Decision No. C25-0747

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24A-0442E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2024 JUST TRANSITION SOLICITATION.

PHASE I COMMISSION DECISION

Issued Date: November 6, 2025
Adopted Date: August 6, 13, 18, 21, and 27, 2025

TABLE OF CONTENTS

I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission approves, with modifications, the Verified Application for Approval of a 2024 Just Transition Solicitation ("JTS") filed by Public Service Company of Colorado ("Public Service" or the "Company") on October 15, 2024. The JTS ties to Public Service's most recent Electric Resource Plan ("ERP") in Proceeding No. 21A-0141E that included a Clean Energy Plan ("CEP") (the "2021 ERP/CEP"). The 2021 ERP/CEP was filed in accordance with § 40-2-125.5, C.R.S. and established the plan for

Public Service to reduce its carbon dioxide emissions by 80 percent by 2030. The JTS continues to execute the plan from the 2021 ERP/CEP and, as initially filed, seeks to address Public Service's need for additional resources from 2029 through 2031, including replacement resources for the Pueblo Unit 3 coal-fired power plant that is set to retire by January 1, 2031.

2. Through this Decision, we establish a pathway for Public Service to acquire the generation and storage resources necessary to replace Unit 3, reliably serve existing and future customers, continue progress on emissions reductions, and help ensure a just transition. At the same time, we require additional customer protections to help protect Colorado ratepayers from the risks associated with investments made to serve prospective large loads like data centers. We also largely adopt Public Service's proposed tools for ensuring a just transition, including community assistance payments, modeling approaches that encourage the selection of new resources within certain just transition communities, and the carbon free future development ("CFFD") proposal. Ultimately, this Decision provides the necessary regulatory certainty for Public Service to move to Phase II in which the Company will solicit and evaluate various bids for new generation and storage resources, compile these bids into various resource portfolios, and present its preferred resource portfolio in the Phase II 120-Day Report.

3. Consistent with the discussion below, we authorize Public Service to implement competitive bidding processes for acquiring cost-effective resources to meet its projected resource need through 2033 and model such bids consistent with the modeling processes and assumptions set forth in this Decision. Among our directives in this Decision, we also address the Company's proposed conforming bid policy, adopt the Company's best value employment metrics ("BVEM"), address certain rule waiver requests, and require the Company to file for approval of an independent evaluator to assist in the established solicitation process.

4. This Decision builds on past ERP processes integral to Colorado's iterative proceedings that establish resource need, address critical state regulatory requirements, and – of particular importance here – continue imperative processes to further support Colorado communities towards a diverse and economically sustainable energy future. In addition, the processes approved in this Decision create flexible opportunities for committed large load growth, while at the same time protecting Colorado ratepayers from development that is more speculative by providing a framework to update the load forecast in the Phase II process.

5. As discussed in detail below, these dynamic competitive bidding processes paired with confirmation of community assistance considerations and credit modeling designed to balance state priorities, ratepayer impacts, environmental impacts, and community support, and at the same time maintain a reliable and robust energy future. While no specific resources are selected or determined at this phase of the process, the process and considerations weighed in it set in motion important future determinations both as next steps and concurrent with ongoing acquisitions to meet resource needs.[1]

B. Background

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

[1] Not only is Colorado meeting future acquisition needs here, but it continues to fill resource needs in an ever-changing environment through ongoing processes in its ongoing and most recent ERP, Proceeding No. 21A-0141E, both through a stepped approach addressing bid flexibility and in near term project acquisition opportunities. While each of these proceeding processes is separate, they work in concert through stepped and phased considerations to best ensure prudent paths forward to address Colorado's energy needs.

that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

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

8. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources. In Phase II, the Commission determines whether the utility should be granted a presumption of prudence for pursuing the acquisition of particular resources.

9. Rule 4 CCR 723-3-3617(c) describes the contents of the Commission's Phase I decision:

> The Commission decision approving or denying the plan shall address the contents of the utility's plan filed in accordance with rule 3604. If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria; and, the alternate scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources.

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

11. At the end of Phase II, the Commission issues a final decision that will approve, condition, modify, or reject the utility's preferred cost-effective resource plan. Rule 4 CCR 723-3-3613(h) describes the contents of a Phase II decision:

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

12. Public Service shall pursue the final cost-effective resource plan in accordance with the Phase II decision, either with due diligence reviews and contract negotiations, or with applications for Certificates of Public Convenience and Necessity ("CPCNs"), as necessary, in accordance with Rule 4 CCR 723-3-3613(h).

13. Additionally, while the above rules and competitive bidding processes are foundational to the Commission's utility resource planning process, subsequent legislative changes, including Senate Bill ("SB") 19-236 further overlay CEP considerations on the Commission's ERP processes. Generally, SB 19-236 enacted § 40-2-125.5(1)(e), C.R.S., which declares the statewide importance of promoting cost-effective clean energy and new technologies

and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost."[2]

14. Just like SB 19-236 iterates on the Commission's ERP process, the Commission's ERP decisions—particularly since the 2012 ERP—are iterative. These ERP decisions build on continuous planning processes, including important state goals that advance a strategic balance of objectives, including maintaining reliability, achieving emission reduction targets, ensuring continued affordability, and supporting local communities. In the 2016 ERP, for example, litigation resulted in consideration of the social cost of carbon ("SCC"), in addition to other pertinent factors. Likewise, the Company's voluntary proposal for the accelerated retirement of Unit 2, which will be implemented at the end of this calendar year, created the opportunity for additional, diverse and reliable resources in addition to important opportunities for transmission interconnection capacity. These opportunities have since been realized through subsequent proceedings,[3] and the ongoing electric resource planning processes. The 2016 ERP, the 2021 ERP/CEP, and other Commission planning decisions relied on the accelerated retirement of Unit 2 when approving the acquisition of additional resources and in planning for the transmission capacity that these new resources would use.[4] The timing and impact of Unit 2 further underlies

[2] Section 40-2-125.5(3)(a), C.R.S., requires that, in addition to the other requirements of the section, Public Service shall meet the following clean energy targets: "(I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels[; and] (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generated from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest, and consistent with the requirements of this section."

[3] *See*, *e.g.*, Hr. Ex. 101, Pascucci Direct Testimony, p. 11 in Proceeding No. 24A-0140E (noting interconnection replacement and substation use given the anticipated shutdown of Unit 2).

[4] *See* Verified Application for Approval of CPCN for Rocky Mountain Project and Arroyo 2 Project, p. 5 in Proceeding No. 24A-0140E.

the Company's claims regarding the continued need for and support of Unit 3.[5] Through the years, the Commission has reviewed parallel cost calculation and depreciation filings for decommissioned generating units, ensuring regulatory certainty and reducing rate impacts.[6]

15. The iterative nature of the Commission's ERP processes also appears in the development of the JTS, which first appears in the Updated Non-Unanimous Partial Settlement Agreement ("USA") that Public Service filed in the 2021 ERP/CEP in April 2022. The JTS ties to provisions in the USA that Unit 3 will retire no later than January 1, 2031. The Unit 3 retirement date in the USA harmonizes with the timing of this JTS, which is intended to help procure the replacement generation for Unit 3 in a way that will help ensure a just transition for the Pueblo community.[7] Because the JTS solicitation was intended to address Public Service's resource needs from 2029 through 2031, it allowed the resource acquisition period ("RAP") in the 2021 ERP/CEP to be truncated such that Public Service would only acquire resources with in-service dates on or before December 31, 2028.

16. The USA requires Public Service to commence the JTS no later than June 1, 2024, and the Commission approved this date in Decision No. C22-0459 ("CEP Phase I Decision") in the 2021 ERP/CEP. On April 22, 2024, however, Public Service filed an Unopposed Motion for Variance to File Just Transition Solicitation no later than August 1, 2024. The Commission granted this Unopposed Motion. Subsequently, on July 17, 2024, Public Service filed another Unopposed Motion to delay the filing of the JTS to no later than October 15, 2024, which the Commission also granted.

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[5] *See, e.g.*, Hr. Ex. 164, Pascucci Supplemental Testimony, Rev. 1, p. 17 in the 2021 ERP/CEP (stating that the accelerated retirement of Unit 2 necessitates the construction of an auxiliary boiler for Unit 3).

[6] *See*, *e.g.*, Proceeding No. 16A-0231E.

[7] *See* 2021 ERP/CEP USA at ¶ 43.

C. Procedural History

17. On October 15, 2024, Public Service filed a Verified Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation ("Application"). The Company submitted Direct Testimony of nine witnesses in support of the Application.

18. In conjunction with its application, on October 15, 2024, Public Service filed an Omnibus Motion for Extraordinary Protection of Highly Confidential Information, and for Partial Waiver of Rules 3606(b), 3612(a), 3618(b)(I), 3613(a) and 3613(d) and waiver of Rule 3608(c)(III)-(IV) ("Omnibus Motion").

19. Through Decision No. C24-0872-I, issued November 22, 2024, the Commission, among other things, set the matter for hearing before the Commission *en banc* and established parties to the Proceeding. Parties consist of the following: Public Service, Trial Staff of the Commission ("Staff"); the Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"); Holy Cross Electric Association, Inc. ("Holy Cross"); Colorado Energy Consumers ("CEC"); Climax Molybdenum Company ("Climax"); Walmart Inc. ("Walmart"); Natural Resources Defense Council ("NRDC") and Sierra Club (collectively, the "Conservation Coalition"); Western Resource Advocates ("WRA") and Southwest Energy Efficiency Project ("SWEEP"); Healthy Air and Water Colorado ("HAWC"); GreenLatinos, GRID Alternatives, NAACP State Conference CO-MT-WY, Pueblo Branch ("NAACP"), Roots to Resilience and Vote Solar (collectively, the "Environmental Justice Coalition" or "EJC"); Pivot Energy Inc. ("Pivot Energy"); the Colorado Renewable Energy Society ("CRES") and the Physicians for Social Responsibility Colorado ("PSR CO") (collectively, "CRES/PSR"); the Board of County Commissioners of Pueblo County ("Pueblo County Board"), City of Pueblo, and Pueblo Economic Development Corporation ("PEDCO") (collectively, "Pueblo Intervenors"); Moffat County,

Colorado ("Moffat County") and the City of Craig, Colorado ("City of Craig") (collectively "Moffat and Criag"); the Town of Hayden, Colorado ("Town of Hayden") and Routt County, Colorado ("Routt County") (collectively, "Routt County Governments"); Colorado Communities for Climate Action ("CC4CA"); Interwest Energy Alliance ("Interwest"); the Colorado Independent Energy Association ("CIEA"); Onward Energy Management LLC ("Onward"); the Coalition for Community Solar Access ("CCSA"); the Eastern Metro Area Business Coalition ("Business Coalition"); the Colorado Solar and Storage Association ("COSSA"), the Solar Energy Industries Association ("SEIA"), and Advanced Energy United ("AEU") (collectively, the "Clean Energy Industry"); and the Office of Justic Transition ("OJT").[8]

20. Through Decision No. C24-0876-I, issued November 27, 2024, the Commission deemed the Application complete for purposes of § 40-6-109.5, C.R.S., and allowed the Application to automatically deem complete on November 30, 2024.

21. Through Decision No. C24-0941-I, issued December 23, 2024, the Commission, among other things, referred future discovery disputes to an Administrative Law Judge and set a deadline for Staff to make a filing addressing the Independent Transmission Analyst ("ITA") scope of work. The Commission also addressed certain requested waivers in the Company's Omnibus Motion but deferred the remaining requested waivers.

22. On December 31, 2024, through Decision No. C24-0956-I, the Commission directed Public Service to file Supplemental Direct Testimony addressing certain topics.

23. On January 22, 2025, the Commission, through Decision No. C.25-0049-I, vacated the prehearing conference.

[8] In addition to the parties established through this order, through Decision No. C25-0366-I, issued May 13, 2025, the Commission denied the *pro se* late intervention filed by Mr. David Thielen.

24. Through Decision C25-0064-I, issued January 29, 2025, the Commission established a procedural schedule, scheduled a remote evidentiary hearing, set procedures for the evidentiary hearing, and directed certain modifications to Staff's scope of work for the ITA. Through this same decision, the Commission also granted the Company's request to extend the deadline to file the previously ordered supplemental direct testimony.

25. Through Decision No. C25-0097-I, issued February 13, 2025, the Commission set a technical conference for March 20, 2025, later rescheduled to March 13, 2025,[9] to address certain models and forecasts Public Service put forth in both this Proceeding as well as the Company's Distribution System Plan.

26. Subsequently, through Decision No. C25-0147-I, issued February 28, 2025, the Commission clarified procedures and adopted an agenda for the technical conference.

27. Public Service, in response to Decision No. C24-0956-I, filed supplemental direct testimony on February 21, 2025.

28. The Commission held a remote technical conference on March 13, 2025, during which the following six categories of information were addressed: (1) electric vehicles ("EVs") and managed charging, (2) beneficial electrification ("BE"), (3) large new loads such as data centers, (4) the 8760 process for peak load forecasts and LoadSEER, (5) the long-term residential customer rate analysis, and (6) a miscellaneous category.[10]

29. On March 25, 2025, through Decision No. C25-0219-I, the Commission added two additional in-person public comment hearings and one remote public comment hearing to the procedural schedule. The public comment hearings were scheduled as follows: (1) an in-person

[9] The initial date for the technical conference was March 13, 2025. The Commission, through Decision C25-0147-I, issued February 28, 2025, granted the Company's request to reschedule the technical conference to March 20, 2025.

[10] The Commission directed the Company to address these categories in Decision No. C25-0168-I.

public comment hearing in Pueblo, Colorado on April 17, 2025; (2) a remote public comment hearing on April 28, 2025; and (3) an in-person public comment hearing in Hayden, Colorado on May 1, 2025.

30. On March 28, 2025, the Commission granted an unopposed motion for intervention out of time by Grid United, LLC ("Grid United") and Grid United became a party to this Proceeding.

31. Through Decision No. C25-0252-I, issued April 3, 2025, the Commission, among other things, granted an Unopposed Motion for Limited Participation filed by the Colorado Department of Public Health and Environment ("CDPHE") to provide a neutral verification review of the Company's Base Portfolio in Phase I and the preferred portfolio submitted in Phase II of this Proceeding. The Commission also clarified that the Phase II Verification Report should be filed 30 days after the Company's submission of its 120-day report.

32. Through Decision No. C25-0279-I, issued April 11, 2025, the Commission denied a motion to reschedule the Pueblo public comment hearing filed by the Environmental Justice Coalition, CRES/PSR. Also through Decision No. C25-0279-I, the Commission added another remote public comment hearing scheduled for June 5, 2025.

33. On April 2, 2025, Public Service filed Hearing Exhibit 115, which provided for the Strategic Reliability Reserve Fund concept. The Company stated this strategic reserve fund was designed to manage supply chain challenges and secure combustion turbines and transformers for the benefit of Colorado customers during the JTS RAP (which ends in 2031).

34. Parties filed Answer Testimony on April 18, 2025.

35. On May 2, 2025, through Decision No. C25-0343-I, the Commission granted, in part, a motion filed by CC4CA requesting that Public Service file supplemental testimony

explaining and supporting the strategic reserve fund proposal. The Commission extended discovery on the limited issue of the strategic reserve fund through the cross-answer testimony deadline of May 23, 2025, and identified specific questions for the Company to address in its supplemental direct.

36. The Company filed supplemental direct testimony regarding the strategic reserve fund on May 9, 2025.

37. Parties filed Rebuttal and Cross-Answer testimony on May 23, 2025.

38. Prior to the evidentiary hearing, in accordance with Decision Nos. C25-0279-I and C25-0219-I, the Commission held four public comment hearings: two were held in-person in the communities of Pueblo and Hayden, and two were conducted remotely.

39. A remote evidentiary hearing was held before the Commission *en banc* on the following dates: June 10-13, 17-18, 20, 23, and 24, 2025. At the start of the evidentiary hearing, the Commission admitted all pre-filed testimony and attachments into the evidentiary record as Hearing Exhibit 2800. During the course of the hearing, the Commission admitted the following hearing exhibits that were offered by parties during their cross-examination or re-direct of witnesses: Hearing Exhibits 112 JLB-1 rev. 1, 126, 127HC, 131, 132, 133, 134, 135, 137, 138, 140HC, 140 (public), 141 restricted HC, 141 (slip), 143, 302, 311 312, 314, 315, 403, 404, 406, 407, 408, 409, 410, 411, 413, 414, 700, 701, 700C, 700HC, 701HC, 700 Att. WAM-5, 700 Att. WAM-5C, 705, 710, 715, 717, 722, 805, 1002, 1306, 1307, 1308HC, 1310, 1403, 1403 Att. 4-1.A1, 1403 Att. 4-1.A2, 1403 Att. 4-1.A3, 2005, 2006, 2007, 2009, 2103, 2105, 2106, 2208, 2208 (executable), 2209, 2212, and 2608. In addition, the Commission took administrative notice of the following Hearing Exhibits: 405, 412, 415, 704, 707, 717, 1704, and 2210.

40. Through Decision No. C25-0514-I, issued July 11, 2025, the Commission extended the deadline for parties to file their Statements of Position ("SOPs") to July 17, 2025, and invited parties to include legal arguments and discussion in their SOPs addressing the impacts that the recently passed federal Reconciliation Bill may have on this Proceeding.

41. Parties filed SOPs on July 17, 2025.

42. On August 4, 2025, Moffat County and the City of Craig filed a motion to strike portions of Pueblo Intervenors' SOP. Through Decision C25-0581-I, issued August 7, 2025, the Commission set a shortened response time to the motion to strike, and Pueblo Intervenors filed a response on August 11, 2025.

43. The Commission deliberated at its August 6, 13, and 27, 2025 Commissioners' Weekly Meetings, as well as at Commissioners' Deliberations Meetings held on August 18 and 21, 2025, resulting in this Decision.

44. Finally, in addition to the evidence admitted during the evidentiary hearing, the administrative record for this Proceeding includes numerous written public comments from individuals, organizations, and elected officials.

D. Public Service's Proposed JTS

45. Given the ERP and CEP structures described above, Public Service's JTS seeks to identify and develop a framework to acquire sufficient resources to meet growing energy and capacity needs and provide new tools such as the CFFD proposal to identify carbon free dispatchable resources like advanced geothermal and nuclear that can provide service in a low- or zero-emission manner. Public Service lists several objectives for the JTS, including achieving an

80 percent emissions reduction by 2030, maintaining reliability in a load-growth environment, delivering a just transition, and improving Colorado's ERP process.[11]

46. Regarding just transition, Public Service's JTS reaffirms the community assistance framework in the 2021 ERP/CEP's USA in which Pueblo County would receive 10 years of payments and Routt County and Morgan County would receive six years of payments, with such payments being offset by any infrastructure investments in the communities. Public Service also offers to "facilitate discussions" with large new loads such as data centers to potentially site these loads in just transition communities.[12] In addition, Public Service seek Commission approval to hardwire certain changes to the Phase II modeling in an effort to drive additional investments in just transition communities. Specifically, the Company proposes to apply a modeling benefit, either in the form of a \$/kW-month or a \$/MWh, to projects in just transition communities. This modeling benefit would be in addition to the property tax tail/offset approach used in the 2021 ERP/CEP. Together, this would essentially make projects located Routt County, Morgan County, and Pueblo County look more economic for purposes of the Phase II modeling and increase the chance that such projects would be included in the approved portfolio of resources.[13]

47. As for the improvements to the ERP process, Public Service proposes several modifications for Phase II the Company asserts are necessary given current and future dynamics. For instance, the Company seeks approval of a conforming bid policy to make the bid evaluation and PPA negotiation process more efficient. In addition, the Company proposes to allow submission of pre-construction development asset bids that will supplement and serve as backups

[11] Hr. Ex. 101, Att. JWI-1, pp. 7-8.
[12] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 52.
[13] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 47-48.

to the Commission's approved Phase II portfolio. The Company also asks that the Commission proactively decide to apply a 120-day timeline for CPCNs arising from the JTS.[14]

48. To meet the objectives of continued emissions reductions and maintaining reliability in an environment where load is increasing, Public Service requests the Commission be prepared to approve in Phase II a large resource portfolio. In particular, in its Direct Testimony, Public Service argued that it would need to acquire almost 14,000 MW of new resources in Phase II.[15] For context, the approved portfolio in the 2021 ERP/CEP, the largest in Colorado's history, was comprised of approximately 5,900 MW resources.[16] In addition emissions reductions and reliability benefits, Public Service argues that Phase II approval of a large resource portfolio will attract new economic development to Colorado. The Company asserts that meeting load growth the right way can bring long-term rate benefits to customers.[17]

49. In its Direct Testimony, the Company proposed acquiring this large portfolio of resources through one RFP with a RAP through 2031. As discussed below, however, Public Service significantly modified its approach in Rebuttal Testimony when it introduced the Phase II Framework. Among other things, the Phase II Framework contemplates a base RFP, a supplemental RFP, and an incremental need pool to quickly respond to changing conditions. The Company now argues that approval of the Phase II Framework is the "fundamental decision needed in this Phase I. . . ."[18]

[14] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 40-42.
[15] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 10.
[16] Decision No. C24-0052, issued January 23, 2024, ¶ 92 in the 2021 ERP/CEP.
[17] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 10.
[18] Public Service's SOP at p. 2.

E. Phase II Framework and Large Load Forecasts

1. Overview

a. Party Positions

50. Several factors led to the Company's estimate that it would need a large resource portfolio in Phase II, including the retirement of coal facilities within the JTS's RAP and projected load from both new EV charging and beneficial electrification. The single largest driver of the Company's projected load growth, however, was speculation on new large loads like data centers. More specifically, for its base load forecast in Direct Testimony, the Company calculated that new data centers were anticipated to account for 62 percent of the projected energy growth and 72 percent of the projected peak demand growth.[19]

51. In response to Intervenor concerns noting the speculative nature of this significant large load growth, costs to ratepayers, stresses on the system, and impacts on emission reduction goals, Public Service substantially modified its approach to Phase II in Rebuttal, and continued to tweak its proposed approach through the hearing as it reached agreement with Staff, CEO, and CIEA on a Phase II Framework.[20] Among other things, the Phase II Framework proposes significant modifications to the standard ERP Phase II process that add flexibility, including a base RFP that would target resources through 2031 and a supplemental RFP in mid-2027 that would target resources through 2033. In addition, the Phase II Framework proposes an incremental need pool consisting of paid backup bids. If a project from the approved portfolio fails or additional load materializes after the JTS Phase II Decision, the Company could activate projects from the incremental need pool in an expedited manner. The Phase II Framework includes a process and

[19] Hr. Ex. 101, Ihle Direct, pp. 28-29.
[20] The details of the Phase II Framework are set forth in Hr. Exs. 144 and 145.

set of next steps to advance additional transmission investment. Under the Phase II Framework, the Company also commits to use the large load commercial principles it set forth in Rebuttal and to make a large load tariff filing no later than January 31, 2026.[21]

52. Public Service characterizes this updated Phase II Framework as the "cornerstone" of the JTS.[22] Among other benefits, the Company states the Phase II Framework provides a dynamic approach to addressing large load additions, including the ability to self-adjust by procuring new resources through the incremental need pool and the supplemental RFP.[23] In this way, the Phase II Framework is proposed as a flexible process that ensures increases in realized large load can be accounted for through the next phase of these proceedings, while also recognizing the filing of subsequent ERP proceedings and ongoing CEP processes regarding near-term acquisitions can also address and make prudent regulatory steps forward regarding Colorado's resource needs.

53. The Phase II Framework assumes the use of the Company's updated base forecast. Compared to the base forecast, the primary difference in the updated base forecast is that the Company only includes large loads that have reached an 80 percent probability (*i.e.*, the data center is negotiating either an electric service agreement ("ESA") or interconnection agreement ("IA") with the Company). In its updated base forecast, the Company retains a group of non-data center prospective loads it categorizes as strategic economic development customers. The Company claims that most information regarding these strategic economic development customers is confidential but states that several have existing facilities in Colorado. While none of the strategic

[21] Hr. Ex. 144, JTS Phase II Framework Redline, p. 5.
[22] Public Service's SOP at p. 2.
[23] Public Service's SOP at p. 3.

economic development customers have reached an 80 percent probability, the Company asserts that the core impediment to negotiating and signing an ESA or IA is the lack of certainty in power.[24]

54. In Rebuttal Testimony, the Company acknowledges that large load customers present risks to existing customers that should be mitigated. In addition to its reduced updated load forecast, the Company asserts that it reduces risk to existing customers by adopting certain commercial principles in its negotiations with large load customers over 100 MW. These commercial principles include customer protections designed to ensure that large customers "have sufficient 'skin in the game' to avoid the risk of procuring generation for speculative new load or procuring load for customers that may move projects to different jurisdictions or disappear altogether."[25]

55. Despite the changes Public Service makes in Rebuttal Testimony such as the reduced updated load forecast and commercial protections, several parties continue to raise concerns that costs for existing customers could inappropriately increase to pay for resources procured to serve large load customers. For instance, WRA and SWEEP argue the record in this Proceeding shows service requests from large loads are uniquely speculative. They reference the fact that even during the pendency of this Proceeding several projected large load customers withdrew their interconnection requests. Moreover, WRA and SWEEP argue the current approach to cost allocation grossly underrepresents the system costs driven by new large loads and assert that residential rates could potentially increase by 50 percent by 2031.[26] WRA and SWEEP also assert that projected demand for large loads has the potential to significantly increase greenhouse gas emissions from Public Service's system, at the exact same time that the Company is seeking

[24] Hr. Ex. 117, Ihle Rebuttal, p. 33.
[25] Hr. Ex. 123, Bailey Rebuttal, p. 41.
[26] WRA's SOP at p. 7.

to decarbonize to meet state clean energy goals. WRA and SWEEP state that responding to speculative interconnection requests from large loads is fundamentally a risk allocation problem. The Company has not agreed to share that risk, and the Company's proposed approach with the commercial principles provides limited risk protection for ratepayers.[27]

56. Conservation Coalition raises similar concerns and states the fundamental problem with the Company's approach is that ratepayers would pay for additional generation resources for new large loads *before* the large loads contractually commit to any customer protections in the commercial principles.[28] Conservation Coalition notes the Company tries to downplay this risk by arguing that other large load customers will materialize if the current ones fail to commit, but during the evidentiary hearing the Company refused to commit to share the financial risk of any associated stranded assets.[29] Conservation Coalition asserts that if the Company and its shareholders are not willing to bear any of the downside risk of Public Service's own proposal, Public Service's ratepayers should not bear that risk either.

57. Conservation Coalition specifically argues that the Commission should exclude large load customers for the load forecast until they sign long-term contracts implementing customer protections. Conservation Coalition argues this would provide certainty to both the Company and new large loads because the Commission would be authorizing the Company to acquire additional resources once the large loads contractually commit to customer protections. Conservation Coalition states the Company has failed to articulate any legitimate concern with requiring large loads to commit to customer protections before Public Service procures additional generation to serve them.[30]

[27] WRA's SOP at p. 8.
[28] Conservation Coalition's SOP at p. 21
[29] Conservation Coalition's SOP at p. 22 (citing Hr. Tr. June 18, 2025, pp. 75-76).
[30] Conservation Coalition's SOP at p. 21.

58. CEC takes a similar position as Conservation Coalition, WRA, and SWEEP. This is particularly noteworthy given that CEC's members are all large industrial electric customers.[31] In its SOP, CEC argues for a conservative and flexible load forecast and for mitigating the risks of overinvestment. CEC argues the unprecedented uncertainty in the new large load forecast requires protective measures that ensure existing customers are not harmed by new large loads. One such protective measure CEC advances is the "fair notice" concept in which prospective large new loads are made aware that they will be moved to the future large load tariff. CEC acknowledges the Company's concerns with this concept but notes that a "fair notice" provision "should not be an insurmountable hurdle for new large customers who are willing and able to pay the appropriate share of their cost of service."[32]

59. UCA similarly argues throughout the Proceeding that the Commission must ensure that non-large load customers are neither harmed nor forced to incur higher rates due to new large loads.[33] UCA proposes several modifications to the Company's commercial principles to reduce the risk to non-large load customers.

60. On the other hand, the Business Coalition supports the Company's JTS, stressing that the Company must have sufficient resources to meet the expanding needs of existing customers. The Business Coalition acknowledges there is no guarantee that the proposed new loads will all come online as anticipated, but asserts that Denver and Colorado have historically experienced positive migration.[34] The Business Coalition further argues that even if the forecasted demand does not materialize precisely as scheduled, the additional capacity on the system could

[31] CEC's Motion to Intervene, p. 3.
[32] CEC's SOP at p. 14.
[33] UCA's SOP at p. 1.
[34] Business Coalition's SOP at p. 3.

then be available for other new customers to utilize without the attendant delays in planning, permitting and constructing new generation and transmission.[35]

b. Findings and Conclusions

61. We find persuasive the concerns raised by intervenors that uncommitted new large load customers could inappropriately and dramatically increase rates for existing customers while also increasing greenhouse gas emissions. At the same time, we recognize the benefits of having greater flexibility within a dynamic Phase II process and appreciate the Phase II Framework. We therefore modify which large loads can be included in the Company's initial load forecast, while at the same time and as discussed further in this Decision, allow a phased in approach through Phase II should additional load materialize.[36]

62. Particularly under the Company's Direct Testimony proposal, ratepayer funds would be used to procure massive amounts of new generation to serve new large loads like data centers before such loads sign an ESA or IA or agree to any of the customer protections within the commercial principles. Out of all the parties in this Proceeding, Public Service is in the best position to know the likelihood of the large loads actually connecting to its system and purchasing electricity, yet even in its more recent positions taken in this proceeding, the Company stated it is unwilling to share the financial risk of the large loads ultimately not materializing.[37] At the same time, this Commission finds compelling party responses that warn against placing the financial risk of large loads that may not materialize on existing Colorado customers. If WRA and SWEEP's

[35] Business Coalition's SOP at p. 4.

[36] While separately decided, this Decision is also considered in the context of years of electric resource planning process procurements in Colorado, ongoing CEP procurements, and in light of future ERP considerations that will also allow measured approaches to ensuring Colorado's resource needs are met. It is in this ecosystem of measured regulatory action that the Commission here continues a reasoned approach that avoids actions that could unreasonably burden ratepayers or emission targets, while providing a path forward for realized load increases in the short and long-term planning processes.

