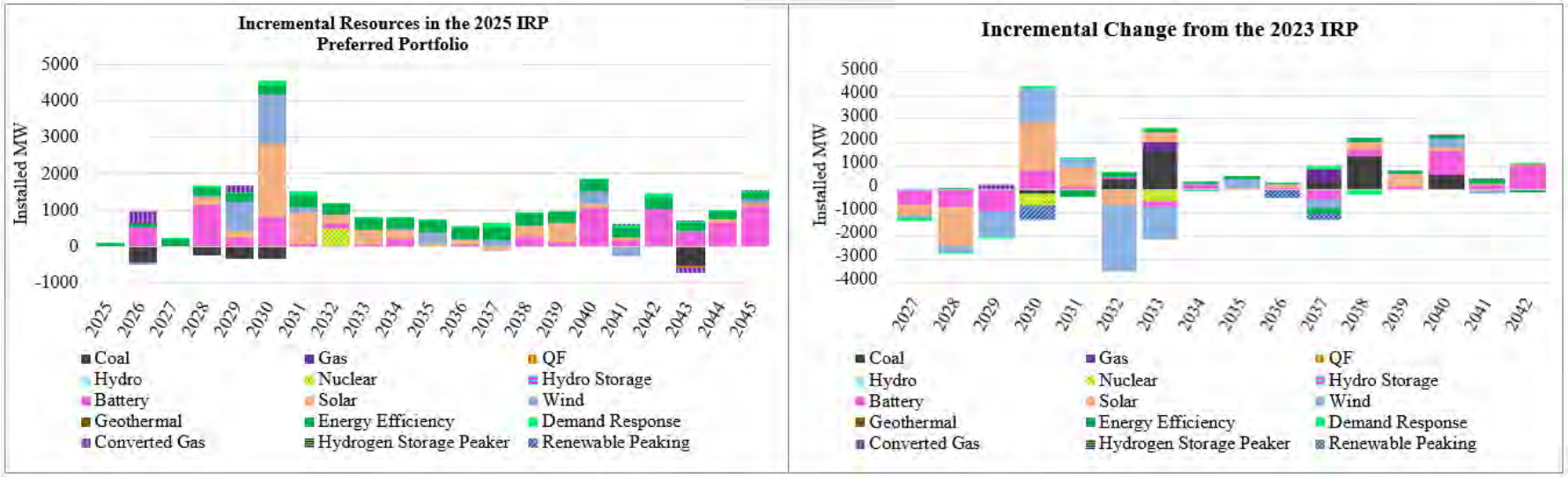
Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets 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	**<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>** • PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• Utah's first planning period disputes have been resolved. • Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>**	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the

	• PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	Natrium™ project and expects to finalize these arrangements by the end of 2025.
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

Action Item	2. New Resource Actions	Status
2a	**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	**<u>Energy Efficiency Targets:</u>** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.	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>
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- 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

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<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.

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</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.

CHAPTER 11 –UTAH EXECUTIVE SUMMARY

ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to these three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

Maintaining customer focus

The Utah Integrated Resource Plan (IRP) is a roadmap for continual progress to 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 the fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

[1] https://pscdocs.utah.gov/electric/23docs/2303510/335635230351009-24-2024.pdf

- The following resources are added in the Utah 2025 IRP:
  - 6,379 megawatts of new wind resources
  - 7,668 megawatts of storage resources, including four-hour, eight-hour, and 100-hour durations
  - 5,492 megawatts of new solar resources
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

Customer Programs

- 5,149 megawatts of capacity saved through energy efficiency programs
- 1,052 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 Wine Country substation near Sunnyside, Washington
- 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon
- 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
- 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)
- 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

Changes to our Portfolio

- 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
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Continue to evaluate 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 allocated 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.[2] 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 are represented:

- Utah, Idaho, Wyoming, and California (UIWC)[3]
  - 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 only allocated 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

[2] 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.

[3] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

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 the draft necessitated 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, PacifiCorp hosted stakeholders in seven online public input meetings. An additional two meetings were held with stakeholders after the distribution of the draft. Analysis conducted aligned to those meetings, after the Draft 2025 IRP filing, informs Chapters 1 through 10 and Appendices A through Z, which comprise the majority of this document.

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 11.1, 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 11.1 – Key Elements of PacifiCorp's 2025 IRP Approach



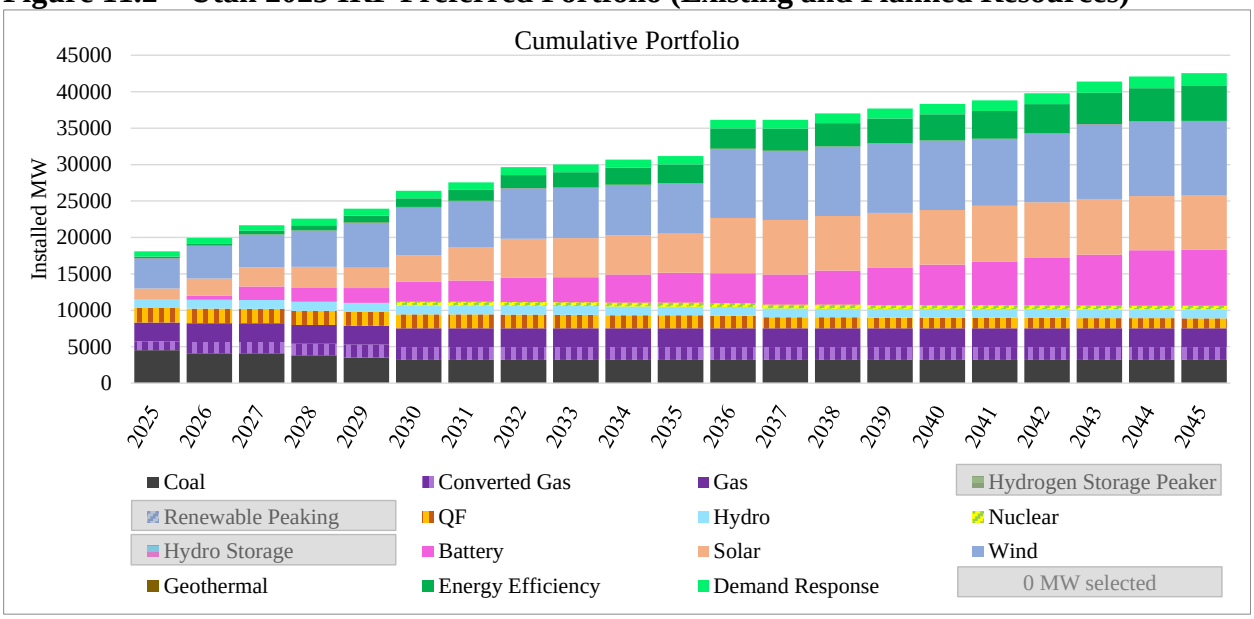
Preferred Portfolio Highlights

PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in Chapters 2 through 8, and the Appendices that follow. Figure 11.2 shows that PacifiCorp's Utah 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and non-emitting peaking resources facilitated by incremental transmission investments.

The Utah 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 Utah 2025 IRP preferred portfolio includes the advanced nuclear Natrium^{TM} demonstration project, anticipated to achieve online status by the end of 2030. By the end of 2032, the preferred portfolio includes 2,801 MW of energy storage resources, including 844 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 20-year planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

Figure 11.2 – Utah 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 Utah 2025 IRP preferred portfolio includes a second 416-mile transmission line from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah, known as Energy Gateway South 2, planned to come online in 2036. Smaller upgrades increase transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley 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. Table 11.1 summarizes the incremental transmission projects in the Utah 2025 IRP preferred portfolio. Note, at this time, 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 11.1 – Transmission Projects Included in the Utah 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Rebuild existing Cameron - Sigurd 138 kV	250	250	250	30	100%	Utah South	Wasatch Front
2027	Cluster 1 Area 11 - Willamette Valley	0	0	199	13	100%	n/a	n/a
	Serial queue - Central Oregon	0	0	152	3	100%	n/a	n/a
2028	Cluster 2 Area 23 - Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 1/2/3 - Walla Walla	0	0	628	66	100%	n/a	n/a
2031	Cluster 1/2/3 - Walla Walla	0	0	393	348	100%	n/a	n/a
	Walla Walla - Wine Country 230 kV	400	400	400	145	100%	n/a	n/a
2032	Cluster 1 Area 14 - Summer Lake	400	400	400	120	100%	Summer Lake	Hemingway
	Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV	450	450	450	413	100%	Willamette Valley	Central OR
2036	Gateway South 2: Aeolus Clover #2 500 kV	1,500	1,500	1,990	1,810	100%	Wyoming East	Clover
	Huntington – Clover 345 kV	800	800	800	264	100%	Utah South	Wasatch Front
	Spanish Fork - Mercer 345 kV	300	300	300	153	100%	Utah South	Wasatch Front
	West Cedar - Three Peaks 138 kV	200	200	200	14	100%	Utah South	Wasatch Front
	S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV	1,500	1,500	665	1,117	100%	Willamette Valley	Southern OR
2041	Serial through Cluster 1 Area 13 - Southern Oregon	0	0	231	52	100%	n/a	n/a
Grand Total		**5,800**	**5,800**	**7,451**	**4,551**			

[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.

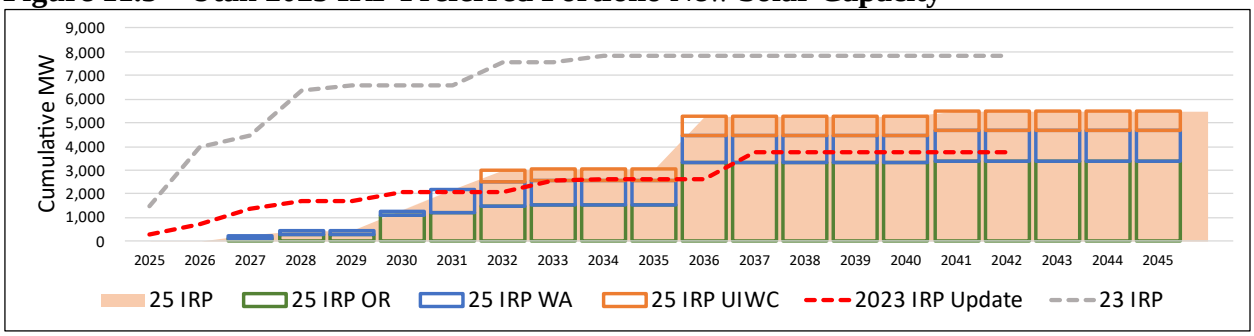
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

In Chapter 12 – Utah Model Results, a sensitivity analysis evaluates the impacts of significant new loads coming online in the 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 Utah 2025 IRP preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and 5,492 MW by the end of 2045, as shown in Figure 11.3.

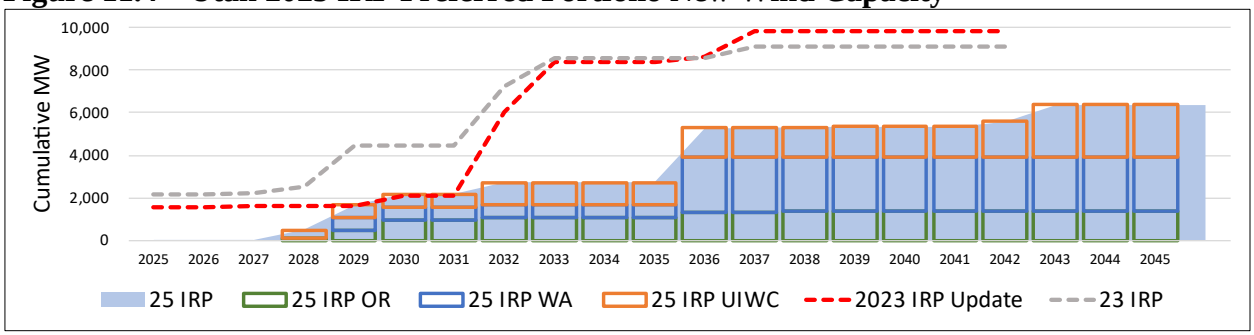
Figure 11.3 – Utah 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 11.4, PacifiCorp's 2025 IRP Utah preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379MW of cumulative new wind by the end of 2045.

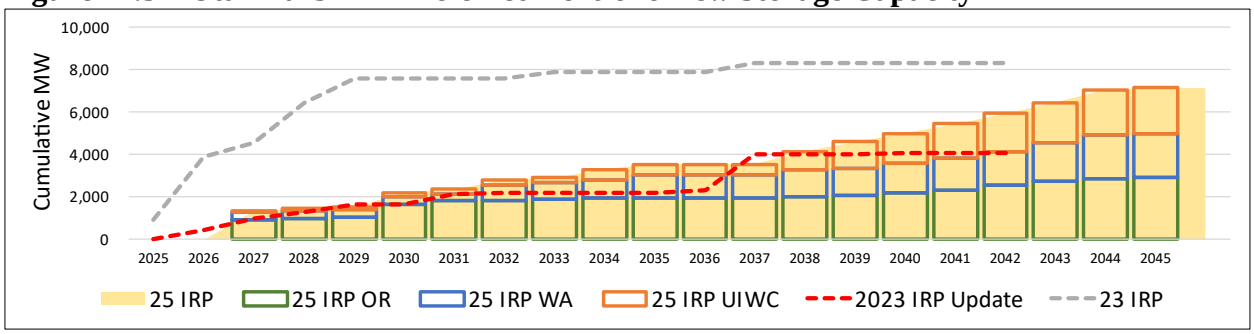
Figure 11.4 – Utah 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

New storage resources in the Utah 2025 IRP preferred portfolio are summarized in Figure 11.5. The Utah 2025 IRP preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4-hour and 8-hour lithium-ion storage. By year-end 2030, the Utah 2025 IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the Utah 2025 IRP preferred portfolio includes 7,668 MW of new storage.

Figure 11.5 – Utah 2025 IRP Preferred Portfolio New Storage Capacity[1,2]

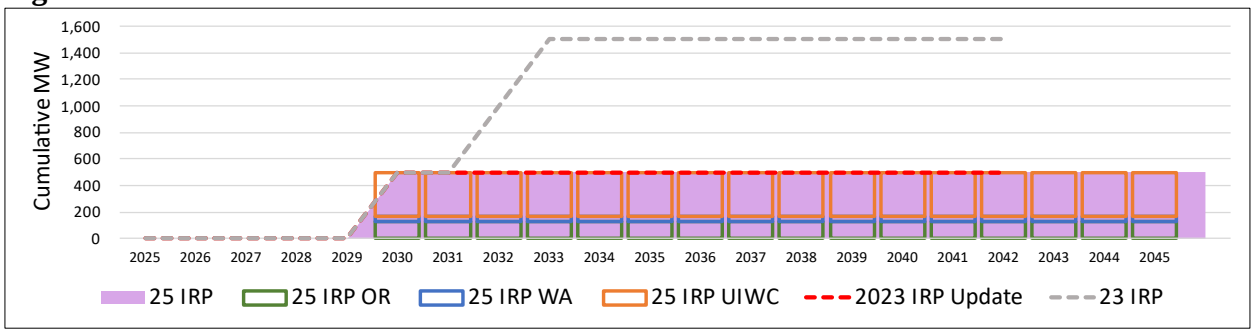


[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

New Nuclear Resources

The Utah 2025 IRP preferred portfolio includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 11.6, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the end of 2030.

Figure 11.6 – Utah 2025 IRP Preferred Portfolio New Nuclear



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 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 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.

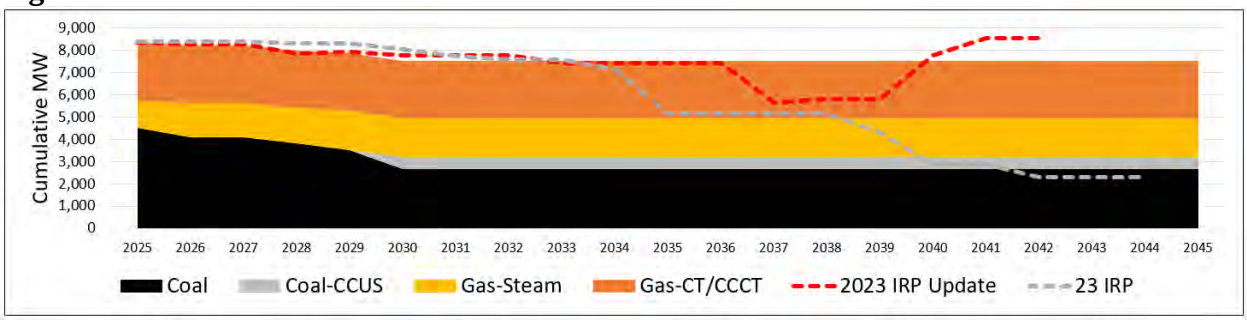
- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
    - 678 megawatts of energy efficiency between 2025 and 2028
    - 213 megawatts of demand response between 2025 and 2028

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, zero-emissions renewable 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 11.7, the Utah 2025 IRP preferred portfolio converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386 MW of minority-owned coal, and also retires 220 MW of majority-owned coal at Dave Johnston by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

Figure 11.7 – Utah 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the Utah 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 11.2. 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 11.2 – 2025 IRP Coal Resource Results Summary

Majority-Owned Coal			
Unit	Utah 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	Not retired (Alt. fuel conv. 2030)	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	7 (Gas conversion 2024)
Jim Bridger 3 & 4	Not retired (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	Not retired (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)

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 11.3 details specific 2025 IRP action items by resource category.

Table 11.3 – 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 Utah 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.

Action Item	1. Existing Actions (continued)
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 Oregon Public Utility Commission 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 needs. 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 issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[4] • In light of the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

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.

[4] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

Action Item	4. Demand-Side Management (DSM) Actions
4a	**Energy Efficiency 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. • PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year.
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 will 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 12 – UTAH MODEL RESULTS

ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

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 Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio continues to include 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 Utah 2025 IRP preferred portfolio includes resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The Utah 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that a forthcoming RFP as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The Utah 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind, 2,308 MW of which is small-scale, and 5,492 MW of new solar.
- 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, a new 230 kV line from the Willamette Valley to Central Oregon, and Gateway

[1] https://pscdocs.utah.gov/electric/23docs/2303510/335635230351009-24-2024.pdf

South 2, a new 500 kV line from the Aeolus substation in Wyoming to the Clover substation in Utah.

- 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 are converted to natural gas where the option is available.

- In the 2025 IRP, four factors 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, 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 as a result 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 Utah 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. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios supporting Washington's Clean Energy Transformation Act (CETA)[2] and discussion of Oregon's compliance position in the Utah 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 modeling results are also summarized in Volume II, Appendix J (Stochastic Simulation Results).

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 12.1 below shows the various phases of the Utah, Idaho, Wyoming and California (UIWC) MN fully initial jurisdictional run to demonstrate a snapshot of how iterative jurisdictional portfolios were

[2] Volume II, Appendix O provides additional detail relevant to Washington requirements.

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 is selected for integration. In Table 12.1, phase 5 was selected as the UIWC initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $21,842 million, and the stream of unserved energy costs that led to a total cost of $1 million which had no unserved energy after 2027. No other phase had both a lower PVRR and a lower unserved energy cost. Other phases which were considered were phase 1, phase 3 and phase 9, however the higher PVRR of phases 3 and 9, and the fact that phase 1 had small amounts of unserved energy through the 21-year study horizon led to phase 5 being selected.

Table 12.1 – Iterative phases of Utah, Idaho, Wyoming and California MN portfolio

Phase	Jurisdiction	Price-Policy	21 Year PVRR	Unserved Energy Cost
0	UIWC	Medium Gas, No CO2	20,628	14
1	UIWC	Medium Gas, No CO2	21,587	1
2	UIWC	Medium Gas, No CO2	21,212	10
3	UIWC	Medium Gas, No CO2	21,848	1
4	UIWC	Medium Gas, No CO2	22,036	22
5	UIWC	Medium Gas, No CO2	21,842	1
6	UIWC	Medium Gas, No CO2	20,942	29
7	UIWC	Medium Gas, No CO2	21,999	1
8	UIWC	Medium Gas, No CO2	21,128	30
9	UIWC	Medium Gas, No CO2	21,932	1
10	UIWC	Medium Gas, No CO2	21,145	25
11	UIWC	Medium Gas, No CO2	22,143	1
12	UIWC	Medium Gas, No CO2	21,157	19
13	UIWC	Medium Gas, No CO2	22,216	1
14	UIWC	Medium Gas, No CO2	20,526	18
15	UIWC	Medium Gas, No CO2	22,503	3

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 Chapter 8 (Modeling and Portfolio Evaluation), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and Utah preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

Jurisdictional Shares of the Preferred Portfolio

Table 12.2 through Table 12.4 present each jurisdiction's assumed *share* of the 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 12.2 – Oregon Share

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
Expansion Options																						
DSM - Energy Efficiency	-	55	79	81	84	87	93	94	94	93	93	83	89	89	87	90	91	101	169	160	151	1,966
DSM - Demand Response	-	24	7	38	6	60	7	4	2	3	1	-	53	51	3	21	30	3	3	37	7	361
Nuclear	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable - Utility Wind	-	-	-	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	0	-	-	246	4	37	5	-	-	-	-	-	-	1,267
Renewable - Utility Solar	-	-	109	165	-	848	102	579	45	4	-	1,888	1	-	-	-	-	-	-	-	-	3,741
Renewable - Battery	-	132	940	7	-	10	-	2	3	1	1	-	-	2	2	3	7	234	1	1	1	1,346
Renewable - Battery (Long Duration)	-	-	1	26	62	590	166	11	93	44	17	-	-	35	53	100	140	-	198	139	44	1,720

Table 12.3 – Washington Share

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
Expansion Options																						
DSM - Energy Efficiency	-	14	13	14	15	15	16	16	16	15	15	13	12	10	9	8	7	7	7	6	4	233
DSM - Demand Response	-	15	4	8	1	-	6	1	-	1	0	-	0	11	1	12	1	1	1	3	1	67
Nuclear	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable - Utility Wind	-	-	-	-	594	-	-	0	-	-	3	1,988	-	-	-	-	-	-	-	-	-	2,585
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	5
Renewable - Utility Solar	-	-	136	17	-	-	794	0	4	0	-	-	-	-	-	-	237	-	-	-	-	1,189
Renewable - Battery	-	37	354	6	-	-	-	400	-	93	173	-	-	247	4	78	95	58	192	274	9	2,020
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	11	-	-	4	-	-	7	8	12	5	-	31	6	-	83

Table 12.4 – 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
Expansion Options																						
DSM - Energy Efficiency	50	57	145	167	172	182	233	219	197	174	157	159	149	134	123	109	102	123	107	103	84	2,947
DSM - Demand Response	14	1	1	98	26	21	-	31	-	42	23	12	13	13	38	18	16	30	68	22	135	622
Nuclear	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable - Utility Wind	-	-	-	403	211	-	-	451	-	-	-	338	-	-	-	-	-	-	-	-	-	1,403
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	236	802	-	-	1,039
Renewable - Utility Solar	-	-	-	-	-	-	-	226	-	0	-	333	3	-	-	-	-	-	-	-	-	563
Renewable - Battery	-	352	2	103	-	30	-	14	-	224	2	-	11	4	4	-	4	197	63	4	4	1,018
Renewable - Battery (Long Duration)	-	-	-	-	-	65	-	-	-	44	46	-	-	285	405	200	180	-	35	187	35	1,481

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 12.5 through Table 12.7 report the entirety of portfolio selections made when planning for the entire system, not just the jurisdictional share, according to each jurisdiction's constraints.

Table 12.5 – 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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	233	253	261	275	325	322	302	277	260	248	250	233	219	208	201	232	283	269	235	5,064
DSM - Demand Response	18	25	7	38	86	60	7	4	2	3	1	-	255	85	47	46	46	27	79	61	43	940
Renewable - Wind	-	-	222	166	-	594	-	-	-	-	3	-	31	256	-	-	-	-	-	-	-	1,272
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	-	-	1,270
Renewable - Utility Solar	-	-	109	165	-	848	102	807	45	4	2	2,221	4	-	-	-	-	-	-	-	-	4,307
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,091	10	-	19	5	3	25	3	4	-	-	146	6	7	16	504	67	6	6	2,438
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80	3,285
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
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**487**	**1,663**	**403**	**666**	**3,035**	**400**	**1,243**	**467**	**372**	**337**	**2,715**	**444**	**855**	**455**	**895**	**246**	**860**	**659**	**435**	**344**	

Table 12.6 – 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	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	179	-	-	-	-	400
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	214	236	243	252	326	322	300	283	265	258	260	243	229	217	210	230	285	271	236	5,058
DSM - Demand Response	18	17	4	8	37	-	185	35	-	54	57	-	26	44	42	52	24	45	30	78	40	796
Renewable - Wind	-	-	1,008	-	594	-	-	17	-	-	3	1,990	130	-	-	-	-	-	-	-	-	3,742
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	157	-	-	-	194	660	1,132
Renewable - Utility Solar	-	-	136	17	-	-	794	630	4	1	-	-	-	406	-	-	237	-	-	-	-	2,225
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	490	6	-	-	5	747	-	296	196	-	-	269	28	471	177	152	347	285	15	4,004
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	25	-	-	132	-	-	121	139	224	92	395	107	108	-	1,343
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)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	892
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total	**107**	**479**	**1,852**	**12**	**972**	**331**	**1,101**	**1,776**	**304**	**631**	**653**	**2,248**	**316**	**1,051**	**559**	**1,121**	**521**	**822**	**722**	**703**	**931**	

Table 12.7 – 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	89	89	203	247	256	271	331	319	298	273	255	259	250	233	220	208	207	232	283	271	239	5,033
DSM - Demand Response	18	1	-	157	40	33	-	46	-	86	29	27	17	17	47	47	46	33	74	61	144	923
Renewable - Wind	-	-	-	486	211	-	-	1,045	-	-	-	340	-	-	-	-	-	-	-	-	-	2,082
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	143	390	802	-	-	1,335
Renewable - Utility Solar	-	-	-	-	-	-	-	1,675	-	4	-	670	4	-	-	-	-	-	-	-	-	2,353
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	4	444	355	134	-	389	-	232	4	-	11	6	6	-	14	462	65	6	6	2,658
Renewable - Battery (Long Duration)	-	-	-	-	-	130	-	-	-	100	78	368	383	359	466	312	325	-	51	332	70	2,974
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
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**463**	**207**	**1,079**	**739**	**647**	**122**	**3,474**	**298**	**692**	**366**	**1,664**	**565**	**583**	**739**	**567**	**337**	**1,117**	**1,228**	**437**	**439**	

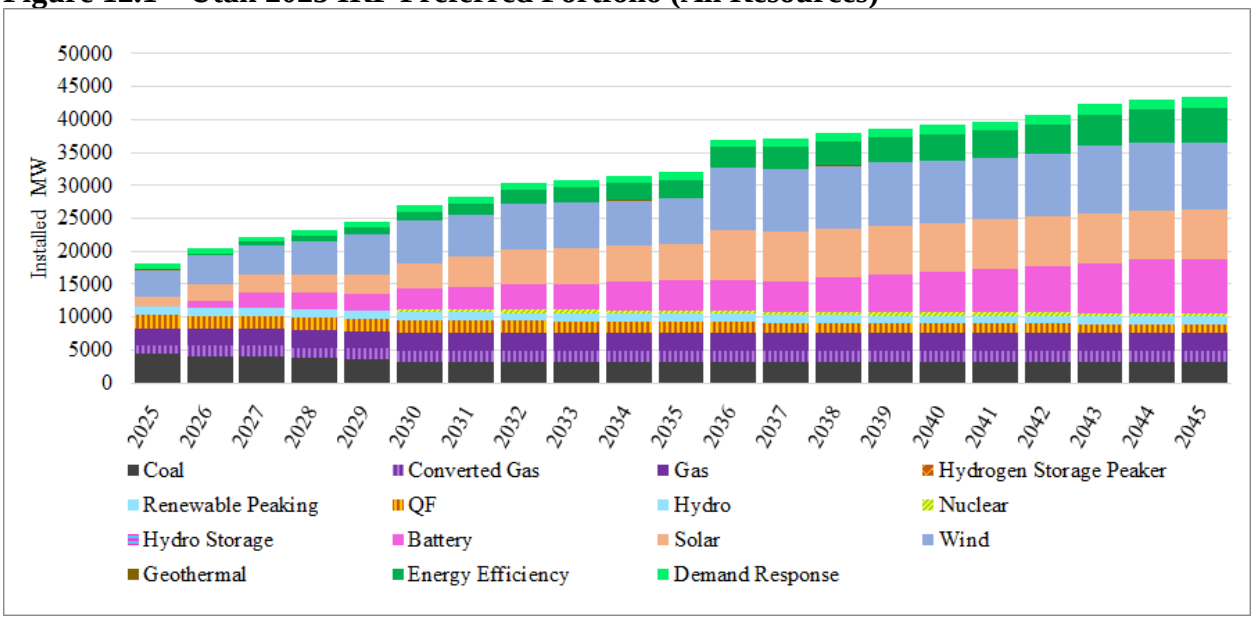
The Utah 2025 IRP Preferred Portfolio

PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 12.1 shows that PacifiCorp's Utah 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 Utah 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 will come online in the 2024 to 2026 timeframe.

The Utah 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the Utah preferred portfolio includes 2,801 MW of energy storage resources, including 844 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 Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

Figure 12.1 – Utah 2025 IRP Preferred Portfolio (All Resources)



New since the 2023 IRP, the Utah 2025 IRP preferred portfolio includes a second 416-mile transmission line, known as Energy Gateway South 2, running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This line is scheduled to be operational by 2036. Additionally, smaller upgrades will enhance transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley 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. Table 12.8 summarizes the incremental transmission projects in the Utah 2025 IRP Preferred Portfolio.

Table 12.8 – Transmission Projects Included in the Utah 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Rebuild existing Cameron - Sigurd 138 kV	250	250	250	30	100%	Utah South	Wasatch Front
2027	Cluster 1 Area 11 - Willamette Valley	0	0	199	13	100%	n/a	n/a
	Serial queue - Central Oregon	0	0	152	3	100%	n/a	n/a
2028	Cluster 2 Area 23 - Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 1/2/3 - Walla Walla	0	0	628	66	100%	n/a	n/a
2031	Cluster 1/2/3 - Walla Walla	0	0	393	348	100%	n/a	n/a
	Walla Walla - Wine Country 230 kV	400	400	400	145	100%	n/a	n/a
2032	Cluster 1 Area 14 - Summer Lake	400	400	400	120	100%	Summer Lake	Hemingway
	Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV	450	450	450	413	100%	Willamette Valley	Central OR
2036	Gateway South 2: Aeolus Clover #2 500 kV	1,500	1,500	1,990	1,810	100%	Wyoming East	Clover
	Huntington – Clover 345 kV	800	800	800	264	100%	Utah South	Wasatch Front
	Spanish Fork - Mercer 345 kV	300	300	300	153	100%	Utah South	Wasatch Front
	West Cedar - Three Peaks 138 kV	200	200	200	14	100%	Utah South	Wasatch Front
	S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV	1,500	1,500	665	1,117	100%	Willamette Valley	Southern OR
2041	Serial through Cluster 1 Area 13 - Southern Oregon	0	0	231	52	100%	n/a	n/a
Grand Total		**5,800**	**5,800**	**7,451**	**4,551**			

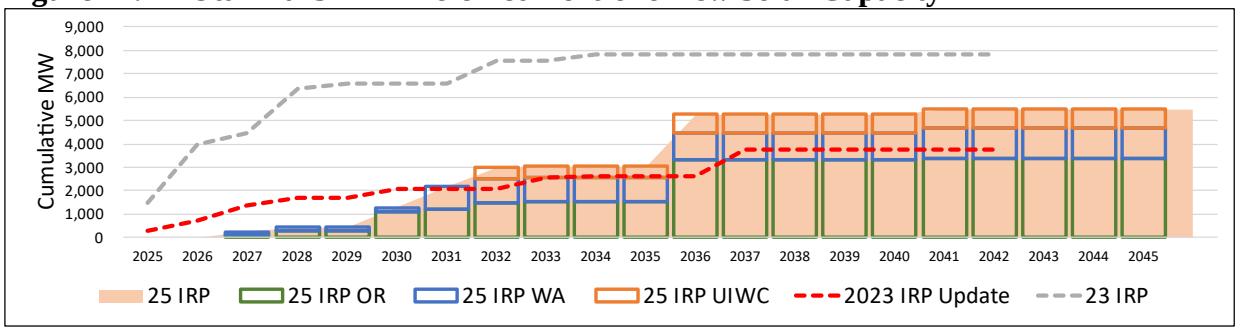
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource 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 project-specific timing and some costs are project-specific.