[37] Hr. Tr. June 18, 2025, pp. 75-76.

warning of 50 percent higher rates for existing residential and other customers comes to pass, it could jeopardize other State objectives, including increasing beneficial electrification ("BE"), promoting the adoption of electric vehicles ("EVs"), and continued economic development.

63. Rather than allowing Public Service to spend money acquiring resources as soon as a large load customer begins negotiating an ESA or IA, large load customers—including the largely confidential strategic economic development customers—must first contractually commit their load additions and the customer protections within the commercial principles as modified by this Commission before they can be included in the load forecast. The Company characterizes the commercial principles as ensuring that large customers "have sufficient 'skin in the game' to avoid the risk of procuring generation for speculative new load. . . ."[38] Public Service has failed to explain why the Company should be allowed to acquire through these ERP competitive bidding processes additional generation before large loads agree to put "skin in the game." A prudent path forward ensures these large loads will commit to Colorado in a way that equitably allocates the costs and benefits associated with serving their load, prior to including them in the load forecast. Overinclusion could risk burdening ratepayers for decades without cause. As discussed below, because we largely adopt the Phase II Framework, Public Service has opportunities through the incremental need pool and supplemental RFP to acquire additional resources in response changing circumstances, including additional large load customers contractually committing to customer protections. The incremental need pool is available after the JTS Phase II decision approving a resource portfolio from the base RFP, and the supplemental RFP is scheduled to issue in 2027. In 2028, the Company is set to file a new ERP application. These pathways in the Phase II

[38] Hr. Ex. 123, Bailey Rebuttal, p. 41.

Framework are in addition to other regulatory pathways the Company has, such as filing a standalone CPCN application for new resources, which it can do at any time.

64. The record in this Proceeding demonstrates how easily large customers can withdraw their interconnection requests even after negotiating an ESA or IA with the Company. Public Service acknowledges that during the period between the Company's Direct and Rebuttal Testimony filings, one of the Company's largest prospective large-load customers withdrew its interconnection request. This withdrawal and the corresponding impact to the load forecast occurred even though this customer was beyond simply negotiating an ESA or IA and had 90 percent probability.[39] Despite this and other evidence regarding the speculative nature of large load customers,[40] Public Service maintains its position that it should be allowed to procure additional generation as soon as a new large load begins negotiating an IA or ESA. We reject this approach and the unnecessary risks it would impose on existing customers.

65. Public Service argues it is in a "chicken and egg" situation regarding large loads in that many new large customers are eager to execute an IA and ESA with the Company, but both the Company and the large customers need certainty that the Company will be able to procure and supply the necessary generation before executing such agreements.[41] As set forth above, allowing the Company to procure a surplus of new generation to attract prospective large customers places an unacceptable amount of risk on the existing customers who will pay for the surplus generation. Nevertheless, by largely adopting the Phase II Framework's incremental need pool and supplemental RFP, our Decision provides greater regulatory certainty to prospective large

[39] Hr. Ex. 123, Bailey Rebuttal, p. 13.

[40] *See e.g.*, Hr. Ex. 1301, Eiden Answer, p. 30; Hr. Ex. 303, Sommer Answer, pp. 8-9; Hr. Ex. 123, Bailey Rebuttal, p. 21 (acknowledging concerns regarding "forum shopping" "where a single project engages with multiple utilities, waiting to see which it is able to procure power from most expeditiously.").

[41] Hr. Ex. 123, Bailey Rebuttal, pp. 10-11.

customers and Public Service so that the Company will be able to swiftly acquire additional generation.

66. To be clear, this Commission is not disregarding arguments and testimony that having sufficient generation resources necessary to serve new large customers may provide economic benefits to the State.[42] In no way are we preventing Public Service from acquiring generation to serve new large loads. Rather, our Decision is aimed at resolving what WRA and SWEEP characterize as a risk allocation problem. Existing customers should not be required to bear higher electricity rates if large loads withdraw their interconnection requests, nor should existing customers be required to subsidize the cost of serving new large loads. If a large customer contractually commits to the commercial principles, our approach provides both the large customer and Public Service the regulatory certainty it needs to swiftly procure additional generation. If new large customers are ready to commit quickly and with fair warning that they may be subject to the new Commission-approved rate, if applicable, then their prospective loads can be included in the updated load forecast that the base RFP will seek to meet. If large customers need additional time, our approvals of the incremental need pool and supplemental RFP (discussed more below) provide another pathway for the Company to quickly procure additional resources. The regulatory mechanisms we approve through this Decision, including the incremental need pool, the supplemental RFP, and the strategic resilience reserve fund, provide unprecedented speed and flexibility compared to our typical ERP processes.

67. Thus, consistent with CEC's arguments, we are approving an initial load forecast now while at the same time providing regulatory flexibility that will quickly permit additional

[42] *See, e.g.*, Hr. Ex. 123, Bailey Rebuttal, p. 19; Public Service's SOP at pp. 14-15; Business Coalition's SOP at pp. 3-4.

generation once there is sufficient assurance that existing customers will not solely bear the well-established risk associated with new large loads. The Commission is eager to support Public Service in acquiring new generation it needs to reliably serve existing customers and new large load customers that are willing to commit to Colorado. We are unwilling to make existing customers commit to pay for additional generation before large loads sign a binding ESA and IA at a rate that equitably allocates the costs and benefits.

68. Thus, to be included in the load forecast,[43] large customers must execute both an IA and an ESA. At a minimum, the ESA must contain the commercial principles (as modified below) as well as an express "fair notice" provision informing individual customers that a future large load tariff will be fully litigated in a subsequent proceeding and that this new rate may apply instead of the existing tariff. As Staff, WRA, and SWEEP observe, no customer is immune from Commission-approved changes in tariffs.[44] Contrary to the Company's position, tariffs are subject to change over time and customers may be migrated to different tariffs or rate classes depending on their load characteristics and the terms and conditions under which they take service. Moreover, the fair notice concept is critical to ensure that existing customers do not inappropriately subsidize the cost of serving new large load customers and—as CEC notes—is not "an insurmountable hurdle for new large customers who are willing and able to pay the appropriate share of their cost of service."[45]

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[43] As referenced above, if a large customer meets the requirements quickly enough to be included in the Company's updated load forecast that it will file prior to the issuance of the RFP, the large customer's associated load will be incorporated into the base RFP. Large customers that meet the requirements after the updated load forecast can serve as the basis for activation of the incremental need pool or be included in the load forecast the Company will use for the supplemental RFP. We note, however, that the Commission may modify these requirements during the course of the large load tariff filing.

[44] Staff's SOP at p. 10; WRA and SWEEP's SOP at pp. 9-10.

[45] CEC's SOP at p. 14.

69. We reject the Company's position that 100 MW should be the size threshold above which these additional protections take effect. On this point, we note that Conservation Coalition argued the threshold should be 50 MW; UCA proposed 75 MW but notes that the Ohio Commission recently approved a limit of 25 MW; and WRA and SWEEP simply argue the commercial principles should be applied to all large load customers. Weighing these various positions, we find that 50 MW strikes the appropriate balance of protecting existing ratepayers while not overly burdening new customers that, while still sizable, are significantly smaller than some of the other anticipated loads. This 50 MW demand threshold applies to a load's projected peak demand over the RAP, as measured across all meters billed to the same entity. The 50 MW threshold applies to all customers, regardless of whether the customer connects to the transmission or distribution system or whether the Company has identified the customer as a strategic economic development customer.

70. For customers smaller than 50 MW that the Company wants to add to the load forecast to support the acquisition of new generation, Public Service must have completed a facility study, begun relevant negotiations, and have executed either an IA or an ESA (or an equivalent contract if the load is connected at the distribution level). However, we generally leave the form and duration of such contracts to the Company's discretion. While the relevant contract for customers smaller than 50 MW need not include the commercial principles, the contract must still include the fair notice provision if the customer is 20 MW or larger. The fair notice concept is not necessary for customers under 20 MW, but consistent with current practice the Commission makes no guarantee that the tariff class for customers under 20 MW will remain unchanged.

71. We note that loads associated with oil and gas electrification will likely be under the 50 MW threshold. The low load forecast assumes 151 MW for oil and gas electrification, which

appears largely unopposed. Thus, as Public Service signs new oil and gas customer contracts and satisfies the other requirements set forth above, both the base and supplemental RFP load forecasts and associated resource acquisitions would be expanded for the new load above the 151 MW already in the low load forecast. Assuming these new oil and gas loads are under the 50 MW threshold, the contracts need not contain the commercial principles.

2. Commercial Principles

a. Party Positions

72. As referenced above, in Rebuttal Public Service proposes a set of commercial principles, which the Company asserts ensure reasonable customer protections by requiring large customers to have sufficient "skin in the game."[46] These commercial principles consist of the following nine components: (1) up-front study deposit, (2) minimum bill, (3) minimum contract term, (4) load threshold/applicability, (5) security, (6) facilities costs, (7) exit fee, (8) assignment, and (9) load flexibility/renewable programs. More specifically, there would be a $250,000 non-refundable up-front study deposit at the time the customer submits an interconnection request.[47] The Company may adjust this upward if needed. The customer's minimum bill would be 75 percent of the projected needs the customer listed in its ramp schedule, and there would be a minimum contract term of 15 years. The load threshold would be 100 MW of new or expanded load.

73. For security, the large customer would be required to provide a letter of credit ("LOC") or cash deposit in conjunction with the signing/effective date of the IA, with process and conditions generally aligned with Company's existing large customer credit/deposit requirements

[46] Hr. Ex. 123, Bailey Rebuttal, p. 41.
[47] Hr. Ex. 123, Bailey Rebuttal, p. 40.

and OATT Schedule Q credit policy: First, the applicant will submit a load ramp in conjunction with Interconnection Request, to contain peak load. Second, the Company will require security through cash or irrevocable standby LOC, which shall be the equivalent of three months (90 days) of estimated bills based on the peak load included in the customer's load ramp schedule. The security shall be posted for at least 36 months after the customer starts taking service, renew annually, and after 36 months, subject to the Company's agreement, it may convert to a parental guarantee with security to remain in place for the duration of the contract. Third, all security will be posted in conjunction with the effective date of the customer's IA. And fourth, the Company will conduct a credit evaluation of each counterparty upon submission of an Interconnection Request, and again prior to executing an IA.[48]

74. Regarding the remaining commercial principle components, the Company will require up-front facilities payment from the customer for all direct assigned facilities, consistent with the Company's current distribution and transmission interconnection policies. In addition, if a customer terminates service prior to the end of the 15-year term, an exit fee shall be assessed equivalent to 75 percent of a customer's needs under customer load ramp schedule for remainder of 15-year term. However, the Company will make commercially reasonable efforts to mitigate and may reduce the exit fee if it can readily serve other customers or sell the excess energy/capacity. The customer cannot assign or transfer ESA/IA absent express Company approval and transferee/assignee meeting the requisite credit metrics. Finally, the Company will encourage all new large load customers to provide load flexibility, including 80-100 hours of interruptible load shed during the year.[49] The Company may consider future filings to adapt its

[48] Hr. Ex. 123, Bailey Rebuttal, p. 40.
[49] Hr. Ex. 123, Bailey Rebuttal, p. 41.

interruptible rate program for new large customers as the Company gains more experience transacting with large load customers during the interim period. Public Service will market its voluntary renewable and DSM programs to all new large load customers.

75. While Public Service asks the Commission to approve these commercial principles as part of its large load strategy, the Company argues that flexibility and the ability to negotiate are important. The Company states there may be circumstances where deviating from the commercial principles is warranted.

b. Findings and Conclusions

76. We appreciate Public Service proposing these commercial principles and generally adopt them as appropriate concepts for inclusion to protect customers, but we find certain modifications are necessary to ensure the proper risk allocation regarding new large customers, existing customers, and the Company. In addition, we emphasize that these principles will be fully litigated in the large load tariff filing expected in January 2026.

77. First, in addition to the requirement that the fair notice concept be included in the commercial principles, the ESA must specifically include the credit support and exit fee concepts. Also, we adopt UCA's suggestion and increase the security commitment to six months of anticipated bills, as opposed to the Company's proposal for just three months.[50] Finally, as part of the large load tariff filing, Public Service shall file a detailed Colorado-specific IA and ESA, and each contract must be consistent with the modified commercial principles we adopt here and clearly lay out the security and exit fee provisions. We anticipate the Commission will further

[50] Hr. Ex. 308, UCA Surrebuttal Comments, p. 5. UCA also proposes that large customers should be required to contribute to tariffs such as the ECA. Although we intend to examine this issue during the large load tariff filing, at this time we refrain from modifying the applicable tariffs. Whatever existing tariff the large customer takes service under, that tariff will control the applicable riders to which the customer must contribute.

refine the commercial principles and other requirements for new large customers through the course of the large load tariff filing.

78. The Company retains discretion to negotiate the applicable agreements as it deems necessary, including the commercial principles. It is our expectation, however, that the customer protections, including the "fair notice" provisions, within the commercial principles will remain. Indeed, the Company's presumption of prudence is contingent on the customer protections being in place. If Public Service negotiates away these approved commercial principles and a large customer does not materialize as expected, Public Service may share the risk associated with the shortfall in expected revenues. In this way, particularly prior to the large load tariff being litigated and approved, the Company retains its discretion in negotiations, but the expectation of customer protections remains constant, appropriately ensuring that the balance and risk of negotiating these concepts further remain on the Company.

3. Large Load tariff Filing

79. As referenced above, as part of the Phase II Framework Public Service commits to make a large load tariff filing no later than January 31, 2026. Some of the primary objectives of this tariff filing includes evaluating cost allocation, establishing terms and conditions of service, and developing a specific rate structure for large load customers.[51] This addition appears responsive to Answer Testimony from UCA, Conservation Coalition, WRA, and SWEEP and the general concept is unopposed.

80. While Conservation Coalition, WRA, and SWEEP support a large load tariff filing, they suggest the Commission should also use this filing to evaluate a clean transition tariff. At a high level, the clean transition tariff should allow large customers to voluntarily pay to be

[51] Staff's SOP at p. 6.

served by innovative, zero-emission resources that public service would not otherwise procure. Conservation Coalition argues that one of the benefits of a clean transition tariff is that it provides a mechanism to develop innovative, zero-emitting resources that may not otherwise be cost-effective to procure as system resources. Conservation Coalition asserts that many companies that are developing large data centers have corporate clean energy goals and may pay a premium for clean electricity.[52]

81. Consistent with its commitment under the Phase II Framework, we direct Public Service to make a large load tariff filing no later than January 31, 2026.[53] This future proceeding will provide the appropriate forum to address cost allocation approaches for large loads including ensuring that this new tariff reflects the actual incremental costs and benefits of serving these new loads in ways that account for differences in load flexibility during critical peak demand periods and locational impact. For example, a new large load customer located outside the transmission-constrained Denver metro area that can flexibly reduce demand during the most at-risk peak demand hours at the Company's request should perhaps have access to a lower rate that reflects the reduced costs that this customer imposes on the system.

82. In contrast, large new load customers that locate in the transmission-constrained Denver metro area and are unable to adjust usage during critical peak demand periods should perhaps pay a higher rate that reflects that customer's pro-rata share of the full incremental generation and transmission costs required to serve growing load as quantified in this resource planning process.[54] As such, the Company is hereby ordered to file in its direct case in the January 2026 advice letter filing separate rate options for the parties to consider that provide appropriate

[52] Conservation Coalition's SOP at pp. 22-23.
[53] Hr. Ex. 144, JTS Phase II Framework Redline, p. 5.
[54] *See, e.g.*, HE 133, Executable Attachment, JWI-5, Rev Req Sheet (summing up the entered Capex on lines 5 through 19 in ways that define the cumulative generation and transmission cost associated with load growth).

large new load customer incentives based on the costs they impose on the system depending on their ability to flexibility reduce load or whether they can locate outside the transmission constrained Denver metro area. Given the size of these potential new customers, the Commission is concerned that the existing demand response or interruptible service approaches will not provide proper incentives and would like to comprehensively explore the options in the advice letter filing.

83. Although the resulting tariff from this future proceeding will likely not be adopted until late 2026, we reemphasize that—consistent with the fair notice concept—the new large load tariff may apply to customers that take service prior to the tariff's adoption. In other words, tariffs and tariff classes are subject to change.

84. In conjunction with its large load tariff filing, Public Service shall also submit its proposal for a clean transition tariff, consistent with recommendations from WRA, SWEEP, and Conservation Coalition.[55] We find the arguments from these parties persuasive and are intrigued by another potential avenue to allow large customers to quickly secure necessary generation resources, especially resources that aid rather than hinder the State's greenhouse gas emissions targets.

85. We also require Public Service in the large load tariff filing to respond to the load volatility concerns UCA raises regarding large loads like data centers. UCA asserts that large loads suddenly disconnecting or reconnecting to the grid could cause regulation violations or transient instability. UCA also asserts that large loads affect ramping needs, reactive power requirements, and reserve margins.[56] We find UCA's concerns to be legitimate. If large loads like data centers present specific risks to the larger system, the costs associated with mitigating those risks should

[55] WRA and SWEEP's SOP at p. 11; Conservation Coalition's SOP at pp. 22-23.
[56] Hr. Ex. 304, Milligan Answer, pp. 28-29.

be borne by those large loads. This is particularly a concern given the Company's focus on a seemingly smaller ramp potential associated with solar generation near Pueblo.[57] Thus, Public Service shall expressly respond to the following concerns UCA raised regarding with large loads: (1) load ramping, variability, and uncertainty; (2) load cycling and oscillation risks; (3) load ride-through performance; (4) power quality and harmonic emissions; (5) sub-synchronous oscillation risks; and (6) impacts on utility protection systems.[58]

86. Finally, the Commission clarifies that, moving forward, any new large load customer cannot take service under an Economic Development Rate. WRA and SWEEP note that the Company does not object to such a restriction.[59]

4. Phase II Framework's Incremental Need Pool

a. Party Positions

87. One of the foundational components of the Phase II Framework is the incremental need pool because it allows for the additional acquisition of resources in between the base RFP and the supplemental RFP. As proposed, the incremental need pool could also be used following the supplemental RFP. Any project included in a Phase II portfolio or identified through the backup bid modeling process can elect to be incremental need pool. Each project electing to be considered for the incremental need pool would provide in its bid a $/MW/year payment amount needed for it to follow the terms of the incremental need pool process, up to an annual cap of the lesser of $3 million or $10,000/MW/year per bid.[60] The Company will propose a portfolio of incremental need pool projects in the 120-Day Report for Commission approval. Once approved, an

[57] *See* Hr. Ex. 102, Landrum Direct, pp. 45-46.
[58] Hr. Ex. 303, Sommer Answer, pp. 20-21.
[59] WRA and SWEEP's SOP at p. 21 (citing Hr. Tr., June 11, 2025, p. 169).
[60] Hr. Ex. 144, JTS Phase II Framework Redline, p. 4.

incremental need pool project must remain exclusive to Public Service for not less than one year, up to a two-year term.

88. If an activation call for that bid occurs, the project would need to abide by the incremental need pool process. All participating projects in the incremental need pool could provide a price refresh within 21 days, subject to a 10 percent cap on the total project cost or PPA rate. Public Service would evaluate the refreshed prices, retaining competitive tension in the process.[61]

89. The incremental need pool activation process can be triggered by either an approved project failing or a new large load reaching the designated criteria. Under the Proposed Phase II Framework, this designated criteria is either the negotiation of an ESA and IA (*i.e.*, Step 8) for loads less than 100 MW or a signed IA or ESA (*i.e.*, Step 9) for loads of 100 MW or more. Upon one of these triggering events, the Company notifies the Commission of the incremental need pool activation and provides a brief alternatives analysis and an updated loads and resources table. This notice will include the results of the price refreshes and the Company's proposed incremental need pool projects to activate. The precise activation process then depends on whether the incremental need pool was triggered by a project failure, a large load and, if a large load, the relative size.[62]

90. In Rebuttal, Public Service explains that if a bid in the approved portfolio fails, the Company will follow a like-for-like process in which it will attempt to find a replacement project with the same ownership and technology type.[63]

[61] Hr. Ex. 144, JTS Phase II Framework Redline, p. 4.
[62] Hr. Ex. 144, JTS Phase II Framework Redline, pp. 4-5.
[63] Hr. Ex. 118, Landrum Rebuttal, p. 13.

91. Public Service, Staff, CIEA, and CEO all support the incremental need pool concept and ask the Commission to approve it without modification.

92. UCA raises concerns with several elements of the incremental need pool process. UCA argues the option payments would lock in the incremental need pool projects exclusively with Public Service. UCA warns this structure may favor incumbent developers or legacy projects, reduce competition, and limit the ability to react to fast-changing market conditions or new technologies. UCA recommends the Commission build in steps to ensure public review of price updates, potential market manipulation, and emissions impacts.[64] UCA also argues there is no performance security or fallback plans for failed bids or delayed projects. UCA recommends the Commission require the Company to require clear accountability metrics, milestone tracking, and strong financial penalties for failed bids included in the resource portfolio or incremental need pool.[65]

93. CEI generally supports the incremental need pool concept but raises concerns the 10 precent price refresh opportunity may not be sufficient. CEI recommends removing any cap on price refreshes, particularly for bids that may have incorporated ITC/PTC tax credits.[66]

94. WRA and SWEEP raise several issues with the incremental need pool as proposed. First, they argue that without strict and enforceable emissions limits, any new thermal resources acquired solely to meet the needs of a new large customer could produce significant levels of greenhouse gas emissions. WRA and SWEEP therefore argue the Commission should require updated emissions verification workbook regardless of the size of load, and the Company should be required to demonstrate that any portfolio of bids activated under the incremental need pool

[64] UCA's SOP at pp. 13-14.
[65] UCA's SOP at p. 14.
[66] CEI's SOP at p. 26.

will meet or exceed the emissions trajectory approved in the Phase II decision. WRA and SWEEP also argue that when the incremental need pool is activated to replace a failed bid, the Commission should require a similar size and technology replacement project to ensure that emission impacts are avoided.[67]

95. In addition, WRA and SWEEP recommend that only loads that reach 90 percent probability and have committed to contractual protections determined through the large load tariff should be eligible to trigger the incremental need pool process. More fundamentally, WRA and SWEEP assert the incremental need pool process should not be used until the large load tariff is in place.[68]

96. Similar to WRA and SWEEP, Conservation Coalition argues the Commission should reject procuring resources through the incremental need pool for large customers that have not yet signed a long-term contract implementing all of the commercial principles and that the Company should be required to provide verification workbooks showing compliance with CEP emission-reduction requirements. In addition, Conservation Coalition asks that in each activation of the incremental need pool, the Commission require Public Service to present at least two alternative resources or portfolios that are the cheapest alternatives to the resources the Company seeks to procure. Conservation Coalition argues the Company's proposal to present only its proposed resources may leave stakeholders and the Commission with no way to meaningfully evaluate the alternatives and no understanding of why the Company proposed one set of resources over others.[69]

[67] WRA and SWEEP's SOP at pp. 19-20.
[68] WRA and SWEEP's SOP at p. 20.
[69] Conservation Coalition's SOP at p. 24.

97. Although CC4CA does not seem to oppose the broader Phase II Framework, CC4CA raises emissions and cost concerns regarding the incremental need pool portion. Regarding emissions, CC4CA argues the Commission should direct the Company to file an emissions verification workbook for all activated incremental need pool resources (except for like-for-like resources activated due to failed bids from an approved portfolio) and only allow additional resources via the incremental need pool if the emissions impact of those resources maintain at least the emissions reduction pathway of 80 percent by 2030 and 100 percent by 2050. Further, in selecting resources activated in the incremental need pool, CC4CA argues the Company should seek to maintain the emissions trajectory of the approved portfolio in Phase II.[70]

98. Regarding ratepayer protections, CC4CA reiterates concerns raised by WRA, SWEEP, and Conservation Coalition regarding potentially overbuilding for large new loads that fail to materialize. For instance, CC4CA argues the Commission should ensure that long-term contracts include consumer protection guardrails before large loads are included in the assumptions underlying resource solicitations. CC4CA also raises concerns about the option payments that the backup bids in the incremental need pool would receive. CC4CA opposes the idea that ratepayers could end up on the hook for up to $3 million per bid in the incremental need pool, while the large customers that trigger the activation of incremental need pool bids would not contribute to such payments. CC4CA suggests the Commission direct the Company to recover the total "option payment" costs of the incremental need pool from ratepayers and large new loads in a manner proportional to the resources activated on a load basis due to failed bids from the approved portfolio and due to demand from large new loads, respectively.[71]

[70] CC4CA's SOP at pp. 9-10.
[71] CC4CA's SOP at pp. 10-11.

99. Walmart argues that the incremental need pool is unnecessary and should be rejected. Walmart notes that with the base RFP, supplemental RFP, and the next full ERP in 2028, there will be three fully competitive RFPs over an approximately three-year period. According to Walmart, these three RFP renders unnecessary the need for the inferior incremental need pool process. Walmart asserts the incremental need pool is comprised of second-rate projects that were not selected during the immediately preceding RFP and that the Company will pay option payments to keep such bids "warm." The resources selected through the incremental need pool will, according to Walmart, not only be inferior but will also come at a cost to customers. Walmart argues that the only risk mitigated by the incremental need pool that is not already mitigated by having three fully competitive RFPs is the risk to the Company's shareholders. [72]

100. In the alternative, if the Commission does not agree to reject the incremental need pool, Walmart argues the Commission should not allow Public Service to move the option payment costs into rates when the corresponding incremental need pool project is not used and useful and may never be placed in service. Walmart asserts that approving recovery of the option payment costs would set a dangerous precedent. Walmart reasons the option payment costs for each incremental need pool project should be recorded to a deferred account, and Public Service can request to recover the option payment costs for only those projects ultimately placed into service for the benefit of customers.[73]

b. Findings and Conclusions

101. As referenced above, we generally support the incremental need pool concept and agree with Public Service, Staff, CEO, CIEA, and others that it will add useful flexibility to the

[72] Walmart's SOP at pp. 7-8.
[73] Walmart's SOP at pp. 8-10.

ERP process. Given the dynamic and uncertain environment developers are in, as well as the possibility for rapid load growth, the incremental need pool presents a reasonable process that allows the Company to swiftly respond to changing conditions. However, consistent with our above discussion and similar to the positions of parties like WRA, SWEEP, and Conservation Coalition, we modify the criteria for when the incremental need pool can be activated to serve a new large customer. Specifically, to be included in the load forecast justifying activation of the incremental need pool, large customers must execute both an IA and an ESA, and the ESA must contain the modified commercial principles, including the fair notice concept.[74] Just as we are unwilling to allow uncommitted large loads into the initial load forecast for the base RFP, we are unwilling to allow uncommitted large loads from triggering the incremental need pool. Nevertheless, this optionality allows both certainty and flexibility by including committed large loads at each incremental step.

102. Aside from this important modification, however, we reject the other intervenor requests. Regarding the various requests for increased emissions reporting, we find the incremental need pool as proposed already contains reasonable protections. For instance, Public Service will provide an updated emissions verification workbook for large customers greater than 100 MW. Even for large customers equal to or less than 100 MW, the incremental need pool "will seek to maintain system emissions performance…" and intervenors have the opportunity to submit comments prior to a Commission decision. This approach appropriately balances the need remain cognizant of emissions impacts while ensuring a quick and flexible process for acquiring additional resources.

[74] During the large load tariff filing, we intend to evaluate whether different criteria should be used once the new tariff is implemented.

103. Similarly, we find the current 10 percent cap on price refreshes to be reasonable and reject CEI's recommendation to eliminate the cap. The 10 percent cap appropriately balances the need for backup bids to have price flexibility to prevent them from going stale while also keeping the incremental need pool projects reasonably close to their initial bid. CC4CA's suggestion that large new loads should be required to pay relevant option payments, while intriguing, would be difficult to implement fairly at this stage. However, we would be open to exploring this concept further in the large load tariff filing.

104. We also reject UCA's requests to add more process to the incremental need pool, including milestone tracking and financial penalties for failed bids. Public Service already specifies in Rebuttal Testimony that an incremental need pool project that is unable to respond timely if called upon must return its option payments, with interest. Beyond these protections, we are wary of adding unnecessary process or trying to establish a milestone payment schedule on this record. For similar reasons, we reject Conservation Coalition's request for an analysis of alternative portfolios.

105. We likewise oppose Walmart's recommendation to eliminate the incremental need pool and Walmart's alternative recommendation to only allow the Company to recover option payments after the associated project is used and useful. While the option payments are a material cost, they help ensure that there will be a sufficient number of backup bids such that there will be competitive tension when the projects are asked to refresh. This competitive tension could result in considerable savings over the long term.

106. Finally, in keeping with the approved backup replacement process in the 2021 ERP/CEP, we modify the Company's proposal to use a like-for-like replacement process for ownership types. Given the misaligned incentives and potential for gaming, any time

Public Service wishes to activate a Company-owned backup bid, the Company must perform an alternatives analysis demonstrating why the utility-owned bid is the most appropriate option. Any time the Company proposes to activate a utility-owned bid, intervenors will have 45 days to file comments, the Company will have 10 days after intervenor comments to file reply comments, and the Commission will aim to issue a decision 45 days after the reply comments.

5. Additional Components of the Phase II Framework

a. Party Positions

107. As proposed, the Phase II Framework proposes that the base RFP would issue in 2026 and would have a RAP through 2031; the supplemental RFP would issue in mid-2027 and would have a RAP of through 2033; and the deadline for the next ERP would be extended to no later than December 31, 2028.[75] In addition, the modeling assumptions and other requirements for both the base RFP and the supplemental RFP would be set in this Decision. Public Service emphasizes that there would not be another Phase I decision prior to the supplemental RFP, although there would still be the typical Phase II process and decision addressing the proposed portfolio of resources from the supplemental RFP. The same portfolios that are used to showcase the results of the base JTS would also be used in the supplemental RFP.[76]

108. Public Service explains the primary differences between the load forecasts used in the two RFPs is that the load forecast in the supplemental RFP would account for contracted resources acquired from the base RFP and allows for bidding into new transmission investment. The supplemental RFP is essentially an “updated” updated base forecast that can adjust to changes in large new loads and any bid failures from the base RFP, time permitting. The Company states

[75] Hr. Ex. 144, JTS Phase II Framework Redline, pp. 1-2.
[76] Hr. Ex. 117, Ihle Rebuttal, p. 36.

it will update the subcomponents of the forecast based on the latest available information, including Clean Heat Plan electrification, EVs, and oil and gas electrification, and large load projections.[77]

109. Staff, CEO, and CIEA all support the Phase II Framework and argue the Commission should adopt it without modification. These parties generally argue the Phase II Framework provides needed flexibility yet reduces the risk of overbuilding by providing several avenues to procure incremental resources as load growth develops.

110. UCA requests certain modifications to the Phase II Framework. First, UCA asks the Commission to allow for a review and comment process for the forecasts modeled after the Phase I decision but before the RFP. Because of concerns raised by the federal Reconciliation Bill, however, UCA does not ask that the process be delayed by a review and comment period. Instead, UCA requests that a timeline be designed that accommodates input and allows processes to occur simultaneously.[78]

111. Interwest broadly supports the Phase II Framework and argues the 50 percent utility ownership target for the base RFP must also apply for the supplemental RFP. Interwest asserts extending the 50 percent ownership target helps ensure that Colorado's robust, competitive landscape for energy project development continues.[79] In contrast, Conservation Coalition argues against using the 50 percent ownership target for the supplemental RFP. Conservation Coalition asserts there is no testimony in the record offering any policy rationale to use the 50 percent ownership target (or any other ownership targets) for the supplemental RFP. Instead, Conservation Coalition argues each portfolio for the supplemental RFP should include the least-cost resources

[77] Hr. Ex. 118, Landrum Rebuttal, p. 11.
[78] UCA's SOP at pp. 11-12.
[79] Interwest's SOP at p. 13.

(subject to the constraints for that portfolio) without any explicit Company-ownership constraint in the model.[80]

112. Grid United, the developer of the Three Corners Connector, an 1,800-MW HVDC interregional line designed to connect Public Service's system in Pueblo to the SPP system in Oklahoma, argues the Commission should approve the proposed Phase II JTS Framework with the extended RAP through 2033. Grid United further requests the Commission expressly direct Public Service to evaluate non-generation capacity solutions, including interregional HVDC transmission projects that can come online before the end of the RAP.[81] Grid United asserts it is "undisputed" that interregional transmission projects like HVDC lines can provide substantial capacity value and customer savings.[82]

113. As referenced above, WRA and SWEEP recommend several changes regarding the large customers that can be included in the load forecast for both the base RFP and supplemental RFP. WRA and SWEEP also recommend the Commission require additional process before the supplemental RFP. They note that, as currently proposed, the supplemental RFP would only provide the same, brief comment process currently used in Phase II, despite the likelihood of significant changes to the Company's load forecast between the Phase I decision and the supplemental RFP. WRA and SWEEP recommend the Commission require the Company to provide its updated load forecast at least three months prior to the supplemental RFP, consider mechanisms to allow limited discovery on updates to the forecast, and retain the flexibility to institute additional procedures in the time leading up to the supplemental RFP.[83]

[80] Conservation Coalition's SOP at pp. 9-10.
[81] Grid United's SOP at p. 7.
[82] Grid United's SOP at p. 5.
[83] WRA and SWEEP's SOP at p. 22.

b. Findings and Conclusions

114. Consistent with the wide support from parties, we approve the basic structure of the Phase II Framework, including the timing and proposed RAPs for the base RFP and supplemental RFP, and the extended deadline for Public Service's next ERP. While novel, the Phase II Framework allows for a more nimble, flexible approach to acquiring resources in a dynamic and uncertain environment. The Commission will, in effect, be enabling resource need pools to move forward with forecasting in 2026 and 2027, with updates for the next ERP expected in 2028. These regular and iterative update opportunities presented by the parties allow the regulatory process to be responsive in coming years especially, despite uncertainty in the near term. Splitting the Phase II process as proposed in the Phase II Framework allows quick reactions in these next critical years and months especially.

115. At the same time and without expanding the process to instigate delay, we agree with WRA and SWEEP that there should be an opportunity for some additional process prior to the supplemental RFP. As these parties note, there will likely be significant changes to the inputs and assumptions used for the load forecast underlying the supplemental RFP, but there will be no Phase I process in which these changes can be evaluated. This is particularly concerning given our skepticism of the load forecast the Company endorses for the initial base RFP, and desire to be flexible if those loads materialize.

116. Thus, Public Service shall file its updated load forecasts it proposes to use for the supplemental RFP and the underlying models used to calculate such forecasts at least three months prior to the planned release of the supplemental RFP. As part of its filing, the Company shall propose a technical conference date that is within two weeks of the filing of the supplemental load forecast. The purpose of the technical conference will be to allow the Commission to quickly

understand more of the nuances of the supplemental load forecast, given the abbreviated schedule prior to the supplemental RFP. After the technical conference, intervenors will have one month to continue conducting discovery and submit comments. The deadline for Public Service to file response comments is two weeks after the intervenor comments. The Commission would then target a decision on the Company's proposed load forecasts within one month after the Company's response comments. If the Commission rejects the Company's supplemental load forecasts, the Commission would establish additional processes that would be required prior to the release of the supplemental RFP.

117. The technical conference and opportunity for comments will allow the Commission and parties to better understand the load forecast underlying the supplemental RFP. This will increase confidence that the results of the supplemental RFP are grounded in reasonable assumptions. If the Commission has no major concerns with the supplemental load forecast, the supplemental RFP will still be able to issue in an abbreviated timeframe.

118. While we agree with WRA and SWEEP regarding the need for additional process prior to the supplemental RFP, we reject UCA's request for additional process prior to the base RFP. Although UCA asks the Commission for more process prior to the RFP, UCA also maintains that such process should not delay the Phase II process. UCA does not offer a detailed explanation as to how the Commission could mandate a meaningful review and comment process that would not require additional time. Moreover, unlike what will likely occur with the supplemental RFP, parties have already had an extensive process to adjudicate the assumptions that will be used in the base RFP. If UCA has significant concerns after the Company files its updated forecasts prior to the base RFP, UCA always has the ability to file any appropriate motion as necessary.

119. As for the utility ownership target for the supplemental RFP, we agree with Conservation Coalition and will not adopt a formal 50 percent ownership target. In the supplemental RFP, the Commission can continue to weigh a balanced ownership percentage as one factor in establishing an appropriate portfolio. Ultimately, the most appropriate resource portfolio may have more or less than 50 percent utility ownership.

120. For the reasons set forth in its SOP and testimony, we grant Grid United's request and expressly direct Public Service to evaluate non-generation capacity solutions, including interregional HVDC transmission projects that can come online before the end of the RAP. For purposes of the supplemental RFP, Public Service shall consider the impacts of any interregional HVDC transmission, including the 1,800 MW HVDC Three Corners Connector, that can come online before the end of 2033. The Company must explain these considerations when it files the updated load forecasts that it plans to use for the supplemental RFP.

6. Transmission Components of Phase II Framework

a. Party Positions

121. The Phase II Framework proposes a two-step transmission planning process.[84] The first step chronologically, referred to in the Phase II Framework as "proactive planning," would focus on assessing needs and alternative solutions for transmission infrastructure needed to support the supplemental RFP. This step begins with the establishment of a Colorado Coordinated Planning Group ("CCPG") Task Force (which has already been accomplished), a study that would continue through March 2026, submission of a CPCN application at the end of 2026 or in early

[84] Hr. Ex. 144, JTS Phase II Framework Redline, p. 2.

2027, and a CPCN decision in August 2027, which would inform bids for the supplemental RFP that will be issued in mid-2027.[85]

122. The second step proposed in the Phase II Framework, referred to as "implementation" or "deliverability/reliability" planning, would focus on the transmission needs of the portfolios approved from the base and supplemental RFPs. In this step, the Company would provide up to four reliability and deliverability analyses as part of the Company's 120-Day Report in early October 2026. The Phase II Framework envisions an opportunity for the Commission to provide feedback on these analyses, followed by re-engagement with stakeholders via the FERC 890 Planning Process and culminating in submission of a CPCN application for these deliverability/reliability projects in early August 2027. The Phase II Framework envisions an identical process following the Commission's approval of a portfolio in the supplemental RFP. This latter process would result in a CPCN application in February 2029.[86]

123. In Hr. Ex. 121, Attachment SM-3, the Company lists the tentative timelines for various steps in both the proactive step and the implementation step.

124. The Phase II Framework also specifies that a small stakeholder group, composed of Staff, CEO, UCA (all supported by the ITA) and the Company would be convened in Summer 2025 to inform both near-term and future transmission planning and modeling. As proposed, this includes revised transmission modeling to be implemented as part of Phase II. This small stakeholder group would have insight and input into both of the steps described above.[87]

125. Staff states that the Phase II Framework provisions bring more oversight to transmission planning and better aligns the timing of transmission projects with the development

[85] Hr. Ex. 145, JTS Phase II Framework, p. 3; Hr. Ex. 121, Martz Rebuttal, pp. 42-45.
[86] Hr. Ex. 145, JTS Phase II Framework, p. 3; Hr. Ex. 121, Martz Rebuttal, pp. 46-48.
[87] Hr. Ex. 144, JTS Phase II Framework Redline, p. 3.

of new resources and load, while giving bidders more certainty regarding the transmission costs that may be needed for their projects. Staff promotes the small stakeholder group as critical, giving its members an opportunity for input and oversight throughout the process that will shape the planning presented in the 120-Day Report and transmission CPCN applications.[88]

126. While CEI broadly supports the Phase II Framework, it asks for certain modifications regarding the transmission elements. First, CEI opposes the fact that the transmission timelines are "tentative," arguing that developers must know where the new transmission lines are located before they bid into the next RFP. CEI requests the Commission direct that these transmission timelines set forth in Hr. Ex. 121, Attachment SM-3 be mandatory.[89] CEI also opposes the Phase II Framework's transmission stakeholder process, because it currently includes no IPP interests. CEI recommends that any changes to the transmission adder or transmission credit only be adopted with additional guardrails such as notice and the ability to comment, consistent with Staff's suggestion during hearing.[90]

127. UCA expresses concern that members of the JTS Transmission Task Force established at CCPG will not be able to vote in the CCPG process. UCA therefore recommends that the Commission direct the Company to consider and evaluate projects proposed by members of the Task Force.[91]

b. Findings and Conclusions

128. We approve the transmission elements of the Phase II Framework, which are largely unopposed. The two-step approach for proactive planning and implementation planning helps align the timing of transmission projects with the development of new resources and load.

[88] Staff SOP at p. 6.
[89] CEI's SOP at p. 25.
[90] CEI's SOP at p. 26 (citing Hr. Tr. June 23, 2025, p. 196).
[91] UCA SOP at p. 14.

We further support the small stakeholder group and hope that the added oversight and analytical review will improve transmission planning before proposals are submitted to the Commission.

129. Turning to CEI's two transmission requests, we reject CEI's first recommendation to convert the tentative transmission timelines to mandatory timelines. While we agree with CEI that clarity regarding the location of additional transmission investment will be important for a successful supplemental RFP, transmission planning is complex, and the Company may not be able to meet strict deadlines. Nevertheless, we emphasize that one of the main justifications for approving the Phase II Framework is the Commission's understanding that the Company will be able to file a CPCN application for proactive transmission investments at roughly the same time as the supplemental RFP. Thus, it is important that the Company strive to meet the tentative timelines. Regarding CEI's second request, CEI raises legitimate concerns about changes to the transmission adders or credits that are made after this Decision. Accordingly, as set forth more in Section L, if the small stakeholder group modifies the transmission adders or credits that will be used in Phase II, Public Service must notify the parties of such a change, and parties will have an opportunity to respond.

130. In response to UCA's concern regarding the JTS Transmission Task Force established at CCPG, the Commission expects UCA, Staff, and CEO to work together with the support of the ITA to develop modeling alternatives. It is also our expectation that the Company will model all alternatives that this group, with advice of the ITA, agrees upon and submits.

F. Contribution of EVs and BE to Load Forecast

1. Load Forecast from EVs

a. Party Positions

131. Public Service's base forecast projects transportation electrification to cause 710 MW in incremental, retail summer peak by 2031.[92] The retail winter peak impact of incremental EVs is projected to be 1,053 MW by 2031. Those values were based on a "High" adoption scenario whereby over 827,000 EVs are based primarily in Public Service's service territory, and over 98 percent of those are Light-duty vehicles.[93] The Company also conducted a lower "Mid" adoption scenario whereby just over 697,000 EVs are operating in the service territory, essentially representing a one-year delay in deployment by the end of the RAP. The "Mid" adoption projection was incorporated in the Company's low forecast. 2024 EV adoption values were estimated at between 114,000 and 140,000, approximately, based on the adoption trend applied.[94]

132. The Base Case and Low scenario EV forecasts estimate EV adoption using two modeling techniques: (1) Bass diffusion modeling, and (2) economic modeling. After establishing forecasts through both methods, the Company averages the results to estimate EV adoption. Bass diffusion models are used to describe technology adoptions patterns in an existing market through an "S" shaped diffusion characteristic and calibrated using state-specific historical EV sales. Economic models use simple payback analysis to estimate potential adoption, incorporating factors such as battery prices, tax incentives, and fuel savings. The Company also incorporates into both the Bass diffusion and economic models a factor for the percentage of vehicles in urban and rural areas, as urban areas have experienced higher adoption than rural areas to date.

[92] Hr. Ex. 114, Goodenough Supplemental Direct, Table SD-6.
[93] Hr. Ex. 101, Att. JWI-2, Vol. 2, Table 2.2-7.
[94] Hr. Ex. 101, Att. JWI-2, Vol. 2, Table 2.2-7.

133. The Base and Low forecast scenarios utilize one managed and one unmanaged charging profile through 2027. The share of managed charging begins at a program participation rate of roughly 10 percent and increases linearly at a rate of an additional 2.5 percent until it reaches roughly 70 percent by 2050. Public Service currently operates one passive managed charging program (*i.e.*, Own Your Charge) and one dynamic managed charging (*i.e.*, Charging Perks); the Company states that more customers participate through the Own Your Charge program than the Charging Perks program.[95] At the projected increase, the Commission calculates that participation in the Company's managed charging programs is expected to reach just under 30 percent by 2031, the last year of the RAP.

134. At hearing, Public Service described that its managed charging load shapes "quickly get to a point where EVs are setting the peak [and] the hour of maximum EV charging is the system peak."[96] To mitigate that effect, the Company implemented a system it refers to as "tranching" in order to simply "move that load around" by shifting it earlier or later in the day to "mimic a managed program… incenting charging at different hours."[97] Public Service explains that, beginning in 2028, all vehicle classes begin to split new managed load additions between multiple tranches.[98] For light-duty vehicles, there are four additional tranches, shifted backward by three, six, 10, and 13 hours. For medium- and heavy-duty vehicles, there is only one additional tranche shifted backward by three hours. The Company explained that it shifts sales toward these additional tranches until sales are roughly equivalent with the original managed charging profile, at which point additions are split evenly across all tranches. The Company also presented

[95] Hr. Tr. June 18, p. 26. The Commission notes the Public Service witness overseeing the load forecast, Mr. Goodenough, had very limited insight into the managed charging programs.
[96] Hr. Tr. June 18, pp. 24-25.
[97] Hr. Tr. June 18, p. 25.
[98] Hr. Ex. 101, Tech. Appendix Vol. II, p. 34.

information that class peak is partially mitigated through its managed charging programs but only presented information for 2025, 2040 and 2050.

135. WRA and SWEEP suggest the Commission should direct the Company to distinguish between plug-in hybrid electric vehicles ("PHEVs") and full battery electric vehicles ("BEVs") and incorporate this distinction into load forecasting.[99] WRA and SWEEP contend Public Service should assess the potential for double-counting due to EV load being present in the baseline use per customer model, and make any necessary adjustments to eliminate double counting.[100] WRA and SWEEP also suggest the Company better distinguish between Level 1 and Level 2 charging (*i.e.*, 120 vs. 240 volts) profiles and usage profiles, and should modify its managed charging profiles to be non-coincident with gross load peak, net load peak, and hours of highest reliability concern. In addition, they argue the Company should be directed to increase its projections of managed charging participation to match the 2024-2026 Transportation Electrification Plan and to use an S-curve growth pattern for future managed charging participation.[101] WRA also suggests the Company eliminate two of the managed charging tranches "as they appear to contribute added load" and to better distinguish between Level 1 and Level 2 charging patterns.

136. CRES/PSR notes that the materials presented during the Joint Technical Conference indicate that the Company is not taking advantage of renewable energy patterns to meet load requirements. CRES/PSR suggests daytime curtailments have been a problem since large quantities of utility-scale PV that became operational in mid-2023 with up to 75 percent of curtailments between 8AM and 8PM on an annual basis during the 2023-2024 period.[102]

[99] Hr. Ex. 1301, Eiden Answer, p. 10.
[100] Hr. Ex. 1301, Eiden Answer, p. 14.
[101] Hr. Ex. 1301, Eiden Answer, p. 67.
[102] Hr. Ex. 1600, Sinton Answer, p. 22.

137. CEO suggests the Commission use 15 percent as starting point for EV managed charging participation rates.[103]

138. In Rebuttal, the Company argues that WRA and SWEEP miscalculated the percentage of customers enrolled in managed charging and provides no evidence for the assumption that customers will opt in based on an S-curve pattern typically assumed for technology adoption. Public Service continues to argue that a linear adoption path for future managed charging projections is more appropriate. As for WRA and SWEEP's concerns about double-counting, the Company generally agrees and offers to "back out estimates of historical EV load" in its Phase II forecasting.[104]

139. With respect to WRA and SWEEP's suggestion to eliminate two EV charging tranches, Public Service argues WRA and SWEEP incorrectly characterize the tranched approach, and that the managed charging program limits the contribution to system peak to 22 MW in 2031 across all five tranches.

b. Findings and Conclusions

140. The Commission notes that transportation electrification adoption and charging patterns will become increasingly important in serving the Company's peak loads. According to Public Service projections, this facet of load accounts for 22 percent of the peak demand growth, or 7 percent of total peak by 2031.

141. Regarding adoption, the Commission notes that, after roughly 10 years of EV adoption there are roughly 140,000 EVs operating in the Company's service territory by the end of 2024.[105] Public Service's "High" EV projection, incorporated in the Base forecast, adds roughly

[103] Hr. Ex. 400, Hay Answer, p. 7.
[104] Hr. Ex. 122, Goodenough Rebuttal, p. 26.
[105] Hr. Tr. June 18, p. 19.

that level every year in the latter half of the RAP. The lower “Mid” EV adoption projection incorporates a slightly lower but still aggressive adoption rate where additions to the pool of EVs in the Company’s service territory escalate more slowly. We find the lower EV adoption rate in the “Mid” forecast is more consistent with historical patterns and better reflects new barriers such as the loss of the federal and state EV rebates. Public Service indicated it will update its economic models to include the change in federal law as part of their Phase II forecast.[106] While the Company’s updated economic modeling likely reduces the Company’s projection of EV adoption, we find it necessary to direct Public Service to update its load forecast for the base RFP using the “Mid” EV adoption trend as presented in the Company’s technical appendix to its application, to net out EVs existing prior to mid-2024 when the Company’s forecast was conducted, and to provide up-to-date information on actual adoption and economic model output in all future forecasts including those developed to support the Supplemental RFP and the Company’s next ERP.

142. With respect to the Company’s commingling of PHEVs and full BEVs, we agree with WRA and SWEEP that there are important distinctions between the two vehicle types relative to battery capacity and the likely willingness to participate in managed charging programs (as PHEV owners have two fuel options: electricity and gasoline). Public Service suggests incorporating such differences is part of the “natural progression of improving forecast assumptions” and “something that we are exploring now.”[107] While we appreciate that Public Service recognizes the importance of distinguishing PHEVs from BEVs, we find it necessary to clearly specify our expectations in the Company’s forecasting efforts. We direct

[106] Hr. Tr. June 18, p. 20.
[107] Hr. Tr. June 18, p. 17:21-24.

Public Service to distinguish between battery capacities and willingness to participate in managed charging programs, among other appropriate attributes, amongst PHEVs and BEVs in its service territory as part of its revised load forecast the Company will use for the base RFP, and to submit its revised forecast to the Commission prior to publication of the Phase II RFP. We also direct Public Service to distinguish between PHEVs and BEVs in this manner in all future load forecasts including those for the Supplemental RFP and the Company's 2028 ERP.

143. As for the managed charging participation rates and program designs, we agree with WRA and SWEEP that the Company must increase its projections of future managed charging for purposes of its load forecast. We find the Company's effort to mitigate expansion of peak load inadequate. We recognize that the tranche concept was incorporated by Public Service in order to mitigate the impacts of the managed charging programs on peak loads without the benefit of delving substantially into program design issues which were outside the scope of this proceeding. Nonetheless, balancing party arguments, we recognize that meaningful improvement in managed charging participation rates and innovative program design will be critical to electrifying the transportation sector affordably. We note the Company is also before us requesting over $1 billion per year in distribution system investment via the Company's combined Distribution System Plan ("DSP") / Aggregated Virtual Power Plant ("AVPP") proceeding.[108] That proceeding is expected to engage the private marketplace through the pooled management of EVs and other technologies, and could expand on the peak load-mitigation capabilities of the Company's programs. Additional expansion of managed charging could further occur through the Company's upcoming Demand-Side Management and Transportation Electrification Program

[108] *See* Proceeding Nos. 24A-0547E and 25A-0061E, the Company's consolidated Distribution System Plan and Aggregate Virtual Power Plant Application.

applications in 2026. Accordingly, through these efforts, there will be ample opportunity to engage customers in managed charging programs critical to meeting electrification goals affordably. Therefore, we direct the Company to incorporate an overall managed charging participation rate of 50 percent for BEVs and 90 percent for PHEVs by 2031 for the purposes of the revised load forecast the Company will use for the base RFP. Future load forecasts should blend these Commission expectations with actual managed charging participation experience. Further, given the growing importance of managed charging programs, we direct the Company to fully support its managed charging programs – including relevant design elements and participation rates – as part of its next ERP including appropriate expert testimony, supporting data and thorough analysis as necessary to meaningfully weigh the Company's managed charging approach to its application for additional supply resources.

144. We also direct the Company to explore in the context of the next Transportation Electrification Plan filing additional ways to improve the managed charging programs and participation, including the possibility of requiring customers who take advantage of utility-sponsored rebates to participate in the managed charging program as a condition of receiving the rebate.

2. Load Forecast from BE

a. Party Positions

145. According to the Company's application, incremental building electrification is projected to cause a five percent increase in energy consumption (or, 2,835 GWh) and a one percent growth in retail peak loads (or, 134 MW) by 2031, the last year in the Company's initial RAP.[109] Notably, the Company projects a 662 MW increase to the winter peak, or roughly five

[109] Hr. Ex. 114, Goodenough Supplemental Direct, Tables JMG-SD-3 and JMG-SD-4.

times the summer peak impact, within the initial RAP.[110] The Company also suggests that its resource needs will increasingly be driven by the winter period beginning in the 2030s.[111] The Company incorporates the same BE-related projection for both its Base and Low forecast.

146. Resource requirements associated with BE are driven by three primary factors: (a) the adoption rates of various BE technologies, (b) the usage patterns of BE appliances, and (c) the electrical requirements of BE technologies (*e.g.*, any supplemental heating requirements). With respect to adoption rates, the Company projects relatively modest adoption patterns through 2026 based on the relevant program goals approved via the Company's DSM Strategic Issues proceeding.[112] In 2027, when the Company's Clean Heat Plan ("CHP") programs come into full implementation, BE adoption is projected to increase dramatically through the end of the RAP. Due to the timing of the JTS Application and supporting analysis, CHP-related adoption is based on Public Service's Amended Preferred Portfolio (presented via Rebuttal Testimony) in its CHP proceeding.[113] The Company indicated at hearing that it would update the forecast to incorporate the Commission's final decision in that case and additional requirements set forth from the decision in the instant case.[114] Accordingly, while final BE adoption values are not known, the JTS includes significant increases in adoption rates. For example, residential water heating BE technologies are projected to increase from 9,289 units in 2026 to over 122,000 units in 2027 (*i.e.*, a 13-fold increase in one year) and ultimately grow by over 100,000 per year to approximately 562,000 by 2031 (before any likely upward adjustment due to the Commission's CHP decision). All-electric heat is projected to grow somewhat slower but still dramatically, adding over 20,000

[110] Hr. Ex. 114, Goodenough Supplemental Direct, Table JMP-SD-6.
[111] Hr. Ex. 102, Landrum Direct, Rev. 1, pp. 34-35.
[112] Hr. Ex. 101, Att. JWI-2, Table 2.2-8, p. 36.
[113] Hr. Ex. 114, Goodenough Supplemental Direct, pp. 19-20.
[114] Hr. Tr. June 18, p. 21.

homes per year from 2026 to 2031.[115] Public Service explains that adoption rates approved in the DSM or CHP proceedings are extrapolated from the growth rate in the final approved year through the end of the forecast period.

147. With respect to BE usage patterns, the Company's technical appendix indicates that the Company applies hourly usage patterns for residential water heat developed by NREL, including peaks driven by relatively inefficient electric resistance elements heat pump water heaters utilize once the water heating tank is emptied due to high usage. At the Joint Technical Conference, the Company agreed with assertions that such usage patterns are highly unlikely to be consistent across customers and offered to apply a flatter electric usage pattern across the pool of residential hot water BE appliances.

148. With respect to the electrical loads of BE technologies (including supplemental appliance usage), the Company's filing offers a figure indicating total peak home usage of approximately 17 kW at -25 degrees F.[116] When asked for supporting documentation to the figure, Public Service referred to the testimony of another witness in another proceeding.[117]

149. WRA and SWEEP and other parties suggest that the load forecast should assume building electrification levels that reflect the Company's approved Clean Heat Plan.[118] WRA and SWEEP also state that Public Service is applying inconsistent assumptions among its electric and gas planning proceedings. In 24M-0261G, which represents a lead-up to the Company's upcoming Gas Infrastructure Planning application, the Company uses lower BE assumptions, leading to

[115] Hr. Ex. 101, Att. JWI-2, Table 2.2-8, p. 36.

[116] Hr. Ex. 101, Att. ZM-1, p. 38 (Figure 4-5).

[117] Hr. Ex. 1301, Att. AE-39, p. 1. (In the Company's response to WRA and SWEEP's question, the Company referred to Hr. Ex 111, Pollock Supplemental Direct, Section IV in Proceeding 24A-0547E (the DSP Proceeding). Mr. Pollock did testify in the instant Proceeding, but his testimony was limited to distributed energy resources and did not directly address the electrification requirements of all-electric homes.)

[118] *See, e.g.*, Hr. Ex. 1301, Eiden Answer, p. 99.

higher gas demand. Meanwhile, the Company's base forecast in the JTS—concerning electric system planning--uses higher BE assumptions, leading to higher electric demand.

150. WRA and SWEEP argue the Company's current projections of BE adoption result in an "unlikely trajectory."[119] They assert that the both the Company's base and low forecasts "assume that sales of residential all-electric heat pumps increase by about five-fold between 2026 and 2027, and that sales of residential heat pump water heaters increase by about twenty-fold between 2026 and 2027."[120] WRA and SWEEP characterize this rapid increase as "improbable."

151. WRA and SWEEP also question the Company's assumptions regarding back-up systems related to heat pumps. WRA and SWEEP note that the Company's assumed household peak use of 17 kW of load at a temperature of -22F (12 kW from the heat pump and another 5 kW from supplemental electric resistance heating).[121] WRA and SWEEP argue that, by assuming that the average all-electric heat pump installation will have significant electric resistance backup, the Company effectively negates its assumption about adoption of highly efficient heat pumps. WRA and SWEEP also argue this assumption does not reflect real-world best practices for installing highly efficient systems. WRA and SWEEP explain that in the Company's CHP case, multiple Colorado-based heat pump contractors testified about the practices they use when sizing and installing heat pumps and about peak load impacts. For example, two-thirds of Elephant Energy's installations in the Front Range of Colorado do not have any supplemental or backup electric resistance heating.[122] There is also data that Elephant Energy's heat pump installations held their setpoint throughout a December 2022 cold snap, during which temperatures in the Denver

[119] Hr. Ex. 1301, Eiden Answer, p. 92.
[120] Hr. Ex. 1301, Eiden Answer, p. 95.
[121] Hr. Ex. 1301HC, Eiden Answer, p. 102, fn. 161.
[122] Hr. Ex. 1301HC, Eiden Answer, p. 101 (citing Proceeding No. 23A-0392EG, Hr. Ex. 1905, p. 5:13-20).

metropolitan area reached a low of -22 degrees F.[123] WRA and SWEEP assert that even for heat pump installations that do require supplemental electric resistance heating, the size of the supplemental heating strips is typically 3 to 8 kW.[124] WRA and SWEEP ultimately recommend the Commission should assume a supplemental heating load of 3 kW and a total peak all-electric household use of 10 kW, rather than the 17 kW peak load the Company assumes.[125]

152. CEO suggests the Commission use the approved CHP portfolio BE assumptions, model increasing heat pump sales post-2030.[126]

153. In Rebuttal, In Rebuttal, Public Service disagrees with WRA and SWEEP's suggestion that backup resistance heat results in only a 3 kW load. The Company asserts that WRA and SWEEP's testimony is based on evidence in another proceeding and is not necessarily accurate information. Public Service further notes the cited range from the other proceeding is 3 to 8 kW, yet WRA and SWEEP recommend using the lowest value in that range. Conversely, Public Service asserts that the Company's modeling is based on a rigorous two-step process where the heat requirement for the building is determined first. After the heat requirement is known for each hour, the most efficient combination of available equipment is utilized to provide the required heat. According to Public Service, arbitrarily limiting the size of one available heating technology (electric resistance heat) does not reflect the choices customers have when selecting or operating their heating equipment. Finally, the Company argues that WRA and SWEEP assume that all electric resistance heat is included in the original installation of the heat pump system. In reality,

[123] Hr. Ex. 1301 HC, Eiden Answer, p. 101 (citing Proceeding No. 23A-0392EG, Hr. Ex. 1905, Att. JL-2).
[124] Hr. Ex. 1301HC, Eiden Answer, p. 101 (citing Proceeding No. 23A-0392EG, Hr. Ex. 701, p. 10, Table DP-2).
[125] Hr. Ex. 1301, Eiden Answer, p. 102.
[126] Hr. Ex. 400, Hay Answer, p. 7.