New Solar Resources

The Utah 2025 IRP preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and more than 5,492 MW by the end of 2045, as shown in Figure 12.2.

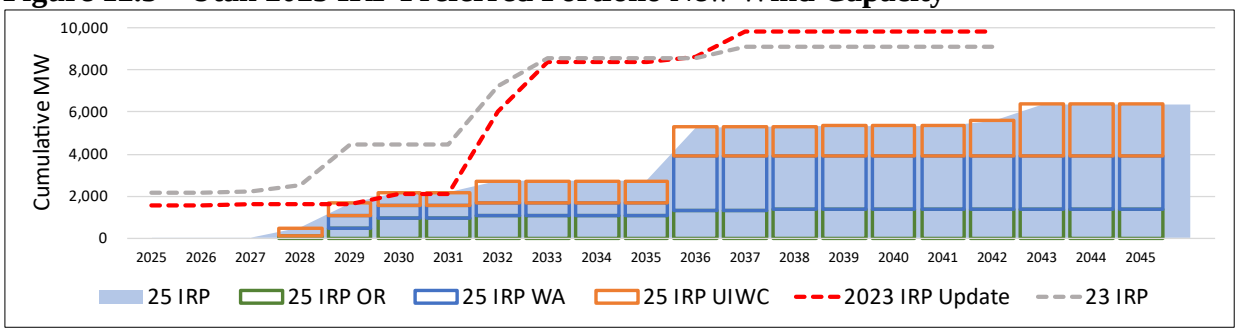
Figure 12.2 – Utah 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 12.3, PacifiCorp's Utah 2025 IRP preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379 MW of cumulative new wind by the end of 2045.

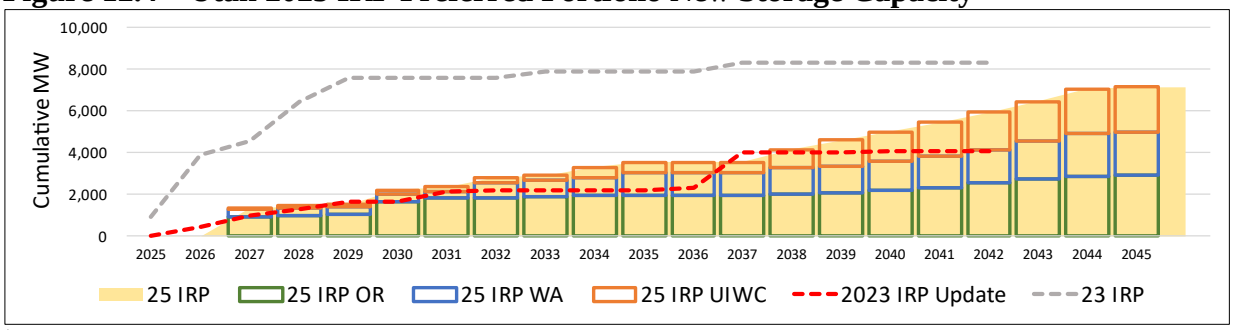
Figure 12.3 – Utah 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

New storage resources in the Utah 2025 IRP preferred portfolio are summarized in Figure 12.4. The Utah 2025 IRP preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4 and 8-hour lithium-ion storage. By year-end 2030, the 2025 draft IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the Utah 2025 IRP preferred portfolio includes 7,668 MW of new storage.

Figure 12.4 – Utah 2025 IRP Preferred Portfolio New Storage Capacity[1]

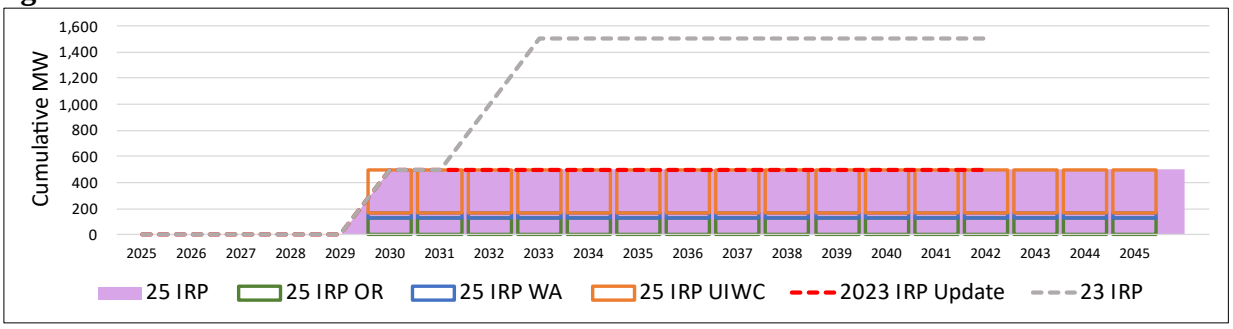


[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

New Nuclear Resources

The Utah 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 12.5, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by summer 2030.

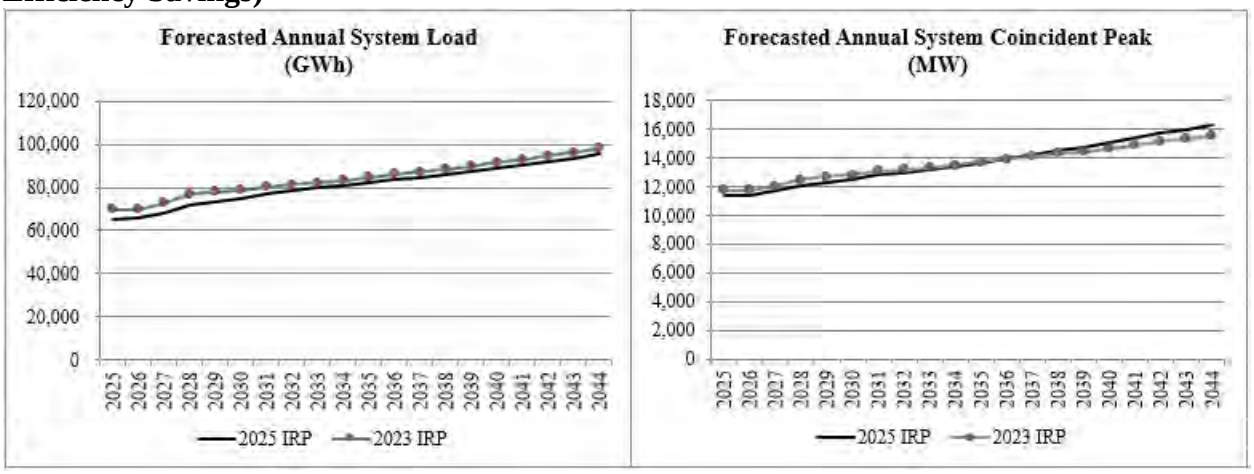
Figure 12.5 – 2025 IRP New Nuclear



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 12.6 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, lowering the commercial forecast.

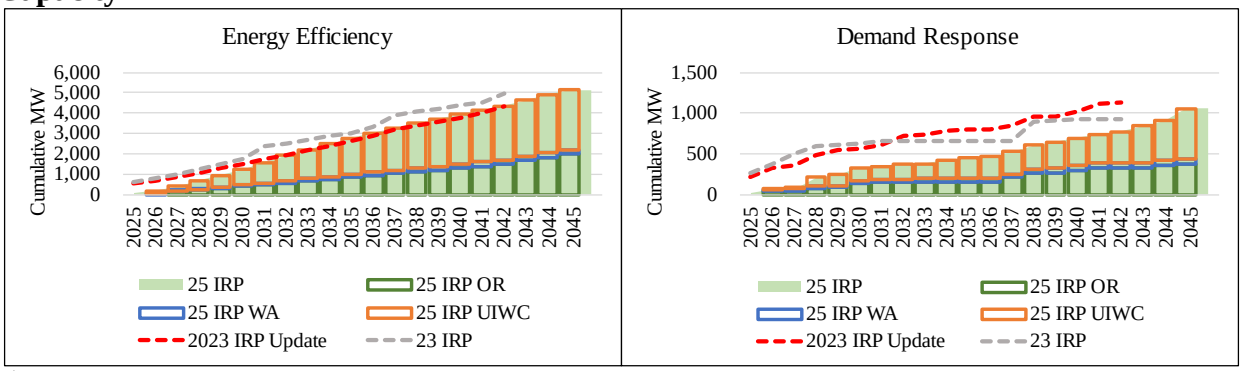
Figure 12.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 12.7 compares total energy efficiency capacity savings in the Utah 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and includes 5,149 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 12.7 compares cumulative demand response program capacity in the Utah 2025 IRP preferred portfolio relative to the 2023 IRP Update preferred portfolio and does not include capacity from existing programs. The 2025 draft IRP has a cumulative capacity of demand response programs reaching 695 MW by 2040. By year-end 2045, the Utah 2025 IRP preferred portfolio has a cumulative capacity of demand response programs reaching 1,052 MW, a 6.3% decrease from the cumulative capacity of demand response programs by the end of the planning horizon in the 2023 IRP Update (1,123 MW).

Figure 12.7 – Utah 2025 IRP preferred portfolio Energy Efficiency and Demand Response Capacity

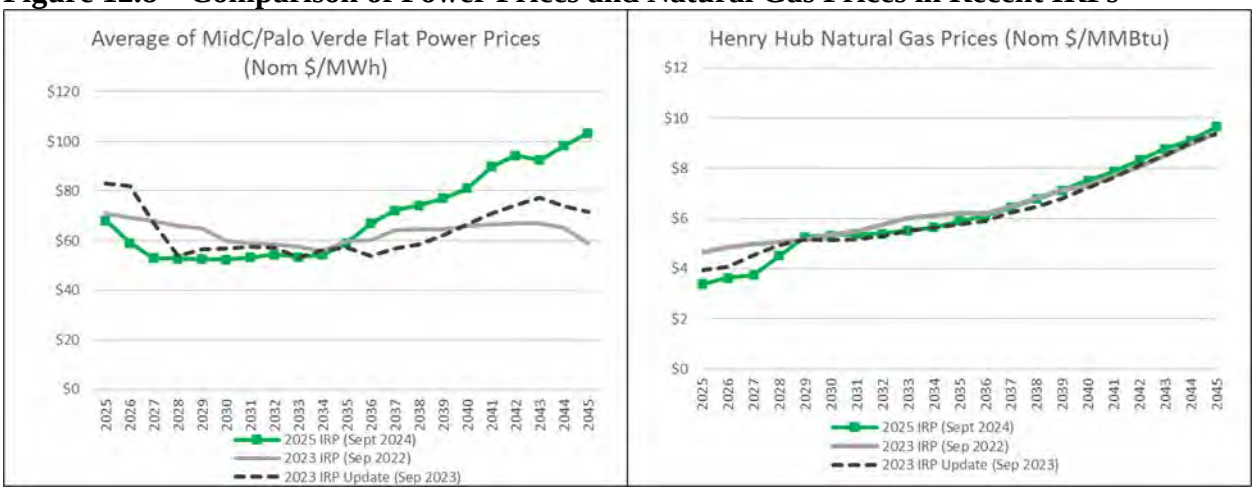


[1] Energy efficiency and demand response in the 2023 IRP Update began escalating two years prior to when escalation begins in the 2025 draft IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 draft IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP Update, the end of the planning horizon.

Wholesale Power Market Prices and Purchases

Figure 12.8 illustrates that the Utah 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 12.8 reports that the Utah 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.

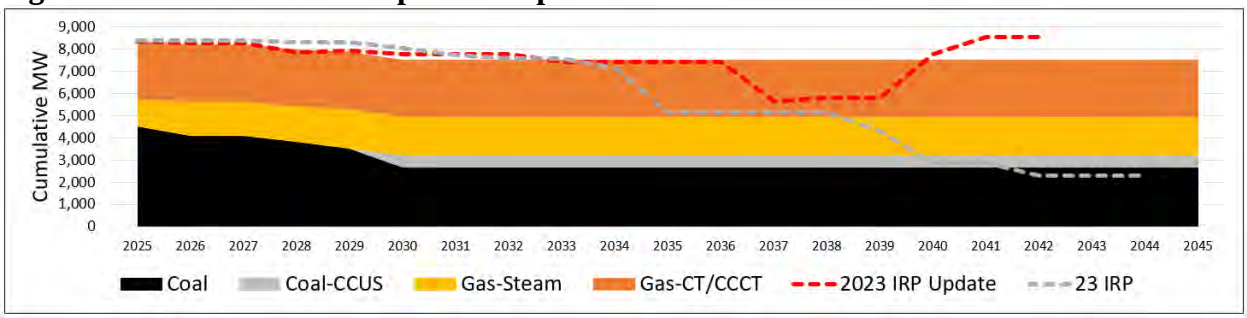
Figure 12.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



Coal and Gas Retirements/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 EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable 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 reasonably 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 12.9, the Utah 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386.2 MW of minority-owned coal, and an additional 220 MW of majority-owned coal by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

Figure 12.9 – Utah 2025 IRP preferred portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the Utah 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 12.9. 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.[3]

Table 12.9 – 2025 IRP Coal Resource Results

Majority-Owned Coal			
Unit	Utah 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	Not retired (Alt. fuel conv. 2030)	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	7 (Gas conversion 2024)
Jim Bridger 3 & 4	Not retired (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	Not retired (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 Utah 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, storage and transmission advancements; and Regional Haze compliance that capitalizes on flexibility.

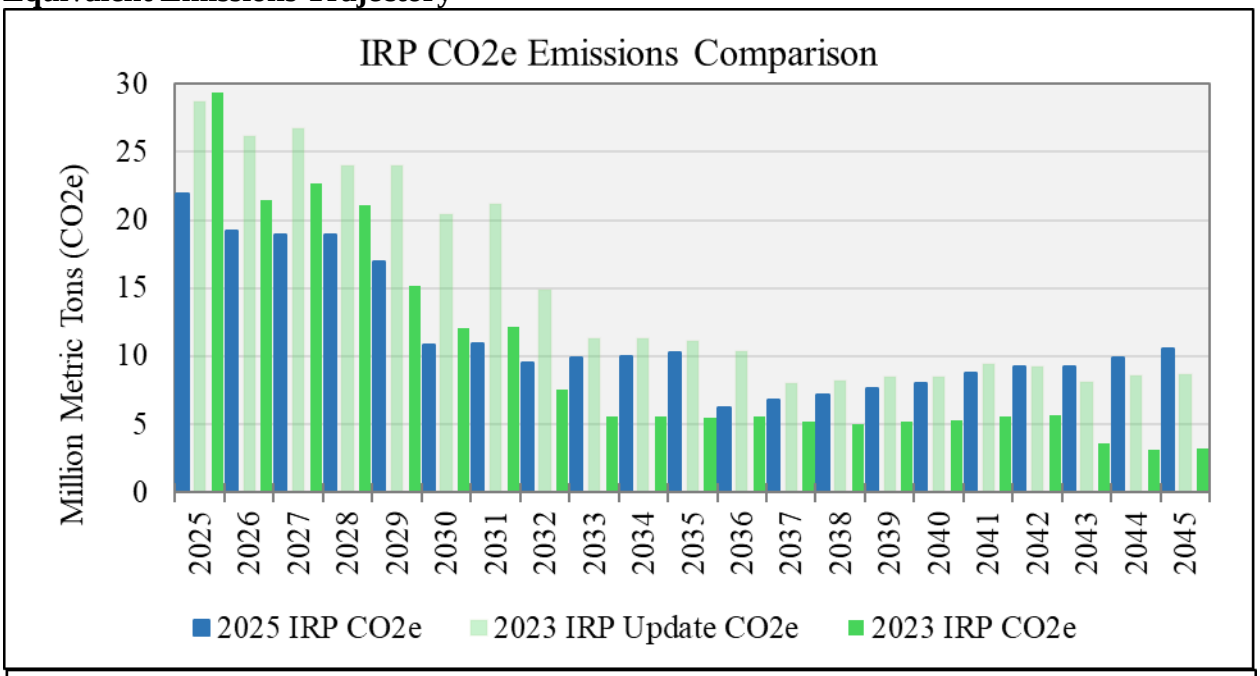
The chart on the left in Figure 12.10 compares projected annual CO_2e emissions across the Utah 2025 IRP, 2023 IRP, and 2023 IRP Update preferred portfolios and is inclusive of emissions attributed to market purchases. The Utah 2025 IRP delivers greater emission reductions between 2025 to 2032 outperforming both the 2023 IRP and 2023 IRP Update, with average annual CO2e emissions down 8% by 2030 relative to the 2023 IRP. After 2032, emissions are forecasted to rise moderately above the 2023 IRP due in part to a higher load forecast in the Utah 2025 IRP and the expiration of existing contracted resources. The difference in emissions from the 2023 IRP also reflects the Utah 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing

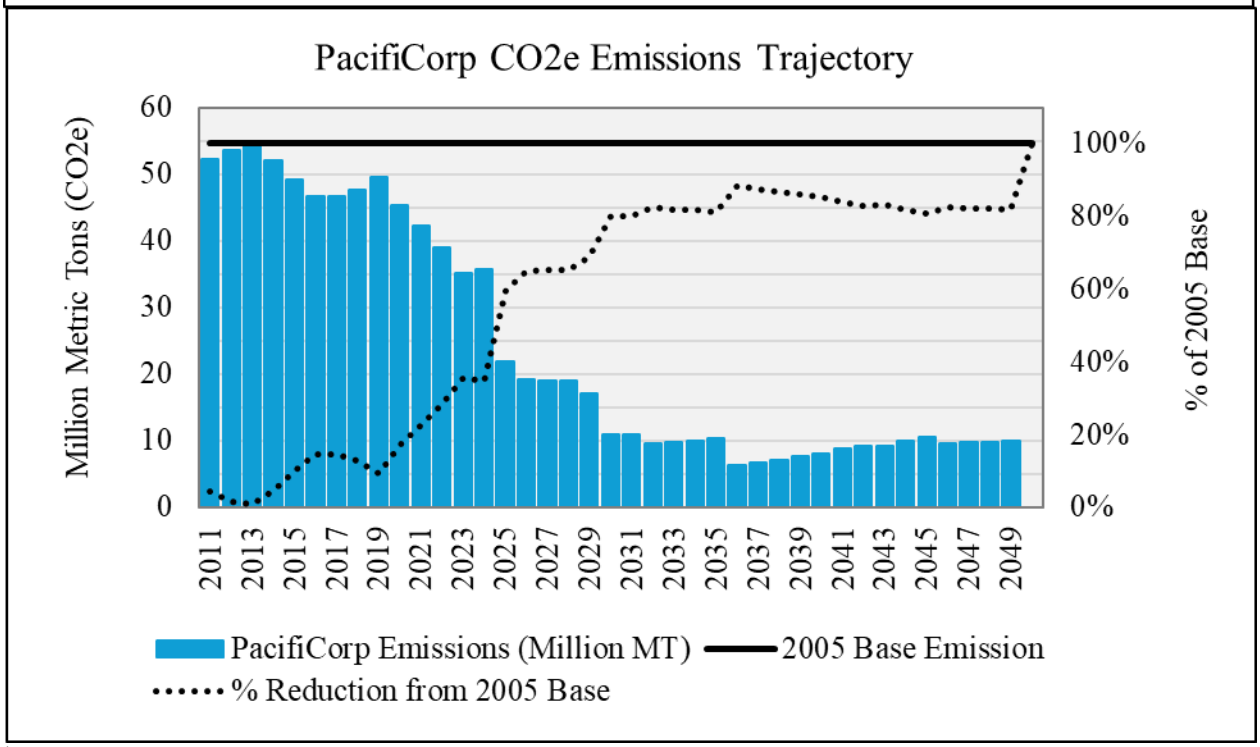
[3] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

existing coal plants to operate through the planning period at a reduced capacity. 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. By the end of the planning horizon, system CO2e emissions are projected to fall from 22.0 million metric tons in 2025 to 10.6 million tons in 2045—a reduction of 52 percent.

The chart on the right in Figure 12.10 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that, relative to a 2005 baseline of 54.6 million metric tons, system CO2 equivalent emissions are down 60 percent in 2025, 80 percent in 2030, and 85 percent in 2040.

Figure 12.10 – Utah 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]





[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. 2023 emissions have yet to be updated for actuals and 2024 emissions were not forecasted in the 2025 IRP. Therefore both 2023 and 2024 reflect the forecast from the 2023 IRP. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the Utah 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. Beyond 2045, emissions reflect the rolling average emissions of each resource from the Utah 2025 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in its Clean Energy Plan.

Renewable Portfolio Standards

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 Utah 2025 IRP preferred portfolio.

Capacity and Energy

Figure 12.13 and Figure 12.14 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 base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[4] On an energy basis, coal generation drops below 20 percent in 2026, falling below 10 percent in 2036, and remaining below 10 percent through the end of the planning period. On a capacity basis, coal resources drop to 12 percent. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources and DSM resources.

[4]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 12.11 – Projected Energy Mix with Preferred Portfolio Resources

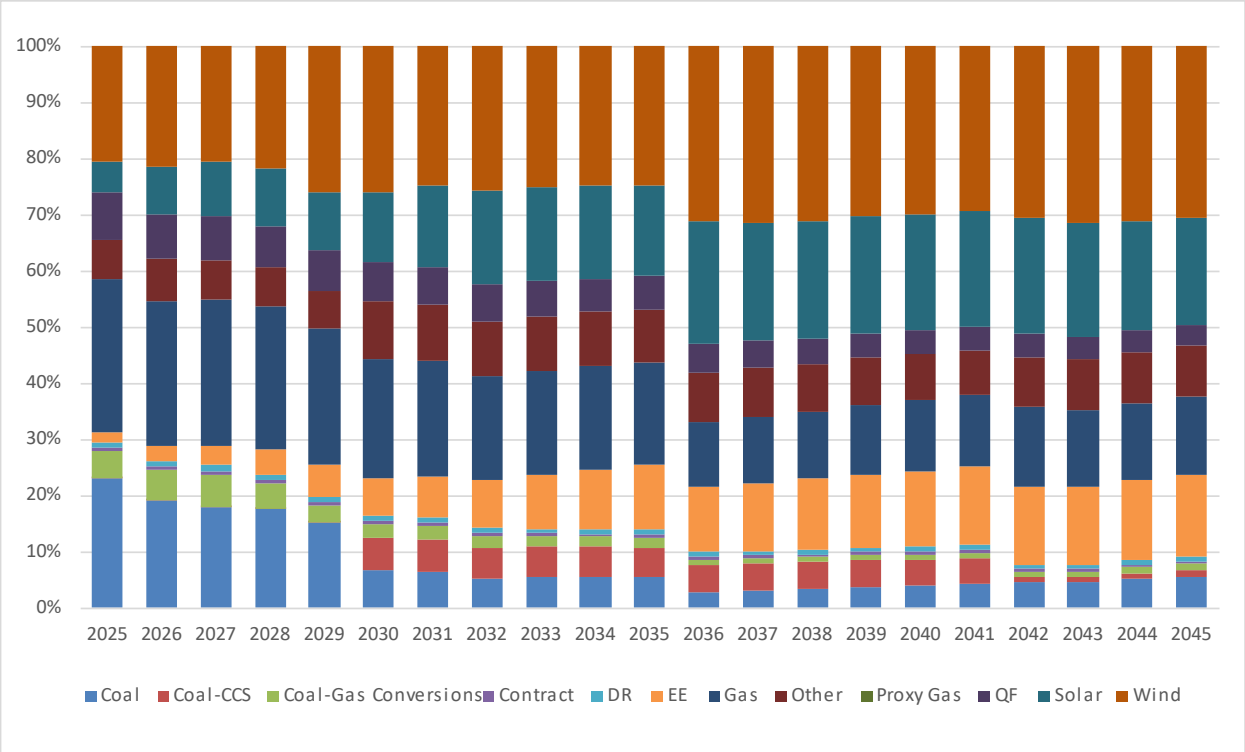
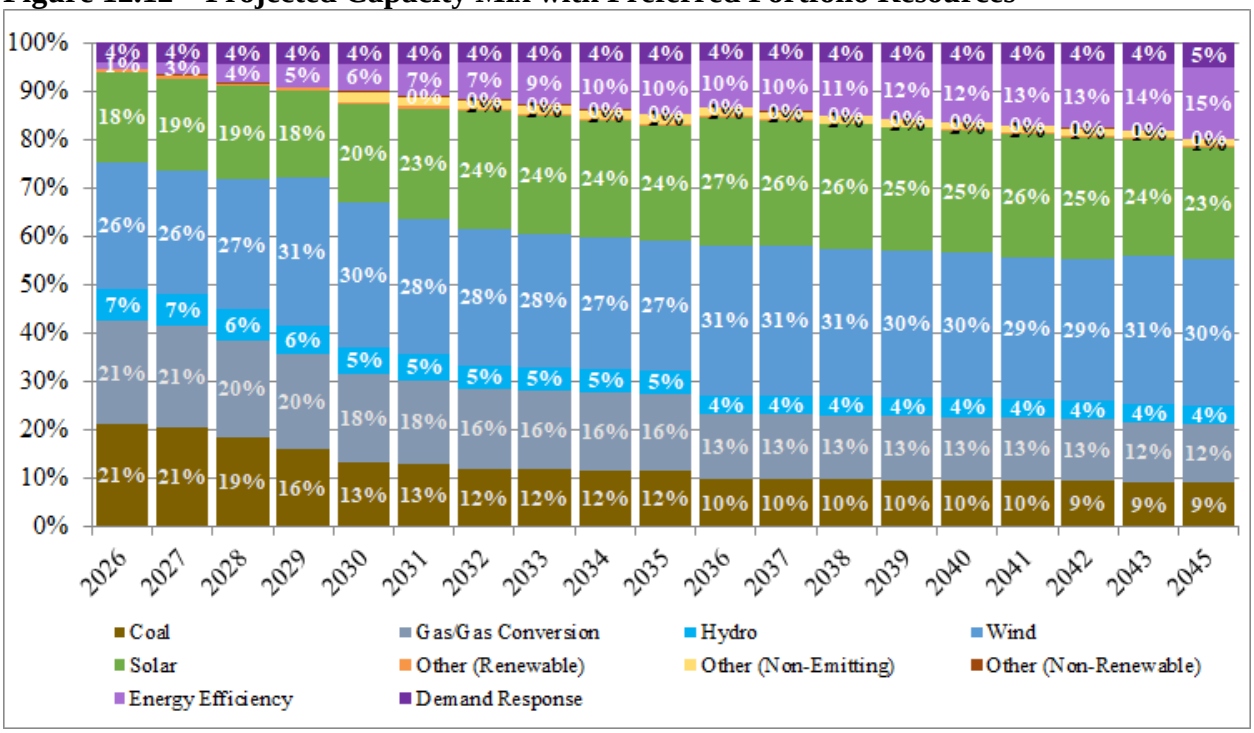


Figure 12.12 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 12.10 provides line-item detail of PacifiCorp's Utah 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon.