Public Service argues, customers may easily add plug-in electric resistance space heaters to their homes at any time.[127]

b. Findings and Conclusions

154. As mentioned above, the Commission understands BE-related peak loads driven by three primary factors: (a) the adoption rates of various BE technologies, (b) the usage patterns of BE appliances, and (c) the electrical requirements of BE technologies (or the customers that adopt those technologies including, for example, through supplemental heating sources). With respect to adoption patterns, we generally agree with parties who argue that the BE adoption forecast should be consistent with the Commission's decision in the CHP proceeding. In that proceeding, the Commission required an aggressive effort to reduce greenhouse emissions associated with the Company's gas system. We note, however, that CHP related adoption was expected to begin in the second half of 2024, but the Company's actual adoption rates are delayed relative to the planned adoption rates from the CHP proceeding. We also note that CHP budgets were only approved through 2027 even as we generally recognized the emissions reduction projection in the approved CHP portfolio through 2030. While the Company's CHP remains a critical goal of the Commission, we believe it is necessary to avoid expensive over-building of the electrical supply portfolio in anticipation of load that materializes at a far slower pace than proposed in another proceeding, potentially causing unnecessary rate and bill impacts. We also find Public Service's projected 2027 shift in BE technology adoption to be inconsistent with actual adoption patterns. Accordingly, we direct the Company to revise its forecast of BE technology adoption in the following manner:

i. Incorporate actual adoption rates through at least first half of 2025 (or additional quarters of data, if available) in the Company's updated load forecast. This step

[127] Hr. Ex. 122, Goodenough Rebuttal, pp. 20-21.

should ensure the Company's reforecast includes customers' actual adoption rates for, separately, hybrid space heating, all-electric space heating, and water heating for residential and commercial customers;

ii. Apply the delay experienced to date in customer adoptions to the approved adoption rates embedded in the DSM-SI and CHP proceedings. Continue until the funds currently approved via the most recent DSM-SI and CHP proceedings are projected to be exhausted given current delays;

iii. Grow the final year BE budgets (as approved in the DSM-SI and CHP proceedings) through the remainder of the RAP at the general rate of inflation;

iv. Develop a thorough projection of most-likely BE adoption rates for both electric and gas systems and submit such as part of the Company's upcoming 2026 DSM/CHP proceeding. The Commission will have an opportunity to reevaluate program expenditures and associated adoption rates in that proceeding; and,

v. Revise the load forecast for the Supplemental RFP with the Step iv. projection required for the DSM/CHP proceeding, if available at that time. If not available, conduct Steps i and ii with then-current info in any load forecast that supports the Supplemental RFP.

155. To be clear, the Commission is excited to support Colorado's leadership in decarbonization and electrification of loads, but we recognize the need to be as precise as possible regarding the projected load forecasts. Building too much generation too fast will likely and unnecessarily increase rates, which could discourage efforts to promote BE. The approach we adopt above uses the assumptions in the prior CHP but adjusts them to reflect up-to-date information regarding actual adoption levels.

156. With respect to usage patterns for BE technologies, we note that the Company voluntarily retracted its application of the NREL water heating curve. We find this appropriate and direct the Company to evaluate, to the extent possible, water heating requirements and electrical usage patterns for a sample of customers for presentation and review in the Company's next ERP filing. Regarding the usage patterns of space heating technologies, we note that – as with EVs – active management of will be critical to efficient and cost-effective use of available resources. It is imperative that the Company continues to expand its capability in this area through

its various demand response, VPP, and similar initiatives to mitigate coincident loads causing system and component-level peaks.

157. With respect to the electrical requirements of BE technologies, we find merit in WRA and SWEEP's arguments that the Company's analysis likely exaggerated the resources needed to serve all-electric customers. In the context of this Proceeding, WRA and SWEEP noted two sources from the Company's CHP proceeding: one that suggested most of its customers require no supplemental heat whatsoever and were able to maintain their household setpoint temperature even during a recent deep freeze; and another that suggested a range of supplemental heating requirements from 3 – 8 kW. WRA recommended a 3 kW supplemental heating requirement and a total household use of 10 kW based on those two testimonies. The Company argued that the testimony WRA relied upon were made by other witnesses in another proceeding. While we appreciate and understand that context, the Commission finds that the testimony referred to by WRA and SWEEP from the CHP proceeding in its Answer Testimony is relevant and informative, and that the Company had appropriate opportunity to respond both in testimony and at hearing. We note that technical issues such as these can play out over many cases, and it can be difficult for parties to engage with its witnesses (who, in this instance, are full-time implementers in the field) over multiple years and cases. Nonetheless, the issues and uncertainties addressed by the installers in the CHP proceeding are strikingly similar to the issues raised here by WRA and SWEEP, and the installers are directly engaged in the design, implementation and maintenance of these systems in the field. Accordingly, we find the testimony from the installers to provide useful insight and input to our Decision here, and it was raised by parties such that appropriate response could be provided by the Company for consideration as well. To that end and on balance here, we also note that the Company provided essentially no analysis in the instant

Proceeding to support its own assumptions. In fact, Public Service itself referred to another witness in another proceeding to justify its input calculations. Particularly where we are considering modeling inputs for analysis in Phase II, for purposes of the instant Proceeding, we find that WRA and SWEEP's suggested 10 kW average household peak usage to be a reasonable starting value for this important input. We direct Public Service to incorporate that value into its revised forecast for the base RFP.

158. Further, we believe the ongoing DSP proceeding (Proceeding No. 24A-0547E) will provide additional opportunities to revisit this issue and is likely to afford us an improved record including the availability of limited AMI data. We intend to further evaluate this issue there and in other future applications so that we may incorporate the best information available when approving investments – and ratepayer dollars – into the Company's energy supply, transmission and distribution infrastructure, including the load forecast that will be used in for the supplemental RFP. With respect to the utilization of AMI data, we believe strongly that such data is central to the issue of comprehending the system and local electrical capabilities required of the Company's growing electric system through unprecedented insight into actual energy requirements across a wide array of customers, geographic regions, weather conditions, and specific technology adoption (to the extent known or discernible). Given the fact that Public Service recently completed the rollout of AMI meters across 1.4 million customers, we expect the Company's ability to evaluate and manage customer usage patterns via AMI data to improve dramatically in subsequent resource and system planning applications.

159. Moving forward, the growing electrical load associated with both BE and EVs have the promise to benefit the system and help provide downward pressure on rates. This promise, however, is contingent on advances in demand response, managed charging, and other programs

or rate structures that minimize the impacts that BE and EVs have on the peak system need. More specifically, the Company seems unable or unwilling to effectively take advantage of the opportunity and instead assumes that these new technologies and uses justify multi-billion-dollar capital spending increases across both the electric and gas systems. As such, this Commission will continue to push for different rate structures, tariffs, and programs, including those that link customer rebates to required participation in managed use programs, that better advance active control of these loads.

160. Despite existing technology that can, for example, cost-effectively manage EV charging by time-of-day, despite the fact that EV batteries soon may be able to back-feed homes in ways that offset other peak demands, and despite Commission orders to significantly increase managed charging incentives, the regulated system must do better at driving EV charging and other similar BE loads off the critical system peak demand hours. The promise of these technologies is to flexibly reduce demand at critical times, yet the Company seems unable or unwilling to take advantage of these opportunities, which looks to result in higher resource needs, adverse rate impacts and reliability risk. More broadly, this Commission may need to explore third-party implementation models for some of these programs given some of the resistance or inability to earnestly pursue these priorities, misaligned financial incentives, and proposed customer costs. We intend to do this through future proceedings including the transportation electrification plans, DSP and VPP proceedings, and rate cases.

G. Strategic Resilience Reserve Fund

1. Party Positions

161. On April 2, 2025, Public Service filed a Notice of Filing and Hearing Exhibit 115, which provides an overview of the Strategic Resilience Reserve Fund concept.

Public Service states the strategic reserve fund is directly responsive to discussion at the Joint Technical Conference and is designed to allow the Company to acquire combustion turbines ("CTs") and transformers to help advance dispatchable generation and transmission projects to facilitate resource portfolios in the JTS.

162. Public Service proposes that the strategic reserve fund would not exceed $500 million in expenditures (for either physical equipment or production slots for eligible equipment) and that the Company would recover the costs associated with the strategic reserve fund through the Purchased Capacity Cost Adjustment ("PCCA"). The Company would earn a return on the invested capital at the Company's weighted average cost of capital ("WACC"), including the costs of any storage or handling costs associated with the equipment.

163. Staff argues the Commission should reject the strategic reserve fund. Staff asserts the Company has failed to show the need for the strategic reserve fund and the proposal lacks ratepayer protections. Staff states there is no indication Public Service is currently prevented from securing manufacturing slots or purchasing equipment without the strategic reserve fund, nor has the Company shown that it will not be able to timely deliver projects or energy supply without the strategic reserve fund. Staff cites testimony from the hearing showing that the Company can and has taken steps well in advance of CPCNs to procure equipment. This includes most recently taking action to reserve and secure gas CTs and wind turbines prior to the Phase II Decision in the 2021 ERP/CEP.[128]

164. Staff goes on to argue that the $500M budget is arbitrary. Staff suggest the Company could use the entire $500M to purchase CTs, which could eventually be used for future Company-owned projects outside the JTS. According to Staff, the proposed strategic reserve fund

[128] Staff's SOP at p. 25.

significantly benefits the Company by shifting nearly all financial risks to ratepayers, generating additional profit, and potentially placing Company-owned project bids at a competitive advantage.[129]

165. Like Staff, CEO opposes the strategic reserve fund and recommends the Commission reject it. CEO asserts the Company admitted during the hearing that only HVDC and CTs require a reservation payment to enter the manufacturing cure—breakers and transformers do not. Regarding HVDC equipment, CEO asserts the Company does not have a clear proposal for such equipment at this time, so the Commission should reject cost recovery for HVDC equipment purchased through the strategic reserve fund. As for CTs, CEO notes the Company admitted during hearing that it reserved gas CTs for two utility-owned projects in the 2021 ERP/CEP in March 2023, which was nearly 10 months prior to the Commission's Phase II decision issued in January 2024. CEO also asserts the Company admitted that it has already secured several gas CT slots for the current ERP cycle, even though they are not tied to a specific project. CEO thus argues that Public Service has already contributed its own capital to secure manufacturing slots for gas CTs and does not need the strategic reserve fund to do so.[130]

166. In the alternative, CEO argues the Commission should at least make significant modifications to the strategic reserve fund proposal, including narrowing the scope and limiting approval to only gas turbines for costs required to enter a queue, deposits to maintain queue position, or final payments. CEO further argues that the Company should make equipment acquired through strategic reserve fund available to both IPP and utility-owned generation projects on an equitable basis.[131]

[129] Staff's SOP at p. 26.
[130] CEO's SOP at pp. 28-29.
[131] CEO's SOP at pp. 29-30.

167. CIEA recommends the Commission approve a significantly modified strategic reserve fund that focuses on transmission and interconnection equipment and equitably distributes such equipment between IPP and utility-owned projects. Specifically, CIEA argues the strategic reserve fund should focus on reserving "high-side" interconnection facilities that are ultimately owned by Public Service. CIEA suggests that strategic reserve fund equipment acquisition costs could be noticed to the JTS parties, and strategic reserve fund equipment acquired and the associated cost should be listed in the RFP. The Company would be reimbursed by IPPs for the overnight costs of the equipment via the LGIP, or costs could be recovered via the ESA which could lower bid prices.[132]

168. Under CIEA's approach to the strategic reserve fund, Public Service would acquire sufficient transformers and breakers to connect entire selected, or Commission-approved, portfolio. CIEA reasons that under its strategic reserve fund proposal, the acquisition process for necessary interconnection equipment could be accelerated by as much as two years.

169. Similar to CIEA, CEI supports a modified version of the strategic reserve fund that focuses on transmission and interconnection equipment that is provided to developers in an ownership-agnostic and transparent manner. CEI asserts the Company's current proposal to acquire CTs that would be reserved for utility-owned generation bids in Phase II raises significant concerns. CEI asserts this aspect is fundamentally anti-competitive because it leverages ratepayer funds to secure critical generation equipment in advance, which IPPs cannot do.[133]

170. CEC opposes the strategic reserve fund and asks the Commission to reject it outright. According to CEC, with the strategic reserve fund the Company seeks to earn a

[132] CIEA's SOP at pp. 26-27.
[133] CEI's SOP at p. 17.

guaranteed return with no associated risk through a program that would leverage ratepayer funds to compete with IPPs for limited resources. CEC recommends the Company continue to purchase equipment in the ordinary course of business as it deems appropriate and seek recovery of its expenses in a general rate case.[134]

171. CC4CA argues the Commission should reject PCCA cost recovery for the strategic reserve fund but approve the Company's plan for acquiring or reserving breakers, transformers, and HVDC equipment for recovery in the next rate case. CC4CA asserts the Company has provided no evidence or argument that the PCCA is an allowable cost recovery mechanism for the proposed strategic reserve fund expenses. CC4CA also takes issue with the Company's proposal to earn WACC through the PCCA. CC4CA asserts this would be inappropriate without a tariff modification. Because transformers and breakers can serve all generation resources acquired as part of the JTS, CC4CA asks the Commission to direct Public Service to acquire this equipment with Company reserves, to be recovered through base rates or another appropriate cost recovery mechanisms. Finally, CC4CA warns against allowing strategic reserve fund funding for CTs. CC4CA reasons that doing so would risk biasing the solicitation in favor of Public Service and puts a thumb on the scale of including new gas in the approved portfolio.[135] CRES/PSR likewise opposes the strategic reserve fund.

172. Grid United supports the strategic reserve fund and specifically recommends the Commission either approve the strategic reserve fund's use for HVDC equipment procurement now or clarify that the strategic reserve fund's use can be expanded in future proceedings, including for HVDC procurement. Grid United asserts the evidentiary record is clear and

[134] CEC's SOP at p. 18.
[135] CC4CA's SOP at pp. 24-26.

undisputed that interregional HVDC lines, especially ones like Three Corners Connector that would connect Public Service's system and SPP's to the east, would bring substantial capacity value and customer savings.[136] Grid United thus argues the Commission should ensure that its decision paves the way for future consideration of such projects.

173. The Pueblo Intervenors support the strategic reserve fund as proposed. They reason that allowing the Company to deal proactively with these supply chain shortages and directing them to immediately secure a supply of CTs and transformers will facilitate the construction of replacement generation within Pueblo. The Pueblo Intervenors reference that with the impending closure of Unit 3, workers will need alternative employment, and that construction of replacement generation should not be delayed.[137]

174. In response to intervenor criticisms, Public Service explains the strategic reserve fund proposal is not about accelerating the manufacturing cycle, it designed to address the race for manufacturing slots and to secure critical equipment like turbines, transformers, and breakers.[138] Public Service states it is open to establishing acquisition targets instead of a flat \$500M budget. The Company estimates that a \$500 million budget could acquire approximately three CTs (\$100 million each), 10-15 transformers (\$5 million each), and 40-50 breakers (\$250,000 each), as an illustrative example.[139] The Company estimates these purchases would allow for approximately 10 interconnected projects in addition to approximately 600 MW of new thermal capacity.

[136] Grid United's SOP at p. 5.
[137] Hr. Ex. 1200, Shaw Answer, p. 14; Hr. Ex. 1201, Graham Answer, pp. 10-11; Hr. Ex. 1202, Swearingen Answer, pp. 14-15; Hr. Ex. 1204, Arnold Answer, p. 5.
[138] Public Service's SOP at pp. 6-7.
[139] Hr. Ex. 116, Ihle Supplemental Direct, p. 11.

2. Findings and Conclusions

175. We agree with parties such as Staff, CEO, and CEC who assert that Public Service has not shown a need for strategic reserve funds to procure CTs. It is unclear why Public Service now needs additional incentive to reserve manufacturing slots for CTs given the strategic reserve fund was apparently unnecessary for the 2021 ERP/CEP. Public Service has also not explained how using strategic reserve fund to acquire CTs would not give the Company a substantial competitive advantage over IPPs who may otherwise bid CTs into the base or supplemental RFPs.

176. On the other hand, the same anti-competitive concerns do not appear to be present for transformers and breakers when such equipment is available to support both PPA projects and utility-owned generation. CIEA and CEI both support a modified strategic reserve fund that focuses on transformers and breakers. Although CEO cites hearing testimony that reserving manufacturing slots for transformers and breakers does not require a down payment, this does not mean that the early procurement of such equipment will be cost free. Moreover, strategic reserve funds would only be recovered once the funds are actually expended.

177. On balance, the Commission finds that the strategic reserve fund concept for transformers and breakers as set forth by CIEA (with a slight modification to cap acquisitions by a $200M budget)[140] is in the public interest. CIEA asserts the acquisition process for necessary interconnection equipment could be accelerated by as much as two years by using CIEA's proposed strategic reserve fund process. This alone could help lower overall costs and increase flexibility. Accordingly, we direct the following: 1) the strategic reserve fund will be available on equitable basis to all PPA and utility-owned projects; 2) Public Service may acquire transformers

[140] The $200M budget we approve for the strategic reserve fund is based on the initially proposed $500M budget but without the anticipated costs of the CTs. Public Service estimated that it would use strategic reserve funds to acquire three CTs at $100M each.

and breakers to help connect the expected Commission-approved portfolio, subject to the $200M budget; 3) PPA and utility-owned bids will include Public Service's overnight costs for transformers and breakers in their bids, which will be noticed in the RFPs; and 4) strategic reserve fund costs can either be incorporated into Large Generator Interconnection Agreements ("LGIA"s) or separated out and recovered via the Energy Cost Adjustment ("ECA").

178. Strategic reserve funds shall not be used to acquire HVDC equipment, at this time. We agree with Grid United that interregional HVDC lines like the Three Corners Connector could bring substantial capacity value and customer savings. Unlike standard transformers and breakers, however, HVDC equipment appears to be application specific.[141] We agree with CEO that Public Service has not demonstrated its plans for HVDC equipment at this time.[142] Consistent with Grid United's alternative request, we clarify that the Commission would be open to Public Service seeking approval for accelerated funds for HVDC equipment in the future once the Company can provide more details on its HVDC plans.

179. Finally, we reject arguments to deny the strategic reserve fund concept outright or eliminate the accelerated recovery of strategic reserve funds. Requiring Public Service to recover costs associated with the strategic reserve fund in the next rate case eliminates the purpose of the strategic reserve fund, which is to provide regulatory certainty the Company needs to acquire long lead time assets on an expedited basis.

[141] Hr. Ex. 116, Ihle Second Supplemental Direct, p. 10.
[142] Hr. Ex. 402, Hay Cross-Answer, p. 34.

H. Just Transition

1. Motion to Strike

180. Moffat and Craig filed a Motion to Strike a portion of Pueblo Intervenors' testimony ("Motion to Strike"). The statement in question, contained in Pueblo Intervenors' SOP, is as follows:

> Craig/Moffat also submitted cross answer testimony claiming that employee impact payments should go to them as opposed to Hayden where the plant is located because many of the employees work at Hayden but live in Moffat County. So Moffat/Craig is fighting with Hayden/Routt as to who should get paid amounts that are not authorized under the statute.[143]

181. The Motion to Strike argues this statement is false, argues alleged facts not in evidence, is advanced for an improper purpose, and should be stricken from the record because (1) Moffat and Craig did not file cross-answer testimony in this Proceeding; (2) there is no evidence in the record that Craig's request for community assistance has been made in lieu of "or as opposed to" the Routt County Governments (rather, their testimony supports Routt County's requests for community assistance); and (3) evidence does not show that the governments have been "fighting," but have been supportive of each other throughout the Proceeding.

182. The Routt County Governments support the motion, Pueblo Intervenors oppose the Motion, and all other parties either take no position or did not respond to conferral.

183. In its response, Pueblo Intervenors contend its statements are supported by the record. Pueblo points to statements made by Routt County Governments witness Commissioner Redmond where he explains that "…it is critical that the Moffat County Government's request not come at the expense of the Routt County Governments. Any interpretation that reallocates or limits Routt County's arguments for economic assistance based on Moffat County's claims of

[143] Pueblos Intervenors' SOP at pp. 20-21.

workforce-related impacts would undermine the purpose of this just transition process."[144] Pueblo also points to Commissioner Redmond's testimony regarding the Carbon Free Future Development Fund where he requests the Commission "[a]nalyze the just transition needs and requests of each just transition community independently and reject any interpretation of the Moffat county Governments' proposal for economic assistance payments as a limitation or subtraction from the economic assistance needed by the Routt County Governments."[145] Pueblo asserts this testimony proves there is a "fight" or dispute between the governments and that it is important to include its statement as it speaks to the problems and confusion that will arise if the Commission fails to follow § 40-2-125.5(4)(a)(VII), C.R.S.

184. We deny Moffat and Craig's Motion to Strike. The Commission has discretion in determining the admissibility of evidence in its proceedings and the appropriate weight to assign to evidence, consistent with § 40-6-101(4), C.R.S. The Commission therefore interprets the quoted testimony not as "fighting," but as the local governments advocating for their own respective interests and weighs the statements of Pueblo Intervenors accordingly in making its determinations in this Proceeding.

2. Background

185. One of the primary issues in the 2021 ERP/CEP was Public Service's proposed coal transition plan. Under this plan, Craig Unit 2 will retire in 2028, Hayden Unit 1 will retire in 2028, and Hayden Unit 2 will retire in 2027. These accelerated retirements were not, however, CEP actions. Rather, in its direct testimony in the 2021 ERP/CEP, Public Service informed the Commission that it had previously decided on the accelerated retirements of these plants in

[144] Pueblo Intervenors' Response to Motion to Strike at p. 4 (citing Hr. Ex. 1803, Redmond Cross Answer, p. 7).

[145] Pueblo Intervenors' Response to Motion to Strike at p. 4 (citing Hr. Ex. 1803, Redmond Cross Answer, p. 9).

conjunction with the plants' other owners. For Craig Unit 2, the Company only owns 10 percent of the plant. The rest of the plant is owned by PacifiCorp, Platte River Power Authority, Salt River Project ("SRP"), and Tri-State Generation and Transmission Association, Inc. ("Tri-State"). Regarding Hayden Unit 1 and Hayden Unit 2, Company owns the units along with PacifiCorp and SRP. Unlike at Craig, however, the Company is the majority owner and operator of the Hayden Station, owning about 75 percent of Hayden Unit 1 and 37.5 percent of Hayden Unit 2.[146]

186. The USA also specifies that the Pawnee coal-fired power plant will be converted to natural gas no later than January 1, 2026. Pueblo Unit 3 is set to retire no later than January 1, 2031. In addition, beginning in 2025, Public Service agreed to begin ratcheting down Unit 3's annual capacity factor. Unlike the accelerated retirements of the coal units at Craig and Hayden, the conversion of the Pawnee Unit and the restrictions Pueblo Unit 3 are considered CEP actions.

187. In the USA in the 2021 ERP/CEP, Public Service committed to modeling in Phase II of the 2021 ERP/CEP just transition costs (*i.e.*, the potential future costs of both workforce transition plans and community assistance plans) for each affected coal plant facing accelerated retirement or conversion (*i.e.*, Hayden, Pawnee, and Unit 3). Public Service maintained during the 2021 ERP/CEP that it was not obligated to provide just transition benefits to Craig 2 because it was a minority owner/non-operator.

188. To model the just transition costs, the Company agreed to use an escalating property tax-based proxy value that runs until the earlier of: (1) a unit's original retirement date (for all units other than Unit 3); or (2) December 31, 2040 (in the case of Unit 3). The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years

[146] *See* Hr. Ex. 101, Jackson Direct, Rev. 1, p. 43 in the 2021 ERP/CEP.

following retirement or conversion for Hayden 1 and Hayden 2, and Pawnee, respectively, and ten years for Unit 3 (*i.e.*, from January 1, 2031, through December 31, 2040, for Unit 3). With regard to Unit 3, the USA further specifically states: "[t]he Company commits to make payments to Pueblo County annually from 2031 through 2040 (and allocated by the treasurer's office accordingly) in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County."[147]

189. The USA contemplates that in 2021 ERP/CEP Phase II, the Commission would approve a final portfolio with the estimated costs of the Just Transition Plan included in the cost estimate of the plan, which will be offset by any investment and corresponding property tax revenue in an affected community. Final community assistance plan costs and workforce transition plan costs (as well as any offsets due to investments in the relevant community) were to be determined in future post-Phase II Just Transition Plan filings. The upshot of the USA's modeling approach is that the model was incentivized to select resources within the just transition communities because these resources would help offset the community assistance payments that were included in the modeling.

190. In addition to the modeling benefits and community assistance payments, the USA requires Public Service to conduct a study to evaluate low-emission or carbon-free dispatchable resources within Pueblo County: "The Company will conduct a study at an amount not to exceed $2 million to evaluate a variety of potential low-emission or carbon-free dispatchable resource

[147] USA, ¶ 42 in the 2021 ERP/CEP.

options located at the site of Comanche Station or within Pueblo County that can contribute to the Company's continued efforts to reduce emissions."[148]

191. In approving the USA provisions regarding the just transition modeling, the Commission noted that although not all communities affected by the coal transition plan are intervenors in the 2021 ERP/CEP Proceeding, Pueblo Country, Pueblo City and Water, and the OJT all support the just transition provisions of the USA.[149]

3. Party Positions

192. In Public Service's Direct Testimony, it recounts the provision of the 2021 ERP/CEP USA committing the Company to a $2 million study for new low-emission or carbon-free dispatchable resources within Pueblo County. The Company explains that this $2 million study led to the formation of the Pueblo Innovative Energy Solutions Advisory Committee ("PIESAC"). Public Service states that many of the Company's just transition proposals come directly out of the PIESAC process.[150]

193. More specifically, the Company frames its just transition proposals as having three distinct proposals: (1) modeling credits that would be applied in Phase II modeling to help drive resource acquisition in these communities; (2) a development component to drive longer-term investments into communities (*i.e.*, the pre-construction development asset proposal[151] and the CFFD proposal[152]); and (3) a broader economic development component to assess which potential new loads have siting flexibility to develop in just transition communities.

[148] USA, ¶ 48 in the 2021 ERP/CEP.
[149] USA, ¶ 109 in the 2021 ERP/CEP.
[150] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 45.
[151] In its Rebuttal, the Company converted the PCDA concept into the incremental need pool. As set forth above, the Commission largely approves the incremental need pool as part of the Phase II Framework.
[152] As set forth in Section I below, the Commission adopts the CFFD proposal, with modifications and clarifications.

194. Starting with the modeling credit, the Company explains that it did not see results from the property tax tail/offset modeling approach used in the 2021 ERP/CEP that suggested it was significant enough to drive investment into the relevant communities. Accordingly, Public Service now proposes to give projects located within Pueblo, Morgan, and Routt counties a modeled benefit, in the form of a \$/MWh or \$/kw-month bonus, in the bid evaluation.[153] Notably, this modeling piece will be in addition to the property tax tail/offset approach agreed to in the 2021 ERP/CEP USA. The proposed just transition modeling credits are set forth below:

- Projects located within target communities will receive a base credit of \$1.00/kw-month or \$2.00/MWh
- Projects located within target communities and that create more than 20 long term jobs will receive an additional bonus credit of \$.50/kw-month or \$1.00/MWh
- Projects located within target communities and that provide more than \$4 million in annual property taxes will receive an additional bonus credit of \$.50/kw-month or \$1.00/MWh
- The total potential credits are \$2/kW-month or \$4/MWh. [154]

195. Regarding the second component of the Company's just transition proposal (driving longer-term investments into communities), Public Service argues that the Company wants to see long-term proposals in just transition communities, and the CFFD concept facilitates that goal. Public Service argues that longer-timeline resources, such as pumped hydro, geothermal, nuclear, geologic carbon-capture, hydrogen or other technologies are now effectively blocked from serious consideration by the current Colorado resource plan process.[155]

196. As for the third component of the just transition proposal, Public Service states that the just transition communities desire to drive economic development beyond just new generation

[153] Public Service notes these two counties (Routt and Pueblo) will see coal plant retirements occur during the RAP.
[154] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 40.
[155] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 50-51.

resources. This could include attracting ancillary businesses to the communities (*e.g.*, clean energy-related manufacturing) or siting large new loads in the communities. Public Service adds that if large new loads have siting flexibility, the Company can try and facilitate discussions with just transition communities about siting those loads in these communities. However, the Company adds that it is "not seeking any Commission findings on this respective component of our just transition approach."[156]

197. In addition to the three just transition components above, Public Service states the Company remains firmly committed to making the community assistance payments contemplated in the 2021 ERP/CEP. The Company provides the below estimate of what the community assistance payments would be without any offset for replacement generation or new infrastructure:

- Hayden 1: average payment of $1,246,333 (for six years), for a total payment of $7,478,000
- Hayden 2: average payment of $1,474,833 (for six years), for a total payment of $8,849,000
- Pueblo Unit 3: average payment of $16,243,900 (for 10 years), for a total payment of $162,439,000
- Pawnee: average payment of $3,433,980 (for six years), for a total payment of $20,603,879[157]

198. As for the implementation of the community assistance payments, Public Service states that once the final JTS portfolio is approved, the Company would bring an application filing that would include the community assistance payment values for each community, netted with any new property tax offsets from the portfolio. The Commission would establish the final values through a decision on this application, along with the cost recovery approach as provided for in statute. For efficiency, the Company plans to file single application

[156] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 52-53.
[157] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 53-54.

would cover all three communities (Pueblo County, Routt County, and Morgan County) with discrete community assistance payment streams established for each community.[158]

199. The Pueblo Intervenors support the Company's proposed just transition modeling credits as one of the tools that could help ensure a just transition for Pueblo.[159] The Pueblo Intervenors argue that it is much more advantageous for the Pueblo community to have new large capital investments in the community as opposed to community assistance payments.[160] The state the Comanche site generates almost $31 million a year in property taxes a year, which is over 10.5 percent of all property taxes Pueblo County collects, and Pueblo Unit 3 provides almost $200 million annually and direct and indirect benefits to the community.[161] They ask the Commission to do everything in its power to expedite the modelling, bidding, and construction of new thermal/gas units in Pueblo. The Pueblo Intervenors reason that the just transition modeling credits will drive new projects to coal communities and states the Commission should adopt the Company's proposal if the Commission cares about a just transition for Pueblo and other coal communities.[162]

200. As for the community assistance payments, the Pueblo Intervenors generally agree with the calculation of payments for Pueblo the Company puts forth in its Direct Testimony, with one caveat. The Pueblo Intervenors assert that 10-year period over which Pueblo will receive the community assistance payments is a long time, especially if there is a materially high inflation period with materially high interest rates. Pueblo County thus reserves its right to argue that the

[158] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 55.

[159] Hr. Ex. 1200, Shaw Answer, p. 13; Hr. Ex. 1201, Graham Answer, p. 11; Hr. Ex. 1202, Swearingen Answer, p. 8; Hr. Ex. 1204, Arnold Answer, pp. 6-7.

[160] Hr. Ex. 1200, Shaw Answer, p. 12.

[161] Hr. Ex. 1201, Graham Answer, p. 3.

[162] Hr. Ex. 1200, Shaw Answer, p. 13; Hr. Ex. 1201, Graham Answer, p. 8; Hr. Ex. 1202, Swearingen Answer, p. 8.

escalator of two percent is too low.[163] The Pueblo Intervenors also request the Commission issue an order quantifying the community assistance payments and the underlying methodology. According to the Pueblo Intervenors, without such a quantification by the Commission, financial agencies could see this as a vulnerability which could increase the interest rate on any debt Pueblo County issues in the future, or impact on Pueblo County's credit rating.[164]

201. The Routt County Governments generally oppose the community assistance structure agreed upon in the 2021 ERP/CEP USA as well as the Company's proposals in this Proceeding. For instance, the Routt County Governments argue it is inappropriate to provide only six years of property tax backfill, when other communities will receive 10 years of tax backfill. In addition, while the Routt County Governments generally agree with providing a modeling benefit to just transition communities, they argue the Company's proposal will likely have limited effectiveness in driving job and property tax creating generation to the Hayden Station site, noting that a gas-fired plant is neither preferable nor viable.[165] Instead, the Routt County Governments express an interest in geothermal and other non-fossil fuel replacement generation.[166]

202. More fundamentally, Routt County Governments oppose the settlement provisions from the 2021 ERP/CEP. They state they were never asked for input when the settlement was being formed and that it is wrong for their economic future to be decided without the Routt County Governments having a seat at the table.[167] Instead of the Company's proposal, the Routt County Governments argue Public Service can provide a just and inclusive transition by offering

[163] Hr. Ex. 1203, Genesio Answer, p. 3.
[164] Hr. Ex. 1203, Genesio Answer, p. 4.
[165] Hr. Ex. 1800, Redmond Answer, p. 27.
[166] *See* Hr. Ex. 1801, Mendisco Answer, pp. 22-29.
[167] Hr. Ex. 1800, Redmond Answer, p. 26; Hr. Ex. 1801, Mendisco Answer, p. 10.

community assistance which is structured similarly to the Tri-State Settlement. The Routt County Governments specifically request the following:

- $43,590,560 in property tax backfill, to be paid over the next 10 years to taxing authorities within Routt County and which could be offset by new investment;
- $49,409,440 in direct economic development payments, not subject to offset, which will be utilized by the Routt County Governments to accelerate economic development and diversification within Hayden and Routt County;
- An order from the Commission requiring either the dedication of, or a pathway to dedication of, the Hayden Station Spur Line, the Pumphouse Property, any unused water rights currently benefiting Hayden Station after the year 2050;
- Incentives or commitments by Public Service to site geothermal electric generation at the Hayden Station site as replacement generation, whether as part of a standalone RFP or any other form determined to be appropriate by the Commission; and
- A binding commitment by Public Service to fully remediate all environmental impacts of Hayden Station upon final decommissioning or a requirement that the issue be addressed in a future proceeding.[168]

203. As part of the justification for the approximately $90 million in payments and other just transition benefits, the Routt County Governments cite an Economic Impact Report that details the significant impacts that closure of the Hayden Station will bring to the community.[169]

204. Moffat and Craig urge the Commission to require Public Service to pay community assistance payments to Moffat County and Craig. Moffat and Craig argue the Commission must disregard Public Service's "Owner-Operator" argument that attempts to shield the Company from providing Moffat and Craig with a just transition. According to Moffat and Craig, Colorado's just transition statutory framework has no language either (i) exempting "minority" coal plant owners or (ii) mandating the majority owner (or given plant's operator) to be completely responsible for community assistance payments. They argue Public Service is legally obligated to provide

[168] Routt County Governments' SOP at pp. 34-35.
[169] *See* Hr. Ex. 1802, Duffany Answer, pp. 10-12.

community assistance to Moffat County and the City of Craig for the accelerated closures at Craig Station on a proportional basis to its property tax contributions.[170]

205. Based on Public Service's ownership stake in Craig Station, Moffat and Craig argue they should receive a community assistance plan accounting for $14,023,800 which amounts to ten years of the Company's Craig Station annual property tax payments following the closure of Craig Station, subject to infrastructure investment offsets.[171] In addition, Craig and Moffat request a community assistance plan accounting of $14,797,200 for direct labor income effects from the workers employed at the Hayden Station but who live in Moffat County.[172] Thus, Moffat and Craig request a total community assistance funding amount of $28,821,000.[173]

206. Moffat and Craig similarly argue the Company should extend the just transition modeling credits to Moffat County to help satisfy the Company's broader community assistance and just transition obligations to help prioritize resources to coal communities.[174] Moffat and Craig further reason that if the Commission allows community assistance payments to Moffat and Craig, then applying the just transition modeling credits to Moffat County is a logical extension. Investments in Moffat County will help offset community assistance payments.[175]

207. UCA strongly recommends Public Service be required to provide community assistance payments to the City of Craig and its share of Craig Unit 1 and 2's retirement. UCA estimates the Company's proportional obligation to be approximately $6,803,738.31 million for each of these units, totaling approximately $13,607,476.62 million. More broadly, UCA argues the Commission should approve a JTS that not only meets resource adequacy and emissions goals

170 Moffat and Craig's SOP at pp. 6-8.
171 Hr. Ex. 2100, Villard Answer, p. 44.
172 Hr. Ex. 2100, Villard Answer, p. 44.
173 Hr. Ex. 2100, Villard Answer, p. 44; Hr. Ex. 2101, Nichols Answer, p. 41.
174 Hr. Ex. 2101, Nichols Answer, pp. 27-30.
175 Moffat and Craig's SOP at p. 23.

but also supports communities and workers as well as reasonable costs to ratepayers.[176] In its SOP, UCA asserts the Company's refusal to provide any community assistance payments for Craig Unit 1 due to its closure date is a narrow and formalistic interpretation of its obligations that ignores the broader legislative intent. UCA also proposes the Commission order in this Proceeding the use of the same payment structure applied in the Tri-State proceeding regarding the closure of Craig Unit 3.[177]

208. OJT also recommends modifying the Company's community assistance proposals. OJT specifically recommends the Commission follow the just transition framework set forth in the 2023 Tri-State ERP, which OJT refers to as the "Moffat model." In general, under this Moffat model community assistance consists of one-third of the total in direct benefit payments at or near the time of the closure, and two-thirds in minimum backstop payments, starting large and tapering down over time. Deductions for new investments are made only against the backstop payments, and then only for new property taxes received prior to each scheduled backstop payment.[178] OJT details how this Moffat model would work for Pueblo, Morgan County, and Routt County based on the total community assistance commitments Public Service puts forth in its direct case.[179]

209. OJT recommends the Commission require Public Service to provide community assistance payments to Moffat County based on the Company's ownership interest in Craig Station.[180]

210. In its SOP, OJT more generally argues the USA is the floor for crafting a just transition for each community. OJT likewise argues the Just Transition statute (§ 40-2-125.5(4),

[176] Hr. Ex. 300, Sermos Answer, Rev. 1, p. 35.
[177] UCA's SOP at pp. 19-21
[178] Hr. Ex. 600, Buchanan Answer, p. 20.
[179] Hr. Ex. 600, Buchanan Answer, pp. 21-23.
[180] Hr. Ex. 600, Buchanan Answer, pp. 27-28.

C.R.S.) sets the minimum community assistance that a CEP must contain and that arguments that the statute prohibits the Commission from considering other types of assistance ignore the Commission's exclusive and broad authority.[181] OJT argues the Commission can consider alternatives in addition to the minimum requirements in the statute unless the constitution or general assembly expressly prohibit it.

211. OJT generally supports the Company's intention to use modeling credits to stimulate investment of future energy projects, including bonus credits for minimum levels of jobs created in communities. In addition to having these just transition credits in Pueblo County and Routt County, OJT argues the Company should also apply these modeling credits to Moffat County and Morgan County. [182]

212. CEO makes clear that it continues to support a strong commitment to just transition communities and impacted workers. More specifically, CEO recommends the Company provide community assistance payments to Morgan, Pueblo, and Routt Counties, and supports OJT's recommendation that the Company provide community assistance payments to Moffat County for Craig 2, proportional to the Company's ownership share at Craig 2. CEO also recommends the Commission adopt OJT's proposal that directs Public Service to allow just transition communities the option to receive up to one-third of their community assistance payments upfront, to the extent that is allowed by the USA from the 2021 ERP/CEP.[183] CEO argues the statutory just transition requirements and 2021 ERP/CEP USA establish a floor for the Company's just transition obligations and asserts that no party has pointed to any language in the USA prohibiting the Commission from going beyond the obligations in that document.[184]

[181] OJT's SOP at pp. 16-17.
[182] Hr. Ex. 600, Buchanan Answer, pp. 28-29.
[183] CEO's SOP at pp. 19-20.
[184] CEO's SOP at p. 18.

213. Regarding the just transition modeling credits, CEO recommends extending the modeling credits to Moffat County. According to CEO, extending these modeling credits is one way to drive investment to Moffat County to help offset some of the economic loss that the community will experience when Craig 2 retires. CEO asserts that at hearing, Company indicated it would not oppose such an extension of the modeling credits. [185]

214. CEI, Interwest, WRA and SWEEP, Conservation Coalition, CC4CA, and EJC all recommend the Commission eliminate the just transition modeling credits in some way or at least model Phase II portfolios with and without the just transition modeling credits so that the Commission and parties can see the true impact of the just transition modeling credits. For instance, CEI argues the thresholds for the credits—a bidder's estimate of the amount of jobs and taxes—are arbitrary and subject to manipulation. Bidders could *estimate* that their projects would generate more than $4 million in taxes or more than 20 jobs, but they are under no obligation to deliver on those numbers via the final projects. CEI also asserts that the thresholds for jobs and tax revenues needed to qualify for the modeling credits are all but unobtainable for renewable based projects. Further, the credits ignore the incremental benefits of smaller projects or the value that several smaller projects can provide to just transition communities in aggregate.[186]

215. CEI asserts that, under the Company's proposal, the actual incremental cost of utilizing the proposed just transition credits will never be known. CEI references analysis put forth in its Answer that shows ratepayers could pay $4.5 million more for a 50 MW project or up to $32.5 million more for a 300MW project located in a just transition community. CEI asserts these costs could double if such projects also qualify for the more lucrative bonus credits.[187]

[185] CEO's SOP at p. 18.
[186] CEI's SOP at pp. 9-11.
[187] CEI's SOP at p. 10.

216. Interwest raises similar arguments, asserting the proposed just transition modeling credits will skew RFP results to favor utility-owned and fossil fuel generation. According to Interwest, without expanding the just transition modeling credits to other communities, the Company holds a significant structural advantage through its exclusive transmission rights. Without scaling these credits for projects of smaller individual impact, the majority of these credits will likely not apply to renewable facilities.[188]

217. WRA and SWEEP recommend the Commission reduce the scale of the just transition modeling credits by half and direct the Company to model Phase II portfolios both with and without the credits. WRA and SWEEP calculate that the full just transition modeling credits would equate to a discount of 21 to 24 percent, which they argue does strike the right balance between the benefits and the cost to ratepayers. WRA and SWEEP further warn that the just transition modeling credits may signal to developers that they can inflate their bid prices in these regions while remaining competitive in the biding process.[189]

218. Conservation Coalition notes the just transition modeling credits were not contemplated in the 2021 ERP/CEP USA. In contrast, the property tax offset approach was included in the USA and, Conservation Coalition argues, is required by SB 19-236. Conservation Coalition goes on to argue that the just transition modeling credits are arbitrary and that the Company never analyzed their cost impacts. Conservation Coalition asserts that, regardless of intent, the practical effect of the just transition modeling credits will be to incentivize the model to select new gas—even in communities like Hayden that have expressly stated they do not want a new gas plant. [190]

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[188] Interwest's SOP at p. 10.
[189] Hr. Ex. 1300, Valentine Answer, p. 79.
[190] Conservation Coalition's SOP at pp. 11-14.

219. In the alternative, Conservation Coalition argues the Commission should at least require the Company to model (1) some portfolios in Phase II with half the dollar amount for the credits, and (2) some portfolios without the just transition modeling credits. Otherwise, Conservation Coalition argues the Commission would *never* understand the cost or resource impact of using these credits.[191]

220. CC4CA argues that if the Commission approves the just transition modeling credits, the credits should apply only to clean resources. Moreover, the Commission should direct Public Service to model all Phase II portfolios with and without the credits, including for Moffat County. CC4CA asserts such information is important to the Commission, Public Service, intervenors, and the public to evaluate the cost and effectiveness of the just transition modeling credits as a just transition tool.[192]

221. EJC argues gas plants should be ineligible for the just transition modeling credits. The EJC supports, however, applying the modeling credits to clean energy resources such as solar, wind, and battery storage. EJC reasons the Commission must apply SB 21-272 for a broader view of just transition and not just consider workforce and economic consideration. EJC notes the Commission must correct historical inequities where possible, provide equity, and minimize impacts and prioritize benefits to disproportionately impacted ("DI") communities. According to EJC, approving a proposal that encourages Public Service to build gas plants in DI communities would flout these requirements.[193]

222. In Rebuttal, Public Service states it needs Commission direction regarding whether the Company should provide community assistance payments based on the accelerated retirement

[191] Conservation Coalition's SOP at p. 16.
[192] CC4CA's SOP at pp. 4-5.
[193] EJC's SOP at pp. 10-11.

of Craig Unit 2.[194] If the Commission directs Public Service to provide community assistance payments for Craig Unit 2, the Company believes that Moffat County should get six years of payments with an offset for new replacement generation and infrastructure, similar to the structure used for Routt County and Morgan County. Public Service calculates the average annual community assistance payment for Craig Unit 2 would be $645,667, for a total of $3,874,000 over the 2029-2034 time period.[195] Public Service clarifies that it is "neutral" on whether to provide community assistance payments for Craig Unit 2, so long as the Commission makes a finding that any estimated tax payments that Public Service makes for these facilities only represent such payments up to the ownership-proportional amount.

223. In contrast to Craig Unit 2, the Company argues against any community assistance based on the early retirement of Craig Unit 1. The Company notes the decision to retire Craig Unit 1 was announced in 2016 to assist with Regional Haze Rule compliance. Public Service notes this announcement was well before the passage of SB 19-236 (with its just transition requirements) and thus argues that Craig Unit 1 is differently situated than all of the other coal units.[196]

224. Except for the possible addition of community assistance payments for Craig Unit 2, Public Service opposes disturbing the community assistance payments agreed upon in the USA.[197] Public Service specifically opposes the recommendation from the Routt County Governments that the Company pay a total of $89 million of combined property tax backfill and direct payments for economic development over a ten-year period for the early retirements of Hayden 1 and Hayden 2. The Company reiterates that Hayden's $16.3 million community assistance payment under the USA is based on replacement tax revenue to the area associated with

[194] Hr. Ex. 117, Ihle Rebuttal, pp. 81-82.
[195] Hr. Ex. 117, Ihle Rebuttal, pp. 82-83.
[196] Hr. Ex. 117, Ihle Rebuttal, p. 81.
[197] Hr. Ex. 117, Ihle Rebuttal, p. 89.

the Hayden units, prior to any offset. According to Public Service, "this value replaces taxes that would have been paid if the generators had operated to the end of their full book lives."[198] The Company asserts that the Routt County Governments' requested $89 million would amount to over $70 million more than the property taxes that Routt County would have received had the Hayden units not been proposed for accelerated retirement.[199]

225. As for the Routt County Governments' request for dedication of real property assets and assurance that the Hayden Station site will be fully remediated of environmental impacts, the Company argues that these proposals "go beyond the scope of this proceeding."[200]

226. Regarding the just transition modeling credits Public Service opposes recommendations to extend the just transition modeling benefits to Moffat County. The Company argues the areas that receive the modeling benefits were the areas where the Company operated coal units that are subject to accelerated retirement under the 2021 ERP/CEP. Public Service asserts it would be inappropriate for the modeling credits to drive generation into Moffat County at the expense of Routt County, Pueblo County, or Morgan County, especially given Tri-State's proposal for new thermal investments in the area.[201]

227. Overall, Public Service stands by its proposal for just transition modeling credits and property tax tail modeling for Pueblo County, Morgan County, and Routt County. Public Service concedes that the just transition credits are not a "perfect" calculation but argues it does not follow that these credits are unnecessary or inappropriate. Public Service urges the Commission to not entertain proposals to develop portfolios with and without the credits.[202]

[198] Hr. Ex. 117, Ihle Rebuttal, p. 86.
[199] Hr. Ex. 117, Ihle Rebuttal, pp. 85-86.
[200] Hr. Ex. 117, Ihle Rebuttal, p. 87.
[201] Hr. Ex. 117, Ihle Rebuttal, p. 85; Public Service's SOP at pp. 22-23.
[202] Public Service's SOP at pp. 22-23.

228. In their SOP, the Pueblo Intervenors reiterate their support for the Company's proposed JTS, which adopts many of the recommendations of the PIESAC Report.[203] In contrast, the Pueblo Intervenors specifically oppose the recommendations to expand community assistance payments based on the Tri-State model. The Pueblo Intervenors argue that the settlement with Tri-State does not provide any authority to modify the terms of the USA, let alone modify the provisions of SB 19-236. The Pueblo Intervenors continue to support the USA but warn that if the Commission orders these types of payments to the other coal communities, then the Pueblo Intervenors should be able to make similar claims pursuant to the Commission's interpretation of the statute and the USA.[204] The Pueblo Intervenors characterize OJT's proposal for community assistance payments to include lump sums as "dangerous." Pueblo argues that a large lump sum could trigger a TABOR event requiring a refund. Having to litigate against even a questionable claim—whether or not the payments in lieu of taxes are actual tax collections—is expensive.[205]

229. The Pueblo Intervenors also support Public Service's position on the just transition modeling credits in that they oppose extending the credits to Moffat County. Pueblo argues that Public Service has a limited amount of time and resources to drive construction of infrastructure into coal communities, and the Company should be focused on the communities in which they have operated coal facilities and with whom they have relationships. The Pueblo Intervenors suggest that the funds Moffat County are expected to receive from Tri-State could be used to provide financial incentives for projects. The Pueblo Intervenors argue that extending the just transition modeling credits will make it an uneven playing field for the other coal communities.[206]

[203] Pueblo Intervenors' SOP at pp. 3-4.
[204] Pueblo Intervenors' SOP at pp. 21-22.
[205] Pueblo Intervenors' SOP at pp. 20-22.
[206] Pueblo Intervenors' SOP at p. 23.

230. Staff supports maintaining community assistance payments for the communities as agreed to in the USA and is not opposed to the Company's ownership-proportional payments for Craig Unit 2. Staff opposes, however, additional community assistance payments because these payments have an affordability impact on all ratepayers, including low-income customers. The Company should instead pursue alternative mechanisms that will prioritize reinvestment in affected communities (*e.g.*, property tax offset incentives, modeling credits, and strong Pueblo, Hayden, and OJT representation in CFFD).[207] Regarding the just transition modeling credits, Staff supports including a Phase II portfolio that excludes the modeling credits. Staff argues that such a Phase II portfolio will help determine the impact of the credits on ratepayers and any potential biases the credits may create.[208]

4. Findings and Conclusions

a. Community Assistance

231. We direct Public Service to provide community assistance payments to Moffat and Craig, based on its ownership interest in Craig Unit 2, consistent with the Company's offer in Rebuttal Testimony and its SOP. Specifically, Moffat County should get six years of payments with an offset for new replacement generation and infrastructure, with the average annual community assistance payment being $645,667, for a total of $3,874,000 over the 2029-2034 time period.[209] We agree with arguments from Moffat and Craig, OJT, UCA, and others that there is little justification for treating Craig 2 differently than Hayden 1 and Hayden 2. The contention that only the operator of a coal plant is responsible for providing community assistance payments is unpersuasive. For the reasons set forth by Public Service, we reject arguments that Public Service

[207] Staff's SOP at p. 29.
[208] Staff's SOP at pp. 11-12.
[209] Hr. Ex. 117, Ihle Rebuttal, pp. 82-83.

should also provide community assistance payments for Craig Unit 1 given that the decision to retire this unit was announced in 2016.

232. With minor exceptions set forth below, we also adopt the Company's position about the level of community assistance payments, including those associated with Craig Unit 2 and Hayden Units 1 and 2, and maintain the basic framework agreed upon in the 2021 ERP/CEP USA.[210] We acknowledge the Routt County Governments and Moffat and Craig did not intervene in the 2021 ERP/CEP and are not part of the USA. Nevertheless, it is our understanding that the community assistance amounts for these communities approximate the replacement tax revenue these communities would have received from Public Service but for the accelerated retirement of the units.[211] The Commission and parties will have an opportunity to finalize the community assistance amounts, as offset by new investments, in the future application proceeding Public Service intends to file. [212] An amount of community assistance that parallels the framework agreed upon in the 2021 ERP/CEP, offset by new investment, is an appropriate path forward that addresses the support of the community, without unnecessarily burdening ratepayers more broadly as it relates to Public Service's ownership interest in these units. To require further assistance would unduly burden the Company, and ultimately ratepayers, and is not supported in this record or by the statutory directives.

233. While we decline to expand the community assistance payments associated with Hayden Unit 1 and Hayden Unit 2, we encourage the other owners in those facilities to contribute their fair share in community assistance payments. We agree with Public Service that a utility's

[210] Commissioner Plant dissents from this point noting that the communities of Hayden and Craig as well as the counties of Routt and Moffat were not parties to the 2021 ERP/CEP and the USA and therefore should not be bound by its agreement on their behalf.

[211] Hr. Ex. 117, Ihle Rebuttal, pp. 85-86.

[212] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 55.

obligation to pay community assistance payments should be based on the utility's proportionate ownership interest. However, just transition communities rely on the full value of the property taxes associated with the facilities, not just the property taxes that Public Service contributes. While our directives are pertinent to requirements of regulated utilities, to further help ensure a just transition, co-owners of the facilities are encouraged to address community assistance payments based on their particular ownership interests. Just as we maintain Public Service has an obligation to Craig as a minority owner, we suggest those with minority positions in Hayden Unit 1 and Hayden Unit 2 have a similar obligation and should honor that obligation to those communities.

234. We do not diminish the impact that the just transition communities face from the early retirement of the coal units, but we agree with Staff that further expansion of the community assistance payments will have affordability impacts on all ratepayers, including low-income customers.[213] The community assistance payments from the Company are directly funded by ratepayers—not Public Service's shareholders. The Commission's approach must balance affordability concerns with the level of community assistance payments. We note that our decisions largely approving the CFFD and adopting additional modeling credits should help drive additional investments to these just transition communities, which appear preferable to limited-duration cash payments.

235. The Commission grants the Pueblo Intervenors' request that the Commission decision quantify the community assistance payments to Pueblo County and the underlying methodology. As set forth in the Company's Direct, and echoed in the Pueblo Intervenors' Answer, pursuant to the approved terms of the 2021 ERP/CEP USA, Public Service will pay to Pueblo

[213] Staff's SOP at p. 29.

County an average annual payment of $16,243,900 for 10 years for a total of $162,439,000.[214] This value is based on the assessed value of Pueblo Unit 3 and includes an annual escalator of two percent and excludes the property tax adjustments from the 2024 special legislative session.[215] These payments are subject to offset from additional investment within Pueblo County, the details of which will be adjudicated in a future proceeding. The Commission acknowledges that Pueblo County reserves its right to argue the two percent escalator is too low, especially if there is a materially high inflation period.[216]

236. Finally, the non-monetary requests from the Routt County Governments appear reasonable, cost-effective methods to help that community achieve a just transition. As such, Public Service shall be required to propose a pathway to the dedication of the Hayden Station Spur Line, the Pumphouse Property, and any unused water rights currently benefiting Hayden Station after the year 2050. This pathway should be explored in the new application proceeding Public Service has committed to file that will finalize the community assistance payments for each community.[217]

b. Just Transition Modeling Credits

237. At the outset, we reiterate that the USA from the 2021 ERP/CEP already contemplates modeling benefits designed to drive new investments to just transition communities. Under this property tax offset modeling approach, all portfolios bear the expected cost of the community assistance payments. Those portfolios that include new investments in the just

[214] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 54; Hr. Ex. 1203, Genesio Answer, p. 3.
[215] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 54; Hr. Ex. 1203, Genesio Answer, p. 3.
[216] Hr. Ex. 1203, Genesio Answer, p. 3.
[217] Regarding the request for incentives or commitments from Public Service for a geothermal unit in Routt County, this issue is more appropriately addressed through the CFFD process. As for the request for a binding commitment to fully remediate all environmental impacts of Hayden Station, such environmental matters are likely outside of the Commission's jurisdiction.

transition communities, however, can deduct from the community assistance costs the anticipated property taxes from the new investments. Thus, the property tax offset modeling approach included in the USA incentivizes the model to select new resources within the just transition communities because these resources would help offset the community assistance costs. Consistent with the USA from the 2021 ERP/CEP, we approve this property tax offset modeling approach for use in the Phase II modeling of this Proceeding.[218] Moreover, Public Service must ensure that the present value revenue requirement ("PVRR") of each portfolio reflects any offset in community assistance payments from new investments. For example, if one of the portfolios includes a new thermal unit located in Pueblo County, that portfolio's PVRR should be reduced by the offset in community assistance payments that the thermal unit would create.

238. In addition to the property tax offset modeling approach, we partly approve Public Service's proposal to expand the modeling benefits beyond what the USA in the 2021 ERP/CEP contemplates via the just transitions modeling credits. As initially proposed, projects located within the just transition communities will receive a base credit of these just transition modeling credits \$1.00/kw-month or \$2.00/MWh. In addition, projects that create more than 20 long term jobs and that are estimated to provide more than \$4 million in annual property taxes will receive an additional bonus credit totally \$1.00/kw-month or \$2.00/MWh. All told, projects could be eligible for just transition modeling credits of \$2.00/kw-month or \$4.00/MWh.

239. We share the concerns raised by multiple intervenors that modeling credits of \$2.00/kw-month or \$4.00/MWh do not strike the right balance between the benefits to just transition communities and the cost to ratepayers. For instance, WRA and SWEEP calculate that

[218] Commissioner Gilman dissents from this point and would have directed the Company to model each of the portfolios without the JTS modeling credits but allow one alternative version of the preferred portfolio to be run with the JTS modeling credits.

a project receiving the full amount of just transition credits would receive a modeling discount of 21 to 24 percent. [219] This significant advantage would be in addition to other advantages such as the transmission capacity that will be made available once the existing coal facilities retire.[220] Given these advantages, we are concerned the full just transition modeling credits could allow developers to inflate the bid price of their projects. To achieve a more appropriate balance, we reject the bonus credits and approve only the base credit of $1.00/kw-month or $2.00/MWh for projects located within just transition communities. Eliminating the bonus credits associated with a bidder's estimate of long term jobs and annual property taxes addresses concerns from parties like CEI, Interwest, WRA and SWEEP, and Conservation Coalition that bonus credits will inappropriately bias the model towards gas generation and are subject to gaming because there is no penalty if a proposed project does not actually achieve the estimated tax or job benefits. The base just transition credit, in contrast, applies equally to all projects types located within the just transition communities.

240. In addition, we agree with CEO, OJT, and Moffat and Craig that the base just transition modeling credits should apply to Moffat County as well as Pueblo County, Morgan County, and Routt County. Extending the just transition modeling credits is consistent with our decision to extend the community assistance payments to Moffat County. As Moffat and Craig note, the just transition modeling credits will help drive additional investment, which would reduce the community assistance payments to Moffat County. In this way, extending the just transition modeling credits to Moffat County is a logical step that could ultimately help offset community assistance payments that Public Service ratepayers would otherwise bear.

[219] Hr. Ex. 1300, Valentine Answer, p. 79.
[220] Interwest's SOP at p. 10.

241. In addition to eliminating the bonus credits, we agree with arguments put forth by Staff, Conservation Coalition, WRA and SWEEP, and others that there should be at least some Phase II modeling that does not incorporate the just transition modeling credits. Public Service chose not to include the just transition modeling credits in any Phase I modeling, nor did the Company provide a robust analysis as to why credits of $1.00/kw-month or $2.00/MWh were appropriate. Without at least some Phase II modeling that excludes the just transition credits, it will be difficult to determine what the modeling credits will actually cost Public Service ratepayers or how the credits impact the selected resources. Moreover, even if the Commission selects a portfolio that includes the just transition modeling credits, requiring three portfolios without just transition modeling credits will lessen concerns that bidders who anticipate receiving just transition modeling credits will inflate their bid prices. Accordingly, we direct Public Service to model three Phase II portfolios without any just transition modeling credits.[221]

242. Recognizing that the modeling credits are just that – credits for the purposes of influencing the economic model – we want to ensure the costs of community assistance payments are accurately portrayed in the PVRR of the Phase II portfolios. For example, if a portfolio does not include any projects within just transition communities, the PVRR of such a portfolio must include the full amount of community assistance payments. In contrast, if a portfolio does include projects within just transition communities, the PVRR of that portfolio must account for how those just transition projects will offset the community assistance payments.