Table 12.11 and Table 12.12 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 12.13 and Table 12.14 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 12.10 – PacifiCorp's Utah 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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239	5,149
DSM - Demand Response	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144	1,052
Renewable - Wind	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-	4,071
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-	2,308
Renewable - Utility Solar	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-	5,492
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15	4,383
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80	3,285
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
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)	(2)	(52)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,792**	**961**	**1,426**	**1,966**	**1,212**	**2,144**	**455**	**735**	**535**	**5,061**	**235**	**893**	**747**	**652**	**516**	**989**	**1,630**	**710**	**456**	

Table 12.11 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,959	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	3,295	3,469	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	246	224	218	211	205	189	168	162	157	151
Solar	342	499	488	476	464	453	441	429	418	406
Other Renewable	46	45	44	42	41	40	38	37	36	34
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	413	404	395	386	377	368	359	348	334	323
Demand Response	305	300	295	290	286	281	276	271	266	262
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	0	(639)	(822)	(627)	(335)	(1,131)	(1,021)	(595)	(628)	(494)
East Existing Resources	**8,373**	**8,709**	**8,480**	**8,434**	**8,567**	**7,549**	**7,598**	**7,975**	**7,889**	**7,974**
Additional Proxy/Short-Term Purchases	190	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	85	185	268	263	273	267	263
Solar	0	0	0	0	0	0	0	0	0	0
Storage	0	0	136	160	220	867	1,029	1,049	1,139	1,224
Nuclear	0	0	0	0	0	300	300	300	300	300
Demand Response	0	0	0	73	92	106	106	127	127	157
East Planned Resources	**190**	**0**	**137**	**319**	**499**	**1,543**	**1,701**	**1,751**	**1,836**	**1,947**
East Total Resources	**8,563**	**8,710**	**8,617**	**8,753**	**9,065**	**9,092**	**9,299**	**9,726**	**9,725**	**9,920**
Load	7,734	7,947	7,952	8,230	8,667	8,855	9,050	9,335	9,335	9,284
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(515)	(354)
Energy Efficiency	(92)	(191)	(234)	(346)	(457)	(566)	(561)	(852)	(880)	(996)
East Total obligation	**7,485**	**7,613**	**7,532**	**7,651**	**7,924**	**7,948**	**8,089**	**8,025**	**7,940**	**7,934**
East Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	15.0%	21.2%	22.5%	25.0%
West										
Coal	140	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	0	0	0	0	0	0	0	0	0	0
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	229	224	212	207	198	194	188	178	174	170
Demand Response	60	59	58	58	57	56	55	55	54	53
Transfers	0	639	822	627	335	1,131	1,021	595	628	494
West Existing Resources	**1,927**	**2,551**	**2,719**	**2,516**	**2,212**	**2,868**	**2,745**	**2,307**	**2,332**	**2,191**
Additional Proxy/Short-Term Purchases	2,145	1,711	568	720	1,079	166	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	0	64	64	64	112	112	111
Solar	0	0	133	225	218	627	1,031	1,363	1,333	1,285
Storage	0	0	847	920	908	923	912	1,186	1,171	1,369
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	6	9	42	44	44	48	49	49	50
West Planned Resources	**2,145**	**1,718**	**1,559**	**1,907**	**2,313**	**1,825**	**2,055**	**2,710**	**2,665**	**2,815**
West Total Resources	**4,072**	**4,269**	**4,278**	**4,423**	**4,525**	**4,693**	**4,799**	**5,017**	**4,998**	**5,006**
Load	3,672	3,826	3,938	4,121	4,271	4,482	4,609	4,828	4,946	4,887
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(244)	(148)
Energy Efficiency	(63)	(41)	(123)	(157)	(191)	(227)	(231)	(229)	(334)	(364)
West Total obligation	**3,560**	**3,731**	**3,740**	**3,866**	**3,955**	**4,102**	**4,195**	**4,386**	**4,368**	**4,376**
West Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%
System										
Total Resources	12,635	12,978	12,895	13,175	13,590	13,785	14,099	14,743	14,723	14,926
Obligation	11,045	11,345	11,272	11,517	11,879	12,050	12,284	12,410	12,308	12,310
Planning Reserves (14.4%)	1,590	1,634	1,623	1,658	1,711	1,735	1,769	1,787	1,772	1,773
Obligation + Reserves	12,635	12,978	12,895	13,175	13,590	13,785	14,053	14,197	14,081	14,082
System Position	0	0	0	0	0	0	45	546	642	844
Reserve Margin	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.8%**	**18.8%**	**19.6%**	**21.3%**

Table 12.12 – 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	2,926	2,926	2,926
Gas	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	145	140	134	128	122	117	81	77	73	69	65
Solar	395	383	343	332	322	311	300	290	279	246	236
Other Renewable	33	32	30	11	11	10	9	9	8	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	314	302	240	231	223	211	204	196	189	182	176
Demand Response	257	252	247	243	238	233	228	223	218	214	209
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(469)	(310)	(491)	(366)	(567)	(653)	(663)	(627)	(708)	(607)	(765)
East Existing Resources	**7,950**	**8,060**	**7,749**	**7,811**	**7,564**	**7,430**	**7,346**	**7,339**	**7,216**	**7,252**	**7,047**
Additional Proxy/Short-Term Purcha	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	258	641	628	621	609	596	583	601	691	675	658
Solar	0	316	306	297	287	278	268	258	249	239	230
Storage	1,288	1,286	1,284	1,605	2,064	2,371	2,690	2,688	2,947	3,273	3,350
Nuclear	301	301	301	301	301	301	301	301	301	301	302
Demand Response	172	181	189	198	230	241	251	265	294	307	401
East Planned Resources	**2,022**	**2,726**	**2,711**	**3,024**	**3,494**	**3,789**	**4,095**	**4,116**	**4,484**	**4,799**	**4,943**
East Total Resources	**9,972**	**10,786**	**10,460**	**10,835**	**11,058**	**11,219**	**11,441**	**11,454**	**11,700**	**12,051**	**11,990**
Load	9,411	9,557	9,767	9,935	10,083	10,201	10,339	10,480	10,664	10,745	10,883
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(1,110)	(1,151)	(1,024)	(1,333)	(1,462)	(1,515)	(1,580)	(1,315)	(1,562)	(1,583)	(1,613)
East Total obligation	**7,916**	**7,990**	**8,298**	**8,129**	**8,118**	**8,156**	**8,202**	**8,581**	**8,492**	**8,528**	**8,610**
East Reserve Margin	26.0%	35.0%	26.1%	33.3%	36.2%	37.6%	39.5%	33.5%	37.8%	41.3%	39.3%
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	0	0	0	0	0	0	0	0	0	0	0
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	143	138	133	129	125	121	100	96	94
Demand Response	52	52	51	50	49	49	48	47	46	46	45
Transfers	469	310	491	366	567	653	663	627	708	607	765
West Existing Resources	**2,159**	**1,992**	**2,153**	**2,021**	**2,213**	**2,293**	**2,276**	**2,235**	**2,293**	**2,187**	**2,341**
Additional Proxy/Short-Term Purcha	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	111	111	110	110	109	109	109	108	108	107	107
Solar	1,235	1,444	1,382	1,320	1,259	1,197	1,208	1,140	1,074	1,008	942
Storage	1,466	1,444	1,431	1,569	1,551	1,576	1,617	1,881	2,001	2,130	2,102
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	50	50	85	107	108	128	138	141	142	170	175
West Planned Resources	**2,861**	**3,048**	**3,008**	**3,106**	**3,027**	**3,010**	**3,071**	**3,270**	**3,325**	**3,415**	**3,327**
West Total Resources	**5,020**	**5,040**	**5,161**	**5,127**	**5,240**	**5,303**	**5,347**	**5,505**	**5,618**	**5,603**	**5,668**
Load	4,944	5,009	5,082	5,189	5,258	5,330	5,397	5,473	5,660	5,651	5,730
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
Energy Efficiency	(394)	(426)	(378)	(502)	(457)	(461)	(475)	(399)	(473)	(463)	(471)
West Total obligation	**4,388**	**4,406**	**4,512**	**4,481**	**4,581**	**4,635**	**4,674**	**4,812**	**4,910**	**4,897**	**4,955**
West Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%
System											
Total Resources	14,992	15,826	15,621	15,961	16,299	16,522	16,788	16,959	17,318	17,653	17,658
Obligation	12,304	12,396	12,810	12,610	12,699	12,791	12,876	13,393	13,403	13,425	13,564
Planning Reserves (14.4%)	1,772	1,785	1,845	1,816	1,829	1,842	1,854	1,929	1,930	1,933	1,953
Obligation + Reserves	14,076	14,181	14,654	14,426	14,528	14,633	14,730	15,321	15,333	15,358	15,518
System Position	917	1,645	967	1,536	1,771	1,888	2,059	1,638	1,985	2,295	2,141
Reserve Margin	**21.8%**	**27.7%**	**21.9%**	**26.6%**	**28.3%**	**29.2%**	**30.4%**	**26.6%**	**29.2%**	**31.5%**	**30.2%**

Table 12.13 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,733	3,733	3,498	3,184	3,014	3,014	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	2,037	1,929	1,836	1,748	1,616	1,456	1,377	1,300	1,226	1,154
Solar	77	104	101	98	95	92	89	86	83	80
Other Renewable	41	39	38	37	35	34	33	31	30	28
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	177	171	167	162	155	150	130	125
Demand Response	139	135	132	129	125	122	119	116	112	109
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,281)	(1,299)	(1,403)	(1,600)	(1,600)	(1,176)	(1,225)	(1,002)
East Existing Resources	**8,062**	**7,890**	**8,104**	**7,749**	**7,379**	**6,841**	**6,748**	**7,083**	**6,931**	**7,070**
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	225	484	691	672	688	666	645
Solar	0	0	0	0	0	0	0	0	0	0
Storage	0	0	90	113	173	821	983	1,003	1,093	1,178
Nuclear	0	0	0	0	0	300	300	300	300	300
Demand Response	0	0	0	73	92	106	106	127	127	157
East Planned Resources	**0**	**0**	**90**	**412**	**750**	**1,920**	**2,063**	**2,120**	**2,188**	**2,283**
East Total Resources	**8,062**	**7,890**	**8,194**	**8,161**	**8,129**	**8,760**	**8,811**	**9,202**	**9,119**	**9,353**
Load	5,724	6,099	6,174	6,448	6,759	6,698	6,869	7,153	7,223	7,397
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(63)	(116)	(174)	(243)	(311)	(385)	(403)	(528)	(613)	(695)
East Total obligation	**5,659**	**5,981**	**5,997**	**6,201**	**6,443**	**6,306**	**6,459**	**6,617**	**6,601**	**6,693**
East Reserve Margin	42.5%	31.9%	36.6%	31.6%	26.2%	38.9%	36.4%	39.1%	38.1%	39.7%
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	61	59	57	54	52	50	47	45	43
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	68	68	60	60	57	56	56	55	55	55
Demand Response	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,281	1,299	1,403	1,600	1,600	1,176	1,225	1,002
West Existing Resources	**3,341**	**3,339**	**3,010**	**3,026**	**3,124**	**3,171**	**3,167**	**2,740**	**2,787**	**2,561**
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	0	64	64	64	112	111	111
Solar	0	0	34	57	55	158	259	340	331	316
Storage	0	0	1,102	1,197	1,180	1,200	1,182	1,538	1,517	1,770
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	6	9	42	44	44	48	49	49	50
West Planned Resources	**0**	**6**	**1,146**	**1,297**	**1,343**	**1,466**	**1,553**	**2,039**	**2,008**	**2,248**
West Total Resources	**3,341**	**3,345**	**4,156**	**4,322**	**4,467**	**4,637**	**4,720**	**4,778**	**4,794**	**4,809**
Load	3,711	3,577	3,676	3,859	4,025	4,478	4,541	4,421	4,477	4,526
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(45)	(79)	(118)	(157)	(199)	(246)	(236)	(328)	(370)	(407)
West Total obligation	**3,665**	**3,498**	**3,558**	**3,701**	**3,825**	**4,230**	**4,303**	**4,091**	**4,105**	**4,117**
West Reserve Margin	-8.8%	-4.4%	16.8%	16.8%	16.8%	9.6%	9.7%	16.8%	16.8%	16.8%
System										
Total Resources	11,404	11,235	12,350	12,484	12,596	13,397	13,531	13,980	13,913	14,161
Obligation	9,324	9,479	9,555	9,902	10,268	10,537	10,762	10,708	10,706	10,810
Planning Reserves (16.8%)	1,566	1,593	1,605	1,663	1,725	1,770	1,808	1,799	1,799	1,816
Obligation + Reserves	10,891	11,072	11,160	11,565	11,993	12,307	12,570	12,507	12,505	12,626
System Position	513	163	1,190	919	604	1,091	960	1,474	1,408	1,536
Reserve Margin	**22.3%**	**18.5%**	**29.3%**	**26.1%**	**22.7%**	**27.2%**	**25.7%**	**30.6%**	**30.0%**	**31.0%**

Table 12.14 – 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	3,015	3,015	3,015
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,082	1,014	948	883	820	674	621	570	522	474	429
Solar	77	74	71	68	66	63	60	57	46	44	41
Other Renewable	27	26	24	8	8	8	7	6	6	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	121	103	98	95	91	87	83	79	75	72	68
Demand Response	106	103	99	96	93	89	86	83	80	76	73
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(911)	(1,183)	(1,390)	(789)	(927)	(938)	(950)	(1,006)	(965)	(865)	(921)
East Existing Resources	**7,078**	**6,712**	**6,426**	**6,936**	**6,725**	**6,558**	**6,481**	**6,365**	**6,339**	**6,375**	**6,265**
Additional Proxy/Short-Term Purcha	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	625	1,530	1,476	1,436	1,383	1,329	1,273	1,286	1,447	1,378	1,311
Solar	0	81	78	75	71	68	65	62	59	55	52
Storage	1,242	1,239	1,234	1,552	2,008	2,312	2,628	2,623	2,880	3,203	3,277
Nuclear	301	301	301	301	301	301	301	301	301	301	302
Demand Response	172	181	189	198	230	241	251	265	294	307	401
East Planned Resources	**2,342**	**3,334**	**3,281**	**3,564**	**3,996**	**4,254**	**4,521**	**4,540**	**4,983**	**5,247**	**5,345**
East Total Resources	**9,420**	**10,046**	**9,707**	**10,500**	**10,721**	**10,812**	**11,001**	**10,905**	**11,322**	**11,622**	**11,610**
Load	7,321	7,508	7,595	7,732	7,856	7,991	8,169	8,340	8,450	8,525	8,664
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(580)	(891)	(834)	(824)	(879)	(926)	(1,042)	(979)	(1,305)	(1,268)	(1,195)
East Total obligation	**6,730**	**6,606**	**6,749**	**6,896**	**6,964**	**7,052**	**7,113**	**7,347**	**7,131**	**7,242**	**7,453**
East Reserve Margin	40.0%	52.1%	43.8%	52.3%	54.0%	53.3%	54.7%	48.4%	58.8%	60.5%	55.8%
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	41	39	36	34	32	30	28	26	24	22	20
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	53	53	52	51	51	50	50	49	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Transfers	911	1,183	1,390	789	927	938	950	1,006	965	865	921
West Existing Resources	**2,467**	**2,736**	**2,940**	**2,336**	**2,471**	**2,480**	**2,489**	**2,542**	**2,499**	**2,397**	**2,451**
Additional Proxy/Short-Term Purcha	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	111	110	110	109	109	109	108	108	107	107	106
Solar	301	349	331	312	294	276	274	254	235	215	195
Storage	1,893	1,865	1,845	2,021	1,997	2,027	2,076	2,412	2,564	2,722	2,685
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	50	50	85	107	108	128	138	141	142	170	175
West Planned Resources	**2,355**	**2,374**	**2,372**	**2,549**	**2,508**	**2,539**	**2,596**	**2,914**	**3,048**	**3,213**	**3,162**
West Total Resources	**4,822**	**5,109**	**5,312**	**4,886**	**4,979**	**5,018**	**5,085**	**5,456**	**5,547**	**5,610**	**5,613**
Load	4,773	4,920	4,989	4,941	5,062	5,136	5,276	5,289	5,398	5,345	5,467
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(642)	(543)	(439)	(755)	(796)	(837)	(919)	(614)	(645)	(538)	(658)
West Total obligation	**4,128**	**4,374**	**4,548**	**4,183**	**4,263**	**4,297**	**4,353**	**4,671**	**4,749**	**4,803**	**4,805**
West Reserve Margin	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
System											
Total Resources	14,241	15,155	15,018	15,386	15,700	15,830	16,086	16,361	16,869	17,232	17,223
Obligation	10,858	10,980	11,297	11,079	11,227	11,348	11,466	12,018	11,880	12,045	12,258
Planning Reserves (16.8%)	1,564	1,581	1,627	1,595	1,617	1,634	1,651	1,731	1,711	1,735	1,765
Obligation + Reserves	12,422	12,561	12,924	12,674	12,843	12,983	13,117	13,749	13,591	13,780	14,023
System Position	1,820	2,594	2,095	2,711	2,857	2,848	2,969	2,612	3,278	3,452	3,200
Reserve Margin	**31.2%**	**38.0%**	**32.9%**	**38.9%**	**39.8%**	**39.5%**	**40.3%**	**36.1%**	**42.0%**	**43.1%**	**40.5%**

Integrated Portfolio Resource Comparisons by Technology and Year

Table 12.15 through Table 12.25 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 12.26 through Table 12.28 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology.

Table 12.15 – 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
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	489	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.16 - 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
MN Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.17 – Renewable Peaking[1]

Study	Cumulative Energy, Gwh																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.18 – 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
MN Base	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239
MR Base	89	89	238	259	266	285	338	329	308	282	265	249	250	239	227	214	210	235	286	271	239
MN - No Coal Post 2032	89	89	238	259	266	281	336	329	303	282	265	248	250	234	220	208	201	232	283	269	240
MN - No CCS	89	89	238	262	270	285	343	329	308	282	270	255	250	234	220	208	202	232	287	272	239
MN - No Nuclear	89	89	238	262	275	289	345	331	308	283	265	252	250	233	227	214	207	235	286	275	239
MN - Offshore Wind	89	89	238	259	270	285	338	329	308	283	265	252	250	233	219	208	207	232	283	271	236
LN Base	89	89	237	257	265	280	334	328	307	281	264	254	249	232	218	206	199	225	276	266	227
HH Base	89	89	244	268	276	291	347	333	312	286	268	268	261	243	229	217	210	235	286	272	240
SC Base	89	89	244	265	272	286	347	333	310	283	265	258	252	240	227	209	210	234	286	271	235

Table 12.19 – 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
MN Base	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144
MR Base	18	40	11	126	43	76	12	39	2	46	16	12	80	80	42	48	48	34	71	43	62
MN - No Coal Post 2032	18	40	11	141	32	60	47	27	2	46	16	12	66	84	42	48	48	34	71	62	43
MN - No CCS	18	40	11	139	38	81	13	36	2	46	24	12	66	76	45	48	60	68	23	153	53
MN - No Nuclear	18	40	19	126	53	94	23	21	18	39	16	1	136	28	42	77	23	29	72	62	144
MN - Offshore Wind	18	40	23	135	38	49	7	37	18	30	24	1	136	47	42	72	24	28	79	61	43
LN Base	18	40	25	138	53	34	13	36	18	31	16	21	85	76	43	50	46	33	72	118	88
HH Base	18	40	23	134	45	34	13	36	2	50	16	12	105	25	39	104	50	19	81	28	65
SC Base	18	40	13	27	115	21	82	26	2	46	16	1	32	91	94	30	67	27	77	27	40

Table 12.20 – 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
MN Base	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	1,417	594	-	-	451	-	-	3	2,954	187	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	1,077	594	153	78	350	-	-	2	3,132	178	-	-	-	-	-	-	-	-
MN - No CCS	-	-	439	970	602	-	-	-	-	-	273	2,634	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	422	834	-	-	412	-	-	199	1,374	616	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	452	792	-	200	-	41	-	270	864	1,126	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	594	-	-	-	-	-	3	3,015	-	-	-	-	-	-	-	-	-
HH Base	-	-	1,187	721	975	233	-	451	-	-	3	2,492	-	-	-	-	-	-	-	-	-
SC Base	-	-	1,417	-	594	-	-	451	-	-	297	3,236	152	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.21 – 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
MN Base	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-
MR Base	-	-	-	-	-	745	-	60	52	-	-	300	98	9	9	-	-	552	28	414	40
MN - No Coal Post 2032	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660
MN - No CCS	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660
MN - No Nuclear	-	-	-	-	-	246	7	-	-	-	21	207	111	17	9	-	-	-	-	105	211
MN - Offshore Wind	-	-	-	-	-	113	-	-	-	-	-	-	-	-	-	-	-	79	1	-	-
LN Base	-	-	-	-	500	349	34	26	-	29	29	29	41	33	9	109	-	-	-	194	660
HH Base	-	-	-	-	133	876	89	-	-	-	14	172	76	75	49	-	402	486	120	125	37
SC Base	-	-	20	-	302	616	35	89	1	-	8	215	32	103	119	-	-	875	92	-	454

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.22 – 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
MN Base	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-
MR Base	-	-	137	107	-	505	794	1,081	522	1	-	2,736	2	406	-	-	237	-	-	-	-
MN - No Coal Post 2032	-	-	245	182	-	848	896	805	87	5	480	4,291	4	-	-	-	237	-	-	-	-
MN - No CCS	-	-	245	182	-	848	896	805	567	5	-	4,291	2	-	-	-	237	-	-	-	-
MN - No Nuclear	-	-	290	237	-	44	181	451	521	2	2,079	2,103	4	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	297	101	-	385	411	634	521	4	-	405	4	-	-	670	-	-	393	-	-
LN Base	-	-	136	317	49	683	985	452	522	300	105	1	4	6	-	-	231	-	-	-	-
HH Base	-	-	419	411	-	546	2,865	452	4	1	-	2,648	800	406	-	-	237	-	-	-	-
SC Base	-	-	336	500	-	281	1,156	415	55	1	66	3,363	1,584	564	139	-	237	793	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.23 – 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
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	61	-	110	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	591	-	1	26	17	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	731	55	72	-	-	3	165	54	8	9	-	-	-	-	-	244
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,121
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	156

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.24 – Battery Storage [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
MN Base	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15
MR Base	-	520	1,135	26	181	390	108	537	37	197	277	-	176	341	73	81	79	651	589	639	15
MN - No Coal Post 2032	-	520	1,297	116	-	19	4	639	12	71	365	-	56	602	220	422	128	227	242	411	17
MN - No CCS	-	520	1,297	16	43	19	4	464	14	242	389	-	438	417	65	488	214	214	355	592	15
MN - No Nuclear	-	520	734	124	318	879	110	317	15	309	148	-	-	314	14	861	174	95	108	43	96
MN - Offshore Wind	-	520	1,360	328	220	558	140	69	122	118	47	-	-	127	10	1,067	322	405	313	244	15
LN Base	-	520	1,235	160	3	-	-	401	6	242	546	156	368	245	412	863	211	456	380	851	9
HH Base	-	520	1,133	66	108	347	141	452	141	12	200	-	74	50	12	193	136	505	399	276	34
SC Base	-	520	1,011	98	-	708	2	592	91	14	181	-	13	313	307	94	393	41	370	695	139

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.25 – Long Duration Storage [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
MN Base	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80
MR Base	-	-	-	-	-	378	-	-	-	-	-	-	-	60	167	496	261	50	108	71	-
MN - No Coal Post 2032	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80
MN - No CCS	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80
MN - No Nuclear	-	-	251	109	-	123	249	97	-	258	126	-	36	152	120	277	229	246	160	104	33
MN - Offshore Wind	-	-	45	15	79	166	-	31	-	339	178	-	-	382	675	305	206	274	327	362	122
LN Base	-	-	93	-	2	803	151	66	102	58	-	-	-	58	94	554	89	109	257	345	23
HH Base	-	-	-	-	-	243	-	-	-	86	131	-	274	375	106	555	-	-	135	346	90
SC Base	-	-	-	-	-	197	-	-	-	103	78	-	24	-	14	399	130	469	373	108	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.26 – 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
MN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Negative values indicate retirement of coal capacity.

Table 12.27 – 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
MN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(264)
HH Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 12.28 – 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
MN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	357	-	-	205	2,397	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	357	-	-	205	3,097	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 9 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. As a consequence, 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.

Table 12.29 – Preferred Portfolio Variant Studies

Variant	Description
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 gas convert by January 1, 2032
Offshore Wind	Counterfactual to the Preferred Portfolio selection
All Coal End of Life	Current coal units cannot gas convert OR select CCS
No New Gas	Proxy gas plants are not eligible for selection
Force All Gas Conversions	All coal plants that can gas convert, must
No Forward Technology	Nuclear, Hydrogen and Biodiesel units are not eligible

Table 12.30 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.

Table 12.30 – Initial and Variant Cases Under Medium Gas/ Zero CO_2

	ST Value			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base MN	22,930	0	1	220,325	66,013	5
Integrated No Coal Post 2032 MN	23,844	914	4	154,979	668	2
Integrated No CCS MN	23,199	269	3	218,003	63,691	4
Integrated Offshore Wind MN	29,231	6,301	6	216,728	62,417	3
Integrated No Nuclear MN	24,295	1,365	5	239,932	85,621	6
Integrated Base MR	22,985	55	2	154,311	0	1

Table 12.31 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 12.31 – Initial and Variant Cases Under Low Gas/ Zero CO_2

Case - LN	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base LN**						
Integrated Base MN	20,981	101	2	215,698	38,760	5
Integrated No Coal Post 2032 MN	21,598	718	4	178,027	1,089	2
Integrated No CCS MN	21,470	589	3	204,546	27,608	3
Integrated Offshore Wind MN	27,395	6,515	6	208,244	31,305	4
Integrated No Nuclear MN	22,085	1,205	5	235,603	58,664	6
Integrated Base MR	20,880	0	1	176,938	0	1

**The Integrated LN Base case was not able to be evaluated in ST prior to publishing the draft. The comparative data for this table will be provided prior to final publication.

Table 12.32 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. Summarized results include energy shortfalls and emissions metrics.

Table 12.32 – Initial and Variant Cases Under High Gas/ High CO_2

Case - HH	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	25,554	0	1	121,431	0	1
Integrated Base MN	27,549	1,995	5	141,740	20,308	6
Integrated No Coal Post 2032 MN	27,315	1,760	3	129,468	8,037	2
Integrated No CCS MN	27,351	1,797	4	132,543	11,111	4
Integrated Offshore Wind MN	33,701	8,146	7	140,389	18,957	5
Integrated No Nuclear MN	29,601	4,047	6	147,714	26,283	7
Integrated Base MR	26,776	1,222	2	130,846	9,414	2

Table 12.33 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. Summarized results include energy shortfalls and emissions metrics.

Table 12.33 – Initial and Variant Cases 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, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base SC	29,603	0	1	61,102	0	1
Integrated Base MN	30,766	1,163	3	68,506	7,404	5
Integrated No Coal Post 2032 MN	30,773	1,170	4	62,173	1,071	3
Integrated No CCS MN	30,665	1,062	2	61,948	847	2
Integrated Offshore Wind MN	36,933	7,330	6	66,925	5,823	4
Integrated No Nuclear MN	32,606	3,003	5	71,961	10,859	6

Initial and Variant Cases Under Medium Gas/ Federal Regulation (MR)

The only variant cases which would be compliant under the current language in EPA 111(d) are the MR case and the No Coal Post 2032 case. The Base MR portfolio is $807 million less in PVRR than the No Coal Post 2032 portfolio when dispatched under the MR gas and market pricing structure. CO_2 emissions are 972 tons higher in the Base MR portfolio than the No Coal post 2032 portfolio.

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 not to be commercially viable at these locations.

Figure 12.15 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. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Given the lower capacity factor of coal plants without CCS, additional resources are needed over the course of the horizon to generate enough energy to meet retail demand. This results in 1,447 MW of additional wind, 2,588 MW of additional solar and 1,420 MW of additional storage as compared to the integrated MN view.

Figure 12.13 - Increase/(Decrease) in Proxy Resources with No CCS

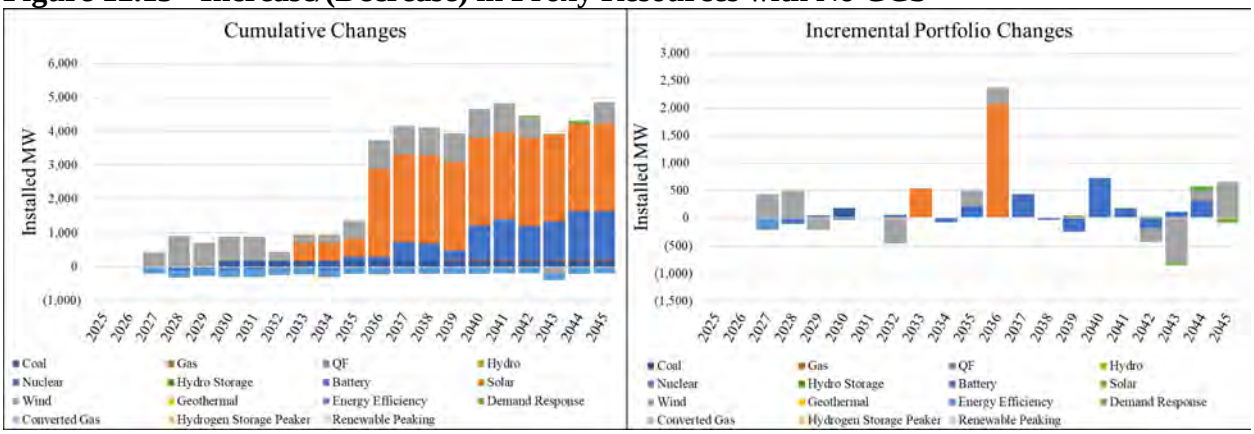
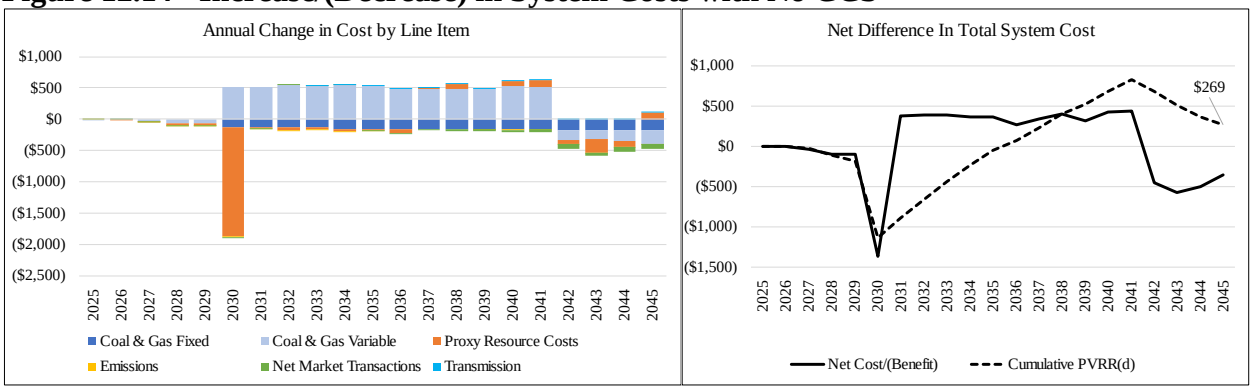


Figure 12.16 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and 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 $269 million 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 12.14 - 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 2030. Additionally, this variant does not allow any other nuclear to be selected as a potential replacement of the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the Natrium™ demonstration or other nuclear project prove not to be commercially viable.

Figure 12.17 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. Given the currently selected nuclear siting at Naughton, overall portfolio changes are somewhat smaller than

in cases where significant coal changes are tested. The variant case selects 40 MW of new gas peaking resources, an additional 468 MW of energy efficiency, 998 fewer MW of wind which is offset by 1,293 additional MW of solar. Finally, an additional 81 MW of storage is selected.

Figure 12.15 - Increase/(Decrease) in Proxy Resources with No Nuclear

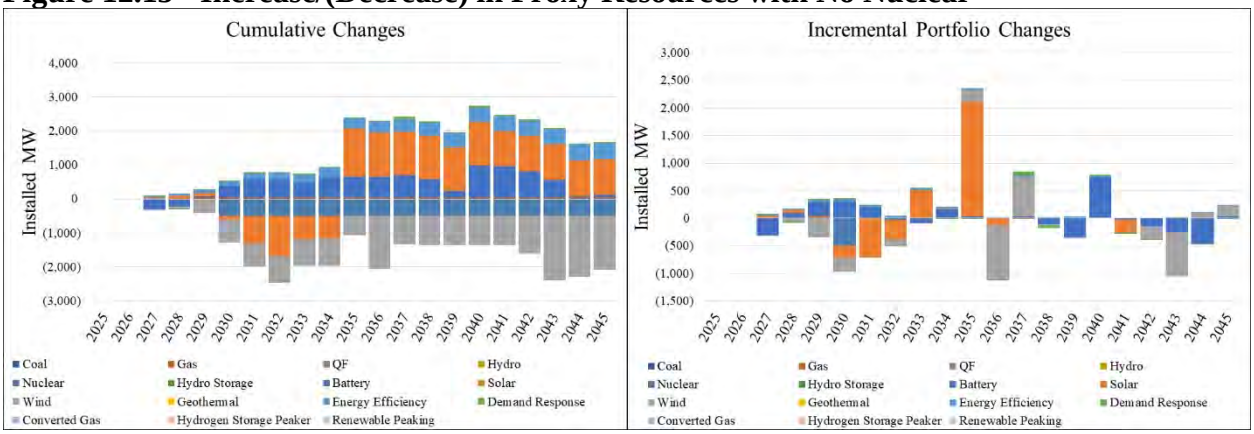
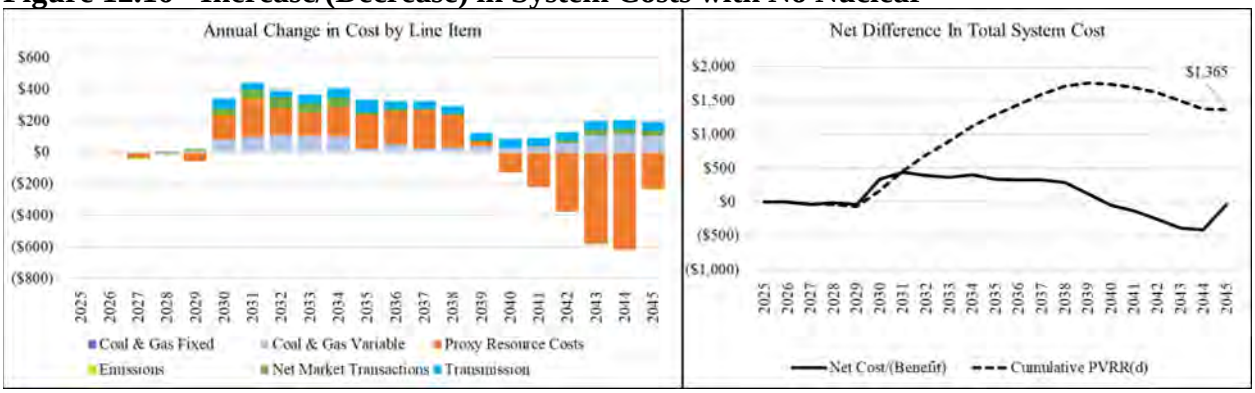


Figure 12.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid 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 $1.365 billion increase in costs compared to the preferred portfolio.

As seen in Figure 12.18 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 12.16 - 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.

Figure 12.19 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 new gas peaking resources whereas the integrated MN view does not. Additionally, more solar and wind is selected in the variant, and less long duration storage is partially offset by additional 4-hour storage.