[221] The specific Phase II portfolios that must be run with the just transition modeling credits are set forth below in Section M.

I. CFFD

1. Party Positions

243. Public Service asserts it has seen very few truly innovative technologies bid into recent resource solicitations. The Company argues that as ELCC values continue to decline and the need for clean, medium-to-long term dispatchable generation continues to increase, there must be more diversity in the potential resources in the solicitations. For instance, the Company's Phase I modeling shows that additions of advanced technologies such as geothermal and nuclear significantly reduce the amount of wind, solar, and storage the system needs. Specifically, the modeling estimates that 3,000 MW of advanced technologies replace 11,000 MW of wind, solar, and storage, for a net reduction of 8,000 MW.[222] The Company asserts, however, that these advanced technologies have long-lead times and high upfront investment costs that make it difficult for such projects to arise from the Commission's current ERP processes.

244. To kickstart the development of advanced power generation technologies in Colorado, Public Service recommends the Commission approve the Company's CFFD proposal. Under the CFFD, the Company would conduct a request for information ("RFI") for things like nuclear, advanced geothermal, and thermal plus carbon capture. An advisory board would review responses to the RFI and make the initial determination on whether to fund projects.

245. Under the Company's proposal, the advisory board would consist of one member from the following: Public Service, Staff, UCA, CEO, the OJT, one member from Hayden, one member from Pueblo, and one member from the environmental community. Meetings would be facilitated by an independent facilitator.

[222] *See* Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 66-67, 81-82.

246. Public Service proposes the several customer protections for the CFFD, including that payments to developers are made upon demonstration of action identified in the milestone payment timeline from the RFI response, the Company has a ROFO on any approved project should the developer seek to sell it to a different counter-party or third-party, and if Public Service chooses not select a project through a future solicitation, the developer may sell the project to another off taker but is required to reimburse Public Service for the cost of development provided by Public Service's customers.[223]

247. Public Service promotes the CFFD as one of the tools that can help promote a just transition. The Company that suggests that relying on resources within the RAP to facilitate a just transition is insufficient given property tax payment structures and the reality of workforce needs of most existing technologies. Public Service reasons the CFFD provides an avenue for long lead time advanced technologies that would not be available within the RAP such as pumped hydro, geothermal, nuclear, geologic carbon-capture, and hydrogen. The Company states that it wants to see these types of long-term proposals located in just transition communities and that the CFFD provides a runway of investment opportunities into these communities over a longer time horizon.[224]

248. In response to intervenor feedback, Public Service offers several modifications to the CFFD concept in Rebuttal. To begin, instead of a one-time RFI, the Company agrees with Staff's recommendation that the CFFD be conducted as a rolling solicitation. Among other positive attributes, the Company states this rolling solicitation approach allows parties to remain focused on the JTS Phase II solicitation.

[223] Hr. Ex. 103, Tomljanovic Direct, pp. 54-55.
[224] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 49-51.

249. Along with the rolling solicitation, Public Service proposes to solicit CFFD proposals twice per year until approximately 2028. While the Company recommends against setting an explicit sunset date for the CFFD, it notes that a 2028 target aligns with the Company's proposal to file the next full ERP in 2028. This would provide a useful check-in point.[225] More specifically, Public Service envisions the advisory board would file a project selection report coming out of each semi-annual meeting with projects selected for funding and the duration of that funding. While Public Service initially sought a budget of $100 million, in Rebuttal the Company states it is "not necessary to have an express budget cap."[226] After the submission of the project selection report, the Commission would have 30 days to review the report and weigh in if it does not support funding any of the projects. If the Commission does not affirmatively act on project recommendations, such proposals would be approved by operation of law.

250. Regarding the advisory board, Public Service recommends adopting CEI's proposal to include a non-voting, technical advisor from either an academic or research institution, but opposes the other various recommendations to expand the advisory board.

251. In addition to the advisory board, the Company continues to believe an independent facilitator would provide a useful role in helping to manage and coordinate meetings and can provide objective minutes from meetings. The Company believes such a role can be filled for a reasonable cost and will confer with the advisory board before selecting an independent facilitator. The Company is also amendable to filing the scope of work for the independent facilitator with the Commission, as it does with other independent consultant roles for transparency, with cost

[225] Hr. Ex. 119, Tomljanovic Rebuttal, p. 16.
[226] Hr. Ex. 119, Tomljanovic Rebuttal, p. 17.

recovery for any independent facilitator being included with other CFFD costs recovered through the ECA.[227]

252. In addition, Public Service clarifies in Rebuttal that project proposals must show a pathway to a viable project suitable for bidding within 10 years of their CFFD submission (not 10 years from the RFI) and cost recovery will only occur after disbursement of funding. The Company further states it is not seeking to earn a return on any of the costs disbursed to developers. Public Service also states that it is willing to provide opportunity for public comment on each semi-annual report.[228]

253. Regarding what technologies are eligible for CFFD funding, the Company supports using the following definition that Staff advances:

> This RFI will consider emerging carbon free electric technologies and long duration storage that enable operation of a carbon-free system. Technologies that will not be considered include commercially mature wind, solar, and short duration storage, and any technology that directly emits carbon dioxide while producing electricity. Examples of eligible technologies include but are not limited to: geothermal, hydroelectric, hydrokinetic, nuclear, renewably sourced hydrogen, long duration storage, and electrical energy from fossil resources with active capture and storage of carbon dioxide emissions that meets EPA requirements.[229]

254. Staff agrees with the Company's shift to conducting the CFFD as a rolling solicitation with semi-annual advisory board meetings, but Staff argues the Commission should maintain the $100 million budget cap. Staff asserts the budget cap is an "important proactive guardrail to reduce the possibility of potentially excessive expenditures."[230] Regarding the advisory board, Staff argues that a large consumer/ratepayer perspective, like CEC, should be

[227] Hr. Ex. 119, Tomljanovic Rebuttal, p. 27.
[228] Public Service's SOP at p. 6.
[229] Hr. Ex. 119, Tomljanovic Rebuttal, p. 21.
[230] Staff's SOP at p. 21.

added. Second, each advisory group member should retain the ability to submit comments to the Commission to explain their voting choice as part of any CFFD funding request.

255. Staff also offers modifications to the Company's plan for the advisory board to file a project selection report after each semi-annual meeting, which would be implemented unless the Commission acts within 30 days. Staff recommends the Commission modify this process to clarify that the Commission retains the right to accept, reject, or modify the results of any advisory group vote prior to Commission approval of CFFD funding. Staff also recommends modifying the proposal for 30-day Commission approval to give the Commission the option to extend the approval timeline to three months with a stakeholder comment period, if the Commission decides more time is needed.

256. Finally, Staff notes that the Company opposes the use of EnCompass modeling to evaluate CFFD technologies. Staff argues the Commission should require at least one modeling study prior to each advisory group vote that includes capacity expansion and production cost models to provide insight for the system value and operation of candidate technologies for CFFD. Staff reasons the CFFD modeling studies will also provide a useful "trial run" that will build experience with emerging technology modeling methods.[231]

257. CEO argues Colorado needs to establish a process for resources with longer-lead-times to incorporate clean resources into the ERP process. CEO states it supports the Company's CFFD proposal if the following five criteria are met: (1) the Company does not earn any return on CFFD dollars, (2) there are two checkpoints on the use of CFFD dollars: approval by the Advisory Board and approval by the Commission, (3) CFFD dollars are equally available to the Company and IPPs (with a firewall at the Company between the team proposing projects

[231] Staff's SOP at p. 23.

and the team deciding which projects receive CFFD dollars), (4) the process for implementing the CFFD, including any by-laws or agreements, is co-developed by the Company and the Advisory Board; (5) any payments under the CFFD are made on a milestone basis for actual costs. [232]

258. CEI generally supports the concept of a CFFD but argues there are too many unanswered questions in the current proposal. CEI asserts that clean firm technologies like next-generation geothermal, green hydrogen, and long-duration energy storage face significant barriers toward deployment based on their high capital costs and long lead times, and a mechanism like CFFD can reduce the risk for innovative clean firm technologies. CEI raises numerous concerns with the Company's current approach, however, including concerns that the Company will be biased towards its own projects, no IPP representatives would be included in the advisory board, the advisory board would not have access to all CFFD bids but would only see the ones the Company selected to advance, and the Company has not committed to computer-based modeling to evaluate potential long-term costs and benefits of the various technologies. Ultimately, CEI recommends the Commission direct Public Service to include, in a separate application, proposals to better standardize bids, ensure neutrality between Company-owned and IPP projects, and methodologies and criteria for evaluating proposals.

259. Alternatively, if the Commission does move forward with the Company's CFFD proposal in this proceeding, CEI argues the Commission should require that (1) all bids are presented to the advisory board, (2) the advisory board includes broader representation, including from the IPP community, (3) that any advisory board member, including the Company, be

[232] CEO's SOP at p. 27.

prohibited from voting on a project proposal that it owns equity in, and (4) that the Commission have final approval authority over any CFFD project.[233]

260. WRA and SWEEP largely mirror CEI's position. WRA and SWEEP support mechanisms that address barriers to the development of carbon-free firm resources, but they assert the Company's CFFD proposal could fund projects that are not carbon-free, does not include transparent evaluation criteria or a transparent advisory committee and approach, and includes a cost recovery approach that prematurely puts more risk on ratepayers.[234]

261. WRA and SWEEP recommend requiring Public Service to refile the CFFD as a standalone application. They suggest Public Service could still proceed with an RFI and then submit an application to the Commission providing the results of the RFI and seeking approval of any proposed CFFD Portfolio.

262. In the alternative, if the Commission moves forward in this Proceeding with the Company's proposed CFFD, WRA and SWEEP recommend several modifications, including the following: require the CFFD Portfolio solely consist of technologies that provide for carbon-free power generation or storage; require the Company to file the draft RFI with the Commission for approval, prior to issuing the RFI; require the Company to provide all parties with all RFI responses, even for projects that are not selected by the advisory board; establish a process for parties and stakeholders to comment on CFFD portfolios proposed by the advisory board, prior to the Commission issuing a decision on the CFFD portfolio.[235]

263. Conservation Coalition opposes the CFFD and recommends the Commission reject it. While CFFD acknowledges that promoting innovative, zero-emissions technologies is a worthy

[233] CEI's SOP at p. 22.
[234] WRA and SWEEP's SOP at p. 24
[235] WRA and SWEEP's SOP at p. 25.

goal, Conservation Coalition asserts its many flaws warrant rejection. According to Conservation Coalition, these flaws include that Public Service never submitted a draft RFI for the CFFD for parties to review; there are no metrics for comparing responses to the RFI; the Company has not committed to EnCompass modeling of the CFFD projects; the Company has not committed to compare RFI responses to other technology types, including conventional wind, solar, and storage;[236] the Company has not mitigated the risk that projects are selected for the CFFD at one price, and then bid into a RFP at a much higher price; and there is no guarantee that customers will receive any benefit in return from the CFFD funds.[237]

264. In the alternative, if the Commission approves the CFFD, Conservation Coalition recommends several changes. These changes include requiring public comment and Commission approval before any ratepayer funds are committed to any CFFD projects; requiring EnCompass modeling of a project before it can receive CFFD funding; comparing each CFFD project to the least-cost portfolio of conventional technologies; and requiring responses to RFIs be made available to parties to this Proceeding subject to confidentiality protections.

265. CEC opposes the CFFD, asserting that with the massive scale of the costs at issue in this Proceeding and the unproven status of advanced technologies, the CFFD is an imprudent use of ratepayer funds. Instead, CEC argues the market should continue to bear the costs necessary to develop these speculative technologies to shovel-ready status.

266. CC4CA's position is similar to CEI, WRA and SWEEP. CC4CA argues the CFFD is incomplete and lacks important details, so CC4CA recommends the Commission require the Company to present the CFFD for approval in a standalone application. CC4CA's specific

[236] Conservation Coalition opposes the underlying premise of the CFFD that customers should fund the pre-development of certain technologies regardless of whether those projects are—or ever will be—more cost-effective than other technologies.

[237] Conservation Coalition's SOP at pp. 17-18.

proposed modifications include adding two representatives to the advisory board—one from a community that seeks 100 percent renewable electricity by 2050 and one from a large commercial and industrial customer with the same or similar goal; requiring all advisory board members to disclose potential conflicts; and prohibiting advisory board members from voting on any RFI response in which the member has a conflict of interest. CC4CA further recommends that the Commission delay a decision on the proposed cost recovery mechanism to a future application or until after RFI responses are received.

267. CRES/PSR similarly request the Commission deny or defer consideration of the CFFD. They further recommend the Commission outright deny proposals to pursue or explore nuclear energy, carbon capture and storage, or hydrogen-based power generation.

268. The EJC recommends the Commission modify the CFFD so that (1) Public Service cannot provide preliminary funding to specific nuclear, carbon capture and storage, and hydrogen projects; (2) the advisory board is more inclusive; and (3) all parties have an opportunity to comment on the Company's funding proposals. Regarding carbon capture and storage, nuclear, and hydrogen technologies, EJC asserts it is improper for Public Service's ratepayers to provide preliminary funding for these types of expensive and uncertain projects. Similar to CEC, EJC reasons the private market should shoulder the costs of developing these technologies to the point that they are commercially available. As for the advisory board, EJC urges the Commission to include a more diverse range of Pueblo community members as well as non-governmental and non-state agency members that represent Public Service ratepayers.

269. OJT generally supports the CFFD concept but argues the advisory board should have representatives from all transition communities, including Morgan County as well as Moffat County.

270. Moffat and Craig support the CFFD proposal but argue the advisory board should be expanded to include one member from Moffat County and one member from Routt County. This modification would create a nine-member advisory board with more diverse coal community viewpoints.[238]

271. The Pueblo Intervenors support the CFFD as proposed, reasoning that many of the advanced technologies, including long duration storage, hydrogen, enhanced geothermal, and advanced nuclear are not yet "mature" in the market and will likely not be during this RAP for the period 2024 through 2031. The Pueblo Intervenors argue that coal communities such as Pueblo need an opportunity to attract these types of investments.[239] The Pueblo Intervenors assert the CFFD "provides an opportunity for Pueblo to be the location of advanced clean technologies including geothermal, hydrogen and yes, possibly advanced nuclear."[240] According to the Pueblo Intervenors, adoption of the CFFD is important to the workers at Pueblo Unit 3 and the Pueblo community because it will provide incentives for not only the Company but IPPs to develop pans and projects for advanced clean energy projects beyond the RAP.[241]

2. Findings and Conclusions

272. At the outset, we find there is broad party support for the CFFD concept, although most parties assert there are significant flaws in the current proposal such that a standalone application proceeding is necessary before allowing the CFFD to proceed. We agree with numerous intervenors who acknowledge the need for a mechanism to address barriers to the development of carbon-free firm resources and approve the CFFD concept. In addition, consistent with testimony from the Pueblo Intervenors, we see the CFFD as another potential mechanism that

[238] Moffat and Craig's SOP at pp. 26-27.
[239] Hr. Ex. 1200, Shaw Answer, p. 15.
[240] Hr. Ex. 1202, Swearingen Answer, p. 15.
[241] Hr. Ex. 1204, Arnold Answer, p. 9.

could help drive new investment in coal transition communities. Indeed, the Routt County Governments indicate their community is uninterested in a gas plant to replace Hayden 1 and Hayden 2, but they expressly request Public Service investigate the feasibility of geothermal generation.

273. The Commission disagrees with proposals from CEI, CC4CA, and WRA and SWEEP to require the Company to file a separate Application proceeding to launch the CFFD. Many of the concerns intervenors raised can be addressed through the advisory board process or decided here. For instance, the precise wording of the RFI and how the costs, benefits, and feasibility of the proposed projects are measured can be left to the advisory board. Given the developmental nature of CFFD projects, it is unlikely the parties and Commission could reach a standard method for evaluating all CFFD projects in advance, even if the Commission directed a standalone application proceeding.

274. Accordingly, we approve the CFFD process as set forth in the Company's Rebuttal, subject to several modifications. First, Public Service's argument that a budget cap is no longer necessary because the CFFD solicitation is rolling is unpersuasive. We agree with Staff that the $100 million budget cap serves as an important proactive guardrail. Although Public Service may make an appropriate request to expand this budget cap if necessary, launching this novel process with no cap on the amount of ratepayer funds is untenable.

275. The Commission also agrees with Staff's proposed changes to the approval process. We clarify that the Commission retains the right to accept, reject, or modify the results of any advisory group vote prior to approval of CFFD funding. The Commission also has the option to extend the approval timeline to an additional three months with a stakeholder comment period, if we decide more time is needed. On this point, we preemptively extend the 30-day period to act on

a project selection report to 60 days. The additional time is warranted given the Company's commitment to provide an opportunity for public comment on each semi-annual report. The additional time is also valuable given the existing demands on the Commission's time and resources. Conversely, it is unclear why approving CFFD funding would be an urgent matter given how the CFFD process is designed to address long lead time projects.

276. The Commission disagrees with the recommendations from Staff, Conservation Coalition, and other parties that the Company be required to conduct EnCompass modeling prior to any CFFD project receiving funding. Although some advisory board members may decline to support a particular project if there is not computer-based modeling, we agree with Public Service that it would be inappropriate for the Commission to mandate EnCompass modeling work for each and every project. The Phase I EnCompass modeling conducted in this Proceeding already shows the value of long-duration energy storage and the fact that relatively small amounts of geothermal or nuclear energy can replace large amounts of wind, solar, and four-hour storage. It is possible that certain CFFD projects may not allow for much more than this generic modeling that has already been conducted. For example, if a CFFD project requested payments to drill geothermal test wells, additional computer-based modeling might not help evaluate the project given fundamental uncertainties about its feasibility.

277. Consistent with CEO's position, we expressly require the process for implementing the CFFD, including any by-laws or agreements, be co-developed by the Company and the advisory board. As part of the formation of the CFFD by-laws or agreements, the advisory board should consider how to mitigate risk that Company-backed CFFD projects will receive preferential treatment. For instance, the advisory board should consider proposals from CEI and others that any advisory board member, including the Company, be prohibited from voting on a project

proposal that it owns equity in. While we stop short of adopting CEI's proposal here, we do endorse the general principle from CEO that CFFD dollars be equally available to the Company and IPPs, with a firewall at the Company between the team proposing projects and the team deciding which projects receive CFFD dollars.

278. In addition, the advisory board shall develop regular reporting requirements for any project that receives CFFD funding. Even though every CFFD project may not be successful, every project may succeed in uncovering valuable information regarding the technology, concepts, and feasibility. To ensure CFFD funding is as useful as possible for ratepayers, the advisor board shall require projects to provide regular reporting including at a minimum what the CFFD money was spent on, why the project ultimately failed or succeeded, and anything learned more generally about the technology.

279. We also agree with the concerns raised by CEI and other intervenors regarding the ability to access the responses to the RFI. CEI asserts the advisory board would not have access to all CFFD bids but would only see the ones the Company selected to advance. We direct the Company to provide all RFI responses to the advisory board, subject to advisory board members executing standard non-disclosure agreements. The Commission acknowledges that some developers may be more hesitant to respond to the RFI if certain information will be shared with the entire advisory board. Nevertheless, this is an appropriate safeguard given developers could receive ratepayer funds.

280. The Commission approves the Company's request for an independent facilitator, with one caveat. The costs of the independent facilitator shall count against the $100 million CFFD budget. This will incentivize Public Service to incur only those costs for an independent facilitator that are necessary.

281. As for the advisory board, we agree with requests from various intervenors to expand its make up. The increased representation will help further ensure that CFFD funds are being allocated appropriately, and with the independent facilitator, the additional administrative demands should be manageable. Specifically, we adopt Staff's recommendation to include a large consumer/ratepayer perspective, like CEC; CEI's recommendation to include a representative from the IPP community; Moffat and Craig's recommendation to include a representative from Moffat County; and OJT's recommendation to include a representative from Morgan County. Thus, the advisory board would consist of one voting representative from the following: Public Service, Staff, UCA, CEO, OJT, the Hayden community, the Pueblo community, the environmental community, a large consumer/ratepayer perspective, the IPP community, Moffat County, and Morgan County.

282. Except for the modifications discussed above, we approve the Company's CFFD proposal as set forth in the Company's Rebuttal. This approval includes the 10-year pathway to Phase II competitive solicitation (*i.e.*, project proposals must show a pathway to a viable project suitable for bidding within 10 years of their CFFD submission); any cost recovery occurs only after disbursement of funding; confirmation of the Company's position that it will not earn a return on any of the costs disbursed to developers; and adoption of Staff's definition of CFFD-eligible technologies.

283. We acknowledge this CFFD process is novel and—despite the additional guardrails adopted here—presents certain risks, including that it is possible for the CFFD funds to not result in cost effective resources deemed prudent to pursue. On balance, however, we find the promises of the CFFD outweigh the risks and could have lasting future benefits. As detailed by Public Service, the Pueblo Intervenors, and others, ideally the CFFD will provide the necessary runway

for the development of advanced technologies that both facilitate the goal of 100 percent clean energy and help ensure a just transition.

J. Resource Adequacy

284. Pursuant to the 2021 ERP/CEP USA, Public Service conducted a "best practice" review of current reliability planning practices.[242] Based on this review, the Company retained Energy + Environmental Economics ("E3") to conduct a resource adequacy ("RA") study ("RA Study"),[243] the main outputs of which are the planning reserve margin ("PRM") and effective load carrying capability ("ELCC") values for each resource type. E3 designed the RA Study around a loss of load expectation ("LOLE") of 0.1 days per year, which is consistent with historical Company practice and with those of many utilities and RTOs around the country.[244]

285. The RA Study differs from that conducted in support of the Company's prior ERP in three ways. First, it utilizes ELCCs for all resources, including thermal resources, which in previous ERPs have been accredited at their net dependable capacities. This change puts all resources on a level footing and shifts the interpretation of the PRM from one based on *installed capacity* to being based on the quantity of *perfect capacity* (*i.e.*, not subject to planned or unplanned outages or resource availability) needed to achieve the reliability target. The Company notes that this accounting change has the effect of reducing the reported PRM since a smaller number of perfect resources can provide equivalent reliability as a larger number of installed but imperfect resources.

[242] Hr. Ex. 102, Att. JTL-1.
[243] The RA Study is Att. ZM-1 to Hr. Ex. 109, Ming Direct.
[244] Table ZM-D-2 on p. 15 of Hr. Ex. 109 presents a list of utilities, RTOs and RA programs using a 0.1 LOLE standard.

286. The second difference between the RA Study in this case and that of prior ERPs is that it developed seasonal PRM and ELCC values rather than annual values. The Company explains that this practice:

> …recognizes that reliability risk is increasingly occurring in both the summer and the winter due to growth in winter loads driven by the electrification of building heating and that many resources (in particular wind and solar) have different availabilities at different times of year due to seasonal availability factors. Therefore, this study separates the year into two seasons, summer (May to October inclusive) and winter (November to April inclusive) and calculates "seasonal" PRM values as the quantity of required perfect capacity to reliably serve peak load in each season. It also calculates seasonal ELCC values as the contribution of each resource toward each season's PRM.[245]

287. The final difference in the RA Study submitted in this Proceeding regards the representation of available market purchases from neighboring utilities. In prior RA studies, the Company made assumptions that neighboring utilities would comply with resource adequacy requirements in their future resource plans, such that the availability of power purchases was a modeling output based on this assumption. In contrast, the RA Study submitted here makes no assumptions about resource adequacy, but bases the availability of market power purchases on the historical average of available purchases during the times when energy is most needed. The Company explains that this change is driven by the recognition that loads and resources in neighboring utilities are increasingly uncertain and are a domain over which the Company has no control. The Company presents this change as a more conservative approach to limit its exposure to the risk that neighbors are unable to fulfil their RA requirements or that market purchases may be extremely costly during periods of scarcity and asserts that this practice is common across many utilities in the Western Interconnection.[246]

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[245] Hr. Ex. 109, Ming Direct, p. 19.
[246] Hr. Ex. 109, Ming Direct, pp. 19-20.

288. The Company contends that its RA Study represents a substantial step forward in the development of the PRM and ELCCs and a substantial step toward rectifying Colorado's resource adequacy concerns over the medium- and long-term. It urges the Commission to approve it for use in both the Base and Supplemental RFPs.[247]

1. Considering Wholesale Market Membership in the RA Study

a. Party Positions

289. UCA argues that since the Public Service is required by SB 21-072 to join a regional market by 2030, the Company's RA modeling should include assumptions about the future impact of joining a market. UCA notes that the larger region encompassed by a market will create a more diverse load (utilities peaking at different times) and will reduce transmission charges, meaning that market purchases will be more economical. UCA contends that market participation will likely reduce the needed PRM and will also change ELCC values.[248]

290. UCA rejects the Company's contention that it is hard to model the impact of new transmission resources on RA due to uncertainty regarding the generating resources accessed by a new line, stating that transmission and remote resources "can be treated in a similar way as uncertainty is already modeled in RA studies."[249]

291. Conservation Coalition expresses concern that Public Service's proposals for Phase II modeling reflect neither the Company's proposed participation in SPP Markets+ nor the statutory requirement to join an RTO or ISO by 2030. Conservation Coalition argues that the Commission should require the Company to update its modeling for the supplemental RFP to reflect any data the Company possesses regarding effects on curtailments and market purchases

[247] Public Service's SOP at p. 22.
[248] UCA's SOP at pp. 14-15.
[249] UCA's SOP at pp. 15-16.

and sales. Conservation Coalition further criticizes the Company's proposal to model all Phase II portfolios assuming that it does not join an organized wholesale market ("OWM") by 2030. Conservation Coalition suggests that the Company's justification that it doesn't not know what values it would use to model joining an OWM as no different than claiming that it should assume a cost of $0/MMBtu for gas simply because it doesn't know what the gas price will be in 2030. Conservation Coalition notes that there is uncertainty associated with virtually every variable used in EnCompass, and that making reasonable estimates of uncertain values is inherent in all modeling. Conservation Coalition argues that there is no reason to treat the impacts of joining an OWM any differently than every other uncertain modeling input.[250]

292. Conservation Coalition contends that the Company's hearing testimony that joining a full OWM would have no impact on the Company's modeling was directly controverted by supplemental direct testimony in which the Company states that joining an OWM would "reduce PRM requirements and potentially boost ELCC values, leading to less resource need."[251] Conservation Coalition notes that reduced capacity requirements and reserve sharing are some of the primary rationales for joining an OWM. On this point, Conservation Coalition cites the 2021 Siemens study conducted for the Commission as further evidence that joining a full OWM would reduce capacity needs. Conservation Coalition contends that this has important implications, as not modeling the impacts of OWM membership will result in the Company procuring excess resources. Conservation Coalition contends further that beyond the potential impact of such modeling in this Proceeding, there is value in modeling participation in an OWM to gain insight into the benefits of OWM membership. It argues that "if [Public Service] never analyzes the

[250] Conservation Coalition's SOP at pp. 27-28.

[251] Conservation Coalition's SOP at pp. 28-29 (quoting Hr. Ex. 111, Landrum Supplemental Direct, Rev. 1, pp. 86-87) (internal quotations omitted).

potential benefits of joining a RTO/ISO, [Public Service] may never join a RTO/ISO, because it will not have examined the benefits."[252] Conservation Coalition therefore recommends that in both the base and supplemental RFPs, at least one portfolio should assume that Public Service joins an OWM by 2030, and recommends that SPP's Western RTO be used as a proxy. Conservation Coalition recommends that at a minimum, the Commission should order the Company to model at least one portfolio for the supplemental RFP that assumes the Company joins an RTO/ISO by 2030, and to have a stakeholder process beforehand.[253]

293. Although CEO's answer testimony was critical of the Company for failing to address in its Supplemental Direct Testimony the impact of joining a wholesale market on resource adequacy (PRM, ELCC and resources selected for portfolios), its SOP comments related to the matter are limited to a note that CEO opposes the Company's plan to join Markets+ until the Commission has more information about the impact of joining an OWM. CEO further notes that it supports revisiting this issue in the supplemental RFP once more information on market participation is available.[254]

294. The Company addresses party criticisms that the RA Study fails to reflect participation in an OWM by claiming that there currently is no information on how such participation would impact the PRM and ELCC values, and so any change to the 2024 RA Study values would be speculative at this time. The Company notes that new market entrants are required to bring resources sufficient to meet their load (including reserves) so that any suggestion to reduce

[252] Conservation Coalition's SOP at p. 29.
[253] Conservation Coalition's SOP at pp. 28-29.
[254] CEO's SOP at pp. 22-23. Commissioner Gilman's suggestion to include additional information about Markets+ participation in the Supplemental RFP is found in Hr. Tr. June 13, 2025, p. 224:11-17.

the PRM and ELCC values now could limit the Company's ability to enter into a market in the future.[255]

b. Findings and Conclusions

295. Absent a finding by the Commission that doing so would be contrary to the public interest, the Company must join an OWM by 2030. We agree with intervenors that joining an OWM would likely exert downward pressure on the Company's PRM while simultaneously increasing the ELCCs of some resources. While we find it essential that the Company's RA studies reflect OWM ownership as soon as possible, there is no evidence in the record indicating specifically what assumptions the Company should use regarding which OWM membership the Company should model, nor the specific impacts that would result from that membership. Given the fact that regional markets are still developing in the West, it would be difficult to confidently determine what assumptions to use in time for the supplemental RFP. Accordingly, the Commission finds that modeling OWM membership in RA studies will remain premature until the 2028 ERP, and we will not therefore require such modeling for either the base or supplemental RFPs in this Proceeding.[256]

296. However, we find that by the time the Company files an ERP, it is already too late to make material changes to the RA Study that are identified during the proceeding. Requiring a revised RA study in a Phase I decision would unduly delay the subsequent solicitation. Our experiences in this Proceeding and its predecessor have demonstrated that, given the leverage that the results of RA studies have in both identifying resource need and the capabilities of the various resource types to satisfy that need, it is necessary for RA modeling parameters and methodologies

[255] Public Service's SOP at p. 21.
[256] Commissioner Gilman dissents on this point and would pursue a process to incorporate OWM assumptions into the supplemental RFP.

to be litigated separately from and well in advance of the ERP proceeding in which they are to be applied so that significant issues can be identified and fully rectified in advance of the Phase II solicitation. Accordingly, we direct the Company to file an application proceeding to litigate RA study assumptions and methodologies no later than March 31, 2027. A filing by this date should allow the Commission to arrive at a decision by the end of that year, providing sufficient time for the Company to conduct the RA study and apply its results to the 2028 ERP.

2. Reliability Rubric

a. Party Positions

297. Following the preliminary creation of the Phase II portfolios, Public Service proposes running each portfolio through a stress test using extreme summer and winter scenarios. If the portfolios indicate any non-zero amount of unserved energy or ancillary service violations under these extreme conditions, the Company proposes to conduct a series of steps to add resources until no unserved energy remains. Only after passing this rubric would the Company consider it to be reliable.[257]

298. In Rebuttal, Public Service agrees to present the results of portfolios that do not initially pass the rubric tests, along with the final resource portfolio determined after applying the corrective actions outlined in the rubric. For the portfolios that initially failed the extreme weather tests, the Company would show the capacity expansion plans (*i.e.*, bids in the portfolio) and the amount of expected unserved energy ("EUE") or ancillary service violations for that portfolio. The Company opposes all other suggested changes to the reliability rubric.

299. CEI criticizes the Company's refusal to demonstrate how its reliability rubric would affect the generic Phase I portfolios, stating that as a result, neither stakeholders nor the

[257] Hr. Ex. 101, Att. JWI-2, Vol.2 - Tech. Appendix, Rev. 2., pp. 233-234.

Commission have visibility into how the rubric would impact the resources required to meet the reliability standard.[258] CEI argues it is essential for the Commission to establish clear parameters for the presentation and application of the reliability rubric in Phase II and recommends the Commission direct the Company to present an economic analysis in its 120-Day Report alongside the reliability results, including the marginal cost of additional resources needed to eliminate the last increment of unserved energy and a comparison to reasonable Value of Lost Load ("VOLL") estimates from industry literature. CEI argues further that the Company should be required to report the magnitude and duration of reliability events, not just the occurrence of unserved energy so that the Commission can assess whether less costly solutions might be appropriate. Finally, it argues the Company should model and present results both with and without application of the most stringent reliability requirements, so that the Commission can clearly understand the incremental costs and benefits of different approaches to reliability. CEI claims these steps will help ensure that the plan adopted is economically rational.[259]

300. CEO and WRA and SWEEP ask that the Commission require Public Service to document and provide as part of its Phase II report the initial portfolio results in terms of the incremental resource additions and PVRR added to that portfolio during each step of the reliability rubric.[260]

301. Staff recommends the Company keep Staff apprised of any changes to the proposed reliability rubric before and during the actual modeling of bids in Phase II. This ensures that Staff is able to confirm that Phase II modeling assumptions are in line with what is approved in a Phase I decision. Similar to other parties, Staff also expresses concern that the Company has not

[258] CEI's SOP at pp. 22-23.
[259] CEI's SOP at p. 24.
[260] CEO's SOP at p. 8; WRA and SWEEP's SOP at p. 29.

applied the extreme weather test to the generic Phase I portfolios, stating that it is unclear how the testing of portfolios will play out in Phase II.[261]

b. Findings and Conclusions

302. We generally believe that any approach that is structured to completely ignore economic issues under extreme assumptions is problematic. As a state and a society, we accept the fact that it may be prohibitively expensive for a utility to attempt to provide perfect reliability. Accordingly, we agree with the parties who addressed this issue that it is vital that the Company provide detailed information on the impact of the reliability rubric on the Phase II portfolios. While we note the importance of addressing reliability in the context of modeling, we also recognize that the Company has many processes to continue to ensure reliability in extreme events. Modeling exercises through the ERP in no way prohibit those endeavors, rather they ensure as they have for decades appropriate proactive measures can be taken based on the best information available. Such pre-planning can help create better cost-effective solutions to known stresses in coming years.

303. We therefore adopt CEO's suggestion and direct Public Service to provide—in addition to the information the Company committed to provide in Rebuttal Testimony—information about each reliability event that causes a portfolio modification due to the reliability rubric. This must include identifying the added resources, the change in portfolio PVRR, the magnitude, duration and EUE of each event, and a comparison of the cost of serving otherwise unserved energy. This information must be presented as part of the 120-Day Report.

[261] Hr. Ex. 2604, Abiodun Answer, pp. 14-18.

304. Further, as recommended by Staff, we direct the Company to keep Staff, the IE, and as appropriate other parties apprised of any modifications to the impacts of the reliability rubric as best as reasonably possible through both the base and supplemental RFPs.

305. To be clear, we make these changes not because we are concerned the Company's proposed rubric will produce unreliable results, but because there may be less expensive ways to plan ahead based on best information for the Company to continue to maintain reliability. The modifications we direct here provide additional transparency about the reliability rubric's impacts on costs.

3. Economic Metrics in the Assessment of Resource Adequacy

a. Party Positions

306. In response to party advocacy to the contrary, the Company thoroughly opposes the notion that economic considerations (such as VOLL) should be included in RA analysis, noting that the 0.1 LOLE standard it applies is accepted practice and current standard in Colorado and around the country. The Company contends that the use of economic reliability as a standard is "functionally non-existent."[262]

307. CEI asserts that the Company's RA Study suffers from several weaknesses that limit its usefulness. Chief amongst these, according to CEI, is the study's failure to consider economics in the analysis, amounting to requiring "perfect insurance" in that the reliability rubric seeks to eliminate all unserved energy regardless of cost without considering whether the incremental benefit of doing so exceeds its cost. CEI is further critical of the Study's failure to distinguish between brief outages affecting a small number of customers and large-scale, multi-hour blackouts. The absence of this distinction leaves decision makers without meaningful

[262] Public Service's SOP at p. 20.

context and fails to consider whether low-cost solutions such as DR, VPPs or targeted reliability programs could address short-duration or low-magnitude reliability gaps.[263]

308. CRES/PSR argues that LOLE alone is an insufficient metric to gauge resource adequacy. CRES/PSR contends that VOLL should supplement LOLE and be used to justify, prioritize or rank transmission or other reliability portfolio investments in Phase II. CRES/PSR contends that the failure to consider VOLL has led to an estimated $1.2 billion in ratepayer costs in 2024, based on Staff's finding in Proceeding No. 24I-0394E (the Commission's investigation into Public Service's Electric System Outages) that system average outage duration that year was 350 minutes. CRES/PSR emphasizes that the Staff report in that proceeding found that customer outages were rarely due to transmission and never due to resource inadequacy, but in almost all cases due to events on the distribution network.[264]

309. CRES/PSR contends that supplementation of the LOLE metric is neither novel nor likely to cause reduced reliability, as the Company argues. For support, CRES/PSR cites a 2024 Energy Systems Integration Group ("ESIG") report detailing the growing obsolescence of single-metric RA analyses and noting the emerging adoption of multi-metric approaches. CRES/PSR also points out that the same conclusion was recently drawn by the North American Electric Reliability Corporation's Probabilistic Analysis Working Group.[265] CRES/PSR contends that these conclusions by NERC and ESIG contradict the Company's "mischaracterization" of economic considerations as an either-or tradeoff that lowers reliability. CRES/PSR also argues that the VOLL is used in assessing non-wires alternatives and undergrounding in both the ongoing Distribution System Plan Proceeding and the company's Wildfire Mitigation Plan. Accordingly,

[263] CEI's SOP at pp. 22-24.
[264] CRES/PSR's SOP at pp. 19-21.
[265] CRES/PSR's SOP at p. 21.

CRES/PSR recommends that VOLL should be considered to justify, prioritize, or rank transmission or other reliability portfolio investments and projects.[266]

b. Findings and Conclusions

310. We find that CRES/PSR and CEI argue convincingly that an evaluation of resource adequacy that considers only LOLE provides an incomplete picture of a system's reliability needs, limiting transparency into the nature of reliability events and limiting the Commission's ability to select the resources that best match the reliability need.[267] We agree with these parties that the Company has provided no information on the magnitude or duration of the modeled reliability events that contribute to the proposed PRM, so neither the Commission nor the parties can have insight into whether the appropriate solution to a reliability event is an additional 200 MW CT, enhanced incentives to stimulate 500 kW of additional load flexibility, or to simply weather the consequences of a small amount of projected unserved energy.

[266] CRES/PSR's SOP at pp. 22-24.

[267] We note the Company's RA Study itself cites a report by the Energy Systems Integration Group ("ESIG") that explicitly states the LOLE metric is no longer an adequate measure of system reliability: "In addition, the reliability events are now more varied; therefore, understanding the size, frequency, duration, and timing of potential shortfalls is essential to finding the right resource solutions. LOLE is an inadequate metric in a world of more varied shortfall events because it provides limited information on shortfall events' size and duration. This makes it difficult to know the true impact of potential shortfalls and nearly impossible to determine the types of resources necessary to reduce the number of shortfalls." (ESIG, "Redefining Resource Adequacy for Modern Power Systems" (2021), p. 10).

311. CRES/PSR admitted an ESIG report that lends additional credence to the notion that LOLE must be supplemented:

> … Some grid operators are already considering changes. PJM, the Southwest Power Pool (SPP), and the Mid-continent Independent System Operator (MISO), for example, are exploring whether to move from LOLE to expected unserved energy (EUE) as the resource adequacy criterion used for calculating capacity accreditation. The Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) are proposing multi-metric criteria for future resource adequacy planning. … As a society, including planners, regulators, policymakers, and ratepayers, we have to decide how much we will pay for reliability and when to accept that there will be times—albeit rare—when the system cannot serve the load. This policy or regulatory decision shapes our resource adequacy criteria, determining the level of supply in which we are willing to invest and recognizing that mitigating all risks on the system may not be worth what that would cost. A resource adequacy criterion does not just measure risk but must also inform actionable investment decisions. Planners and regulators must weigh different types of investments to improve resource adequacy against a growing set of planning objectives, including costs for ratepayers, environmental objectives, and other options to improve reliability, such as distribution-level outages, transmission stability, or cybersecurity. Different options also come at different costs, which requires decision-makers to evaluate these trade-offs in a consistent manner. Effective multi-metric criteria should enable planners and regulators to delve beyond frequency metrics, like LOLE, to more fully characterize system reliability and better inform these investments.[268]

312. The authors of this report subsequently draw the following conclusion: "In short, using loss-of- load expectation as the sole resource adequacy criterion represents only a single dimension of risk. The full detail of the system's risk profile cannot be described by a single number; it needs to be supplemented…."[269]

313. The authors discuss several justifications for this among which are that 1) a single-metric criterion provides inadequate differentiation among the size, frequency, duration, and timing of shortfalls and thus fails to reflect nonlinear damages; and 2) as more energy

[268] Hr. Ex. 1602, Att. JG-3, pp. 4-5.
[269] Hr. Ex. 1602, Att. JG-3, p. 10.

limited resources are added to electric systems, the types of reliability events are far more diverse than they've been historically, and the rough proportionality between LOLE and EUE that existed historically becomes a less accurate assumption.

314. Given the above, we find the Company's opposition to the inclusion of economic considerations in the assessment of resource adequacy to be neither well-founded nor supported as an industry best practice going forward. The absence of economic considerations in assessing resource adequacy can leave the Commission blind to potentially large discrepancies between reliability events and the type and magnitude of the resources identified to address them. Accordingly, in conjunction with the Resource Adequacy Application filing discussed above, we direct the Company to propose a multi-metric approach to resource adequacy, including at minimum LOLE and EUE (or EUE normalized to annual consumption) as the target metrics. The Company shall retain the 1-day-in ten-years metric for LOLE. For EUE, the Company shall conduct research on existing and emerging practices for the use of EUE in multi-metric RA frameworks and shall propose and justify an EUE target based on this research.

4. Modeling of Market Purchases in the RA Study

a. Party Positions

315. The Company defends its practice of limiting market purchases in the RA Study to the average availability of purchases during high risk hours in recent years, and is critical of party suggestions that it should model neighboring systems to determine availability of purchased power, noting that loads and resources of these systems are increasingly uncertain, making any modeling attempt "an exercise in speculation." The Company notes further that its ability to import power is limited by transfer capacity, further limiting its ability to rely on its neighbors in times of

need. It contends that no party presented compelling testimony supporting greater reliance on imports and warns that such reliance could have implications for future reliability.[270]

316. UCA contends that market representation in the RA Study should reflect historical purchases as modified by the addition of new transmission interconnections or OWM market entry.[271]

317. Conservation Coalition is critical of the Company's representation of market purchase availability as the average availability when energy was most needed. Conservation Coalition contends that this is not consistent with Commission direction from the 2021 ERP/CEP that the Company should model all WECC regions and not limit market purchases based on historical purchases. Conservation Coalition points out that the Company's practice here could create additional risk if its neighbors have less power available than it has assumed, and that this practice could fail to identify good opportunities for interregional transmission. Conservation Coalition recommends that the Commission require the Company to update its RA Study for the supplemental RFP to reflect any data the Company possesses regarding effects of Markets+ participation on curtailments and market purchases and sales.[272]

b. Findings and Conclusions

318. We direct Public Service to include relevant new information based on its experience with Markets+ as it goes into the base and supplemental RFPs. In addition, the representation of market purchases must be updated in the 2027 RA study Application filing discussed above to reflect the Company's participation in the SPP Markets+ market.

[270] Hr. Ex. 1602, Att. JG-3, pp. 19-21.
[271] UCA's SOP at pp. 14-15.
[272] Hr. Ex. 801, Stenclik Answer, pp. 38-40; Conservation Coalition's SOP at pp. 27-28.

5. Treatment of Distributed Solar and Demand Response in the RA Study

a. Party Positions

319. The Company treats both distributed solar and demand response ("DR") as resources rather than load modifiers, adding their impacts back into its net (or "obligation") load to get to gross (or "native") load.[273] ELCCs were then applied to these resources to model their impacts to load in capacity expansion.

320. WRA and SWEEP argue that distributed solar is market driven and procured by customers rather than the utility so it is illogical to use an ELCC methodology for it. WRA and SWEEP also make methodological criticisms of the Company's approach to determining the ELCC for distributed solar. With regard to DR, WRA and SWEEP criticize the Company for limiting its DR forecast only to the types of DR programs it currently offers, which are subject to tariff limits on schedule, frequency and duration of dispatch, limiting their ability to respond to reliability events from 2-7 p.m. WRA and SWEEP also discuss additional, untapped DR resources such as controllable water heaters and cold thermal storage for which it claims there is large economic potential. WRA and SWEEP recommend DR be modeled as a load modifier rather than with an ELCC and that the Company should evaluate additional DR resource types for its next ERP along with interactive effects of combining DR with energy efficiency and distributed solar under a VPP framework.[274]

321. The Company opposes the WRA and SWEEP recommendation that DR be treated as a load modifier rather than evaluated in the ELCC framework. The Company argues that doing so would result in inaccurate representation of DR's reliability impact and would require that the

[273] Hr. Ex. 106, Goodenough Direct, p. 10; Hr. Ex. 109, Ming Direct, p. 32; Hr. Tr. June 18, 2025, p. 50:17-24.

[274] Hr. Ex. 1301, Eiden Answer, pp. 73-78, 80-88.

entire RA Study be redone, as this would represent a fundamental alteration of the Study. The Company contends that the time and expense of re-doing the study would not be prudent.[275]

b. Findings and Conclusions

322. We find compelling the WRA and SWEEP contention that as distributed solar and DR are resources implemented by customers rather than the Company, they should be treated as load modifiers rather than resources to which ELCCs are applied. Accordingly, we direct the Company to apply the hourly impacts of both these resources as load modifiers in all modeling conducted for Phase II of this proceeding, rather than applying ELCCs as the Company proposes. While this modification will impact the Company's resource need, we do not require Public Service to revise its RA Study to incorporate this issue.

6. Impact of daytime EV charging on ELCC for Solar

323. CRES/PSR argues that the RA Study will need to be redone once a revised forecast is produced that incorporates significant daytime charging of EVs. CRES/PSR attributes solar's low ELCC of 6-16 percent in summer and 0-3 percent in winter to the Company's assumption that load growth would primarily occur at night. CRES/PSR contends that starting in 2026, nearly all EV load should be considered to be managed, and that EV load between 5 p.m.-9 p.m. should be reduced by at least 40 percent due to the approximately $450 annual incentive created by the TOU rates that will take effect this October (in addition to the impact of the Company's managed charging programs). CRES/PSR contends that this change in assumptions will modify the load shape and significantly change both the Company's PRM and resource ELCCs.[276]

[275] Public Service's SOP at p. 21.
[276] CRES/PSR's SOP at pp. 5-10.

324. While we agree with CRES/PSR that the TOU rates will shift some EV charging to daytime off-peak periods, thereby modifying the overall load shape and potentially improving the actual load carrying capacity of solar resources, we find that much remains to be learned about the dynamics of consumer charging behavior and its response to utility programs, aggregator programs and revised TOU rates. While TOU rates may be successful in convincing many consumers to shift EV charging to lower-cost daytime hours when ample solar resources are available, we note that, at least in the short-term, limitations on the availability of workplace chargers may limit the degree to which this shift can occur. Accordingly, we do not find that there is sufficient evidence in the record to justify requiring the Company to modify its RA Study at this time as CRES/PSR request.

7. RA Study Representation of Correlated Outage Potential for Thermal Generators

325. CRES/PSR also criticizes the RA Study's treatment of "tail risks" for gas generation, stating that the Study fails to adequately reflect the temperature dependence of thermal generators. CRES/PSR notes that the RA Study relies on only five years of data and uses only average daily temperatures rather than hourly temperatures. CRES/PSR claims that other studies using more extensive data sets consistently found temperature dependence of thermal capacity availability, particularly at low temperatures. CRES/PSR contrasts this with the RA Study, which it claims has in some cases only one sample per temperature bin at temperatures below 20 degrees F. CRES/PSR argues no statistical inference can be drawn from such sampling.

326. Accordingly, CRES/PSR requests the Commission review this portion of the RA Study with the Company and Staff to determine its potential impacts on the conclusions the Study draws on the ELCC of firm gas resources. CRES/PSR suggests this could lead to a review of

weatherization practices and fuel supply chain vulnerabilities, potentially avoiding gas-related interruptions that have plagued other regions. CRES/PSR supports either a more conservative assumption for the ELCC of gas resources at extreme temperatures or a showing by the Company that its gas resources are not subject to this vulnerability.[277]

327. We find that the data in the RA Study that CRES/PSR cites as problematic indicates no temperature dependence of unit availability. Since there is no information on the record that the Company's thermal units are subject to correlated outage at extreme temperatures, we see no basis for CRES/PSR's request that an adjustment be made to the ELCCs of thermal units. However, we direct the Company to ensure that in the future it presents a more rigorous evaluation of any potential temperature dependence of thermal unit availability, perhaps using hourly rather than average daily temperatures.

K. May Valley – Longhorn Extension

328. The May Valley Longhorn Extension ("MVLE") is a proposed 90-mile, 345 KV line that would extend the Colorado Power Pathway south from the May Valley substation, providing access to the wind resource in southeast Colorado. In Proceeding No. 21A-0096E, the Commission granted Public Service a conditional CPCN for the MVLE, which could become unconditional upon approval of a resource portfolio including its costs in the 2021 ERP/CEP. While such a portfolio was not selected there, the Commission did grant an extension to the conditional CPCN to this proceeding, where again, the CPCN for the MVLE will become unconditional if the Commission approves a portfolio including its costs in Phase II. In Proceeding No. 21A-0096E, the Company estimated MVLE costs at just under $250M.

[277] CRES/PSR's SOP at pp. 24-27.

1. Party Positions

329. In its Rebuttal and SOP, the Company requests that the MVLE CPCN be granted prior to the conclusion of Phase II of this proceeding, stating that costs are likely to continue to escalate as time goes on, and that the line would provide bidders certainty of access to some of the lowest cost wind resources in the state. The Company also notes support for the MVLE from both CEI and WRA and SWEEP. The Company states that unconditional approval is more critical now to capture time limited tax-advantaged generation. In Rebuttal, the Company provides an updated cost estimate of $304 million, with an in-service date of Q3 2029. If a CPCN is granted, the Company proposes to work with Staff to develop a performance incentive mechanism ("PIM") parallel to that used for other Colorado Power Pathway segments and to submit it in Proceeding No. 21A-0096E.[278]

330. The Company also notes that per the JTS Transmission Study, large amounts of new renewable generation in southeastern Colorado, *i.e.*, in the area of the MVLE, could trigger the need for additional 345 kV transmission capacity running from May Valley to Sandstone and/or an additional 345 kV line to network the existing Pronghorn tie line. Public Service indicates this additional capacity would add between $224 and $786 million to the costs estimated in the JTS Transmission Study. The Company anticipates that it should be able to provide preliminary indication in its Phase II Report if there is a need for this additional capacity.[279]

331. CEI states simply that the Commission should approve the MVLE in the Phase I decision, and that it would support the PIM that was applied to the Colorado Power Pathway.[280]

[278] Public Service's SOP at pp. 26-27.
[279] Hr. Ex. 105, Siebenaler Direct, pp. 61-62.
[280] CEI's SOP at p. 27.

332. CIEA advocates that the Commission approve the MVLE CPCN, stating that the line is comparatively low-cost tapping perhaps the best wind resource in the state. It notes that the MVLE would increase geographic diversity and allow for additional low-cost interconnections.[281]

333. WRA and SWEEP state that the MVLE should be made available as an option for bidders to consider during Phase II of this Proceeding and that if the MVLE project is included in the approved portfolio, the Commission should grant the Company a full CPCN for the project.[282]

334. UCA opposes an unconditional CPCN for the MVLE, unless the selected portfolio can justify its $304 million estimated costs along with those of the $1.8 billion Harvest Mile-Chambers-Sandown-Cherokee ("HCSC") line, which UCA claims generation connected to the MVLE would necessitate. UCA argues these costs are unnecessary if there is capacity that does not require these transmission additions and points out that their costs are not included in the net present values shown in the Company's application.[283]

335. Climax takes no position regarding the approval of the MVLE, but advocates that any PIM for the MVLE not be adjudicated in this Proceeding. Instead, Climax argues any PIM should be considered in associated CPCN proceedings and guided by the same parameters applied to Power Pathway projects. Climax also asserts that if the MVLE is approved, its baseline cost should be fixed at $304 million.[284]

336. CEO recommends that the Commission adopt the same approach to the MVLE that it did in the 2021 ERP/CEP. CEO recommends that bidders be allowed to specify interconnection to the MVLE, that bidders proposing interconnection to the MVLE be required to specify an

[281] CIEA's SOP at p. 30.
[282] WRA and SWEEP's SOP at p. 30.
[283] UCA's SOP at pp. 26-28.
[284] Climax's SOP at p. 6.

alternate interconnection point and to include project costs assuming MVLE interconnection and the alternate interconnection point.[285]

337. Staff argues that the Commission should reject the Company's Rebuttal proposal. It notes the Commission's prior decision to approve an unconditional CPCN in this proceeding only if the approved portfolio includes the MVLE. Staff reacts to the Company's claim that MVLE approval now will reduce costs by stating that there still remains uncertainty about whether the line will actually be needed, and that this uncertainty will be reduced in Phase II. Staff states that this approach is particularly appropriate due to the uncertainty introduced by recent changes to renewable tax credit eligibility, since the need for the MVLE will be based on wind bids.[286]

2. Findings and Conclusions

338. Although there is considerable uncertainty regarding how the phase out of the renewable tax credits under the federal Reconciliation Bill will be implemented, it is unlikely that an accelerated approval of the MVLE in Phase I will impact whether the associated renewable projects connecting to that line will be eligible for the tax credits. If current regulations regarding the definition of the term "begin construction" are largely maintained, developers will not need the approval of the MVLE to begin construction. If this definition is substantially modified consistent with the recent executive order, it is doubtful new renewable projects arising from the JTS could be eligible for the tax credits. Ultimately, there is too much uncertainty for this factor to control whether an unconditional CPCN for the MVLE should be granted in Phase I.

339. Moreover, if the addition of new renewable generation capacity in southeast Colorado necessitates additional costly transmission capacity for system reliability or power

[285] CEO's SOP at pp. 30-31.
[286] Staff's SOP at pp. 18-19.

deliverability, the Company's estimate of the cost of such transmission must be a factor that we consider in our Phase II Decision, including as to the cost effectiveness of the MVLE. Accordingly, we direct the Company to incorporate a line item presenting its estimate of the PVRR for all such additional transmission required for any Phase II portfolio that would trigger the need for it. This line item shall be separate from and in addition to the estimated cost of the MVLE, if that line is triggered by one or more of the Phase II portfolios. Waiting until we have a better understanding of the full costs of the transmission necessary for new renewable generation in southeast Colorado further supports our decision to defer granting the CPCN for the MVLE until after Phase I.

340. The Commission recognizes the evidence in the record that Public Service lacks sufficient transmission capacity to acquire the magnitude of renewable generation the JTS envisions, even though our decision to reduce the Company's load forecast may make the need for additional transmission capacity somewhat less acute. Ultimately, however, we agree with Staff, CEO, and UCA that the Commission should maintain our initial approach and defer granting the MVLE CPCN until Phase II of this Proceeding. The decision on whether to move forward with this considerable investment will wait until there is a showing that a portfolio including the cost of the MVLE and any related transmission investment in southeast Colorado is in the public interest.

L. Transmission Cost Adders and Credits

1. Party Positions

341. In Direct, the Company asks the Commission to approve a set of modeling adders and credits designed to reflect the locational- and interconnection voltage-dependent costs that new generating resources impose on the system. These adders and credits are intended to incentivize the Company's capacity expansion planning model to select bid resources that

minimize the combined cost of generation and transmission. Based on transmission cost estimates developed through its JTS Transmission Study, the Company proposes a modeling adder of $238/kW for all bids other than those connecting to the distribution system, those interconnecting to the Colorado Power Pathway or those that propose to reuse the interconnection facilities of retiring generators. Bidders proposing interconnection within and west of the Denver Metro Constraint would be credited $191/kW. Also, any distribution-connected bids connecting to eligible feeders,[287] including aggregated distributed energy resources ("ADERs"), would be given a modeling credit of $69/kW-year.

342. UCA opposes the application of blanket adders and credits, arguing that bids should be burdened or credited based on the actual costs that their interconnection would impose on the system. UCA contends that the Company's proposal removes the incentive for bidders to find low-cost locations and propose projects that save customers money. Noting that the value of the adder is driven primarily by the $1.8 billion HCSC project, UCA argues that these costs should not be socialized but should be added only to those projects that would make the HCSC necessary. UCA therefore recommends the Commission require the Company to carefully define where projects would trigger the need for the HCSC project. Similarly, UCA states that it also opposes the use of a blanket distribution credit, arguing that such a credit should be based on actual costs that a project would avoid, which are location specific.[288]

343. While CCSA supports the basic structure of the Company's adder and credit proposal, it states that the specific values it recommends more accurately reflect the costs that bids impose or value they provide based on their location. CCSA begins its argument by noting that the

[287] Per the Company's VPP application, feeders are eligible if they are over the 75% planning load limit, do not have mitigations in service by the end of 2025 and have a load shape similar to the bulk system load shape.
[288] UCA's SOP at pp. 28-30.

Company's projected transmission and distribution capital expenditures over the next 20 years accounts for between 67 percent and 73 percent of total capital expenditure, depending on load forecast. It contends that the Company's initial estimates of transmission spending have been conservative in the past, citing the "$2 billion surprise" in the 2021 ERP/CEP. CCSA argues that unless the Company accurately accounts for the cost of delivering JTS generation, these costs will drive significant upward pressure on rates. It notes that its members plan to bid distribution-connected solar and storage resources that can defer or avoid these delivery-related transmission and distribution costs, but CCSA contends that it is essential to account for the very substantial delivery costs of utility-scale resources in the bid evaluation process. CCSA argues that approving its adder and credit values will help to ensure that dispatchable, distribution-connected resources, which it claims do not require new transmission investments, can compete fairly.[289]

344. CCSA advances a $290/kW transmission adder, which is based on two adjustments to the Company's calculation of $238/kW: 1) CCSA uses the cost and load calculations across both the base and low forecast, whereas the Company only considers the base forecast; and 2) CCSA includes the cost of the MVLE in its analysis for the five scenarios in which the MVLE is expected to be needed, whereas the Company excludes that cost completely. With regard to the first adjustment, CCSA argues it is more reasonable to use all scenarios to capture a broader range of possible future transmission buildouts. Regarding the MVLE, CCSA contends this treatment is consistent with how all other potential transmission projects are treated, noting that the Company provides no explanation why the MVLE should be treated differently. CCSA notes the Company makes no attempt to rebut these methodology adjustments.[290]

[289] CCSA's SOP at pp. 4-6.
[290] CCSA's SOP at pp. 7-8.