Figure 12.17 - Increase/(Decrease) in Proxy Resources with No Coal Post 2032

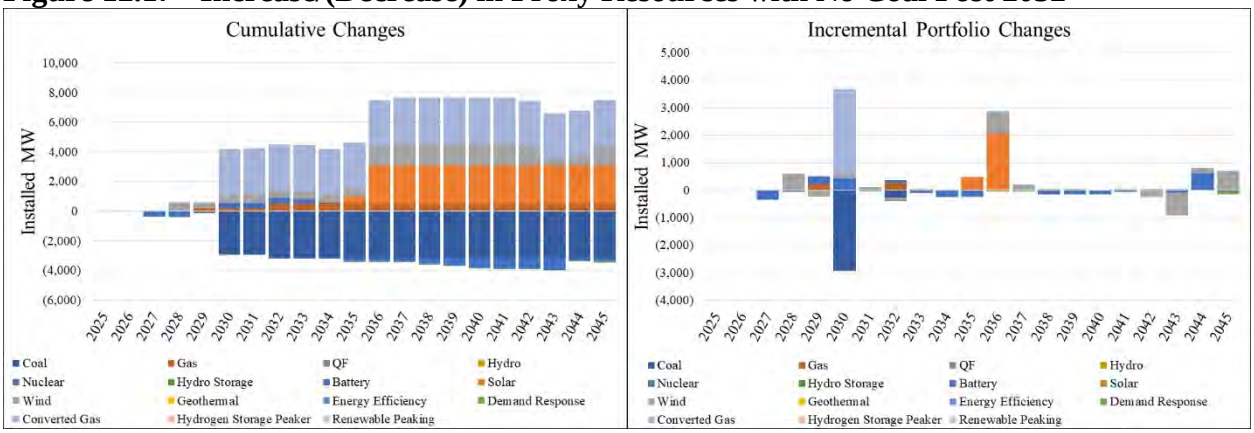
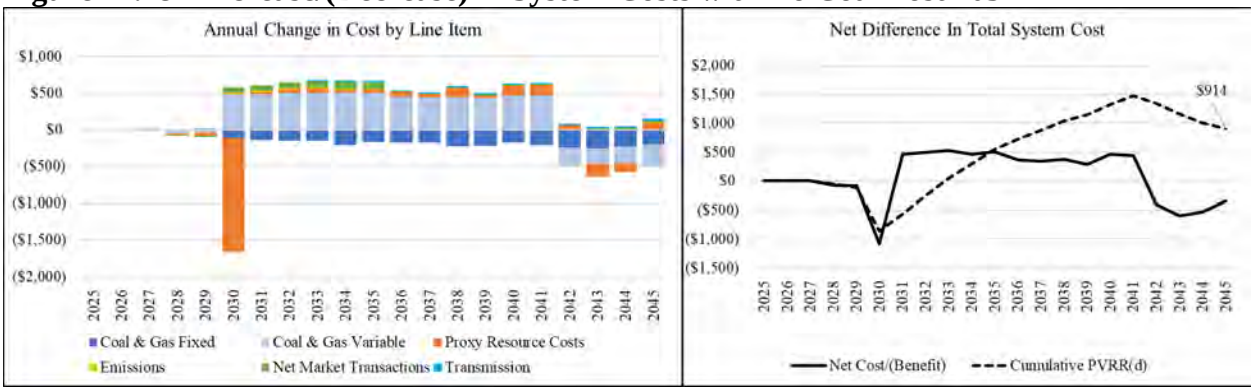


Figure 12.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the 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 gas converted by 2032, the resulting portfolio has a $914 million increase in costs compared to the preferred portfolio.

As seen in Figure 12.20 below, like in the No CCS case, the loss of 45Q tax credits more than offsets the reduced capital cost to install CCS. Additionally, this case has higher levels of market purchases, and additionally has higher proxy resource costs in nearly all years of the study horizon.

Figure 12.18 - 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 12.21 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio 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 higher capacity factor of the offshore wind resource results in 300 MW less utility scale wind being selected in the portfolio compared to the preferred portfolio. Additionally, the portfolio has 1,669 MW less utility scale solar. Less small-scale wind is offset by more small scale solar. For capacity and reliability needs, 1,824 more MW of storage is selected in the offshore wind case, 1,603 MW of which is 4-hour storage. Retirements are the same between the studies.

Figure 12.19 - Increase/(Decrease) in Proxy Resources with Offshore Wind

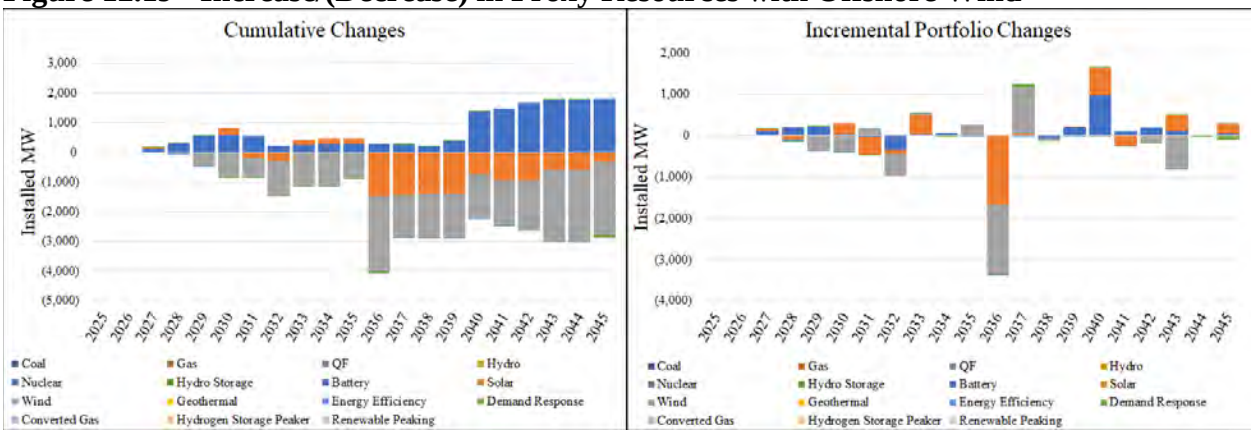
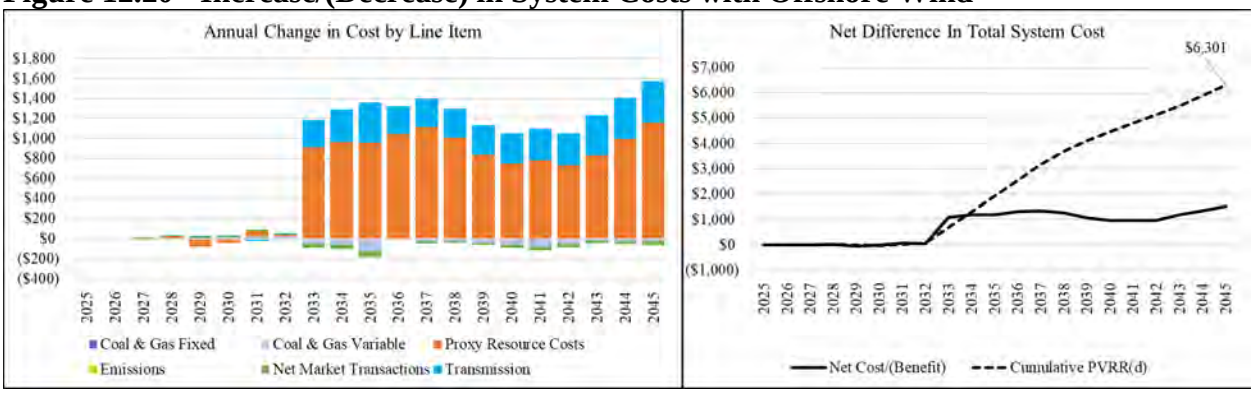


Figure 12.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total 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 $6.301 billion increase in costs compared to the preferred portfolio.

As seen in Figure 12.22 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 12.20 - Increase/(Decrease) in System Costs with Offshore Wind



CHAPTER 13 – UTAH ACTION PLAN

ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

CHAPTER HIGHLIGHTS

- The Utah 2025 Integrated Resource Plan (IRP) action plan identifies steps, determined when the analysis was conducted, that PacifiCorp would pursue over the next two-to-four years to deliver resources aligned with the Utah preferred portfolio.
- PacifiCorp's Utah 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).[2]
- 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 Utah 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 Utah 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

[1] https://pscdocs.utah.gov/electric/23docs/2303510/3356352303510o9-24-2024.pdf

[2] 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).

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 Utah 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.

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 Utah 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the Utah 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 Utah 2025 IRP Action Plan

The Utah 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 2021 IRP action items by resource category.

Table 10.1 – Utah 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 Utah 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 Oregon Public Utility Commission 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 Utah 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 issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] • In light of the differentiated resource needs by jurisdiction identified in the Utah 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

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.

[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 (Oregon Public Utilities Commission)

Action Item	4. Demand-Side Management (DSM) Actions
4a	**Energy Efficiency 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. • PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year.

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 will 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 Utah 2025 IRP action plan. The status for all action items from the Utah 2025 IRP is summarized in Table 10.2.

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 the 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 the second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp 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 Oregon Public Utility Commission 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.	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the 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.	• 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.

	• 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.	
Action Item	**2. New Resource Actions**	**Status**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024.
2b	**<u>2025 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025	The Utah 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term.

	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 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 the 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.	• 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.

	• 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 the final shortlist. PacifiCorp will file 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.	• 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 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	**Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):** • 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	**Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
3c	**Boardman-to-Hemingway (500 kV transmission line):** • 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.	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 to participate in "pre-construction" activities in support of the 2026-2027 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

Action Item	4. **Demand-Side Management (DSM) Actions**	Status
4a	**<u>Energy Efficiency Targets:</u>** PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.	• PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and is on track to achieve its 2024 Class 2 DSM target. • PacifiCorp has launched a number of new demand response programs in 2022 and 2023. Additionally, the company is currently expanding its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023 incremental

		capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs.
Action Item	5. **Market Purchases**	**Status**
5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

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 Utah 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 Utah 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 Utah 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the Utah 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, 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."[4] 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.

[4] 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.

A full acquisition path analysis relevant to all jurisdictions is presented the Chapter 10 (Action Plan), Table 10.3.

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 and resilient grid operations. 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, 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 PacifiCorp's entire resource procurement strategy.

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 of 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 Utah 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.

Resource Procurement Strategy

To acquire resources outlined in the 2023 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. 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 such as 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 2023 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFP 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, define 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[5]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on the 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 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.

[5] 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.

Small Scale Renewable Energy Supply

In order to fulfill Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by 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 addressed in PacifiCorp's 2023 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. While the level of imputation associated with long-term contracts is expected to be lower than the debt associated with owned resources, it still may affect 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 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.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit HH: SPP, *SPP Reliability Plan* (Jun 2, 2025)

SPP RELIABILITY PLAN

0820EXT00108

Business Owner: Derek Hawkins
Effective: 06/02/2025
Revised: 06/2/2025
Version: 8.0

Approved By:	Brian Strickland	Digitally signed by Brian Strickland Date: 2025.06.11 13:41:29 -05'00'
SME Signature (Brian Strickland)		Date

Approved By:	Derek Hawkins	Digitally signed by Derek Hawkins Date: 2025.06.11 13:42:26 -05'00'
Business Owner Signature		Date

Revision History

Author	Version	Revision Date	Effective Date	Description
ORWG	1.0	6/1/05		Complete re-write to align with revised NERC Policy 9 as approved by NERC 06/15/04.
		6/15/05		Per NERC ORS request, removed Appendix B – Reliability Assessment Process and Procedure.
		1/11/06		Added CLECO to the plan.
		1/26/06		Added Constellation Balancing Authorities BCA, CNWY, DENL, DERS, PUPP, and WMUC to the plan.
		1/27/06		Updated to reflect changes in SPP processes and procedures after the SPP EIS Market is implemented.
		2/9/06		Made necessary changes to conform with NERC functional model terminology present in existing reliability standards.
		9/8/06		Added LAGN to the plan with an effective date of November 1, 2006
		12/5/06		Added Constellation Balancing Authority BUBA
		1/1/09		Changes consistent with Criteria 12.3. Corrected Batesville Generating Station acronym from BCA to BBA. Added Missouri Public Service (MPS) to footprint.
		4/1/09		Added Nebraska entities – LES, NPPD and OPPD
		10/1/09		Added Constellation Balancing Authorities OMLP and PLUM
		4/1/10		DENL Balancing Authority moved from operation by Constellation to operation by NRG and changing DENL to NLR
		1/1/11		CNWY and WMUC Balancing Authority moved from operation by Constellation to operation by NRG and changed from CNWY to CWAY and from WMUC to WMU
		2-15-11		City Utilities of Springfield (SPRM) becoming a stand-alone Balancing Authority Areas instead of a TOP imbedded inside the SPA Balancing Authority Areas.
		4/11/12		Added Brazos Electric to list of Balancing Authorities. Updated map to reflect addition. Changed “OPS1” application in reference to outage scheduling to “CROW” application reference. Clarified the RTCA and monitored elements by voltage in sections C.4. and E1. Noted the primary and BUCC location changes in 2012 in section I.

Author	Version	Revision Date	Effective Date	Description
		6/1/13		Transferred the southern reliability members from SPP to MISO (with exception of the CECD entities) per Entergy move to MISO
		12/19/13		Removal of the CECD entities from the SPP Reliability footprint. Changed cover page date to Dec 19, 2013.
		3/1/14		Replaced "EIS" with "Integrated", removed OPS1 references, replaced PowerWorld with E-terravision, removed member map, and changed list of BA/TOPs to reflect new consolidated BA (SPP BA).
		6/1/15		Added the IS entities of WAPA, Corn Belt to the TOP list within the Introduction and the SPP Reliability Areas. Changed WECC references to PEAK Reliability.
	2.0	4/21/16		Changes made due to overall review, and to correct studies, update tools, Operating Criteria changes, DC tie additions, reduce redundancy of sections and Market constraint management.
Terry Oxandale	3.0	4/30/2019	4/30/2019	Modified for SPP RC for Western Interconnect effective 12/3/2019. Added changes in RE, additional TOPs in Appendix A, and included aspects of the Western Interconnect not included in the current Eastern Interconnect practices. Converted to current template and assigned new Operations document ID 0820PCS00108.
Brian Strickland, Derek Hawkins	3.1	11/20/2019	11/20/2019	Updated with additional information on loss of necessary applications, weather, Cyber Attack, and SPS/RAS. Updated AZPS (under CAISO RC) to AEPC (under SPP RC). Updated for clarifications per RCRT review. Deleted Gila River Power (GRMA) from Appendix A table being they are not a TOP per Bryan Wood.
Brian Strickland, Yasser Bahbaz	3.2	2/10/2021	4/1/2021	Added GRID effective 4/1/2021 to "BAs and TOPs in SPP RC Areas" section in Appendix A. Also updated file name of documents referenced in Appendix B.
Brian Strickland	4.0	1/07/2022		Added language to GMD to address monitor responsibilities and added a section on voltage. Changed business owner and SME per B. Wood.
Julie Gerush, Brian Strickland	5.0	04/12/2023	04/12/2023	Comments addressed from Operations review. Changes to accommodate changes to IDC. Updated cover pages.

Author	Version	Revision Date	Effective Date	Description
Heather Harris, Brian Strickland	6.0	04/01/2024	04/01/2024	Removed Appendix B (RC Related procedures), updated to identify no delegation of task or actions requested for adjacent RCs, minor language changes to mirror requirement language. Removed GRIF under entities due to merger with GRID. Added language for SOL/IROL communication and general cleanup Changed document ID.
Hayden Johnson	7.0	01/31/2025	02/01/2025	Added First Light Energy (BNBA) to the list of BAs/TOPs in the Appendix.
Hayden Johnson	8.0	06/02/2025	06/02/2025	Removed New Harquahala Generation Station (HGMA) from the list of BAs/TOPs in the Appendix.

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Introduction

The North American Electric Reliability Corporation (NERC) delegates its authority to monitor and enforce compliance with NERC Reliability Standards to the Regional Entities (RE). The RE carries out their reliability activities with the Registered Entities for their reliability region. Southwest Power Pool (SPP) is recognized as the Reliability Coordinator (RC) for all Transmission Operators (TOPs) and Balancing Authorities (BAs), listed in **Appendix A**, in both the Eastern and Western Interconnections.

SPP RC is responsible for the bulk transmission reliability and power supply reliability within its RC Areas. Bulk transmission reliability functions include assessment of real-time and next day operating conditions, congestion management, coordination of transmission and generation outages and instructing curtailment of transactions and/or load. SPP RCs use a risk-based approach to communicating actual and potential SOL exceedances with impacted TOPs, as described in SPP's Reliability Coordinator Area System Operating Limit Methodology and Reliability Coordinator Area System Operating Limit Methodology Western Interconnection. Power supply reliability entails monitoring BA Areas performance and coordinating BAs and TOPs actions, including instructions, for load curtailment, generation and transmission actions, and adjustments to voltage schedules in situations where the system is in jeopardy. SPP RC procedures and policies are consistent with those of NERC.

Operating agreements are in place to facilitate communication, notification, exchange of information, and coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.

SPP RC communication mediums include phone, the SPP Reliability Communications Tool (R-Comm), the Reliability Coordinator Information System (RCIS), email, NERC Hotline, cellular phones, satellite phones, etc.

NOTE: Unless explicitly defined, any reference to "RC" is applicable to both East and West.

A. Responsibility and Authority

1. SPP has a wide-area view, operating tools, processes, procedures, authority and responsibility for the reliable operation of the Bulk Electric System (BES) within the SPP RC Areas in accordance with NERC Reliability Standards including applicable regional variances, the SPP Membership Agreement, SPP Required Data Specification (RDS), and SPP Reliability Customer agreements. These executed agreements are posted on the SPP website under SPP Documents & Filings/Governing.

    1.1. The SPP RC has a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and

real-time conditions. More details are provided in appropriate sections of this document.

1.2. The executed agreements give the SPP RC clear decision-making authority to act and instruct actions to be taken by the SPP RC Members and Reliability Customers to preserve the integrity and reliability of the BES. SPP's responsibilities and authorities, as well as its RC members' and customers' responsibilities are clearly defined in SPP's governing documentation.

2. SPP acts first and foremost in the best interest of the BES before that of any other entity. This expectation is clearly identified in the SPP Membership and Reliability Customer agreements, and in the job description of the SPP personnel acting in the role of the RC.

3. Per the SPP RC Member and Reliability Customer agreements, the BAs, TOPs, and other operating entities in the SPP RC Areas (i.e. West and East RC Areas) shall carry out required emergency actions as instructed by the SPP RC, including the shedding of firm load if required, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. In those cases, SPP RC Members or Reliability Customers must immediately inform the SPP RC of the inability to perform the operating instruction.

4. Weather-related event is to be determined in advance, based on weather evaluations, storm information, next day studies, etc., for action to be taken by SPP RC as necessary. The evaluation and coordination of analysis information may lead to issuing a Weather Advisory or Conservative Operations. In a coordinated effort, SPP has a process to exchange information related to weather events where SPP or a portion of SPP expects temperatures at a level that is of concern, or where tornado, ice storm, or high wind might be forecasted. Weather Advisories may be issued to prepare personnel and facilities for expected extreme weather conditions.

   4.1 For the Western Interconnection, SPP has a process to exchange information related to potential reliability impacted weather events, including utilizing R-Comm, emails, satellite phones, etc.

5. SPP Information Technology (IT) group maintains an awareness and level of protection from Cyber Attacks. SPP IT group has a process to determine if and when notifications should be made to Operations staff to increase awareness of potential cyber activities. In the event that Operations suspects or detects a Cyber Attack first, they will follow the process in accordance with the SPP Sabotage Procedure to notify the necessary parties.

6. In the event of the loss of a necessary application, SPP shall notify neighboring RCs, BAs, and TOPs to monitor the SPP RC Areas footprint when necessary.

B. Responsibilities – Delegation of Tasks

The SPP RC has not delegated any RC tasks. Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

C. Common Tasks for Next Day Operations

1. SPP coordinates operations and ensures reliable operation of the BES by utilizing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) during the real-time and next day operating horizons for the SPP RC Areas including additional thermal, voltage and stability-related analysis as necessary. SPP will communicate and coordinate the results of its reliability assessments with those performed by the SPP RC Members and Reliability Customers, to ensure that any potential or actual SOL exceedances are properly identified and reported. SPP models a sufficient wide-area view to ensure properly coordinated operations with neighboring RCs. SPP will share its Operational Planning Analysis (OPA) via its secure FTP site.

2. SPP is responsible for determination of IROLs within the SPP RC Areas, and does so via documented methodologies. As part of the daily OPA and/or RTA, SPP highlights additional potential SOLs. That list of potential SOLs and the existing list of SOLs are screened for potential IROL criteria. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in cascading outages or widespread voltage problems, unless there are studies or system knowledge that the SOL is not an IROL. Additionally, when temporary constraints are defined for various operating circumstances identified through OPA and/or RTA, this process is performed to verify if an IROL exists. SPP disseminates IROL information within its RC Areas and with neighboring RCs.

3. SPP ensures that SPP RC Members and Reliability Customers operate to prevent the likelihood that a disturbance, action or non-action in the SPP RC Areas will result in an SOL or IROL exceedance in another entity of the Interconnection. SPP's RC Members and Reliability Customers are required to adhere to NERC Reliability Standards. SPP is required by its seams agreements with its neighbors to coordinate maintenance outages in such a way that impacts on the other systems' reliability are minimized. SPP performs OPA on a daily basis for the next day. If a potential SOL or IROL exceedance is observed on a neighboring party's system, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan, if one does not already exist. In instances where there are differences in operating limits derived by SPP and its neighbors or between SPP entities, SPP will operate to the most conservative result until the reasons for these differences can be identified and an agreement is reached.

4. SPP ensures that its RC Members and Reliability Customers are always operating under known and studied conditions and ensures that they reassess and re-posture their systems following contingency events within 30 minutes. SPP performs next day OPA pursuant to the Reliability Assessment Process Overview. These analyses are performed for each day. These analysis model peak conditions for the day being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. SPP performs an N-1 contingency analysis monitoring the post-contingency flow of both SPP and neighboring system facilities. If a potential SOL or IROL exceedance is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan if one does not already exist.

   SPP performs a next-day assessment of capacity and adequacy for each hour of the day, as well as a next-hour assessment of capacity and adequacy on an hourly basis. These analyses model peak conditions for the day/hour being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. If a capacity issue is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan.

   SPP monitors, in real-time, all facilities considered critical. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at the facility ratings, SOL and IROL levels. SPP tracks real-time and applicable post-contingency flows on all constraints and alarms when applicable SOLs and IROLs are approaching the limit or are exceeded. Additionally, when any identified IROL is exceeded in real-time, an email notification of the exceedance is sent to operations management and engineering staff to initiate post-event analysis.

   SPP also uses a State-Estimator solution to run its Real-Time Contingency Analysis (RTCA) application at least every 6 minutes. SPP has defined all branches and transformers with low side voltages of 115 kV and higher (with some 69kV) within the SPP RC Areas and all branches and transformers with low side voltages of 230 kV and higher within the first-tier BA Areas as contingencies in RTCA. SPP monitors the post-contingency flow on all SPP branches and transformers with low side voltages of 115kV and higher. Alarms are triggered if that flow exceeds the emergency rating of the branch or transformer. Additionally, SPP monitors post-contingency flow on all branches and transformers with low side voltages of 230 kV and higher within neighboring systems as well as selected lower voltage facilities within neighboring systems that are known to be impacted by an SPP contingency. The RC receives alarms for any RTCA exceedance.

5. The SPP RTO acts as the Transmission Service Provider (TSP) for all Transmission Owners in the Eastern Interconnection, subject to the SPP Tariff. For these entities,

SPP uses Flowgates as proxies for transmission limitations in the determination of ATC. The same Flowgates monitored in real-time by the SPP RC and their associated SOLs are also incorporated in the models used by SPP to calculate ATC and administer its OATT. SPP limits sales of transmission service to the SOLs of all identified Flowgates. When a need for a new Flowgate is determined by the SPP RC, the new Flowgate is included in the models used by the SPP TSP for calculation of ATC. These Flowgates are posted on the SPP OASIS.

5.1 SPP is not the TSP in the Western Interconnection, with the exception of WAUW.

6. SPP communicates reliability Operating Instructions in a clear, concise, and definitive manner. Per SPP RC procedures, the SPP RC requires the recipient to repeat back any reliability Operating Instructions communicated by the SPP RC. Proper communications protocols are included in Operator training provided by SPP.

D. Next Day Operations

1. SPP performs an OPA to identify potential SOL and IROL exceedances pursuant to the Daily Reliability Assessment Procedure. These analyses are performed daily with the exception of the weekend and holiday analyses being performed on the previous Friday, or day prior to the holiday. SPP's day-ahead reliability assessment consists of off-line PSS/E studies of the modeled system conducted by the Operations Engineering staff. Contingency-based analyses are conducted daily, which include Remedial Action Schemes (RAS). In these contingency analyses, at a minimum, SPP includes BES facilities in SPP and first-tier area above 100 kV as contingencies, and monitors facilities above 100 kV. SPP will include other facilities identified with impact to BES or with significant risk to the BES. SPP also runs a 7-day contingency analysis to review upcoming operating conditions over the next week for the Eastern Interconnection. Planned transmission and generation outages within the SPP RC Areas are coordinated with adjacent RCs. Outages external to the SPP RC Areas are obtained from neighboring RCs. Peak conditions are modeled using anticipated generation dispatch to support the forecasted load plus expected scheduled net interchange.

    1.1 If, in the next day OPA, parallel flows from the SPP RC Areas are observed as causing a potential problem on a neighboring system, SPP will contact the neighboring RC and coordinate to determine if the problem could result in an SOL or IROL exceedance. If it is agreed that an exceedance could occur, SPP will coordinate with the neighboring RC to develop an appropriate mitigation plan, if one does not already exist. The mitigation plan will identify appropriate actions to be taken to prevent the exceedance from materializing which may include creation of appropriate constraints to be monitored, commitment of appropriate generation capacity, reconfiguration of the transmission system, or re-dispatch of generation as well as actions to be taken in the event the

exceedance materializes in real-time, including identifying potential transmission system reconfigurations, generation that can be re-dispatched, schedules that can be curtailed, and, if necessary, load that can be shed.

2. SPP receives operating information, such as transmission and generation facility maintenance schedules, tap settings, and generation resource plans, required for performing an OPA from responsible SPP RC Members and Reliability Customers. The applicable SPP RDS requires SPP RC Members and Reliability Customers to submit the necessary data to SPP. SPP receives similar information from its neighbors. SPP uses load forecast, generation forecast, and/or tag data as its basis for incorporating Interchange Transactions into the OPA.

3. SPP shares the results of its OPA, when conditions warrant, or upon request, with other RCs. SPP also posts the results of its analyses via its secured FTP site for appropriate SPP RC Members, Reliability Customers, and neighboring RCs. If the results of the OPA indicate potential reliability problems and efforts outlined in (4.) below do not resolve the potential condition, the SPP RC issues the appropriate alerts via the RCIS.

4. The SPP RC initiates conference calls, or other appropriate communications, such as R-Comm, as necessary when conditions revealed by the OPA warrant. Conditions that warrant communications with other RCs include potential IROL exceedances determined as described in part 1.1 of this section and capacity deficiencies that could result in shedding of firm load.

E. Current Day Operations

1. SPP monitors facilities within the SPP RC Areas and adjacent RC Areas to ensure determination of potential SOL and IROL exceedances.

   1.1 SPP will make reasonable efforts to provide notice to a neighboring RC if SPP identifies a potential reliability problem in that RC's Areas. If both parties agree that a reliability problem exists, SPP will coordinate with its neighboring RCs any actions required to mitigate the situation. In the event that all parties cannot agree on the reliability issue, SPP will follow the most conservative approach. This coordination may include evaluation of the impact of maintenance and forced outages on the situation, implementation of existing emergency procedures or operating guides, reconfiguration of the transmission system, curtailment of point-to-point transactions, re-dispatch of generation, and load shedding.

2. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at both SOL and applicable IROL levels. SPP uses constraint monitoring applications that track post-contingency flows on all constraints and alarms as applicable SOLs

and IROLs are approached and/or exceeded. Post-contingency flows on constraints are calculated using real-time flows and Line Outage Distribution Factors (LODFs) that are updated to reflect current system topography.

3. SPP monitors the necessary RC Area's parameters to ensure it is continuously aware of conditions within the SPP RC Areas.

   3.1. SPP monitors the status of BES elements using an EMS complete with State Estimator, Alarming, Real-Time Contingency Analysis, and Power Flow applications. SPP receives the data necessary to maintain the EMS from its RC Members and Reliability Customers in accordance with applicable SPP RDS.

   3.2. The SPP EMS model represents the SPP RC Areas, neighboring BA Areas and other portions of the Eastern and Western Interconnection. For the Eastern Interconnection, SPP's RC Area represents approximately one-third of the SPP EMS network model of Eastern Interconnection facilities. The EMS uses near real-time measurements received from these same entities via ICCP.

      3.2.1. For the Western Interconnection, SPP maintains a full model referenced from the Western Interconnection-wide Model (WIM) consistent with the Western Interconnection Modeling and Monitoring Methodology.

   3.3. SPP monitors, in real-time, pre-contingent and anticipated post-contingent element conditions. This is achieved through the EMS and constraint monitoring tools which utilize real-time Line Outage Distribution Factors based on the latest system topology.

   3.4. SPP monitors real-time flows and statuses of facilities 100 kV and above and select lower voltage facilities in the Eastern Interconnection. Contingencies of facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are studied. The post-contingent flow on facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are monitored.

      3.4.1. For the Western Interconnection, the monitoring of facilities is consistent with the Western Interconnection Modeling and Monitoring Methodology agreed upon according to applicable NERC standards.

   3.5. SPP monitors real and reactive reserves. SPP receives real-time operating reserves data from its RC Members and Reliability Customers, and compares this data to the operating reserves required. SPP monitors and displays the reactive output of generators within the SPP RC Areas as well as the remaining reactive capability by BA Area. SPP receives real-time voltages on critical buses

which alarm the RC when a voltage limit is exceeded. SPP will contact the appropriate TOP or BA as necessary to develop mitigation plans. SPP RC makes all reasonable efforts to provide notification and coordination of actions that may impact adjacent RC Areas for voltage control, including coordination of reactive resources.

3.6. SPP monitors voltage points based upon a ±5% tolerance around nominal voltage. This tolerance may vary per TOP and for nuclear power stations. When a high or low voltage alarm is received from the EMS system indicating limit violations, SPP will coordinate with the affected TOP to determine if the indicated voltage is correct and verify the TOP's voltage limits for that particular area. SPP will assist the affected TOP in developing a course of action to address undesirable voltage conditions including verifying and changing status of static reactive devices, reconfiguration, coordinating resource commitments, establish power transfer limits and re-dispatch as appropriate, etc.

3.7. The SPP RTO within the Eastern Interconnection monitors capacity and adequacy conditions through the SPP Reserve Sharing System (RSG) and market applications. SPP also receives resource plan information for all resources participating in the SPP Integrated Marketplace (Eastern Interconnection). This information contains data for each resource for each hour of a 7-day horizon beginning with the current day and is updated as necessary throughout the day. SPP will use this and other system information to perform hourly assessments of capacity and adequacy for the next hour.

3.7.1. For the Western Interconnection, SPP West RC will monitor capacity and adequacy conditions utilizing applicable RSG and BA submitted data as documented in the required data specifications.

3.8. SPP monitors current ACE and frequency in real-time for all BA Areas in the SPP RC Areas using the real-time data sent by the BAs through ICCP pursuant to applicable SPP RDS. This information is displayed to the SPP RC constantly.

3.9. SPP monitors current external impacts on its system from external network load, Market flows in the Eastern Interconnection, external generation to load (GTL) and transactions.

3.10. SPP receives and reviews resource plans and generation schedules from its Reliability Customers.

3.11. SPP monitors planned and unplanned transmission and generation outages. SPP's RC Members and Reliability Customers are required to submit all generator and transmission outages. Timing requirements and approval

procedures are documented in the applicable SPP Outage Coordination Methodology and applicable SPP RDS. The generator and transmission outages are sent to the Outage Scheduler database of the EMS system and used by the State Estimator and RTCA if the real-time measurements of the facility do not contradict with the submitted outage. The SPP RC Operators are constantly verifying the submitted outage data using State Estimator displays and its alarming application. They contact the appropriate SPP RC Member or Reliability Customer if a scheduled outage does not materialize in real-time as planned or if a line, transformer or unit trips without having a scheduled outage.

SPP utilizes graphical display systems designed to increase SPP RC situational awareness of the SPP RC Areas. The systems use near real-time and/or EMS data to provide a wide-area view.

4. SPP monitors BES parameters that may have significant impacts upon its RC Areas and neighboring RC Areas as follows:

4.1. SPP maintains awareness of all Interchange Transactions that wheel-through, Source, or Sink in the SPP RC Areas.

4.1.1. SPP acts as a Scheduling Entity on behalf of the Market Operating Entities or PSEs in its Eastern Interconnection RC Area by approving all transactions that wheel-through, Source and Sink in its Eastern Interconnection RC Area. SPP makes available its Eastern Interconnection RC tag information to all RCs in the Eastern Interconnection as necessary.

4.1.2. SPP is not a scheduling entity in the Western Interconnection. The RC maintains awareness of scheduling impacts on constraints through the Enhanced Curtailment Calculator (ECC).

4.2. SPP evaluates and assesses additional Interchange Transactions that could violate SOLs and/or IROLs. SPP utilizes Interchange information, real-time data in the SPP EMS, and SPP's constraint monitoring tools to make an assessment of the impacts of additional transactions on constraint loading. SPP is authorized to utilize all resources, including load shedding, to address a potential or actual IROL exceedances. This authorization is reiterated to each SPP RC Operator in their job description and by a personal memorandum from SPP's Chief Operating Officer (COO).

4.3. SPP monitors operational data submitted by BAs within the SPP RC Areas to ensure that the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards (CPS) and Disturbance Control Standards (DCS). If necessary, SPP will instruct the BAs in the SPP RC Areas to arrange for assistance from neighboring BAs. SPP has the

authority to instruct the acquisition of generation capacity and, if that instruction is not satisfied, instruct the shedding of load in the deficient BA Areas.

4.4. SPP will identify the cause of potential or actual SOL or IROL exceedances. SPP shall initiate control actions or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. SPP will choose the most effective means of relieving the IROL exceedance within 30 minutes including instructing generation re-dispatch, facility switching, and load shedding. SPP is authorized to instruct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

4.5. SPP will communicate start and end times for time error corrections to all BAs within its RC Area in both the Eastern and Western Interconnections.

4.6 SPP will review TOP submitted Geo-Magnetic Disturbance (GMD) plans and acknowledge, via email, of both receipt and review. SPP will ensure that all TOPs and BAs within its RC Areas are aware of GMD forecast information and will assist in the development of any required response plans. For GMD levels K8 or above, SPP RC will initiate a satellite phone call test to ensure satellite phone functionality has not been damaged during the event. SPP will communicate GMD forecast information to its BAs and TOPs via one or more of the following; R-Comm, email communication, ICCP, and/or phone communication.

While performing the role of the GMD monitor, for all K-7 or higher GMD warnings and alerts, SPP will participate in the Space Weather Prediction Center (SWPC) initiated phone communication with other Reliability Coordinators via the NERC Hotline and perform a roll call of RCs expected to participate. As the GMD monitor, SPP RC will contact RCs who did not participate in the SWPC call, provide details concerning the GMD notification and post a message to the Reliability Coordinator Information System and, for the Western Interconnection RCs, to R-COMM utilizing the blast message option outlining the GMD event information.

4.7. SPP will participate in NERC Hotline discussions, assist in the assessment of the reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. SPP will disseminate this information within its RC Areas as necessary.

4.8. SPP monitors system frequency and its BAs' performance, and if necessary, will instruct any rebalancing required for a BA to return to CPS and DCS compliance to ensure reliability. SPP receives at least one real-time frequency point via ICCP for each Balancing Authority Areas in the SPP RC Areas. At the instruction

of SPP, its BAs shall utilize all resources, including firm load shedding, to balance load and generation.

4.9. SPP coordinates with other RCs and neighboring BAs or TOPs, as needed, in the development and implementation of mitigation plans for potential or actual SOL, IROL, CPS or DCS exceedances. SPP coordinates pending generation and transmission maintenance outages with other RCs, as necessary, in both the real-time RTA and next day OPA timeframes. SPP participates in periodic conference calls with neighboring RCs as necessary.

4.10. SPP will assist the BAs in the SPP RC Areas in arranging for assistance from neighboring RCs or BAs by issuing reserve sharing contingency notifications (for the Eastern Interconnection SPP RSG Members) or EEAs as appropriate.

4.11. SPP identifies sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and will implement corrective actions with the appropriate BA. SPP receives the real-time ACE for each BA Area in the RC Areas via ICCP. The SPP RC receives an alarm if any ACE values change significantly or exceed a predefined limit. Excessive ACEs would be addressed by a call to the BA to determine the cause of the deviation and the course of action that the BA has planned and/or implemented to address the situation. Assistance would be provided in the Eastern Interconnection RC Areas by accessing operating reserves with the SPP Reserve Sharing Group to address the deviation should that be required. Should the situation be causing overloads on system facilities, instruction would be issued to dispatch/re-dispatch generation to relieve the situation.

4.12. SPP maintains awareness that Special Protection System (SPS) or Remedial Action Scheme (RAS) within the SPP RC Areas are armed. The host BA/TOP is required pursuant to applicable SPP RDS to keep SPP informed of the operational status of the SPS. If there is concern with the state of an SPS/RAS, and if not previously informed, the RC shall contact the responsible TOP, or neighboring entity as applicable, to inquire about the SPS/RAS state change.

5. SPP will alert all affected BAs and TOPs in its RC Areas, and all affected RCs within the Interconnection when it foresees an IROL exceedance or a significant loss of real and/or reactive generation capacity within its RC Areas through OPA and/or RTA. SPP will disseminate this information to its BAs and TOPs, utilizing appropriate communication channels, such as R-Comm, verbal communications, etc.

6. SPP confirms RTA and/or OPA results and determines the effects within its RC Areas and adjacent RC Areas. SPP will derive and discuss options to mitigate potential or actual SOL or IROL exceedances and identify and implement only those actions as necessary as to always act in the best interest of the Interconnection at all times.

Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

F. Emergency Operations

1. In the event the loading of transmission facilities progresses to, or is projected to progress to, an SOL exceedance, SPP will use congestion management processes to reduce the loading to prevent an exceedance as soon as practicable. In the event the loading of transmission facilities progresses or is projected to progress to an IROL exceedance, SPP will take immediate actions, but no longer than 30 minutes, to return loading to the facility rating up to and including load shed.

2. SPP maintains copies of all pertinent operating guides/instructions as supplied by SPP RC Members and Reliability Customers. SPP reviews and coordinates these instructions with the BAs and TOPs in the SPP RC Areas. The SPP RC Operator maintains communication with the Transmission Operator who may be implementing these guides for local area relief to ensure regional reliability is not jeopardized by the implementation of said procedures. SPP RC Operators will instruct the appropriate Transmission Operators to take specific actions on how to mitigate the situation.

3. For the Eastern Interconnection RC Area, SPP will comply with the provisions of the NERC TLR procedure as follows. If the SPP RC is the sink RC and receives notification via the IDC that another RC has issued a TLR that calls for curtailment and/or halts of transactions sinking in SPP, the SPP RC will use the IDC to acknowledge the transaction curtailments and/or halts for the next hour, or current hour, and monitor the transactions to ensure that the transaction curtailments/halts are properly implemented. SPP acts as the sink RC in the IDC for transactions sinking into ERCOT across the East and North DC ties and for transactions sinking into Western Interconnection across the Eddy County, Stegall, Blackwater, Rapid City, Miles City, Lamar and Sidney HVDC ties.

    3.1. If SPP determines, through Source-to-Sink impact evaluation, that curtailment of a transaction as identified by the IDC would actually increase flows on the constraint for which relief has been requested, it will not acknowledge curtailment of such transaction. SPP may also determine that, through Source-to-Sink impact evaluation, transactions having a significant impact on the constraint exist but are not identified for curtailment by the IDC. In those cases, SPP will instruct curtailment of those transactions as necessary.

    3.2. If SPP receives notification from the IDC that SPP has a Generation to Load (GTL) relief obligation in response to a TLR issuance, SPP will utilize its market systems to calculate and send dispatch instructions to its Market Participants (MPs) necessary to achieve the relief.

3.3. SPP will follow procedures included in Market Protocols and its operating procedures to implement relief procedures, up to and including the point that emergency action is necessary. When SPP observes constraint loading that approaches the applicable SOL, it will communicate with the constraint owner to verify actual real-time flows and coordinate necessary actions to be taken. SPP will make a coordinated decision based on current and/or anticipated conditions to pursue relief by using the congestion management process.

4. For the Western Interconnection, SPP will utilize the Western Interconnection Congestion Management Methodology, including Unscheduled Flow Mitigation Procedure (UFMP).

5. SPP will monitor system frequency and its BAs' performance. If SPP determines that one or more of its BA areas are contributing to a frequency excursion, SPP will instruct the BA(s) to use all resources available, including load shedding, to comply with CPS and DCS requirements.

6. SPP will take or instruct whatever action is needed, including load shedding, to mitigate an energy emergency within the SPP RC Areas. SPP will provide assistance to other RCs experiencing an energy emergency as necessary.

7. SPP requires that any BA Area within its RC Areas that is experiencing an energy emergency, first use Operating Reserves available within its applicable Reserve Sharing Group (RSG). If the energy emergency still persists, SPP will issue an EEA on behalf of the deficient BA Area.

G. System Restoration

1. SPP is knowledgeable of the restoration plans of each of the Transmission Operators in its RC Areas and has a written copy of each plan in its possession. SPP verifies that the most current plans are on file on an annual basis. During system restoration, SPP monitors the restoration progress and coordinates any needed assistance.

2. SPP has regional restoration plans for the SPP RC Areas that provides coordination between individual restoration plans of each SPP Transmission Operator and that ensures reliability is maintained during system restoration events. The SPP RC Areas Regional Restoration Plans and NERC Reliability Standards require that the role of the SPP RC during system restoration is to facilitate this coordination. Furthermore, the SPP RC approves, communicates, and coordinates re-synchronization of system islands or synchronizing points such that a burden is not caused on adjacent TOP, BA, or RC Areas. SPP Communications Protocols delineate the processes for Emergency Communications.

3. SPP will disseminate information regarding restoration to neighboring RCs and BAs/ TOPs not immediately involved in restoration by posting pertinent information on the RCIS and/or via phone call. SPP will also use the NERC Hotline for updates to other RCs as needed.

H. Facility

SPP performs the RC function at each of its two Coordination Centers. Each Coordination Center has the necessary facilities for the SPP RCs to perform their responsibilities. Full functionality is provided with full backup of the systems, communications, data, and tools required for SPP to perform as the RC for its RC Members and Reliability Customers. Both primary and alternate sites are staffed and functional 24x7.

1. SPP has redundant data communications between the two SPP sites, which are staffed 24x7 with working communications such as voice and data links between RC Member and Reliability Customer sites and SPP systems. SPP also employs a Voice-over-IP (VOIP) phone system that allows the phones to ring at both Coordination Center sites simultaneously. Cell phones are used as the alternate voice communication capability.

   SPP IT's 24x7 desk and additional on-call staff provide support of the voice and data communications, hardware, and software, working with communication service companies as appropriate.

2. A satellite phone system is installed at both of SPP's Coordination Centers as well as at all SPP RC Areas BA/TOP primary operations centers, for purposes of communicating during emergency conditions per SPP Communications Protocols. This system bypasses the Public Switched Telephone Network (PSTN) and can be used for point-to-point or broadcast (all-call) communications. The satellite service can also route a phone call to a land line, providing access to any operable wire or wireless phone.

3. SPP has detailed real-time monitoring capability of the SPP RC Areas and sufficient monitoring capability of surrounding RC Areas to ensure that potential or actual SOL or IROL exceedances are identified. SPP has monitoring systems that provide information that can be easily understood and interpreted, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure. SPP monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within the SPP RC Areas. SPP monitors both real and reactive power system flows,

operating reserves, and the status of system elements that are or could be critical to SOLs and IROLs and system restoration requirements within the SPP RC Areas.

4. SPP utilizes two separate EMS clusters, an Authorized cluster and an Unauthorized cluster. If the Primary Location is lost, the primary EMS systems in the Alternate Location will automatically take over EMS functionality at the Alternate Location. As part of the EMS model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

5. SPP utilizes two separate ICCP clusters, a primary cluster and a back-up cluster (secondary ICCP). If the Primary Location is lost, the primary ICCP systems located in the Alternate Location will automatically take over primary ICCP functionality. As part of the ICCP model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

6. Per the applicable SPP RDS, SPP RC Members and Reliability Customers are required to send and receive near real-time data to both the primary and secondary systems concurrently as appropriate. Data from both systems are fed to the EMS providing an alternate data source for use when the primary source is failed for any reason.

I. Staffing

1. SPP 24x7 operations consists of four RC Operators and two Shift Engineers. The personnel is split between our primary and our alternate facilities with two RC Operators and one Shift Engineer at each location. These RC Operators and Shift Engineers are required to hold the NERC RC certification as well as being desk qualified at their position. SPP requires its RC Operators to complete yearly training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

2. SPP ensures that its RC Operators have a comprehensive understanding of the SPP RC Areas and required interaction with neighboring RCs. The SPP RC Operators have an extensive understanding of the RC Member and Reliability Customer systems within the SPP RC Areas such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. SPP makes year-round training opportunities available for the RC Operators, which includes the use of a Dispatcher Training Simulator (DTS) to provide realistic simulations of system emergencies described in the previous section.

   SPP creates training and performance support to ensure the SPP RC Operators understand the SPP region and the interface with neighboring regions. This includes opportunities for continuing education hours, including required

emergency operations and simulation hours. This training includes familiarization with Member BAs/TOPs by including RC training on the RC Members' and Reliability Customers' operating guides, system configuration, and transmission facilities. Control Center evacuation training and performance-based exercises are provided annually through instructor-led courses. Operations personnel who have a role in the evacuation plan are required to participate in the evacuation training and performance-based exercise annually. In addition, SPP conducts regional system restoration drills annually.

SPP's training department documents all training for recordkeeping and reporting purposes. All information required by the NERC Continuing Education program is available in a variety of report formats.

3. An Officer of SPP has signed the NERC Reliability Coordinator Standards of Conduct on behalf of the SPP RC. Each SPP RC Operator is required to sign and receive training on the SPP Standard of Conduct annually. The SPP Standard of Conduct requires the signatory to maintain proper confidentiality procedures and processes. SPP is an independent organization with an independent Board of Directors. SPP's independence enables its staff to fully comply with both the NERC and SPP Standards of Conduct.

Appendix A – BAs and TOPs in SPP RC Areas

Balancing Authorities and Transmission Operators in the SPP Reliability Coordination Areas:

Entity	BA	TOP	East	West
Arlington Valley Power Cooperative (AVBA)	X			X
American Electric Power – West (AEP)		X	X	
Arizona Electric Power Cooperative/SW Transmission Coop (AEPC)		X		X
Black Hills Corporation (BHE)		X		X
City Utilities of Springfield (CUS)		X	X	
Colorado Springs Utilities (CSU)		X		X
Corn Belt Power Cooperative (CBPB)		X	X	
El Paso Electric (EPE)	X	X		X
Empire District Electric Company/Liberty Utilities (EDE)		X	X	
Farmington Electric Utility System (FEUS)		X		X
First Light Energy (BNBA)	X			X
Grand River Dam Authority (GRDA)		X	X	
City of Independence Power & Light Department, Missouri (INDP)		X	X	
Gridforce Energy Management (GRID)	X			X
CORE Electric Cooperative (CORE)		X		X

Entity	BA	TOP	East	West
ITC Great Plains (ITC)		X	X	
The Board of Public Utilities, Kansas City, Kansas (BPU)		X	X	
Kansas City Power and Light Company (KCPL)		X	X	
KCP&L Greater Missouri Operations Company (UCU)		X	X	
Lincoln Electric System (LES)		X	X	
Midwest Energy, Inc. (MIDW)		X	X	
Nebraska Public Power District (NPPD)		X	X	
Oklahoma Gas and Electric (OKGE)		X	X	
Omaha Public Power District (OPPD)		X	X	
Platte River Power Authority (PRPA)		X		X
Public Service of Colorado (PSCO)	X	X		X
Sunflower Electric Power Corporation (SEPC)		X	X	
Southwest Power Pool (SPP)	X		X	
Southwestern Power Administration (SPA)	X	X	X	
Southwestern Public Service Company (SPS)		X	X	
Tri-State G & T (TSGT) *		X	X	X
Tucson Electric Power (TEPC)	X	X		X
Western Areas Power Administration (WACM)	X	X		X
Western Areas Power Administration (WALC)	X	X		X
*Western Areas Power Administration (WAUE)		X	X	
Western Areas Power Administration (WAUW)	X	X		X
Western Farmers Electric Cooperative (WFEC)		X	X	
Westar Energy, Inc. (WRGS)		X	X	

**Eastern and Western Interconnections*

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit II: NERC, *Emergency Operations*

A. Introduction

1. Title: **Emergency Operations**

2. Number: **EOP-011-4**

3. Purpose: To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. Applicability:

4.1. Functional Entities:

4.1.1 Balancing Authority

4.1.2 Reliability Coordinator

4.1.3 Transmission Operator

4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. Effective Date: See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit JJ: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF BRAD NEBERGALL ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

December 1, 2020

Colorado PUC E-Filings System

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ATTACHMENTS

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Table 1 Summary of Electric Resource Plan Scenarios

GLOSSARY

Term	Meaning
AQCC	Colorado Air Quality Control Commission
Basin	Basin Electric Power Cooperative
BoR	Bureau of Reclamation
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
CEP	Clean Energy Plan
CO_2	Carbon Dioxide
DSM	Demand-Side Management
EE	Energy Efficiency
ERP	Electric Resource Plan
EV	Electric Vehicle
GHG	Greenhouse Gas
GW	Gigawatt
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
MW	Megawatt
PSCo	Public Service Company of Colorado
RAP	Resource Acquisition Period
RE Act	Rural Electrification Act
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
Tri-State	Tri-State Generation and Transmission Association, Inc.
WAPA	Western Area Power Administration
WESC	Wholesale Electric Service Contract

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Brad Nebergall. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Senior Vice President, Energy Management.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY PRIOR TO BECOMING AN EMPLOYEE OF TRI-STATE.

I graduated from Iowa State University with a B.S. in Business Administration and a focus in finance. I also have an MBA from the University of Houston. After several years working in commercial banking, I joined an affiliate of InterNorth in 1986, which eventually merged with another company to become Enron Corp. I spent the next 20 years serving in various roles within Enron affiliates, including founding Enron's natural gas trading business in England, co-founding an initiative to capture opportunities within NOx and SO_2 emissions credits trading, and managing Enron's Midwest Region with responsibility for all power, natural gas and diesel sales to large regional energy consumers. After Enron declared bankruptcy in 2001, I was recruited post-bankruptcy to restructure the wind power

operations of Enron Renewable Energy Corporation. I was responsible for all commercial and operational activities for 28 producing wind farms. I held that position through 2006.

Q: WHEN DID YOU BEGIN YOUR EMPLOYMENT WITH TRI-STATE?

A: I became a Tri-State employee in 2007. In 2008, I was promoted to my current position of Senior Vice President, Energy Management.

Q: WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT, ENERGY MANAGEMENT FOR TRI-STATE?

A: I am responsible for Tri-State's activities related to marketing, energy trading, origination, risk management, resource dispatch, corporate development and resource planning. My responsibilities require that I have knowledge of Tri-State's operations, strategic initiatives, costs/expenses, and long-term commitments to Members, lenders and other third parties. In addition, my job requires that I study and track market and industry conditions, including market prices for Tri-State's purchased fuel, its capital expenses and the price at which wholesale electricity can be bought and sold on the spot market.

Q: DO YOUR RESPONSIBILITIES INVOLVE PLANNING TRI-STATE'S FUTURE GENERATION NEEDS AND THE RESOURCES TRI-STATE WILL BUILD OR PURCHASE TO MEET THOSE NEEDS?

A: Yes. Tri-State's resource planning function is a significant part of my responsibility.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: Given that this is the first Electric Resource Plan ("ERP") that Tri-State is filing under new Commission Rule 3605, it may be helpful to provide some background on Tri-State and context for the Commission's and parties' consideration of Tri-State's 2020 ERP. In that regard, my testimony begins with an overview of Tri-State, including its organization, membership, and generation and transmission systems, and discusses how Tri-State is different from investor-owned utilities and how those differences are relevant to the Commission's evaluation of Tri-State's ERP.

The next section of my testimony discusses the evolution of the Commission's regulation of Tri-State's resource planning and some of the unique challenges associated with the current ERP cycle. Next, I discuss Tri-State's Responsible Energy Plan ("REP"), which describes Tri-State's vision for transitioning to a clean energy portfolio and grid, and the relationship between the REP and Tri-State's 2020 ERP. The next section of my testimony provides an overview of Tri-State's resource planning process and discusses some of the key considerations that factored into the development of Tri-State's 2020 ERP.

Finally, I will provide an overview of Tri-State's 2020 ERP, including the objectives of the ERP, the various scenarios and alternatives that were considered, and Tri-State's preferred plan for purposes of moving forward into Phase II of this ERP proceeding.

Q: PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL BE TESTIFYING ON BEHALF OF TRI-STATE.

A: Tri-State's witnesses are:

Ms. Lisa Tiffin, Senior Manager, Analytics & Forecasting. Ms. Tiffin will address various topics associated with the Phase I of the ERP, including Tri-State's load forecast, the assessment of existing resources, planning reserve margins, and the forecasted assessment of need for additional resources.

Mr. Brian Thompson, Resource Planning Manager. Mr. Thompson's testimony will address technical aspects of Tri-State's Phase I filing, including costs and benefits of the integration of intermittent renewable energy resources; studies commissioned and prepared by Tri-State to support the development of this filing; modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems; emissions and water usage and the social cost of carbon.

Mr. Andy Berger, Senior Manager, Environmental Policy. Mr. Berger will provide an overview of the environmental laws and policies influencing Tri-State's resource planning and will explain how compliance with state and federal environmental laws affects Tri-State's Electric Resource Plan ("ERP").

Mr. Christopher Pink, Vice President, Transmission Engineering. Mr. Pink will discuss transmission system capabilities, including injection capabilities, of Tri-State's transmission system, Tri-State's transmission planning process, and, finally, he will provide a discussion of Tri-State's transmission needs and planned projects. He will provide information as required by Commission Rule 3605(d) or identify where such information can be found in the ERP.

Ms. Susan Hunter, Senior Manager, Origination. Ms. Hunter's testimony will address Tri-State's plan for meeting the resource need, including the Phase II evaluation process and Tri-State's proposed RFP.

III. OVERVIEW OF TRI-STATE

Q: SINCE THIS IS THE FIRST TIME THE COMMISSION WILL EVALUATE AND ISSUE A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN, IT MAY BE HELPFUL TO PROVIDE SOME BACKGROUND ON TRI-STATE, ITS MEMBERSHIP, AND ITS MISSION. WHEN WAS TRI-STATE ESTABLISHED?

A: Tri-State was established in 1952.

Q: WHY WAS TRI-STATE ESTABLISHED?

A: A full answer to that question requires a short history review. Congress passed the Rural Electrification Act ("RE Act") in 1936. At that time, 90 percent of rural America lacked electric power. Congress was concerned with the failure of then-existing electric utilities to extend service to rural communities and determined that the national interest would be served by subsidizing rural electrification. The RE Act allowed rural electric distribution cooperatives such as Tri-State's original Members to receive government-subsidized loans to facilitate the delivery of electricity to rural customers.

In late 1951, discussion began among rural electric cooperatives in Colorado, Nebraska, and Wyoming concerning the adequacy of power being supplied to them by the United States Bureau of Reclamation ("BoR"). These cooperatives

ultimately determined that the supply of federal power on which they had historically relied would not be sufficient to meet their growing needs. The cooperatives decided they should develop electric generating facilities that they would own to ensure adequate power supplies for the future. The cooperatives formed Tri-State in 1952 to fulfill that purpose – to ensure a sufficient and reliable power supply for its Utility Members – and Tri-State's Members continue to own and govern Tri-State to meet their collective needs. This is important because this original purpose and the underlying collective benefit for its Members has continued to guide Tri-State and its resource planning decisions for the last nearly 70 years.

Q: WHAT IS TRI-STATE'S MISSION ON BEHALF OF ITS MEMBERSHIP?

A: Tri-State's primary corporate mission is to provide its Utility Members a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles.

Q: PLEASE DESCRIBE TRI-STATE'S MEMBERSHIP.

A: Tri-State has 42 Class A Utility Members and three Non-Utility Members. Tri-State's Utility Members consist of rural electric distribution cooperatives and public power districts which, like Tri-State, operate on a not-for-profit basis. Tri-State's Utility Members include 11 distribution cooperatives located in New Mexico, 17 distribution cooperatives located in Colorado, eight distribution cooperatives located in Wyoming, and two distribution cooperatives and four public power districts located in Nebraska. In addition to providing retail electric service in the

four states in which they are located, certain of Tri-State's Utility Members also provide retail electric service that extends into multiple other states. Tri-State's three Non-Utility Members are all located in Colorado. Figure 1 below generally depicts Tri-State's Utility Members and their service territories.

Figure 1. Tri-State's Utility Members and Their Service Territories



Tri-State operates in interstate commerce and facilitates the generation and transmission of wholesale electricity across a four state, 200,000 square mile area. Tri-State's Utility Members, in turn, serve customers in 56 Colorado counties, 20 Nebraska counties, 28 New Mexico counties, and 14 counties in Wyoming.

All of Tri-State's Colorado Utility Members have voted to exempt themselves from regulation by the Commission, as permitted by the Colorado Public Utilities Law.

Q: HOW IS TRI-STATE GOVERNED?

A: As I have described, Tri-State is a multistate, regional, generation and transmission cooperative corporation that operates on a not-for-profit basis in interstate commerce providing wholesale electric power and transmission services to its Utility Members. To best serve the varying and unique needs of its Members, Tri-State is directly owned and governed by its Members through a Board of Directors.

Tri-State's Board of Directors is comprised of representatives from each of its Utility Members who are elected by the local boards of their respective cooperative or public power district. Tri-State's Board meets on a monthly basis to make decisions regarding the strategic and business affairs of the cooperative. All matters requiring a decision by the Board are decided by a majority vote of the Board members present and voting. Each Utility Member is entitled to one vote. The Members, acting through their representatives on the Board, are responsible for approving rates, major capital investments, long-term contractual commitments and, as relevant here, Tri-State's resource planning decisions.

Recognizing that Board decisions have a significant impact on all Members, the Board acts for the collective benefit of all Members and seeks to treat all Members equitably. This means that Tri-State's assets and system are planned and operated on the basis of mutual benefits and the sharing of costs and risks among all Members. Through its democratic control, Tri-State's Board works to ensure that corporate decisions balance the interests of all Members in all states.

Q: HOW IS TRI-STATE DIFFERENT FROM COLORADO'S INVESTOR-OWNED ELECTRIC UTILITIES?

A: I believe the primary differences are that Tri-State is owned by its Members rather than shareholders, does not seek to generate a profit for outside investors, and is a multistate wholesale electricity supplier that does not provide retail electric service.

Q: WHY ARE THESE DIFFERENCES IMPORTANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN?

A: In several ways. First, Tri-State is a wholesale electricity supplier – an aggregator of its Utility Members' loads. It is not a retail electric utility like Colorado's two investor-owned electric utilities. This is important because Tri-State does not have a direct relationship with end-use retail consumers; that relationship is the exclusive province of Tri-State's Utility Members. As a result, Tri-State is not in the same position as Colorado's retail electric IOUs when it comes to certain resource planning issues such as energy efficiency and demand side management.

Second, unlike Colorado's two retail electric IOUs, which are essentially single-state utilities serving only Colorado customers, Tri-State is a multistate utility serving Members in four states which, in turn, serve customers in multiple states. This difference is important for two reasons. Rather than having a system that is designed to serve the needs of only one state, Tri-State's system has for decades been designed, constructed and operated to serve its Members in multiple states and without regard to state boundaries. As a result, Tri-State's resource planning decisions in Colorado, as well as the Commission's decisions within the scope of its resource planning authority, will have an impact on system operations outside of Colorado and vice versa. Likewise, Tri-State's integrated system must take into consideration the legislative and regulatory requirements and public policy goals of all states in which it operates, not just in Colorado.[1] These state requirements and goals differ among the states yet, under the cooperative business model, the associated costs of compliance are shared by all Members in all states.

Finally, while Tri-State's Board and Members share the Commission's interest in ensuring a reliable and affordable power supply, Tri-State's not-for-profit business model means many of the issues related to utility profits and ownership of resources, which frequently arise in IOU ERP proceedings and lead into subsequent rate cases, are not present in Tri-State's ERP. And, like the wholesale power rates of Colorado's two electric IOUs, Tri-State's wholesale power rates are

[1] Tri-State also has resource planning obligations and submits an Integrated Resource Plan to the Western Area Power Administration.

regulated by the Federal Energy Regulatory Commission ("FERC").

These and other differences between Tri-State and the two Colorado electric IOUs require different considerations as the Commission evaluates Tri-State's 2020 ERP. These considerations are discussed throughout Tri-State's Electric Resource Plan and the testimony of Tri-State's witnesses.

Q: YOU HAVE MENTIONED TRI-STATE'S INTERSTATE GENERATION AND TRANSMISSION SYSTEM SEVERAL TIMES. PLEASE PROVIDE A BRIEF OVERVIEW OF TRI-STATE'S SYSTEM.

A: Tri-State's generating fleet includes: Craig Generating Station, Laramie River Station, Springerville Generating Station Unit 3, J.M. Shafer Generating Station, Rifle Generating Station, Limon Generating Station, Frank R. Knutson Generating Station, Pyramid Generating Station, and Burlington Generating Station.[2] Tri-State's resource mix also includes power provided by Basin Electric Power Cooperative ("Basin") and the Western Area Power Administration ("WAPA") under long-term power purchase agreements. Finally, Tri-State's resource mix includes power purchase agreements associated with the following existing renewable resources: Cimarron Solar, Kit Carson Windpower, Colorado Highlands Wind, Carousel Wind, San Isabel Solar, Alta Luna Solar, and Twin Buttes II Wind, as well as contracts with six small hydropower producers.

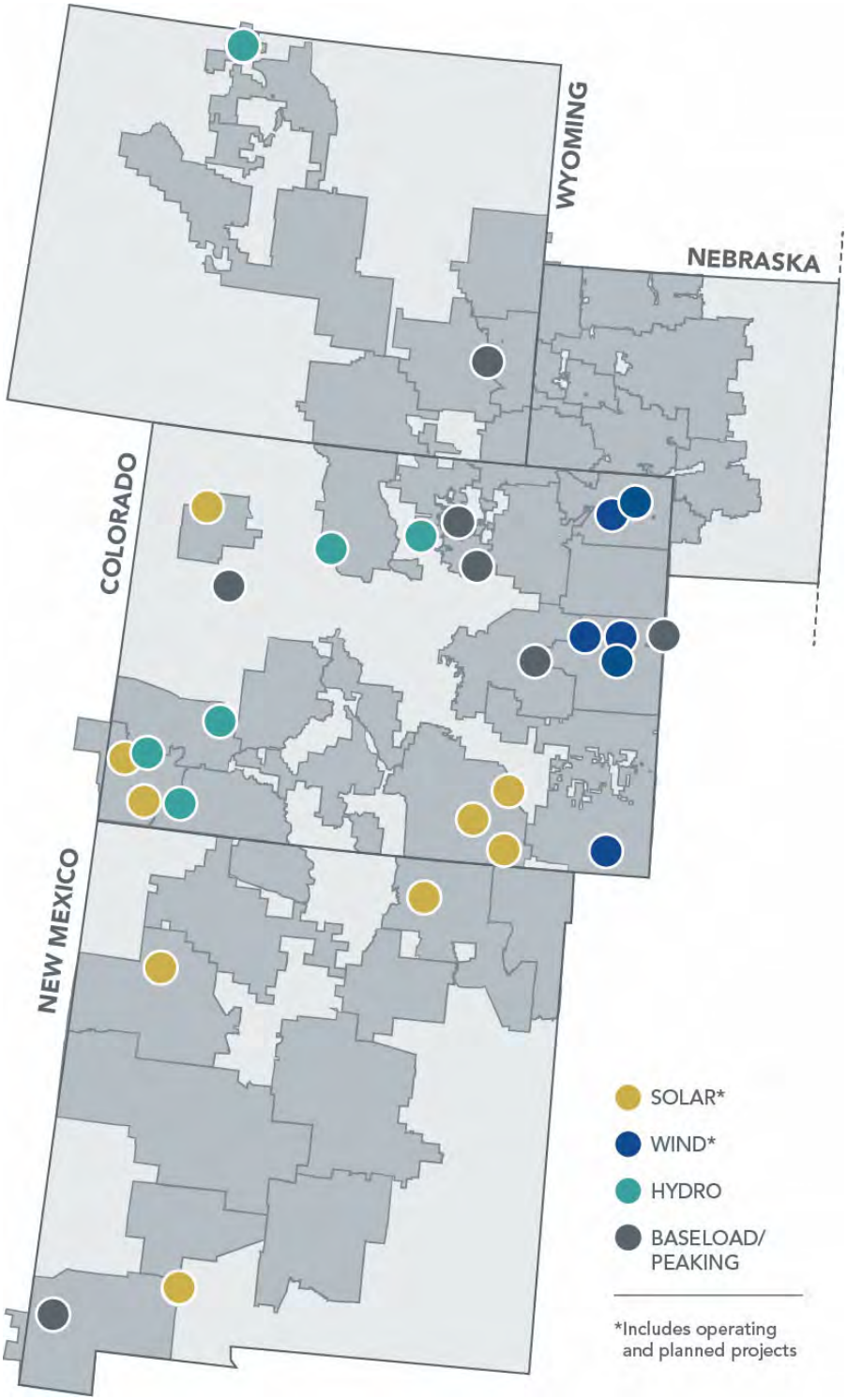
Tri-State's total system resource mix includes 2,432 MW of thermal generation

[2] Tri-State's Escalante Station, located in New Mexico, was retired on November 19, 2020, and is not included in this list.

resources, 452 MW of renewable wind and solar resources, 27 MW of small hydropower resources, and 580 MW of WAPA hydropower resources. Additionally, Tri-State Members own or contract for 131 MW of additional generation resources, consisting of renewable resources such as small solar, hydro, wind, landfill-gas and waste heat.

As a result of competitive bidding processes that Tri-State initiated in 2018 and 2019, Tri-State has executed contracts for additional wind and solar resources that are in various stages of development. Figure 2 below provides a general depiction of Tri-State's operating and planned generation resources. These resources are discussed in greater detail in Volume II of Tri-State's 2020 ERP.

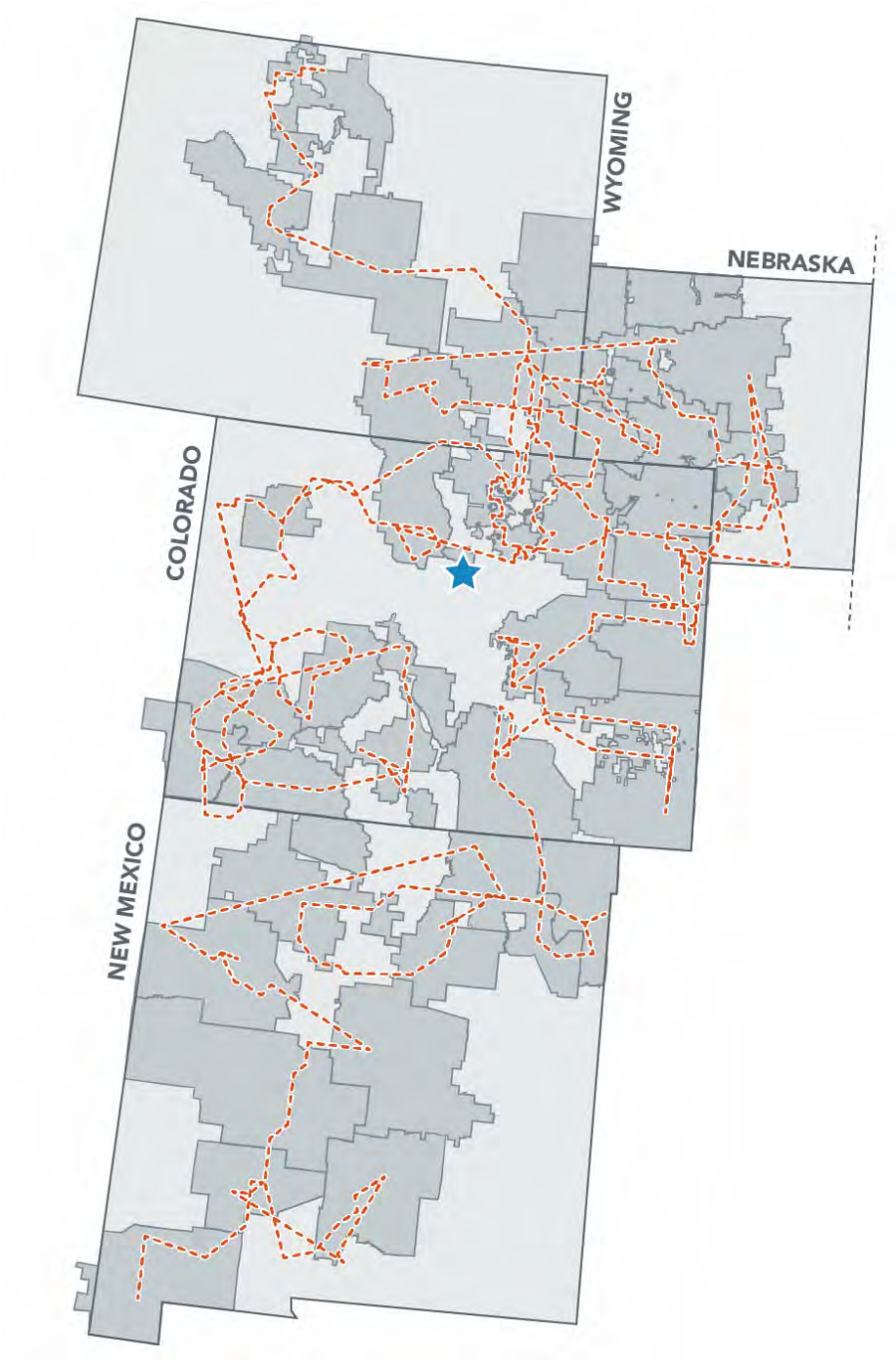
Figure 2. Tri-State's Operating and Planned Generation Resources



In 2019, Tri-State's Utility Member system peak demand was 3,009 MW and Utility Members purchased 16,413 GWh of energy from Tri-State. Tri-State's existing resources, resources under development, plans to retire certain of these resources, and Tri-State's projected resource mix in 2030 are discussed in greater detail in Ms. Tiffin's direct testimony.

Tri-State presently owns, operates, and maintains an extensive interstate transmission system with facilities located in four states: Colorado, New Mexico, Wyoming, and Nebraska. This transmission system includes over 5,665 miles of transmission lines with operating voltages up to 345 kV, 409 substations and switchyards, and over 475 communications sites used for system operations. In addition, Tri-State owns and operates the David A. Hamil DC Tie located in Stegall, Nebraska, which provides a means to transfer electric power between the Eastern and Western Interconnections. As of 2020, Tri-State's total transmission system investment is approximately $559,000,000. Tri-State also relies upon wheeling agreements with PSCo, WAPA, Public Service Company of New Mexico ("PNM"), PacifiCorp, and other transmission service providers for delivery of resources to its Utility Members. Figure 3 provides a general depiction of the location and extent of Tri-State's interstate transmission system.

Figure 3. Overview of Tri-State's Transmission System



Mr. Pink discusses Tri-State's transmission system and the information required by Commission Rule 3605(d) in greater detail in his testimony.

IV. REGULATION OF TRI-STATE'S RESOURCE PLANNING

Q: AT THE BEGINNING OF YOUR TESTIMONY, YOU NOTED THAT THIS IS THE FIRST TIME THE COMMISSION WILL BE EVALUATING AND ISSUING A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN. HOW HAS THE COMMISSION'S REGULATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN CHANGED OVER THE YEARS?

A: During the nearly 70 years since Tri-State was established, the Commission has regulated Tri-State's resource planning to varying degrees. For the last 10 years, Commission Rule 3605 has required Tri-State to file its ERP as an informational report; however, during that period, the Commission did not conduct related adjudicatory proceedings and the Commission did not issue decisions approving Tri-State's ERP. This approach was the result of a proposal advanced by Tri-State and Western Resource Advocates in Docket No. 09I-041E and approved by the Commission in Decision No. C10-0101. Pursuant to that Decision, Tri-State filed its first ERP report on November 30, 2010, a subsequent full ERP report on October 30, 2015, and Annual Progress Reports in the intervening and subsequent years.

Q: DID THAT INFORMATIONAL FILING REQUIREMENT SUBSEQUENTLY CHANGE?

A: Yes. Pursuant to previous Commission Rule 3603, Tri-State's next full ERP would have been due on October 31, 2019. However, in 2019, the Colorado General Assembly passed Senate Bill 19-236, which became Colorado Revised Statute §

40-2-134. That statute required the Commission to promulgate rules requiring wholesale electric cooperatives to submit electric resource plans to the Commission for approval, and rules for the Commission's evaluation and approval of such ERPs. Given these new requirements and the timing of the associated rulemaking proceedings, Tri-State requested in Proceeding No. 19V-0311E a variance of the October 31, 2019, ERP filing deadline. The Commission granted that variance in Decision No. C19-0629 and held that the timing of Tri-State's next ERP filing would be established in the rulemaking proceeding required by § 40-2-134, C.R.S.

On July 31, 2019, the Commission issued its Notice of Proposed Rulemaking in Proceeding No. 19R-0408E regarding electric resource planning rules for wholesale electric cooperatives. The resulting new Rule 3605 went into effect nearly one year later on July 15, 2020, and established a December 1, 2020, filing deadline for Tri-State's full ERP. Commission Rule 3605 requires that Tri-State submit an electric resource plan that, in many respects, is substantially similar to those required of PSCo and Black Hills Energy. Rule 3605 also provides for Phase I and Phase II ERP processes for Tri-State.

Unique to this first ERP filing, Rule 3605 also required Tri-State to file the Assessment of Existing Resources section of its ERP into an adjudicated proceeding on June 1, 2020, for review by the Commission and interested parties. Finally, I would note that certain of the Commission's ERP rules that are at issue in Proceeding No. 19R-0096E apply to Tri-State; however, those rules have not

been finalized and, therefore, are not incorporated into Tri-State's 2020 ERP.

Q: HOW IS THE CHANGE IN THE RESOURCE PLANNING RULES RELEVANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN?

A: The change in resource planning rules applicable to Tri-State presents primarily practical challenges that Tri-State believes the Commission should consider as it evaluates this first ERP under the new rules.

First, the new rules presented timing challenges for Tri-State. While Tri-State was preparing to file its ERP in October 2019 under the prior resource planning rules applicable to Tri-State, those efforts were largely suspended when SB19-236 became law and Tri-State awaited the Commission's development of new resource planning rules for wholesale electric cooperatives. As noted previously, those new rules did not take effect until July 15, 2020 – only four-and-a-half months before Tri-State's first ERP under the rules was due to be filed. Tri-State had a general understanding of what those rules would be as a result of participation in the rulemaking proceeding; however, it could not proceed with certainty until the rules were finalized.

At the same time, Tri-State was required to prepare, file, and respond to numerous and extensive discovery requests related to its June 1, 2020, Assessment of Existing Resources (Proceeding No. 20M-0218E). The Rule 3605(c) information required in this advance filing ordinarily would not be filed separately and would be included in the full ERP itself, as is the case for similar information contained in the

ERPs filed by Public Service and Black Hills. However, in its Decision Adopting Rules, the Commission explained that such advance filing would "allow for Staff and other parties to Tri-State's initial 2020 ERP proceeding to conduct discovery and learn about Tri-State's generation fleet and the underlying financial requirements in the months leading to the later assessment of Tri-State's complete ERP filing." Given the limited nature of the Commission's historical involvement in Tri-State's resource planning, Tri-State recognizes the potential benefits of providing this information in advance of its initial ERP filing. Nevertheless, preparing that filing and responding to over 750 discovery requests presented a substantial challenge at the same time that the same Tri-State personnel were working on the scenario development, modeling, and analyses for the full ERP.

During the course of the Assessment of Existing Resources proceeding, several parties provided recommendations concerning the process for developing, or the contents of, Tri-State's ERP. As Tri-State explained in its response to initial comments filed in that proceeding, not all of those recommendations were appropriate, and it was impossible to accommodate certain of these recommendations in time for the 2020 ERP filing. Depending on the particular recommendation, further changes could be addressed in a subsequent rulemaking or incorporated into Tri-State's next ERP, which is scheduled to be filed on June 1, 2023.

When the Commission deliberated on whether to close the Assessment of Existing Resources proceeding, it discussed further expectations of what Tri-State should

include in its full ERP filing. The Commission's written decision, however, did not issue until the afternoon of November 25, 2020 – two business days before the ERP was due on December 1, 2020. Accordingly, Tri-State did not have the Commission's written decision so as to specifically inform it of these additional requirements or in time to address all of these requirements in the ERP filing. Tri-State will review these new requirements and will supplement its ERP filing, as appropriate, as soon as possible.

Tri-State encourages the Commission to use this first ERP under the new rules to determine what does and does not make sense for purposes of the Commission's review of Tri-State's 2020 ERP, and consider any potential additional or changed requirements in the context of the 2023 ERP.

V. TRI-STATE'S RESPONSIBLE ENERGY PLAN

Q: IN JANUARY 2020, TRI-STATE ANNOUNCED ITS RESPONSIBLE ENERGY PLAN. PLEASE PROVIDE AN OVERVIEW OF THAT PLAN.

A: Earlier this year, Tri-State's Board of Directors described its vision for the future of the cooperative in the Responsible Energy Plan ("REP"). The Responsible Energy Plan is included as **Attachment BN-1** to my testimony and outlines Tri-State's commitments and goals to help make that vision a reality. The REP focuses on reducing Tri-State's greenhouse gas ("GHG") and carbon dioxide ("CO_2") emissions, increasing Tri-State's use of renewable and clean energy resources, increasing Utility Member flexibility with respect to their power supply options, extending the benefits of a clean grid to our Utility Members and their customers

through various beneficial electrification initiatives, supporting our employees and communities as Tri-State implements these transitions, and striving to meet Colorado's clean energy goals while maintaining or reducing Tri-State's wholesale rates to its Utility Members.

Q: SINCE JANUARY, SOME QUESTIONS HAVE BEEN RAISED CONCERNING THE DECISIONS INCLUDED IN TRI-STATE'S REP AND THE COMMISSION'S RESOURCE PLANNING AUTHORITY OVER TRI-STATE. WHAT IS TRI-STATE'S POSITION RELATIVE TO THIS ISSUE?

A: Following SB19-236 being signed into law last year, Tri-State recognizes that its electric resource plans are subject to review and approval by the Commission. The announcement of the REP does not intrude upon or interfere with the Commission's resource planning jurisdiction. Some actions related to the REP - such as the retirement of existing generation resources, the assessment of need for additional resources, and Tri-State's plans for acquiring those resources - will require Commission approval in this or subsequent proceedings, and Tri-State will apply for those approvals. Other REP actions, however, do not necessarily require Commission approval; these include changes to the wholesale contract structure between Tri-State and its Utility Members, support for Utility Members' electric vehicle programs and other beneficial electrification initiatives, and Tri-State's support for employees and communities impacted by the transition from fossil fueled generation.

Q: LET'S DISCUSS THE REP COMPONENTS IN MORE DETAIL. PLEASE DESCRIBE HOW THE RESPONSIBLE ENERGY PLAN IS INTENDED TO REDUCE TRI-STATE'S GREENHOUSE GAS AND CARBON DIOXIDE EMISSIONS.

A: The REP, as originally announced, called for actions that would result by 2030 in a reduction of 90%, relative to 2005 levels, in the CO_2 emissions from generation resources owned or operated by Tri-State in Colorado. These actions were part of an overall effort that would also result in in a reduction of 70% by 2030, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales, compared to the base year of 2005. The REP contemplated a combination of plant retirements, the addition of new clean energy resources, and other actions needed to achieve these reductions including the retirement of the three Craig Station units by 2030. Additionally, the REP committed Tri-State to cancel its participation in the Holcomb Station project. These REP actions in Colorado are paired with Tri-State's decision to retire the Escalante Station in New Mexico by the end of 2020, and Tri-State separately announced the early retirement of the Nucla Station in 2019.

Q: DURING THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING, SOME COMMENTERS CLAIMED THAT TRI-STATE'S RESPONSIBLE ENERGY PLAN WOULD NOT ACHIEVE THE 70% REDUCTION IN CO2 EMISSIONS IN COLORADO BY 2030 THAT YOU JUST MENTIONED. WERE THOSE CLAIMS ACCURATE?

A: No. I believe those commenters confused the base case projections in the Assessment of Existing Resources with the REP initiatives. The 34% CO_2 emissions reduction shown in the base case projections reflected a "business as usual" base case and did not include GHG and CO_2 emission restrictions. It was not intended to illustrate all of Tri-State's Responsible Energy Plan commitments or the emission reductions associated with it, nor did it include additional actions required to reach Colorado GHG emission targets. Tri-State has modeled many scenarios for its full ERP, including scenarios related to CO_2 emission reduction and costs as required by Rule 3605 and to meet the commitments of the Responsible Energy Plan. These scenarios and the associated emission reductions are discussed in the testimony of Ms. Tiffin.

Q: HAS TRI-STATE SUBSEQUENTLY REVISED ITS EMISSION REDUCTION PLANS AS COMPARED TO WHAT WAS ORIGINALLY DESCRIBED IN THE RESPONSIBLE ENERGY PLAN?

A: Yes. Tri-State's plans for emission reductions continue to evolve. The REP, as originally presented, called for a reduction of 70%, relative to 2005 levels, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales by 2030. The preferred plan included in Tri-State's 2020 ERP now calls for a reduction of 80%, relative to 2005 levels, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales by 2030. This is consistent with Colorado's overall GHG and CO_2 emission reduction goals and is consistent with what would be required if Tri-State had voluntarily submitted a Clean Energy Plan.

Tri-State's preferred plan is discussed in greater detail in Ms. Tiffin's direct testimony.

Q: PLEASE DESCRIBE THE RESPONSIBLE ENERGY PLAN'S PROVISIONS RELATED TO INCREASING TRI-STATE'S USE OF RENEWABLE AND CLEAN ENERGY RESOURCES.

A: The REP calls for Tri-State to add to its system one Gigawatt (1 GW) of new utility scale renewable energy projects by 2024. These new resources consist of six utility scale solar projects and two utility scale wind projects: Axial Basin Solar (145 MW; 2023), Coyote Gulch Solar (120 MW; 2023), Dolores Canyon Solar (110 MW; 2023), Escalante Solar (200 MW; 2023), Spanish Peaks Solar (100 MW; 2022), Spanish Peaks II Solar (40 MW; 2023), Crossing Trails Wind (104 MW; 2020), and Niyol Wind (200 MW; 2021).[3] (See Figure 2) These additions will bring Tri-State's total renewable resources to over 2 GW, and we forecast that by 2024 50% of the power consumed by Tri-State's Utility Members' customers will come from renewable resources.

Q: IN THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING THAT PRECEDED THIS ERP, SOME PARTIES EXPRESSED CONCERNS REGARDING THE POWER PURCHASE AGREEMENTS ("PPAs") TRI-STATE ENTERED INTO IN CONNECTION WITH THESE NEW RESOURCES. PLEASE EXPLAIN TRI-STATE'S POSITION WITH REGARD TO THOSE PPAs.

[3] Figures and dates represent each project's nameplate capacity and anticipated commercial operation date.

A: First, I would note that Tri-State provided detailed data on these PPAs as part of its Assessment of Existing Resources and throughout the discovery process in Proceeding No. 20M-0218E. Information on these resources also is included in the revised Assessment of Existing Resources in the 2020 ERP.

These eight resources were contracted through a competitive request for proposals ("RFP") process in 2018 and 2019 prior to the Commission's new ERP rules for Tri-State. Tri-State's competitive acquisition process assured that these new resources provide the best value for its Utility Members. Furthermore, the timing of this competitive acquisition process was intended to ensure that the projects, and by extension Tri-State and its Utility Members, could secure the maximum benefits under the Investment Tax Credit and Production Tax Credit.

These resources will play a significant role in Tri-State's transition to a cleaner portfolio and its ability to timely achieve its emission reduction objectives. These resources also contribute to achieving Colorado's overall legislative and policy goals related to clean energy and emission reductions. Revisiting, let alone reopening, these past renewable RFPs would be counterproductive to Colorado's policy goals and to the interests of Tri-State's Utility Members and their customers in Colorado and in other States. Tri-State believes that the present ERP process should focus on future resource acquisitions and the retirement of existing resources.

Q: WHAT STEPS HAS TRI-STATE TAKEN UNDER THE RESPONSIBLE ENERGY PLAN TO INCREASE ITS UTILITY MEMBERS' FLEXIBILITY WITH REGARD TO POWER SUPPLY OPTIONS?

A: For nearly 20 years, Tri-State's Utility Members have had the option to self-generate up to 5% of the energy they need to serve their member-customers. This option has been very popular and successful, with approximately half of Tri-State's Utility Members taking advantage of it, resulting in 130 MW of renewable energy projects in service or under development. Over the years, Tri-State has provided substantial financial subsidies in connection with such projects. Furthermore, some of Tri-State's Utility Members also have developed local renewable energy projects that exceed the 5% self-generation option pursuant to a Tri-State Board policy addressing such projects.

Given the growing interest in local clean energy, many of Tri-State's Utility Members have expressed a desire for more flexibility in their power supply options. In response, the Tri-State Board, as part of the REP and otherwise, has taken a number of steps to provide that flexibility.

In December 2019, the Tri-State Board approved a new community solar program developed and recommended by the Members' Contract Committee. Under that program, Utility Members have the option to build or contract for community solar projects up to established energy thresholds. Solar generation under the program would not be included in the 5% self-supply option in the Utility Members' Wholesale Electric Service Contract ("WESC") with Tri-State. If all Tri-State Utility

Members took advantage of this new program, it would yield 63 MW of new local community solar projects. This program is being considered by the Federal Energy Regulatory Commission ("FERC") in a pending proceeding.

In 2019, the same Contract Committee began considering possible changes to the WESC that would provide Utility Members even greater power supply flexibility in the form of a partial requirements contract. In October 2020, the Tri-State Board approved a flexible partial requirements contract option and its associated board policies. Under that option, Utility Members may express their intent to transition from their current full requirements contract to a partial requirements contract by participating in an "open season" that will begin in early 2021. This initial "open season" will allocate up to 300 MW to the Utility Members. This self-supply option is in addition to the 5% self-supply option already included in the WESC and the community solar option. The partial requirements contract option also is being considered by FERC in a pending proceeding.

Q: HOW ARE THESE VARIOUS SELF-SUPPLY OPTIONS FACTORED INTO TRI-STATE'S 2020 ERP?

A: While we know which of Tri-State's Utility Members already are taking advantage of the 5% self-supply option under the WESC, we don't yet know how many Utility Members will implement community solar projects or transition to partial requirements contracts and, if so, in what capacity amounts. This challenge and how it was considered in the 2020 ERP is discussed in the testimony of Ms. Tiffin.

Q: YOU MENTIONED ONE OF THE RESPONSIBLE ENERGY PLAN'S OBJECTIVES IS TO EXTEND THE BENEFITS OF A CLEAN GRID TO TRI-STATE'S UTILITY MEMBERS AND THEIR CUSTOMERS. PLEASE EXPLAIN THAT AND THE STEPS TRI-STATE HAS TAKEN SO FAR.

A: Tri-State recognizes that the transition to a cleaner grid and power supply brings opportunities to power homes and businesses with reduced emissions electricity and to more efficiently use that electricity. Tri-State is committed to making sure that its Utility Members, and the retail end-use customers they serve, are able to take advantage of these opportunities.

So far, Tri-State has committed $2 million to extend the electric vehicle ("EV") charging network across our Utility Members' service territories by allocating each Utility Member $45,000 to install EV charging stations. Access to these charging facilities will make EV charging more available in rural communities and will give rural consumers the option to choose an EV the next time they buy a vehicle. It also will substantially expand the regional and state EV charging networks for everyone to use thereby advancing one of the Governor's Roadmap goals. Tri-State also is working with its Utility Members to explore additional opportunities for energy efficiency and demand-side management programs that can lower energy bills and energy use. Tri-State's beneficial electrification, EE and DSM initiatives, and the role they play in Tri-State's 2020 ERP are discussed further in the testimony of Ms. Tiffin.

Q: HOW IS TRI-STATE SUPPORTING ITS EMPLOYEES AND THE VARIOUS COLORADO COMMUNITIES THAT WILL BE AFFECTED BY THE REP AND THE SHIFT TOWARD CLEAN GENERATION RESOURCES?

A: Tri-State recognizes that its transition to a cleaner energy portfolio will affect the many employees who have worked hard for decades to "keep the lights on" by ensuring the safe and reliable operation of Tri-State's coal-fired power plants, and also will affect the Tri-State and subsidiary employees who have ensured the fuel supply for those plants. Similarly, this transition will affect the communities in which those plants are located.

Tri-State is providing support to the communities impacted by plant closures. For Craig Station and the Colowyo Mine, Tri-State is providing retraining and transition support for employees. Tri-State is working with its employees and community members to identify economic development opportunities, retraining programs, and other strategies to ease the transition over time. For example, one of the new solar projects I mentioned will be located on Colowyo Mine property. Tri-State also is working with local, state, federal, and industry leaders to develop, provide financial support for, and implement retraining, educational, and economic development solutions in addition to those that Tri-State is implementing on its own. While this issue is not addressed in the Commission's ERP rules for Tri-State, it is an important issue to Tri-State, its employees, and the impacted communities.]

VI. TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN

Q: WHAT ARE THE OBJECTIVES OF TRI-STATE'S 2020 ERP?

A: Consistent with the Commission's ERP Rules, Tri-State's 2020 ERP is intended to describe Tri-State's need for additional electric resources, and ultimately identify a cost-effective resource portfolio to reliably meet such need. Tri-State's 2020 ERP also is intended to accomplish these regulatory objectives while complying with the legislative and public policy requirements and goals that I discussed previously, and advancing progress toward Tri-State's own goals set forth in the Responsible Energy Plan.

I also would note that the 2020 ERP, together with the complementary initiatives in the REP, is intended to respond to what Tri-State's Utility Members and their member-customers have been asking for – a transition to a cleaner power supply, reduced GHG emissions, and an opportunity to realize the potential benefits of lower cost electricity. Tri-State believes that the preferred plan submitted as a part of the 2020 ERP meets these objectives.

Q: PLEASE PROVIDE AN OVERVIEW OF THE ERP FILING.

A: Tri-State's 2020 ERP consists of two volumes containing the ERP itself and 18 appendices. Tri-State's 2020 ERP is included as **Attachment BN-2** to my testimony.

The ERP begins with an Executive Summary and an Introduction and Background section that discusses the development and organization of the 2020 ERP, and provides an update on progress made since Tri-State's 2015 ERP informational

filing.

The next section of the ERP addresses the current resource planning "landscape" in terms of Tri-State's system energy mix, market dynamics, and other external factors, and presents much of the information required by Rule 3605(a)(IV). As discussed in this section, Tri-State's 2020 ERP uses a 20-year resource planning period from 2021 through 2040 and, as required by Rule 3605(a)(IV)(A), a 10-year resource acquisition period ("RAP") beginning in 2021 and extending to the end of 2030. Tri-State believes that the next 12 to 24 months will provide greater clarity with respect to the variables, challenges, and opportunities that I discussed previously, and Tri-State recommends a measured approach to acquiring new resources during the RAP. Furthermore, Tri-State believes that additional time may allow for the development of new non-emitting dispatchable resources that could be cost-competitive for future acquisition, and Tri-State's 2023 ERP will provide an opportunity in the relatively near future to further consider these options.

The next section of the ERP provides Tri-State's assessment of resource needs, including current load and resource balance, RES/RPS requirements, GHG/CO2 reductions and demand-side management and energy efficiency.

The next section of the ERP presents Tri-State's Alternative Resource Analysis. This section discusses the Base Case as well as the multiple alternative plans that Tri-State considered, including the social cost of carbon and other plans required by Commission rules. This section compares the various plans and presents Tri-State's preferred plan. The next section outlines Tri-State's action plan for the

RAP, including the competitive bidding process and the ERP Implementation Report Plan.

The last section of Volume I of the ERP identifies the relevant confidential and highly confidential information, as required by Rule 3605(a)(IV)(K).

The first section of Volume II of the ERP provides load forecasting as required by Rule 3605(b) followed by details on commodity pricing.

The next section of the ERP presents Tri-State's Assessment of Existing Resources, including some of the information identified in the Commission's November 25, 2020 written decision closing Proceeding No. 20M-0218E.

The next section of the ERP addresses Tri-State's transmission system and transmission planning, and presents the information required by Rule 3605(d).

The next section of the ERP discusses in detail the Phase I modeling including constraints, assumptions, and methodology.

The last section of the report includes detailed environmental data for all scenarios.

Q: WHAT IS THE RESOURCE NEED IDENTIFIED IN THE ERP?

A: Tri-State's analysis shows a need for new capacity to provide replacement capacity support for the retirement of the Craig 3 unit in 2029. Tri-State also identifies the preferred addition of renewable and energy storage resources prior to that time, which will serve to achieve GHG reductions in the relatively near-term.

Q: PLEASE DESCRIBE THE ALTERNATIVES TRI-STATE CONSIDERED IN DEVELOPING THE 2020 ERP.

A: In addition to the Base Case, Tri-State considered seven alternative plans: four different base load scenarios yielding an 80% Colorado CO_2 emissions reduction, relative to a 2005 baseline, by 2030; two different low load scenarios yielding 80% Colorado CO_2 emissions reductions, relative to a 2005 baseline, by 2030; and a scenario that applies the social cost of carbon to all thermal generation units. Table 1 below provides a summary of the alternatives Tri-State considered.

Table 1. Summary of Electric Resource Plan Scenarios

Scenario	**Description**
Base Case	Business as usual case to be used as a reference to measure other scenarios against.
80% CR V1	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes forced (i.e. not a cost-driven model selection) expansion plan low level demand-response and aggressive level energy efficiency resources in Colorado.
80% CR V2	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes only existing demand-side management and energy efficiency.
80% CR V3	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that is similar to 80% CR V2, but includes an additional wind

	resource to improve carbon dioxide reduction and enhance reliability.
80% CR V4	An 80% carbon-reduction by 2030 scenario that is similar to 80% CR V2, but includes an additional solar resource to improve carbon dioxide reduction and enhance reliability.
Low Load 80% CR V1	An 80% carbon-reduction by 2030 scenario that allows for low-level demand-response and/or low- or aggressive-level energy efficiency resources and uses the low load forecast.
Low Load 80% CR V2	An 80% carbon-reduction by 2030 scenario that includes only existing demand-side management and energy efficiency resources and uses the low load forecast.
Social Cost of Carbon	A Social Cost of Carbon scenario that uses the technical support document under Executive Order 12866—Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, to determine the social cost of carbon and it applies the appropriate cost to carbon-emitting resources.

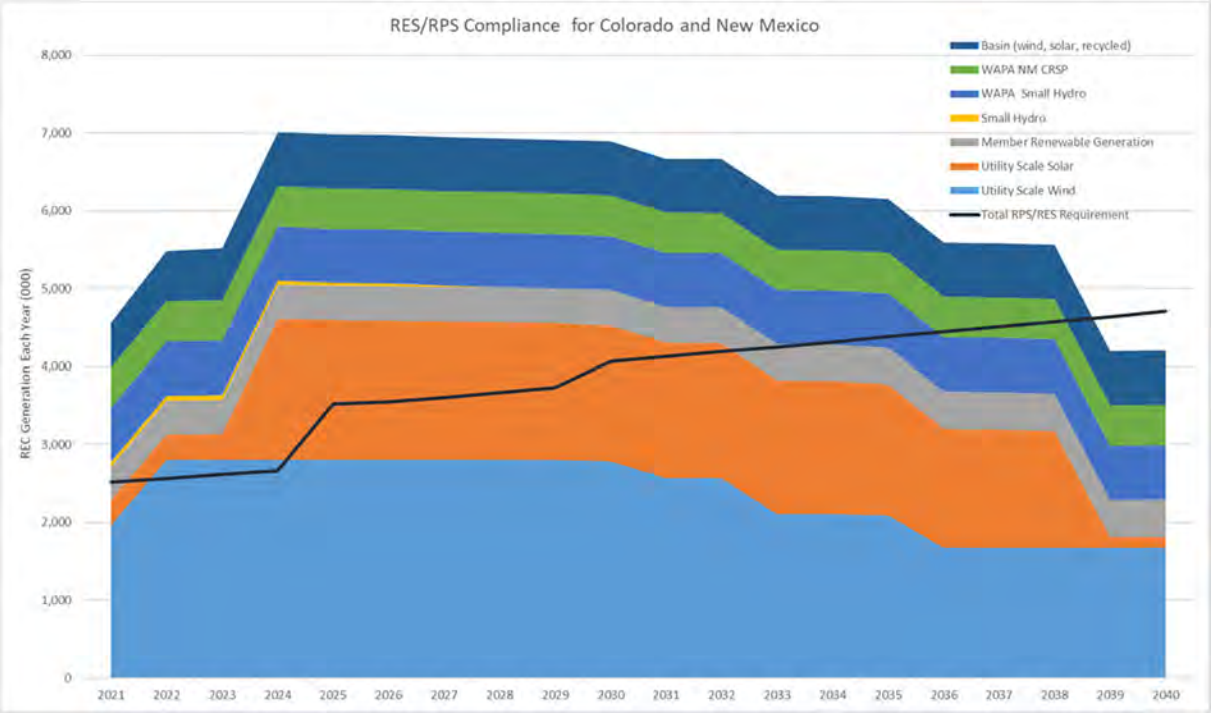
Q: IS TRI-STATE PRESENTING A PREFERRED PLAN IN ITS 2020 ERP?

A: Yes. Tri-State's preferred plan, which is forecast to result in an 80% CO_2 reduction as previously described, is detailed in Ms. Tiffin's testimony.

Q: DOES THE PREFERRED PLAN ENABLE TRI-STATE TO COMPLY WITH ITS COLORADO RENEWABLE ENERGY STANDARD OBLIGATIONS AND SUPPORT ITS COLORADO UTILITY MEMBERS' OWN RENEWABLE ENERGY STANDARD AND RENEWABLE PORTFOLIO STANDARD OBLIGATIONS?

A: Yes. Given that Tri-State operates an integrated generation and transmission system, the preferred plan will provide for compliance with Tri-State's and the Utility Members' RES and RPS obligations in Colorado and New Mexico. Figure 4 graphically depicts Tri-State's compliance with Colorado's RES and New Mexico's RPS.

Figure 4. RES/RPS Compliance for Colorado and New Mexico



RES and RPS compliance issues are discussed in greater detail in Ms. Tiffin's testimony.

Q: ARE YOU FAMILIAR WITH THE RECENT HEARING AND DECISION BY THE COLORADO AIR QUALITY CONTROL COMMISSION IN CONNECTION WITH THE STATE IMPLEMENTATION PLAN FOR REGIONAL HAZE?

A: I did not participate in that hearing and am not directly responsible for issues related to Tri-State's compliance with the Regional Haze State Implementation Plan. I am, however, generally familiar with the Colorado Air Quality Control Commission's ("AQCC") actions at its recent hearing. Mr. Berger discusses the AQCC's actions in more detail in his testimony.

Q: PLEASE DESCRIBE HOW THE RECENT ACTIONS BY THE AQCC MIGHT INFLUENCE TRI-STATE'S 2020 ERP.

A: On Friday, November 20, 2020, the AQCC took action in a Regional Haze proceeding that would call for the retirement of Craig Unit 3 and several other coal-fired generating units in Colorado by December 31, 2028. The AQCC characterized its action as a "preliminary final action"; as such, the AQCC's decision is not final as of the date of Tri-State's ERP filing, and it is unclear at this time whether the AQCC's final decision will be the same as what was discussed at the recent hearing and, if so, when the final decision will be issued.

While Tri-State will continue to evaluate options related to the AQCC's action, if this action does, in fact, require the retirement of Craig Unit 3 by December 31, 2028, that retirement date would be inconsistent with certain analyses contained in this ERP filing. Specifically, the scenarios in this ERP (except for those requiring consideration of the social cost of carbon) provide for the retirement of Craig Unit

3 one year later, by December 31, 2029. Tri-State will address the AQCC's final decision, as appropriate, during Phase 1 of this ERP proceeding.

Q: DOES TRI-STATE'S 2020 ERP FILING COMPLY WITH THE COMMISSION'S ERP RULES?

A: Yes. Tri-State's 2020 ERP complies with all of the requirements of new Commission Rule 3605. A Compliance Table is included at page 4 in the ERP report.

Q: WHAT APPROVAL IS TRI-STATE REQUESTING IN THIS PROCEEDING?

A: Tri-State requests approval of its 2020 ERP, including Tri-State's assessment of need for additional resources during the current resource acquisition period, Tri-State's plans for acquiring such additional resources, and the proposed RFP to be used in conjunction with such resource acquisitions.

Q: DOES THAT CONCLUDE YOUR TESTIMONY?

A: Yes.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF Colorado)
) ss:
COUNTY OF Adams)

I, Brad Nebergall, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Signed this 24th day of November, 2020, at Westminster, Colorado.

Subscribed and sworn to before me this 24th day of November, 2020.

Witness my hand and official seal.

Notary Public Faith Warner

My Commission expires: September 7, 2022

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES SEPTEMBER 7, 2022

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit KK: Division, *Operating Permit No. 96OPMF155* (July 1, 2021)



Colorado Department of Public Health and Environment

OPERATING PERMIT

Tri-State Generation & Transmission Association, Inc.

Craig Station

First Issued: May 1, 2005
Renewed: July 1, 2021

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME: Craig Station

OPERATING PERMIT NUMBER

96OPMF155

FACILITY ID: 081/0018

RENEWED: July 1, 2021
EXPIRATION DATE: July 1, 2026
MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Tri-State Generation & Transmission Association, Inc.
1100 W. 116th Street
Westminster, CO 80234

PLANT SITE LOCATIONS:

Craig Station
2101 S. Ranney Street
Craig, CO

INFORMATION RELIED UPON

Operating Permit Renewal Applications Received: May 1, 2009 and May 21, 2010
And Additional Information Received: Various

Nature of Business: Steam and Electricity Generation
Primary SIC: 4911

RESPONSIBLE OFFICIAL

Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

FACILITY CONTACT PERSON

Name: Mike Tomasovic
Title: Environmental Supervisor
Phone: (970) 824-4411

SUBMITTAL DEADLINES –

Semi-Annual Monitoring Periods: January 1 – June 30, July 1 – December 31
Semi-Annual Monitoring Reports: Due February 1 & August 1
Annual Compliance Periods: January 1 – December 31
Annual Compliance Certification: Due February 1

Note that the Semi-Annual Monitoring Reports and Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

SEE SECTION III OF THIS OPERATING PERMIT FOR ACID RAIN SUBMITTAL DEADLINES

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit ≥ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit ≥ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

4. Accidental Release Prevention Program (112(r))

4.1 Based on the information provided by the Source, this facility is subject to the provisions of the Accidental Release Prevention Program in Section 112(r) of the Federal Clean Air Act (CAA).

5. Compliance Assurance Monitoring (CAM)

5.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling and Storage – Unit 3	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse
			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

Table 1 - Craig Station Emission Unit Summary

SECTION II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.) 4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1) SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)		CEMS	Continuous
Acid Rain	1.11	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 2 - Unit 1 Emissions and Requirements Summary

1.1 **Particulate matter (PM)** emissions must not exceed the following limits:

1.1.1 **0.10 lb PM/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 **0.03 lb PM/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 **0.03 lb PM/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To **demonstrate compliance** with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.2.2 **1.2 lb/MMBtu heat input, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

1.2.3 **0.11 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. **0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis**;

b. **0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis**.

1.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days

(including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

1.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of **0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

1.3.3 **0.28 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.3.4 Craig Unit 1 must meet an **annual NO_x limit of 4,065 tons per year by December 31, 2020** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

1.5 **Opacity**

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control

equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an

intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

1.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a **NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average** going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual **NO_x limit of 4,065 tons per year by December 31, 2019** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV) 0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2) NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)		CEMS	Continuous
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 3 – Unit 2 Emissions and Requirements Summary

2.1 **Particulate matter (PM)** emissions must not exceed the following limits:

2.1.1 **0.10 lb/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 **0.03 lb/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 **0.03 lb/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To **demonstrate compliance** with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

2.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

2.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.2.2 **1.2 lb/MMBtu, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

2.2.3 **0.11 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

2.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25

percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with **NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

2.3.3 **0.08 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average

shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

2.5 **Opacity**

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity

observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

2.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired

belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in

§60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

2.10 **Colorado Regulation No. 23, Regional Haze**

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

2.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

2.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

2.13 Compliance Assurance Monitoring (CAM)

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, and L.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da) 0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 4 – Unit 3 Emissions and Requirements Summary

3.1 **Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10})** emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the

BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 **[Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu**

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 **[Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 **0.03 lb PM/MMBtu**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To **demonstrate compliance** with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

3.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 **0.20 lb/MMBtu heat input**, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 **80% reduction of the potential combustion concentration of SO_2**, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 **2,125 tons of SO_2 per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part

60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are

monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 **0.4 lb/MMBtu heat input, 3-hour rolling average**, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 **0.15 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period

of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in

Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 **6,752 tons of NO_x per year**, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 **0.28 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions

shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 3.3, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly

NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to **1.25 lb/MMBtu on an 8-hour rolling average**. The Source must comply with Best Available Control Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 **4,332 tons of CO per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 **VOC: 58 tons per year**

3.5.1.2 **Lead (Pb): 0.054 tons per year**

3.5.1.3 **Sulfuric Acid Mist (SAM): 0.10 tons per year**

3.5.1.4 **Fluorides: 4.47 tons per year**

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 4, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

3.6 **Opacity**

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 **Affirmative defense** for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 **Reporting requirements**, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected

facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 3.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, and M.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 5 - Subpart UUUUU Table 2 Requirements

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU

by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

5.2 **§63.10000 What are my general requirements for complying with this subpart?**

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an

alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided

more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU

shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

5.3 **§63.10006 When must I conduct subsequent performance tests or tune-ups?**

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the

unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3.1) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3.1) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 **[Time between performance tests]**

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

5.4 §63.10007 What methods and other procedures must I use for the performance tests?

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also

develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

5.5 **§63.10009 May I use emissions averaging to comply with this Subpart?**

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-

group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 **[Equations]** The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j)*Smm_j*Cfm_j)]+\sum_{k=1}^{m} Ter_k*Smt_k*Cft_k}{\sum(\sum_{j=1}^{p} Smm_j*Cfm_j)+\sum_{k=1}^{m} Smt_k*Cft_k}$$ Eq. 1b

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i*Rm_i))_p+\sum_{i=1}^{m}(Ter_i*Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p+\sum_{i=1}^{m} Rt_i}$$ Eq. 2a

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i}$$ Eq. 2b

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p}$$ Eq. 3a

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p}$$ Eq. 3b

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware

that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual

performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

5.6 **§63.10010 What are my monitoring, installation, operation, and maintenance requirements?**

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day.

Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice

standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with

monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \qquad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day

rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-

up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of

Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

5.10 §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

5.11 §63.10030 What notifications must I submit and when?

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

5.12 **§63.10031 What reports must I submit and when?**

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g)

(Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition

5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

5.13 **§63.10032 What records must I keep?**

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63,

§63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

5.14 **§63.10033 In what form and how long must I keep my records?**

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 6 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	6.4	See Condition 6.4			
Equipment Operation	6.5	See Condition 6.5			
NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6	

Table 7 - P101 Emissions and Requirements Summary

6.1 **Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276**

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

6.2 **PM and PM_{10} emissions** shall be calculated using the annual coal throughput, emission factors from Table 7 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 7 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

6.3 **Opacity**

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

6.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

6.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 8 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		

		F102g F102l				
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	7.4	See Condition 6.4				
Required Controls	7.5	See Condition 7.5				
NSPS Y	7.6	Opacity not to exceed 20%			See Condition 7.6	
CAM	7.7	Condition 7.7				

Table 9 - P102 Emissions and Requirements Summary

7.1 **Coal consumption, Colorado Construction Permit 12MF322-2**

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

7.2 **PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2**

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 9 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 9 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

7.3 **Opacity**

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

7.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

7.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7.7 **Compliance Assurance Monitoring (CAM)**

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 10 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Limestone Delivery	8.1			Recordkeeping	Annually
PM & PM_{10}	8.2	F201a	PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4			
Equipment Operation	8.5	See Condition 8.5			
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%			

Table 11 – P201 Emissions and Requirements Summary

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 11 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 11. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

8.3 **Opacity**

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

8.6 **40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of

which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 12 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 13 – P202 Emissions and Requirements Summary

9.1 **Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)**

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

9.2 **PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)**

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 13 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 13. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

9.3 **Opacity**

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

9.4 **Colorado Construction Permit 12MF322-4**

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 14 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Ash Processed	10.1			Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c	PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4			

Table 15 – P203 Emissions and Requirements Summary

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 15 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

10.3 **Opacity**

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

10.4 **Colorado Construction Permit 11MF332** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 16 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%	
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28		

				Unpaved: 3.6 EF in lb per vehicle mile traveled		
Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4				

Table 17 – P204 Emissions and Requirements Summary

11.1 **Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3**

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

11.2 **PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3**

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 17 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 17, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates

and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

11.3 **Opacity**

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

11.4 **Colorado Construction Permit 12MF322-3** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 18 – S401 & S402 Emissions and Requirements Summary

12.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195**

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

12.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195**

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

12.3 **PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

12.4 **VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

12.5 **Opacity**

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as

records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 19 – S403 Emissions and Requirements Summary

13.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141**

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

13.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141**

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall

be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

13.3 **PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141**

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

13.4 **VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141**

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 19 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

13.5 **Opacity**

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance

procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

14.3 **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]**

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.*

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator

maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be

performed at least semiannually. If any such observation indicates an exceedance of the applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of

these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 **[Unit 3 Baghouse Only]** The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be

converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the **Unit 3 CO CEMS** is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The **SO_2, NO_x (and diluent), CO_2, and flow monitors** are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The **Unit 3 stack inlet SO_2 and CO_2 monitors** are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The **COMS** are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 **QA/QC plans** shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 **[Units 1 & 2 COMS]** The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The **SO_2, NO_x, and CO CEMS** are subject to the following requirements:

19.1.8.1 **[Relative Accuracy Test Audits (RATA)]** RATA shall be conducted in the units of the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 **[Data Acquisition and Handling System (DAHS)]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

19.2 **General Provisions**

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

19.3 **Data Replacement Requirements**

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 **[COMS]** When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

19.4 **Recordkeeping and Reporting Requirements**

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility

(40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

19.5 **Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only**

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J .Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix L. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by

reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP

was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements

(such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

Alternate Designated Representative
Name: Barry Ingold
Title: Senior Vice President – Generation
Phone: (303) 452-6111

Note: Changes to the Designated and Alternative Designated Representatives shall be made according to the requirements of 40 CFR Part 72, §72.23.

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

	2016	2017	2018	2019	2020	2021
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149
NO_X Limits	C1, C2, C3: 0.46 lb/MMBtu of heat input on annual average basis (40 CFR Part 76, §76.7(a)(2))					

Under the provisions of 40 CFR Part 72, §72.84(a) any allowance allocations to, transfers to and deductions from an affected unit's Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 2013 edition of the CFR.

3. Standard Requirements (40 CFR Part 72, §72.9)

Boilers C1, C2, and C3 (Units 1, 2, and 3) are subject to the provisions of the Acid Rain Program as described herein. The Source has certified that they will comply with the following standard conditions.

3.1 Permit Requirements

3.1.1 The designated representative of each affected source and each affected unit at the source shall:

3.1.1.1 Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR Part 72, §72.30; and

3.1.1.2 Submit in a timely manner a complete reduced utilization plan if required under 40 CFR Part 72, §72.43; and

3.1.1.3 Submit in a timely manner any supplemental information that the permitting authority

determines is necessary to review an Acid Rain permit application and issue or deny an Acid Rain permit.

3.1.2 The owners and operators of each affected source and each affected unit at the source shall:

3.1.2.1 Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

3.1.2.2 Have an Acid Rain Permit.

3.2 Monitoring Requirements

3.2.1 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

3.2.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3.2.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

3.3 Sulfur Dioxide Requirements

3.3.1 The owners and operators of each source and each affected unit at the source shall:

3.3.1.1 Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, §73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

3.3.1.2 Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

3.3.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3.3.3 An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

3.3.3.1 Starting January 1, 2000, an affected unit under 40 CFR Part 72, §72.6(a)(2); or

3.3.3.2 Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, §72.6(a)(3).

3.3.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

3.3.5 An allowance shall not be deducted in order to comply with the requirements under Condition 3.3.1 of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

3.3.6 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72, §72.7 and §72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

3.3.7 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

3.4 Excess Emissions Requirements

3.4.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR Part 77.

3.4.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

3.4.2.1 Pay without demand, to the Administrator of the U.S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

3.4.2.2 Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

3.5 Recordkeeping and Reporting Requirements

3.5.1 Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

3.5.1.1 The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72, §72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

3.5.1.2 All emissions monitoring information, in accordance with 40 CFR part 75; provided that to the extent that Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

3.5.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

3.5.1.4 Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

3.5.2 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

3.6 Liability

3.6.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 70, §72.7 or §72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

3.6.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3.6.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

3.6.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

3.6.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

3.6.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

3.6.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

3.7 Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 72, §72.7 or §72.8 shall be construed as:

3.7.1 Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean

Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

3.7.2 Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

3.7.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

3.7.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

3.7.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

4.1 Reports shall be submitted to the addresses identified in Appendix D.

4.2 Pursuant to 40 CFR Part, §75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR Part 75, §75.64.

4.3 Pursuant to 40 CFR Part 75, §75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

4.4 Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §72.80 through §72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

5. Comments, Notes and Justifications

5.1 As set forth in 40 CFR Part 70, §72.22, the alternate designated representative may act on behalf of the designated representative for this Acid Rain Permit.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Non-Applicable Requirement	Justification
B001 & B002 - Units 1 & 2	Construction Permit 10MF579 reference to May 1, 1973 Subpart D	The Units are subject to the most current version of Subpart D.
Facility-Wide	Colorado Regulation No. 1, V	Applies to coke ovens at Iron and steel plant operations only.
	Colorado Regulation No. 1, VII	Applies only to listed electric generating stations owned and operated by the Public Service Company of Colorado
	Colorado Regulation No. 1, VIII	Applies to listed stationary sources in the Denver PM_{10} nonattainment area only.
	Colorado Regulation No. 1, IX	Applies only to Refinery Fluid Bed Catalytic Cracking Units located in nonattainment areas for carbon monoxide
	Colorado Regulation No. 4, and General Condition 31 of this permit	Sale and use of wood burning devices does not apply to the Craig Station
	Colorado Regulation No. 7, except for Part B, Section III	Applies to sources in ozone nonattainment area. Part B, Section V applies in attainment areas, but diesel storage is exempt. Section V applies in attainment areas, but applies to crude oil storage tanks having a capacity of greater than 40,000 gallons. Part D, Section II, III, IV, and V apply in attainment areas, but contain provisions applicable to the oil and gas industry only.
	Colorado Regulation No. 8, Part D	Applies only to existing sources wishing to obtain a compliance extension and the Craig facility has not triggered this provision
	Colorado Regulation No. 9 – Open Burning, Prescribed Fire, and Permitting	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 10 - Conformity Determinations Respecting Federal Actions	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 11 - Motor Vehicle Emissions Inspection Program	Subject matter does not cover the Craig facility.

	Colorado Regulation No. 12 - Reduction of Diesel Vehicle Emissions	Geographic area of applicability does not include the Craig facility.
	Colorado Regulation No. 13 - The Oxygenated Fuels Program	Area of geographic applicability does not include the Craig facility.
	Colorado Regulation No. 16 - Street Sanding	Geographic area of applicability does not include the Craig facility.
	5CCR 1001-20 - Nonattainment Areas	Craig facility is not located in geographic areas classified as nonattainment.
	Colorado Regulation No. 19 - Lead Based Paint Abatement	Applies only to homes constructed prior to 1978, child-occupied facilities, and only those projects where the intent is to abate lead-based paint hazards
	40 CFR Part 55 - Outer Continental Shelf Air Regulations	Craig facility is outside the geographic scope of this provision.
	40 CFR Part 56 - Regional Consistency	Relates to authorities within the various offices of the EPA.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Stream-lined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield,

compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

Emission Unit Description & Number	Applicable Requirement	Justification
Section II, Conditions 1.2.5.2, 1.3.5.1, 2.2.5.2 and 2.3.4.2 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" be "whenever coal is combusted" instead of what was defined in the CO SIP which was less stringent.
Section II, Conditions 3.2.2 & 3.3.3	NSPS Da definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" use the most stringent definition of "whenever fossil fuel is combusted" in lieu of the NSPS definition.
Section II, Condition 1.9.3 & 2.9.3 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Required quarterly reports	The included reporting requirement is more stringent since reports may be requested at any time by the Division with seven (7) days notice.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(b) – Opacity not to exceed 20%, except for one 6-minute period per hour of not more than 27%	This requirement is less strict than the BACT limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(c)(1) – PM emissions not to exceed 0.015 lb/MMBtu	This requirement is less strict than the BACT PM limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(g) and (p) §60.49Da(t) and (v) – Options for PM CEMS to demonstrate compliance with NSPS Da PM requirements	Since the PM limit has been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(o)(1) and (2) – PM monitoring with annual stack test and 24-hour opacity option for compliance demonstration with NSPS Da limits	Since the PM and opacity limits have been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limits.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.52Da – Recordkeeping requirements for opacity observations	The opacity condition has been streamlined out under BACT wherein records are already required
Section II, Conditions 1.1, 2.1, 3.1 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section II.A.1.c – PM emissions shall not exceed 0.1 lb/MMBtu	This limit is less strict than the Regional Haze (Units 1 & 2) and BACT (Unit 3) limits.
Section II, Condition 4 (Units 1, 2, & 3)	NSPS D/Da requirements associated with combusting non-coal fuels (40 CFR Part 60, Sections §60.43(a)(1), §60.43(b), §60.43(c), §60.44(a)(1), §60.44(a)(2), §60.44(b), §60.43Da(b), §60.43Da(b)(1)/(2), §60.44Da(a)(1), §60.44Da(a)(2)	So long as the fuel heat input limit under Condition 4 is met, these NSPS limits will change less than 2% as compared to the only-coal combustion requirements.

Section II, Condition 13.1	Colorado Construction Permit 98MF0141 – Annual Circulating Water Throughput: 94,608 * 10^6 gallons/year	This limit is merely the annualized PTE of the short term limit.
Section II, Condition 17.2 (Units 1 & 2)	Colorado Regulation No. 23, Section V.B.1. – Regional Haze stack testing	Testing under 40 CFR Part 63, Subpart UUUUU (MATS) is more stringent.
Section II, Condition 19 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section IV – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1, 2, & 3)	40 CFR Part 60, Subpart D, §60.45 – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Section VI.13 – CEMS for Units 1 and 2 (NO_x, SO_2, CO_2, and flow)	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) Section VI.10 – COMS for Units 1 and 2	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.

SECTION V - General Permit Conditions (ver 1/21/2020)

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals

an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four

hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

   (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

   (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

   (i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D or as provided for in Regulation No. 3, Part A, § II.A.2 for oil and gas well production facilities. A revised APEN shall be filed

annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part D § I. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Requirements for Major Stationary Sources

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit's annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

25. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

26. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

27. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

28. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

29. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

30. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard and to the 8-hour Ozone Control Area and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 7, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally

spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

31. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

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DISCLAIMER: None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

A. Appendix A - Inspection Information

A.I. Directions to Plant:

The facility is located approximately 5 miles south of Craig, CO near Highway 13. Ranney Street, which goes south from the town of Craig, also leads to Craig Station

A.II. Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

A.III. Facility Plot Plan:

The attached Figures (following the insignificant activities list) shows the plot plan as submitted via email on March 20, 2018.

A.IV. List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

For insignificant activities marked with an asterisk (*) the owner or operator must maintain sufficient recordkeeping to verify that the exemption applies (e.g., annual throughput is less than 400,000 gallons). Such records shall be made available for Division review upon request (Colorado Regulation No. 3, Part C, Section II.E).

A.IV.1. Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories (Colorado Regulation No. 3, Part C, Section II.E.3.i.(i))

A.IV.2. *Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.) (Section II.E.3.j.)

A.IV.3. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design rate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation) (Section II.E.3.k.)

A.IV.4. *Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons per day (Section II.E.3.n.)

A.IV.5. *Landscaping and site housekeeping devices equal to or less than 10 HP in size (lawnmowers, trimmers, snow blowers, etc.) (Section II.E.3.bb.)

A.IV.6. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers. (Section II.E.3.mm.)

A.IV.7. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable. (Section II.E.3.zz.)

A.IV.8. Storage tanks of capacity less than 40,000 gallons of lubricating oils. (Section II.E.3.aaa.)

A.IV.9. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged annually. (Section II.E.3.ccc.)

A.IV.10. *Storage tanks meeting all of the following criteria (Section II.E.3.fff.):

A.IV.10.i. Annual throughput is less than 400,000 gallons; and

A.IV.10.ii. The liquid is one of the following:

(a) Diesel fuels 1-D, 2-D or 4-D;

(b) Fuel oils #1 through #6;

(c) Gas turbine fuels 1-GT through 4-GT;

(d) An oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of 0.025 PSIA).

A.IV.11. Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is solely for heating buildings for personal comfort. (Section III.E.3.ggg.)

A.IV.12. Stationary Internal Combustion Engines which (Section II.E.3.nnn.):

A.IV.12.i. Power portable drilling rigs; or

A.IV.12.ii. Are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

A.IV.12.iii. Have actual emissions less than five tons per year or rated horsepower of less than 50.

A.IV.13. *Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level. (Section II.E.3.a.)

A.IV.14. *Emergency diesel fire-pump engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 1,068 hours per year.)

A.IV.15. *Unit 1 & 2 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 389 hours per year.)

A.IV.16. *Unit 3 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 764 hours per year.)

A.IV.17. 3,200 Btu/hr propane space heater @ west warehouse (Section III.E.3.ggg.)

A.IV.18. 500 gallon propane tank @ east warehouse (Section II.E.3.zz.)

A.IV.19. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.20. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.21. *Plant Solvent Parts Cleaners (Section II.E.3.a.)

A.IV.22. *Emergency Generator Fuel Oil Day Tank Vent (100 gal) (Section II.E.3.a.)

A.IV.23. *Aboveground Diesel Tank Vent - Diesel (12,000 gal) (Section II.E.3.a.)

A.IV.24. *Aboveground Gasoline Tank Vent (10,000 gal) (Section II.E.3.a.)

A.IV.25. Chemical Laboratory (Section II.E.3.i.(i))

A.IV.26. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.27. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.28. *Hauling Miscellaneous Wet Wastes (Section II.E.3.a.)

A.IV.29. *Bottom Ash Storage and Handling (Section II.E.3.a.)

A.IV.30. *Dry Outage Waste Handling/Hauling (Section II.E.3.a.)

A.IV.31. *Gritblasting and sandblasting activities during outages (Section II.E.3.a.)

A.IV.32. Street and Parking Lot Striping (Section II.E.3.s.)

A.IV.33. Aerosol Can Usage (Section II.E.3.u.)

A.IV.34. Road and Lot Paving (Section II.E.3.x.)

A.IV.35. *Limestone Handling/Hauling for Road Repair and Pond Rip-Rap (Section II.E.3.a.)

A.IV.36. *Limestone Storage Piles (Section II.E.3.a.)

A.IV.37. Welding Operations (Section II.E.3.r.)

A.IV.38. *Used Oil Space Heater (Section III.E.3.a.)

A.IV.39. *Various Oil or Propane-Fired Heaters ranging from 500,000 to 900,000 Btu/hr (Section III.E.3.a.)

A.IV.40. *Unit 1 and 2 Limestone Transfer Conveyors (Section II.E.3.a.)

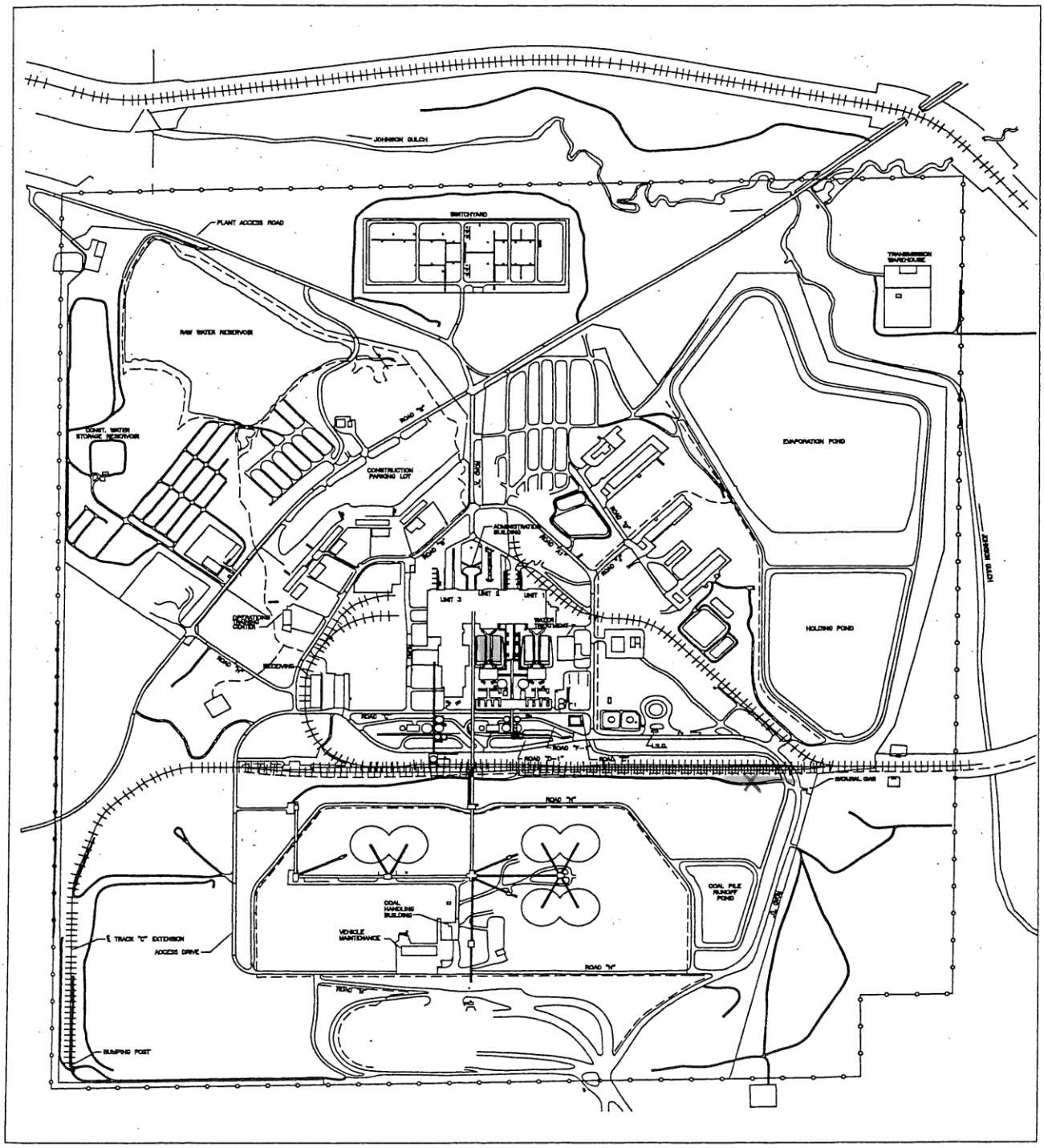
A.IV.41. *Dry Sorbent Injection Silo (Section II.E.3.a.)

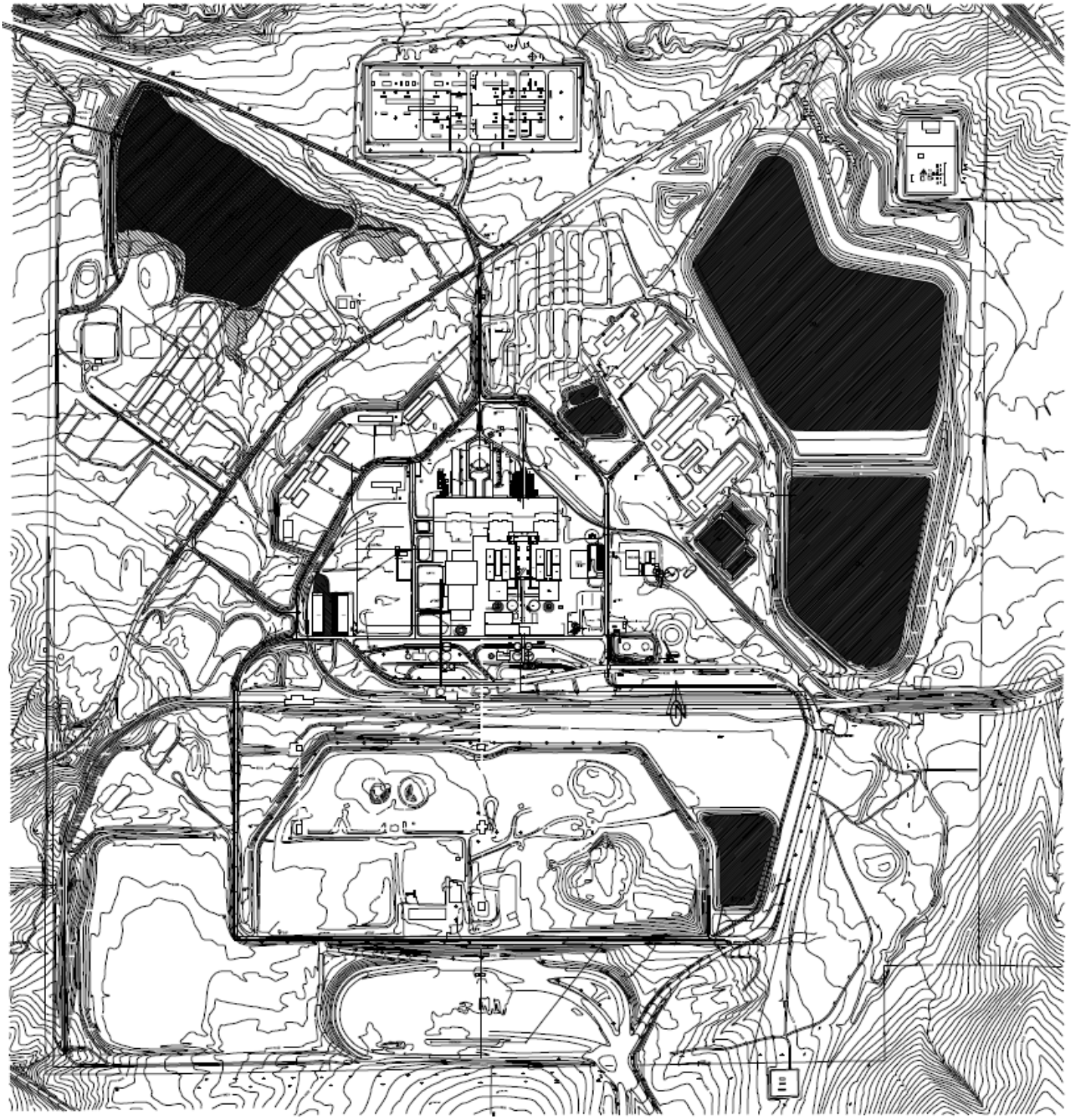
A.IV.42. *Anhydrous Ammonia Storage (Two 50,000 Gallon Tanks) and Transport System (Section II.E.3.a.)

A.IV.43. *Urea Storage and Transport System (Section II.E.3.a.)

A.IV.44. *Common Coal Drive House (Section II.E.3.a.)

A.IV.45. *Light Plants and Small Portable Generators and Welders (Section II.E.3.a.)


JOHNSON GULCH
PLANT ACCESS ROAD
SWITCHYARD
TRANSMISSION WAREHOUSE
RAW WATER RESERVOIR
CONST. WATER STORAGE RESERVOIR
CONSTRUCTION PARKING LOT
EVAPORATION POND
ADMINISTRATION BUILDING
UNIT 3
UNIT 2
UNIT 1
WATER TREATMENT
HOLDING POND
RECEIVING
ROAD "A"
ROAD "B"
ROAD "C"
ROAD "D"
ROAD "E"
ROAD "F"
ROAD "G"
ROAD "H"
ROAD "I"
ROAD "J"
ROAD "K"
ROAD "L"
ROAD "M"
ROAD "N"
ROAD "O"
ROAD "P"
ROAD "Q"
ROAD "R"
ROAD "S"
ROAD "T"
ROAD "U"
ROAD "V"
ROAD "W"
ROAD "X"
ROAD "Y"
ROAD "Z"
COAL HANDLING BUILDING
VEHICLE MAINTENANCE
COAL PILE RUNOFF POND
TRACK "C" EXTENSION
ACCESS DRIVE
BUNSPND POST



B. Appendix B – Reporting Requirements and Definitions

Version 8/20/2014, with codes

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) Makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) Fails to notify or report as required under the Act; or

(C) Falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The Source must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits. All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the

owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred (only for emission points subject to CAM).

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

Startup, Shutdown, Malfunctions and Emergencies,

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

B.I. Appendix B – Monitoring and Permit Deviation Report - Part I

B.I.1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

B.I.2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

Emission Unit	Facility ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/Emergency Condition Reported During Period?	
			YES	NO		YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157					
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156					
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602					
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2					
		F101b – Coal unloading to grizzly – Units 1 & 2					
		F101c – Coal surge pile					
		S101d – Primary coal crushing – Units 1 & 2					
		S101e – Secondary coal crushing building – Units 1 & 2					
		S101f – Common Coal Transfer Building Belt A					
		S101g – Common Coal Transfer Building Belt B					
		S101h – Coal stackout building – Units 1 & 2					
		F101i – Coal stackout – Units 1 & 2					
		F101j – Coal storage piles – Units 1 & 2					
		S101k – Coal reclaim A – Units 1 & 2					

		S101l – Coal reclaim B – Units 1 & 2					
		S101m – Coal tripper deck & silos – Units 1 & 2					
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2					
		S203b – Ash storage silo B – Units 1 & 2					
		F203c – Ash truck loading – Units 1 & 2					
		S203d – Silo B dry ash unloading – Units 1 & 2					
		S203e – Silo A dry ash unloading – Units 1 & 2					
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling					
		S201b – Limestone truck unloading					
		S201c – Limestone silo #1 – Units 1 & 2					
		S201d – Limestone silo #2 – Units 1 & 2					
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3					
		S102b – Coal conveyor portal building – Unit 3					
		S102c – Coal conveyor portal building – Unit 3					
		S102d – Secondary coal crushing (2 crushers) – Unit 3					
		S102e – Coal stackout building – Unit 3					
		F102f – Coal stackout – Unit 3					
		F102g – Coal storage pile – Unit 3					
		S102h – Coal reclaim system – Unit 3					
		S102i – Coal tripper deck & silos – Unit 3					
		S102j – Loadout coal to railcars – Unit 3					
		S102k – Common coal transfer building extension					
		F102l – Coal train loading					
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3					
		F204b – Ash truck loading – Unit 3					
		S204c – Recycle ash truck					
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3					
Lime Handling – Unit 3	P202	F202a – Lime hauling					
		S202b – Lime unloading					
		S202c – Lime conveying and silo					

		S202d – Lime day bin					
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74					
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74					
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79					
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower					
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower					
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower					
General Conditions							
Insignificant Activities							

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate

1 = Standard: When the requirement is an emission limit or standard
2 = Process: When the requirement is a production/process limit
3 = Monitor: When the requirement is monitoring
4 = Test: When the requirement is testing
5 = Maintenance: When required maintenance is not performed
6 = Record: When the requirement is recordkeeping
7 = Report: When the requirement is reporting
8 = CAM: A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other: When the deviation is not covered by any of the above categories

B.II. Appendix B – Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency _____ Malfunction_____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown _____ Malfunction ____

Normal Operation _____

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _____ Division Code QA: _____

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: U.S.S. Enterprise
OPERATING PERMIT NO: 64OPZZXXX
REPORTING PERIOD: 1/1/2369 - 6/30/2369

Is the deviation being claimed as an: Emergency / **Malfunction** / N/A

(For NSPS/MACT) Did the deviation occur during: Startup / Shutdown / **Malfunction** / Normal Operation

OPERATING PERMIT UNIT IDENTIFICATION:

Holodeck generator with nanobot-repaired filtration system – Unit TNG

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Tribbles in the console

Duration

START- 1730 4/10/2369
END- 1800 4/10/2369

Action Taken to Correct the Problem

Transported Tribbles to Klingon vessel.

Measures Taken to Prevent Reoccurrence of the Problem

Permanent ban of Tribbles as pets. Increased structural integrity of console.

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/2369 to J.L. Picard, APCD

Deviation Code _____ Division Code QA: _____

B.III. Appendix B – Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station

FACILITY IDENTIFICATION NUMBER: 081-0018

PERMIT NUMBER: 96OPMF155

REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature of Responsible Official Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

C. Appendix C – Required Format for Annual Compliance Certification Reports

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Emission Unit	Facility ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
			Previous	Current	YES	NO	YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157						
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156						
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602						
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2						
		F101b – Coal unloading to grizzly – Units 1 & 2						
		F101c – Coal surge pile						
		S101d – Primary coal crushing – Units 1 & 2						
		S101e – Secondary coal crushing building – Units 1 & 2						
		S101f – Common Coal Transfer Building Belt A						
		S101g – Common Coal Transfer Building						

		Belt B						
		S101h – Coal stackout building – Units 1 & 2						
		F101i – Coal stackout – Units 1 & 2						
		F101j – Coal storage piles – Units 1 & 2						
		S101k – Coal reclaim A – Units 1 & 2						
		S101l – Coal reclaim B – Units 1 & 2						
		S101m – Coal tripper deck & silos – Units 1 & 2						
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2						
		S203b – Ash storage silo B – Units 1 & 2						
		F203c – Ash truck loading – Units 1 & 2						
		S203d – Silo B dry ash unloading – Units 1 & 2						
		S203e – Silo A dry ash unloading – Units 1 & 2						
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling						
		S201b – Limestone truck unloading						
		S201c – Limestone silo #1 – Units 1 & 2						
		S201d – Limestone silo #2 – Units 1 & 2						
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3						
		S102b – Coal conveyor portal building – Unit 3						
		S102c – Coal conveyor portal building – Unit 3						
		S102d – Secondary coal crushing (2 crushers) – Unit 3						
		S102e – Coal stackout building – Unit 3						
		F102f – Coal stackout – Unit 3						
		F102g – Coal storage pile – Unit 3						
		S102h – Coal reclaim system – Unit 3						
		S102i – Coal tripper deck & silos – Unit 3						
		S102j – Loadout coal to railcars – Unit 3						
		S102k – Common coal transfer building extension						
		F102l – Coal train loading						
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3						
		F204b – Ash truck loading – Unit 3						

		S204c – Recycle ash truck						
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3						
Lime Handling – Unit 3	P202	F202a – Lime hauling						
		S202b – Lime unloading						
		S202c – Lime conveying and silo						
		S202d – Lime day bin						
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74						
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74						
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79						
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower						
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower						
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower						
General Conditions								
Insignificant Activities[4]								

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-

compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility _____ is _____ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _____ will be _____has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

D. Appendix D – Notification Addresses

D.I. Air Pollution Control Division

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530
ATTN: Matt Burgett

D.II. United States Environmental Protection Agency

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Code 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

E. Appendix E – Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in MMBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit

RACT - Reasonably Available Control Technology
SCC - Source Classification Code
SCF - Standard Cubic Feet
SIC - Standard Industrial Classification
SO_2 - Sulfur Dioxide
TPY - Tons Per Year
TSP - Total Suspended Particulate
VOC - Volatile Organic Compounds

F. Appendix F – Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

G. Appendix G – Units 1 and 2 Baghouses Particulate Matter Compliance Assurance Monitoring Plan

G.I. Background

G.I.1. Emission Unit Description

G.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

G.I.2.i. Unit 1:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 1.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 1.1.2); and

(c) 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 1.1.3).

G.I.2.ii. Unit 2:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 2.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 2.1.2); and

(c) 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 2.1.3).

G.I.3. Monitoring Requirements

G.I.3.i. Visible emissions (opacity).

G.I.4. Control Technology

G.I.4.i. Each boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouses have a particulate removal efficiency greater than 99%.

G.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).
II. Indicator Range	An excursion is defined as an opacity value greater than 15.0% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60, Subpart A, §60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60, Subpart A, § 60.13.

G.III. Justification

G.III.1. Background

G.III.1.i. The large pollutant specific emission units (PSEU) are two (2) coal fired boilers, that burn natural gas for startup, shutdown and/or flame stabilization. Each boiler is equipped with a baghouse to control particulate matter emissions.

G.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a

thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

G.IV. Rationale for Selection of Performance Indicators

G.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

G.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

G.IV.2.i. Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

G.V. Rationale for Selection of Indicator Ranges

G.V.1. Visible Emissions (Opacity)

G.V.1.i. In their May 1, 2009 Operating Permit renewal application, a CAM plan was submitted (with respect to PM emission limitations) for Units 1 and 2. In the application, the Source proposed visible emissions (short-term opacity) as an indicator. The Source proposed that an opacity reading greater than 15%, is an indication of potential reduction in baghouse performance. In response to this indicator, an investigation is triggered to locate the cause of the excursion. If the maintenance actions are taken, the results of the work performed are to be documented.

H. Appendix H – Unit 3 Baghouse Particulate Matter Compliance Assurance Monitoring Plan

H.I. Background

H.I.1. Emission Unit Description

H.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

H.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM/PM_{10} requirements:

H.I.2.i. Unit 3:

(a) 443 tons PM/year, 403 tons PM_{10}/year, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.3) (Note that this limit includes both filterable and condensable PM/PM_{10}, but only the filterable portion of the emissions are subject to the CAM requirements as there is no control device for the condensable portion of the limit);

(b) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.1);

(c) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Regulation No. 23, Section IV.B – Regional Haze (Condition 3.1.2).

H.I.3. Monitoring Requirements:

H.I.3.i. Visible emissions (opacity).

H.I.4. Control Technology:

H.I.4.i. The boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

H.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).

	Indicator 1
II. Indicator Range	An excursion is defined as an opacity value greater than 7.5% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (midnight to midnight) will be averaged together to get a 24-hour average.

H.III. Justification

H.III.1. Background

H.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a baghouse to control particulate matter emissions.

H.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

H.IV. Rationale for Selection of Performance Indicators

H.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the

monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

H.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

H.IV.2.i. Visible Emissions (Opacity)

(a) Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

H.V. Rationale for Selection of Indicator Ranges

H.V.1. Visible Emissions (Opacity)

H.V.1.i. In the May 21, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, the Source submitted a CAM plan with respect to PM emission limitations. In the May 21, 2010 application, the Source proposed using a baseline opacity monitoring method, akin to the requirements in 40 CFR Part 60, Subpart Da, as an indicator. This method involves establishing a baseline opacity during PM performance testing and then comparing the 24-hour average opacity against the baseline. Any 24-hour average opacity value that exceeds the baseline level shall be cause for investigating the control device.

H.V.1.ii. The inclusion of the short-term opacity indicator of 7.5% over 6 minutes was chosen to reflect the necessity for continuous monitoring which was not completely covered by the Source's request for the baseline opacity monitoring method. A short-term opacity indicator is standard for this size of industrial boiler. The 7.5% value was chosen because it is below the BACT limit of 10% specified in Colorado Construction Permit 12MF322-1. If the baghouse is operating properly, opacity should be below 7.5%. The short-term opacity indicator serves to provide an indication of proper baghouse operation and can be a reasonable indicator that Unit 3 is in compliance with the PM limitations.

I. Appendix I – Coal Handling System for Unit 3 (P102), Secondary Coal Crushing Building (S102d) Particulate Matter Compliance Assurance Monitoring Plan

I.I. Background

I.I.1. Emission Unit Description

I.I.1.i. S102d – Secondary Coal Crushing Building for the P102 Coal Handling System for Unit 3. The building contains two crushers which process coal for Unit 3. The system can also process coal for Units 1 and 2, as necessary.

I.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

I.I.2.i. S102d:

(a) 1.7 tons PM/year, Colorado Construction Permit 12MF322-2 (Condition 7.2).

I.I.3. Monitoring Requirements:

I.I.3.i. Visible emissions; and

I.I.3.ii. Differential pressure monitoring.

I.I.4. Control Technology:

I.I.4.i. The secondary coal crushing building is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

I.II. Monitoring Approach

	Indicator 1	Indicator 2
I. Indicator	Visible Emissions	Differential Pressure Monitoring
Measurement Approach	Visible emissions from the baghouse will be monitored monthly by conducting a six-minute visible emission observation in accordance with the procedures in Method 22 while the crushers are active.	The pressure drop across the baghouse will be monitored on a daily basis. Pre-baghouse and post-baghouse pressures will be reported to a system which will trigger an investigation should the differential pressure exceed the indicator threshold.

	Indicator 1	Indicator 2
II. Indicator Range	An excursion is defined as any visible emissions seen during the Method 22 test. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.	An excursion is defined as a pressure differential of less than 5 inches of water or greater than 8 inches of water. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria		
a. Data Representativeness	Visible emissions from the baghouse under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.	Measurements taken pre- and post-baghouse are used to calculate the differential pressure, indicating proper operation of the control device.
b. Verification of Operational Status	The Source will maintain documentation to verify that the Method 22 has been performed while the system is in operation.	The pressure measurement system will alert the operator if the system is not functioning properly.
c. QA/QC Practices and Criteria	Certification is not required for Method 22 observations, but personnel shall be trained in general procedures for the determination of visible emissions. Persons performing visible emission observations shall be trained in determining the presence of visible emissions. A list of observers trained to perform the visible emission observations shall be maintained.	The pressure monitors will be calibrated maintained, and operated according to manufacturer's specifications. Documentation of all required calibrations and maintenance in accordance with these specifications shall be maintained by the Source.
d. Monitoring Frequency	Monthly	Daily
e. Data Collection Procedures	The EPA Reference Method 22 procedures shall be followed.	The pressure monitors will report on a daily basis to the operator via digital or analog signal. The data will be logged.
f. Averaging Time	N/A	N/A

I.III. Justification

I.III.1. Background

I.III.1.i. The pollutant specific emission unit is a coal processing building which houses two coal crushers. The building is equipped with a baghouse to control particulate matter emissions.

I.III.1.ii. Particulate matter removal is accomplished by passing the particulate laden gases through a porous fabric material. The solid particles buildup on the fabric surface

to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

I.IV. Rationale for Selection of Performance Indicators

I.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

I.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

I.IV.2.i. Visible Emissions

(a) Based on the relationship between particulate matter in a particulate laden gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

I.IV.2.ii. Differential Pressure

(a) The physical action of forcing particulate laden air through the baghouse filters causes a pressure drop of the gas stream. This differential pressure is indicative of normal operation of the baghouse when it remains in a specific range. If the pressure drops below the normal range, it could indicate a preferential pathway through the baghouse. If the pressure rises above the normal range, it could indicate that particulate cake has built up in the system which restricts flow and could cause issues in normal operation.

I.V. Rationale for Selection of Indicator Ranges

I.V.1. Visible Emissions

I.V.1.i. If the control device is operating properly, no visible emissions should be seen during the Method 22 test.

I.V.2. Pressure Differential

I.V.2.i. In the May 1, 2009 application to modify the Title V permit the Source submitted a CAM plan with respect to PM emission limitations for S102d. In the May 1, 2009 application, the Source proposed using differential pressure monitoring. Values outside of the normal operating range of 5 to 8 inches of water shall be cause for investigating the control device. This indicator range is the normal operating range for the baghouse as recommended by the operator.

J. Appendix J – Units 1 and 2 Wet Limestone SO_2 Scrubbers Compliance Assurance Monitoring Plan

J.I. Background

J.I.1. Emission Unit Description

J.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

J.I.2.i. Unit 1:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 1.2.3)

J.I.2.ii. Unit 2:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 2.2.3)

J.I.3. Monitoring Requirements:

J.I.3.i. Continuous SO_2 emissions monitoring.

J.I.4. Control Technology:

J.I.4.i. Units 1 and 2 are equipped with flue gas desulfurization devices (FGD – wet limestone scrubbers) to control SO_2 emissions.

J.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)

	Indicator 1
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the wet scrubber performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

J.III. Justification

J.III.1. Background

J.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a wet scrubber to control SO_2 emissions. The scrubber also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

J.III.1.ii. The limestone reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

J.IV. Rationale for Selection of Performance Indicators

J.IV.1. Units 1 and 2 are equipped with SO_2 CEMS and are equipped with wet limestone scrubbers which are operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 Regional Haze limits is acceptable monitoring for CAM.

J.V. Rationale for Selection of Indicator Ranges

J.V.1. Ongoing monitoring with the CEMS for Units 1 and 2 which shows emissions below the applicable standards presumes continued and successful operation of the wet scrubbers.

K. Appendix K – Unit 3 Lime Spray Dryer SO_2 Compliance Assurance Monitoring Plan

K.I. Background

K.I.1. Emission Unit Description

K.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

K.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

K.I.2.i. Unit 3:

(a) 0.20 lb/MMBtu heat input, daily average, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.1);

(b) 80% reduction of potential combustion concentration of SO_2, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.2);

(c) 2,125 tons of SO_2 per year, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.3);

(d) 0.4 lb/MMBtu heat input 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4. (Condition 3.2.3);

(e) 0.15 lb/MMBtu heat input, 30-day rolling average, Colorado Regulation No. 23, Section IV.B (Condition 3.2.4);

(f) As applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a) (Condition 3.2.2):

(i) 520 ng/J (1.2 lb/MMBtu) heat input and 10 percent of potential combustion concentration (90 percent reduction) (40 CFR Part 60, §60.43Da(a)(1));

(ii) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

(iii) 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

(iv) 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

K.I.3. Monitoring Requirements:

K.I.3.i. Continuous SO_2 emissions monitoring.

K.I.4. Control Technology:

K.I.4.i. Unit 3 is equipped with a flue gas desulfurization device (FGD – lime spray dryer) to control SO_2 emissions.

K.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu or any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the lime spray dryer performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

K.III. Justification

K.III.1. Background

K.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a lime spray dryer to control SO_2 emissions. The spray dryer also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

K.III.1.ii. The lime reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

K.IV. Rationale for Selection of Performance Indicators

K.IV.1. Unit 3 is equipped with an SO_2 CEMS and is equipped with a lime spray-dryer which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 BACT and Regional Haze limits are acceptable monitoring for CAM.

K.V. Rationale for Selection of Indicator Ranges

K.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the lime spray-dryer.

L. Appendix L – Unit 2 SCR Compliance Assurance Monitoring Plan

L.I. Background

L.I.1. Emission Unit Description

L.I.1.i. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

L.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

L.I.2.i. Unit 2:

(a) 0.08 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV (Condition 2.3.3)

L.I.3. Monitoring Requirements:

L.I.3.i. Continuous NO_x emissions monitoring.

L.I.4. Control Technology:

L.I.4.i. Unit 2 is equipped with a selective catalytic reduction system for control of NO_x emissions.

L.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

L.III. Justification

L.III.1. Background

L.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective catalytic reduction system to control NO_x emissions.

L.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream. The reaction is aided by flowing the gas stream through a catalyst. Over time, the catalyst becomes plugged and degraded and requires replacement.

L.IV. Rationale for Selection of Performance Indicators

L.IV.1. Unit 2 is equipped with a NO_x CEMS and is equipped with a SCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

L.V. Rationale for Selection of Indicator Ranges

L.V.1. Ongoing monitoring with the CEMS for Unit 2 which shows emissions below the applicable standards presumes continued and successful operation of the SCR.

M. Appendix M – Unit 3 SNCR Compliance Assurance Monitoring Plan

M.I. Background

M.I.1. Emission Unit Description

M.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

M.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

M.I.2.i. Unit 3:

(a) 0.28 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV.B (Condition 3.3.4)

M.I.3. Monitoring Requirements:

M.I.3.i. Continuous NO_x emissions monitoring.

M.I.4. Control Technology:

M.I.4.i. Unit 3 is equipped with a selective non-catalytic reduction system for control of NO_x emissions.

M.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SNCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

M.III. Justification

M.III.1. Background

M.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective non-catalytic reduction system to control NO_x emissions.

M.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream.

M.IV. Rationale for Selection of Performance Indicators

M.IV.1. Unit 3 is equipped with a NO_x CEMS and is equipped with a SNCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

M.V. Rationale for Selection of Indicator Ranges

M.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the SNCR.

N. Coal Sampling Plan

Rev. 6 – 6/5/2020

Note: Tri-State G & T follows ASTM procedures for coal sampling, sample preparation and sample analyses. In general, Tri-State will endeavor to use the latest revisions of the appropriate ASTM procedures for the equipment in use.

N.I. Coal Sampling

N.I.1. Background

Craig Station operates and maintains three coal sampling systems: A2, A3 and B3. Two of the systems (A3 and B3) are “As Fired” systems that are utilized to sample the day's coal burn in each of the three boilers. The “As Fired” sample results may be used to calculate the potential combustion concentration, or average inlet emission rate, of sulfur dioxide derived from the burning of coal in the boilers. This coal sampling plan therefore, describes the sampling, analysis and data management for the "As Fired” Samples.

Coal is delivered to Craig Station by truck and train. Each delivery is processed through the station's coal handling system. Coal from any delivery system can be used in any one, or all three, of the station's coal fired boilers.

N.I.2. A3 - As Fired Sampling System

This sampling system is located on A5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the A3 Sampling System because it samples coal that is weighed by scales located on the A3 conveyor system.

N.I.3. B3 - As Fired Sampling System

This sampling system is located on B5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers. Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the B3 Sampling System because it samples coal that is weighed by scales located on the B3 conveyor system.

N.I.4. Coal Sampler Operation And Maintenance

All of the station coal samplers are set up and operated using the practices defined in ASTM D2234-99, Standard Practice for Collection of a Gross Sample of Coal.

Coal Handling Operators monitor the coal sampler operation. When the Samplers are in-service they discharge samples into heavy plastic bags attached to the sampler discharge. When the sampling is complete the Operator seals the sample bag, weighs the total sample, and labels each sample bag. The sample label identifies the Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The Operator then transfers the sealed and labeled sample bags to a protective container in a secured area to await pickup by a Laboratory Technician.

N.II. Sample Preparation and Laboratory Analyses

N.II.1. Sample Pickup and Preparation

Laboratory Technician retrieves the coal samples from the protected storage, checks the sample bags for damage, checks the labeling and rechecks the sample weight. The Technician then moves the samples to the Coal Preparation Laboratory where they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information, the Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet.

The Technician prepares the samples for analysis in the Coal Preparation Laboratory in accordance with ASTM 2013-00, Standard Method of Preparing Coal Samples for Analysis.

N.II.2. Coal Preparation Laboratory Sample Analyses

The Technician analyzes the samples for moisture using the procedures defined in ASTM D3302-00a, Standard Test Method for Total Moisture in Coal.

N.II.3. Main Chemistry Laboratory Sample Analyses

The 60 mesh samples prepared in the Coal Preparation Laboratory are taken to the Main Chemistry Laboratory where they are analyzed as described in the ASTM procedures as cited below.

N.II.3.i. ASTM D3173-00, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke

N.II.3.ii. ASTM D5865-00, Standard Test Method for Gross Calorific Value of Coal and Coke

N.II.3.iii. ASTM D3174-00, Standard Test for Ash in the Analysis Sample of Coal and Coke from Coal

N.II.3.iv. ASTM D4239-00, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods

N.II.4. Laboratory Data Management

Laboratory data and results from the sample analyses for moisture, calorific value, ash and sulfur are entered and maintained in the Tri-State G & T Fuels Data Management System. The tonnage from vendor coal deliveries and daily coal burns are also maintained within the data management System.

N.III. Chain-Of-Custody Method

N.III.1. The sample chain-of-custody begins with each of the coal sampling systems described above. Prior to starting a sampling system, the Coal Board Operator identifies the origin of the coal to be sampled. This information is noted on sample identification labels. The sampling process is started and the Coal Handling Operator monitors the sampler system until sampling is complete.

N.III.2. When the sampling is completed the Coal Handling Operator seals the sample bags and labels the sample bags with the following information: Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The samples are then placed in a secure and protected location until a Laboratory Technician retrieves them.

N.III.3. When a Laboratory Technician retrieves the samples from the sampler area, and moves them to the Coal Preparation Laboratory, they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information along with Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet. This process identifies the sample label information as well as who is now handling the samples in the Coal Preparation Laboratory.

N.III.4. When the prepared samples are moved to the Main Chemistry Laboratory for analysis, they are transferred in sealed sample bottles labeled with the Sample ID. In the Main Laboratory the samples are analyzed according to the Sample ID and the names of the Technician(s) performing the analyses are noted on the Fuels Analysis Sample Prep Log Sheet.

N.III.5. The Technician who enters the laboratory data and results from the sample analyses into the Tri-State G & T Fuels Data Management System enters their name as Data Entry Technician on the Fuels Analysis Sample Prep Log Sheet.

N.IV. Coal Shipment and Sample Analysis Records

N.IV.1. Coal shipment and sample analysis records are maintained by the TriState G & T Craig Station and are available for review by the Division upon request. Craig Station maintains paper copies of the records for one year. The records are also kept electronically in Tri-State G & T's Fuels Data Management System.