345. CCSA notes Staff's argument that the $1.8 billion HCSC project should be removed from the adder calculation because it appears in all scenarios and therefore the same cost would be applied to all bids regardless of location, resource type, or interconnection point. However, CCSA asserts this reasoning is flawed because the transmission adder will not apply to distribution-connected bids. CCSA argues this is exactly the purpose of the adder—to level the competitive playing field between utility-scale bids and distribution-connected bids by reflecting the significant costs of transmission. CCSA also opposes UCA recommendation to reject the proposed adder by arguing that the record of this case does not include sufficient information to enable more locationally precise adders. CCSA contends the perfect should not be the enemy of the good.[291]

346. CCSA also advances a "Base Transmission Credit" of $263/kW for resources connected anywhere on the distribution system, which would be stackable with an adjusted version of the Company's proposed credit for resources interconnected within the Denver Metro Constraint. CCSA proposes that the Base Transmission Credit be calculated by dividing the difference in long-run transmission costs between the base forecast and the lower low forecast—importantly, excluding the cost of the two projects on which the Denver Metro Transmission Credit is based—by the long-run change in loads between the two forecasts. CCSA also contends the Company's calculation of the Denver Metro Transmission credit is well founded conceptually but flawed in that the denominator of the calculation assumed that all DER are located within the Constraint. CCSA argues that since approximately 15 percent of DER installed would be outside of the metro area, the denominator should be only 85 percent of the difference in DER installed between the two scenarios used to calculate the credit, raising the credit

[291] CCSA's SOP at pp. 8-9.

from the Company's proposed $191/kW to $210/kW. Because the costs of transmission upgrades associated with the Denver Metro Credit were excluded from CCSA's calculation of its proposed Base Transmission Credit, CCSA asserts these two credits should be stackable for resources interconnecting within the Constraint.[292]

347. Interwest points out that in response to questioning by Chair Blank at hearing, the Company acknowledged that transmission costs identified in portfolios remained similar, yet the transmission adder of $238/kW is based on the idea that transmission costs are linearly related to generation added. Interwest contends that record does not indicate that transmission costs are related to the size of a generator, and so argues the transmission adder should be eliminated or addressed more granularly. Interwest argues further that under the Phase II Framework, transmission costs will be more clearly identified for bidders when they submit bids, so this "arbitrary" adder is unneeded. Interwest asserts significant reduction in the adder is warranted.[293]

348. Staff argues the transmission adder the Company proposes is excessive and will result in a bias toward smaller, gas-intensive portfolios. Staff contends that since it showed up in every scenario the Company modeled in its JTS Transmission Study, the $1.8-$1.9 billion HCSC project is not avoidable, and so should not be included in the costs used to calculate the adder. Staff demonstrates the impact by applying the Company's proposed $238/kW adder to the high-gas, moderate-renewables Baseline portfolio and the high-renewables Bookend I portfolio simulated in the Transmission Study. The modeling penalty from the adder amounts to $1.84 billion for the Baseline portfolio and $3.39 billion for the Bookend I portfolio, which Staff argues, demonstrates the adder will insert a bias toward gas-heavy portfolios. Staff therefore

[292] CCSA's SOP at pp. 9-13.
[293] Interwest's SOP at p. 11.

recommends the cost of the HCSC be removed from the adder calculation, resulting in an adder of $23/kW. Staff recommends that if the Commission does not approve this lower adder, the Commission should direct the small stakeholder group convened to address transmission issues under the Phase II Framework to evaluate and propose a more appropriate adder for use in Phase II.[294]

349. With regard to the proposed credit for resources located within the Denver Metro Constraint, Staff argues that both the calculation and application of the credit are not well supported. Staff points out that the Company calculated the credit as the ratio of the cost difference between the Bookend 2 and Baseline portfolios from the JTS Study—less the cost of the MVLE—to the difference in installed ADER between the two portfolios. Staff argues this method assumes that ADER is the only factor affecting transmission costs between the two portfolios, ignoring that the Bookend 2 portfolio has much less wind and solar, none of which is connected to the MVLE (unlike the Baseline portfolio). Staff also echoes CCSA that not all of the modeled ADER are located within the Denver constraint. Staff thus concludes it is inappropriate to assume that the reduced transmission costs in the Bookend 2 portfolio are due solely to ADER.[295]

350. Staff also takes issue with the credit boundary map the Company provided in its Rebuttal, noting that it differs greatly from the map presented in the CPCN Proceeding on the Denver Metro upgrades (Proceeding No. 24A-0560E), which purports to show the general areas that provide value to mitigating the Denver Metro Constraint. Staff contends the map captures areas in the west that require more study and excludes areas northeast of Denver that were identified as beneficial to the constraint. This, Staff argues, makes it difficult to determine if the

[294] Staff's SOP at pp. 12-14.
[295] Staff's SOP at pp. 14-15.

credit is being applied properly. Staff recommends the Commission require the Company to perform additional comparative transmission modeling to fix the deficiencies in the calculation and application of the credit. Staff further recommends the small stakeholder group proposed under the Phase II Framework have the opportunity to review the Company's additional modeling.[296]

351. Like Interwest and Staff, CRES/PSR notes the lack of correlation between transmission investment cost and portfolio size in the Company's modeling and argues there is no reason to believe that the additional cost or use of transmission is somehow proportional to portfolio size. CRES/PSR is therefore critical that the use of a $/kW adder will penalize renewable resources with low capacity factors, and supports Staff's proposal (removing the cost of the HCSC from the calculation) as being the most reasonable approach for this Proceeding.[297]

352. Pivot Energy supports CCSA's arguments regarding the utilization of all eight transmission portfolios for determining the transmission adder and for including the cost of the MVLE in the calculation. With regard to the latter, Pivot Energy notes the updated cost estimate from Rebuttal for the MVLE is $304 million but CCSA used the $272 million cost included in Direct. Using the updated cost would raise the adder from the $290/kW CCSA proposes to $293/kW. Pivot Energy also supports CCSA's argument that the Company calculation of the Denver Metro credit should have assumed only 85 percent of the DER capacity as the denominator or the calculation and therefore supports CCSA's contention that the credit should be $210/kW.[298]

353. Noting that the only way to defer or avoid the Company's enormous projected costs for transmission investments over the next 20 years is to take them into account in the ERP process, Pivot Energy states it supports the logic and analysis in CCSA's answer testimony and SOP that

[296] Staff's SOP at pp. 15-16.
[297] CRES/PSR's SOP at pp. 12-13.
[298] Pivot Energy's SOP at pp. 6-10.

there should be a Base Transmission Credit of $263/kW for any distribution connected resources anywhere on the Company's system and that this should be stackable with the Denver Metro credit (as adjusted by CCSA).[299]

354. CIEA argues the Commission should treat the Company's estimated JTS transmission costs as fixed, since they will be needed under any scenario to connect the JTS resources to be procured under both the base and supplemental RFPs. CIEA contends the adder would be applied equally to a project next to a Public Service substation and one located in Wyoming, terming it "a blunt tool that is really just a proxy for the lack of current transmission investments that should be assumed to arise out of whatever Phase II portfolio is adopted."[300] As a result, CIEA contends the transmission adder is unnecessary. CIEA argues further that the Denver Metro credit is unlikely to be effective, since the defined area is "small, mostly mountains or built area" and that it does not have the ability to host 4,500 MW of wind.[301] CIEA claims that even with unreasonable generation assumptions, the JTS Transmission Study shows that it is not possible to avoid Denver Metro upgrade costs.[302]

355. CEI states that the Company's reluctance to adopt avoided distribution and transmission values in this Proceeding is not unexpected given its bias to favor capital expenditures. CEI supports the alternative values calculated by CCSA for transmission and distribution credits and recommends that if the Commission does not accept those values, it should ensure the avoided cost valuations developed in the DSP/AVPP proceeding include both a base

[299] Pivot Energy's SOP at pp. 10-13.
[300] CIEA's SOP at p. 29.
[301] CIEA's SOP at p. 28.
[302] CIEA's SOP at p. 28.

credit value and a locational value based on the expected avoided costs of constrained circuits or feeders.[303]

356. CEO supports Staff's positions on the transmission adder. [304]

357. Public Service counters arguments raised in Answer by stating that the Company's methodology for determining the adders and credits is reasonable because the assumptions it used are representative of future load and generation additions. The Company acknowledges that its methodology is only an approximation but that it is reasonable and should be approved.[305]

358. While Public Service acknowledges there are many ways to approximate a transmission adder or credit, the Company asserts that there is no "correct" value, because the variability of possibilities representing the ratio of incremental transmission costs to incremental kilowatt of generation is large. The Company supports this contention by noting the large range between Staff's proposed $23/kW adder and CCSA's proposed $290/kW adder. The Company therefore states that it stands by the adder and credit values in its Direct. The Company asserts this is reasonable because the Base cases are more likely representative of future load and generation additions and because the values quantify a relationship that can only be approximated and that they "intuitively seem about right."[306]

359. The Company disagrees with Staff's recommendation to exclude the Harvest Mile 345 kV to Cherokee 230 kV line from the transmission adder contending that line is an actual expected transmission cost of adding new generation and excluding it would artificially lower the "marginal cost." The Company suggests that without the Harvest Mile to Cherokee project

[303] CEI's SOP at pp. 17-20.
[304] CEO's SOP at pp. 15-16.
[305] Public Service's SOP at pp. 25-26.
[306] Hr. Ex. 118, Landrum Rebuttal, pp. 44-45.

included in the adder, the model's decision-making would be blind to the significant incremental transmission investment required to add incremental generation.[307]

360. Regarding CCSA's recommendation to incorporate all eight Base and Low JTS Transmission Study cases in the transmission adder calculation, the Company again states that it believes the Base Case scenario is the more likely expectation of future load and resource additions. Public Service also argues that one could combine all the different transmission findings in various ways to come up with multitudinous variations of cost ratios, none of which is likely that much more precise than another. The Company supports the adder and credit values from its Direct Case as a reasonable approximation.[308]

2. Findings and Conclusions

361. The Commission recognizes the importance of transparency with the linkage between different portfolios of generation resources and the comparative transmission costs imposed on the system, especially given the shortcomings in the 2021 ERP/CEP in this regard. With regard to UCA's advocacy for a system of adders and credits based on costs caused or avoided by individual bids, we find that this recommendation is impracticable if not impossible, as determining the costs imposed or avoided by individual bid resources would require a degree of modeling analysis that simply cannot be done in the constrained time between the selection of bids and the Company's Phase II Report. Moreover, a single bid might not impose or avoid specific incremental costs, whereas a portfolio of selected bids would, making it much more difficult to assign specific costs and benefits to individual resources.

[307] Hr. Ex. 118, Landrum Rebuttal, pp. 44-45.
[308] Hr. Ex. 118, Landrum Rebuttal, pp. 44-45.

362. CCSA's point that the Company considered only the transmission costs it identified for the base forecast in calculating the adder and leaves out all results for the Low Forecast is well taken. Given the approved load forecast appears to be more in line with the Company's low forecast,[309] we agree with CCSA that the adder methodology should include the cost and transmission capacity results of the Company's modeling for the low forecast. We therefore direct the Company to recalculate the adder using all results modeled as suggested by CCSA, subject to additional changes discussed below.

363. CCSA and Pivot Energy ask that the cost of the MVLE be included in the calculation of the transmission adder because the MVLE is likely to be needed for any portfolio and not including it is inconsistent. In hearing, however, the Company pointed out that the costs of the MVLE will be included for any portfolio that includes one or more bid resources connecting to the MVLE, so that including its costs in the adder would be double counting.[310] We agree with the Company's logic that the cost of the MVLE should be excluded from this calculation.

364. Regarding Staff's contention that the $1.8-$1.9 billion HCSC project is unavoidable and so should be excluded from the adder calculation, we note that this cost was the primary contributor to the "$2 billion surprise" in the 2021 ERP/CEP. This specific project was removed from the ongoing CPCN application for Denver Metro transmission upgrades (Proceeding No. 24A-0560) largely because the Company determined that it was not needed to support the approved portfolio from the 2021 ERP/CEP. However, the Company's JTS Transmission Study identifies the need for the HCSC project in almost every portfolio it evaluated. Accordingly, we agree with Staff that the record suggests this project is unavoidable, and therefore

[309] As discussed above, the load forecast used for the base RFP will depend in part on how many large loads execute binding agreements prior to the RFP's release.

[310] Hr. Tr. June 13, 2025, p. 192:9-18.

that it should be excluded from the adder calculation. This will have the effect of dramatically reducing the adder, and largely addressing the bias toward smaller, gas-intensive portfolios that Staff discusses.

365. We do not agree, however, with the parties advocating that the adder should be entirely eliminated. It appears the transmission costs that are truly incremental and avoidable should be attributed to projects that necessitate them, where such costs can be practically identified and included in the capacity optimization process, as the Company has attempted to do here. Furthermore, CCSA makes the valid point that distribution-connected resources are unlikely to contribute to the need for transmission upgrades, and the transmission adder properly reflects this benefit in expansion planning.

366. Parties raise essentially three types of criticisms regarding the Company's calculation of its proposed Denver Metro transmission credit: (1) the denominator of the calculation assumes that all DER are installed within the Denver Metro constraint; (2) the calculation fails to account for modeled portfolio differences other than the quantity of DER installed; and (3) the map the Company provides in Rebuttal indicating where the Denver Metro transmission credit would be applicable is inconsistent with that provided in the Denver Metro CPCN and requires additional study. We agree with these parties that there are significant shortcomings to the Company's credit calculation methodology. CCSA recommends that the denominator in the calculation (change in DER MW between the Baseline and Bookend 2 portfolios) be reduced by 15 percent because it claims that is the amount of DER that will be installed outside of the Denver Metro Constraint. However, CCSA includes nothing in the record to substantiate this specific value. However, Staff is correct that the change in installed DER assumption is far from the only factor affecting the costs of the portfolios referenced in the credit

calculation. We therefore endorse Staff's recommendation that the Commission require the Company to perform additional comparative transmission modeling to fix the deficiencies in the calculation and application of the credit, and that the small stakeholder group have the opportunity to review and comment on the results of this modeling.

367. While we recognize the risks of adding more process between this Decision and the RFP, CEI raises a legitimate request that if the transmission credit is modified after the Phase I Decision, parties should be notified of the change in the transmission credit and should have an opportunity to respond—prior to the Phase II modeling. We therefore grant CEI's request and require that the Company file a notice of any changes to the adder or credits following this Phase I Decision, describing the changes made along with the methodological justifications for the changes. Parties will then have the opportunity to respond.

368. Finally with regard to transmission adders and credits, we note that neither the Company nor any other party responded to the CCSA proposal that there should be a credit for all distribution-connected resources system wide that would be in addition to the credit for resources connecting at the distribution level within the Denver Metro constraint. As there is little on the record to support the CCSA position, we will deny its request and approve the Company's proposal to provide a \$69/kW credit to resources interconnecting on constrained distribution circuits.[311]

M. Phase II Portfolios

1. Party Positions

369. Public Service proposes to model two groups of Phase II portfolios or "solution sets." The first solution set meets the 80 percent emission reduction by 2030 target and then

[311] Commissioner Gilman dissents on this point and would have directed the small stakeholder group to work with the ITA and the Company to study the issue and revise the credit.

declines to 100 percent emission reduction by 2050. The second solution set contains an 86 percent emissions reduction constraint in 2030 to match the modeled emissions reduction form the approved portfolio in the 2021 ERP/CEP as well as a 90 percent emissions reduction target in 2033. After 2033, this second solution set declines to 100 percent emission reduction by 2050.[312]

370. Each solution set will have the following six portfolios, for a total of 12 portfolios: 1) informational least cost plan with SCC, 2) SCC with Company-ownership requirements, 3) SCC with accelerated emissions reduction in which there is a linear reduction in emissions to 100 percent remission reduction by 2030, 4) a least cost informational plan with $0 SCC, 5) Company ownership requirements with $0 SCC, and 6) a $0 SCC accelerated emissions reduction with a linear reduction in emissions to 100 percent by 2030. [313]

371. In addition to the above 12 portfolios, Public Service proposes modeling two checkpoint portfolios in which there is no emissions reduction constraint. [314] The Company states that neither checkpoint portfolio is meant for ultimate selection but asserts these portfolios may be "useful, if not critical, in final portfolio decision making."[315] The Company states it is critical for intervenors and the Commission to understand the impact of the emissions targets on acquisition plans. Public Service adds that while the checkpoint cases will inform the baseline for the CEP Rider, the Company submits that the CEP Rider baseline development is more complex than simply using the checkpoint case. Instead of using the checkpoint portfolios for the CEP Rider baseline, the Company proposes to address the CEP Rider baseline in the 120-Day Report based on the presented portfolios in the JTS Base RFP Phase II process.[316]

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[312] Public Service's SOP at p. 8.
[313] Hr. Ex. 117, Ihle Rebuttal, p. 57.
[314] Hr. Ex. 117, Ihle Rebuttal, p. 57.
[315] Hr. Ex. 118, Landrum Rebuttal, p. 15.
[316] Public Service's SOP at pp. 9-10.

372. The Company proposes a "midpoint ownership" portfolio, which would only be run if the level of Company ownership in the least-cost plan is less than 30 percent on a nameplate MW basis. Public Service maintains that the least-cost plan, which contains no utility-ownership constraint, already tests the cost-effectiveness of utility ownership and that the midpoint ownership portfolio would potentially provide an additional portfolio consistent with party proposals for a low ownership portfolio.[317]

373. To determine backup bids, the Company proposes to rerun the Preferred Portfolio through EnCompass for each technology type (wind, solar, hybrid, storage, firm dispatchable, etc.) by locking in all resources except the selected type, removing the selected bid for the specific type, and only allowing bids of that type to come in as replacements.[318]

[317] Public Service's SOP at p. 9.
[318] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 66.

374. Staff proposes the following 14 Phase II portfolios, matching the number proposed by the Company:

1) Checkpoint portfolio with $0 SCC
2) A least cost portfolio with $0 SCC, an 80 percent by 2030 emissions constraint, and no required Company ownership
3) A least cost portfolio with $0 SCC, a 90 percent by 2033 emissions constraint, and no required Company ownership
4) A Company-ownership portfolio with $0 SCC, an 80 percent by 2030 emissions constraint, 50 percent Company-ownership requirement, and a linear emissions constraint
5) A Company-ownership portfolio with SCC, an 80 percent by 2030 emissions constraint, 50 percent Company-ownership requirement, and a linear emissions constraint
6) A Company-ownership portfolio with $0 SCC, a 90 percent by 2033 emissions constraint, and a 50 percent Company-ownership requirement
7) A Company-ownership portfolio with SCC, a 90 percent by 2033 emissions constraint, and a 50 percent Company-ownership requirement
8) An accelerated emissions portfolio with SCC, emissions constraints of 86 percent by 2030 and 90 percent by 2033, a 50 percent Company-ownership requirement, and a linear emissions constraint
9) An accelerated emissions portfolio with SCC, emissions constraints of 86 percent by 2030 and 90 percent by 2033, and a 50 percent Company-ownership requirement
10) A lower Company-ownership portfolio that matches the metrics of the preferred portfolio that the Company advances in Phase II but with a maximum 40 percent Company ownership
11) A low new gas portfolio that matches the metrics of the preferred portfolio but constrains new gas capacity to no more than 50 percent of the capacity included in the Company's preferred portfolio
12) A no tariff costs that matches the metrics of the preferred portfolio but excludes any tariff costs identified by bidders
13) An alternative tariff portfolio that matches the metrics of the preferred portfolio but uses either half of the identified tariff costs or doubles the identified tariff costs, depending on the level of tariffs in place at the time of project bidder.
14) A just transition credits portfolio that matches the metrics of the preferred portfolio but eliminates the just transition modeling credits.[319]

[319] Hr. Ex. 2606, Att. SJD-10; Staff's SOP at pp. 11-12.

375. While most of Staff's proposed modeling scenarios are similar to those of the Company, Staff argues its proposal provides a broader range of distinctive "looks," including looks at increased emission reductions, lower Company ownership, lower new gas resources, and the impact of import tariffs, all without increasing the number of portfolios.[320] Staff notes the Company characterized Staff's proposed Phase II portfolios as a reasonable alternative at hearing.[321]

376. WRA and SWEEP state they are directionally supportive of Staff's proposed suite of Phase II portfolios but suggest certain modifications. First, WRA and SWEEP argue the Commission should strive to include a 90 percent by 2033 emission constraint in as many of the portfolios as possible and an 86 percent by 2033 emission constraint in at least several of the portfolios. In addition, they argue the Commission should require the Company to model all portfolios with and without the inclusion of just transition modeling credits. WRA and SWEEP assert these portfolios together with Staff's existing proposals would only result in 22 total portfolios—far fewer portfolios that what was presented in the 2021 ERP/CEP. In the alternative, the Commission should at minimum require that a sensitivity of the preferred portfolio be modeled with and without just transition credits. They note the downsides with this approach include the lack of comparability to other portfolios, and the inability for the Commission to take corrective action if the portfolio modeled without just transition credits indicates that the credits added substantial cost to every other portfolio in which the credits were included.[322]

377. WRA and SWEEP also support two post-Phase II portfolios. The first would exclude large loads to provide an initial approximation of the incremental resource selection and costs driven by the addition of large load customers. The second would be the checkpoint

[320] Staff's SOP at pp. 11-12.
[321] Hr. Tr. June 17, 2025, at p. 80.
[322] WRA and SWEEP's SOP at p. 23.

portfolios. If one or both of the checkpoint portfolios is modeled at all, WRA and SWEEP argue it should be after the Phase II decision to expedite Phase II and ensure consistency with the statute and USA.

378. Conservation Coalition recommends modeling Phase II portfolios with a goal of producing meaningful variations across three main factors: cost to customers; emissions reductions; and just transition benefits (with a minimum level of reliability across all portfolios). Conservation Coalition accordingly offers several recommendations. For instance, Conservation Coalition argues the Commission should decide in Phase I whether to include the SCC in the portfolios (*i.e.*, using $0 SCC or SCC in capacity expansion). Conservation Coalition asserts this would save time and resources compared to running each portfolio in Phase II both with SCC and with $0 SCC. Regarding the checkpoint portfolios, Conservation Coalitions argues they should only be run after the Phase II Decision, if at all, and should be modified to include the 100 percent emissions reduction by 2050. Conservation Coalition would also delete Staff's proposed linear emissions constraint. Conservation Coalition reasons that what happens after 2033 is of little importance to the base and supplemental RFP and there will already be portfolios with a 90 percent emissions constraint by 2033. Conservation Coalition recommends adding at least one portfolio in which Public Service is assumed to join a full ISO/RTO by 2030 and rejecting or reducing by half the just transition modeling credits.[323] Conservation Coalition goes on to suggest modified versions of the two suites of Phase II portfolios that Public Service and Staff advance.

379. Finally, Conservation Coalition argues the Commission cannot simply reuse the same portfolios for the base RFP and the supplemental RFP. Conservation Coalition asks the Commission to direct that the portfolios for the supplemental RFP not use the Company ownership

[323] Conservation Coalition's SOP at pp. 4-8.

targets. Instead, Conservation Coalition argues that each portfolio for the supplemental RFP should include the least-cost resources (subject to the constraints for that portfolio) without any explicit Company-ownership constraint in the model. Conservation Coalition similarly argues that if the Commission approves the use of the just transition modeling credits in the base RFP, it should consider whether it is still appropriate to use them for the supplemental RFP.[324]

380. CEC argues that § 40-2-125.5(3), C.R.S. requires the Commission to approve a resource plan that enables Public Service to achieve an 80 percent emissions reduction by 2030 and "seek to achieve" a 100 percent reduction by 2050 or sooner if it is "*technically and economically feasible*" and "in the public interest."[325] The statute also indicates that its purposes include "promot[ing] the development of *cost-effective* clean energy" that will "allow Coloradans to enjoy the benefits of *reliable* clean energy at an *affordable cost*."[326] Based on the likely cost increases for clean energy resources, CEC argues the Commission should evaluate any incremental impacts to reliability and affordability that result from exceeding the 80 percent threshold and select the most cost-effective Phase II portfolio that meets the 80 percent threshold while ensuring reliable service.

381. CC4CA opposes the Company's proposed checkpoint reference cases, arguing that Phase II modeling should be reserved for portfolios that the Commission can lawfully approve. Instead of the checkpoint portfolios, which have no emission reduction constraints, CC4CA argues the Commission should require two "Business as Usual" reference cases that would maintain the emissions constraints approved in the CEP.[327] CC4CA further argues that at least half of the Phase II portfolios should use the 86 percent by 2030 emissions constraint to be consistent with

[324] Conservation Coalition's SOP at pp. 9-11.
[325] CEC's SOP at p. 15 (quoting § 40-2-125.5(3)(a) (emphasis in original)).
[326] CEC's SOP at p. 15.
[327] CC4CA's SOP at p. 3.

the approved portfolio from the 2021 ERP/CEP. CC4CA also recommends two additional portfolios. First, CC4CA requests a no new gas portfolio, which only allows the model existing gas units with retirement dates during the RAP that can be extended as well as current PPAs that expire during the RAP and can be extended or rebid. Second, CC4CA recommends the Commission direct the Company to model a "health impacts analysis" portfolio, which would be a sensitivity of the Company's preferred portfolio that accounts for the costs of the health impacts of newly-constructed gas units, using either approach put forth by Healthy Air and Water Colorado.[328] Similar to other intervenors, CC4CA requests the Commission require Phase II portfolios be modeled with and without the just transition modeling credits.[329]

382. Interwest recommends an additional low Company-ownership portfolio in which Company ownership is limited to 45 percent. This 45 percent constraint would be applied to resources in excess of the $690 million investment or 500 MW accredited capacity minimum specified in the 2021 ERP/CEP's USA. Interwest argues this portfolio would help show the impact of higher Company ownership on cost, emissions reductions, reliability, BVEM score, and ability to address future concerns, allowing the Commission to weigh the various considerations appropriately.[330]

383. CIEA argues the Company should be required to provide Solution Sets that provide different views of Company ownership versus PPA projects. While CIEA does not advocate deviating from the utility ownership levels agreed upon in the 2021 ERP/CEP, CIEA notes that the CEP showed that Company-owned projects faced same uncertainties with supply chain and pricing that IPPs faced. In addition, CIEA requests that the Company provide a Solution Set where

[328] CC4CA's SOP at p. 4.
[329] CC4CA's SOP at p. 5.
[330] Hr. Ex. 501, Wilson Answer, pp. 23-24.

bidders that had appeared in multiple other Solution Sets could be removed from consideration and allow other bids to be populated. [331]

384. CEO argues the Commission should only run the checkpoint portfolios after Phase II. CEO also recommends the Company run at least one portfolio that includes an 86 percent reduction by 2030, a 90 percent reduction by 2033, and a 100 percent reduction by 2050, with SCC included.[332]

2. Findings and Conclusions

385. With certain modifications, we adopt Staff's proposed suite of Phase II portfolios, which we find to be superior to the Company's proposal. Staff pares down the Company's portfolios that simply test the impact of including SCC. For instance, Staff's least cost portfolios do not include the SCC. Conversely, Staff's accelerated emissions portfolios only include SCC and contain no $0 SCC. This is a reasonable approach for eliminating portfolios that provide little value and is directionally consistent with Conservation Coalition's recommendation to decide in Phase I whether to use SCC instead of modeling every portfolio twice. Staff replaces these mostly redundant portfolios with portfolios that examine lower Company ownership and lower new gas. These portfolios provide more varied options for Commission consideration without adding additional Phase II modeling burdens.

386. While Staff's suite of portfolios are preferable to the Company's proposal, we find certain additional modifications are necessary. To begin, we agree with concerns raised by WRA and SWEEP, Conservation Coalition, and CC4CA regarding the Company's checkpoint portfolios, one of which Staff includes in its proposed suite of portfolios. As CC4CA observes, it

[331] Hr. Ex. 700, Monsen Answer, pp. 85-86.
[332] CEO's SOP at pp. 20-21.

is unclear why Phase II resources should be expended modeling a portfolio that does not contain the statutory requirement to achieve an 80 percent emissions reduction by 2030. Instead of the checkpoint portfolio Staff proposes, we adopt a modified version of CC4CA's business as usual portfolio. Under this modified portfolio, the model would still be required to achieve the 80 percent by 2030 emissions reduction target but would have no subsequent emissions constraints. This portfolio meets the bare minimum required by statute and allows the Commission and parties to evaluate a scenario in which the model is not required to achieve 100 percent emissions reductions using existing technologies.

387. To be clear, this business as usual portfolio does not abandon the statutory goal of 100 percent emissions reduction by 2050. Rather, the portfolio leaves open the possibility that future emissions reductions from things like VPPs, increased market participation, additional interregional transmission, and new technologies like advanced geothermal and long duration storage could render unnecessary some of the wind, solar, and short-duration storage that would otherwise be acquired in the short-term. Given the documented price increases of wind, solar, and lithium-ion storage, recent changes to federal tax credits, and uncertainties about federal tariff policies, we want to ensure there are some portfolios in which the model is not forced to acquire large amounts of existing technologies when better alternatives may be available in the future.

388. In addition, we see little value in Staff's two portfolios that test the impacts of tariffs (*i.e.*, the no tariff costs portfolio and the alternative tariff case portfolio). While we do not discount the potential cost impacts of tariffs, given the dynamic nature of federal tariff policy, it is unlikely that these two portfolios would materially influence which portfolio is ultimately selected, let alone be selected themselves. Also, given how quickly the tariff situation may change, it is not clear that

tariffs modeled based on policies from the time the projects are bid will still be applicable when they are expected to be developed.

389. Instead of Staff's tariff portfolios, we direct Public Service to model two new portfolios. The first such portfolio is a no-new Company-owned gas portfolio. This portfolio would include the just transition modeling credits, the SCC, the 80 percent by 2030 and 100 percent by 2050 emissions constraints, and the 50 percent Company-ownership target. However, the portfolio would be restricted from including any new Company-owned gas units. As the Commission referenced in the 2021 ERP/CEP, reducing the amount of Company-owned gas resources increases the Company's ability to transition away from carbon emitting resources as we approach 2050 and reduces the risk that Colorado ratepayers will be burdened with the cost of stranded assets associated with gas units.[333]

390. The second new portfolio that replaces Staff's two tariff portfolios is an accelerated emissions portfolio that is modeled without just transition modeling credits. As set forth above, we find persuasive arguments from Staff, Conservation Coalition, CC4CA, and WRA and SWEEP, that there should be Phase II portfolios modeled both with and without the just transition modeling credits. This will help parties and the Commission understand the impacts the just transition modeling credits have on costs and resource selection and my help alleviate concerns that the just transition modeling credits may reduce competitive tension. This accelerated emissions portfolio will use the SCC, will have emissions constraints of 86 percent by 2030, 90 percent by 2033, and 100 percent by 2050, and will include at least 50 percent utility ownership. This portfolio will not include the just transition modeling credits.

[333] Decision No. C24-0052 at ¶ 100 issued in the 2021 ERP/CEP (Jan. 23, 2024).

391. We also replace Staff's proposed Portfolio 8, which is one of four portfolios testing Company-ownership, with a new portfolio that tests accelerated near term emissions reductions without the 100 percent by 2050 emissions constraint. We find that this additional accelerated emissions reduction portfolio will provide more useful information than another Company-ownership portfolio. Under this new accelerated emissions reduction portfolio, the just transition modeling credits will be included, the model will use SCC, there will be a 50 percent Company-ownership requirement, and the portfolio will have the following emissions constraints: 86 percent by 2030, 90 percent by 2033, but no 100 percent by 2050 constraint. As referenced above, given the cost pressures and changing federal policy, we find it appropriate to have another portfolio that leaves space for the use of future technologies, interregional transmission, and increased market participation to meet the 100 percent by 2050 goal.

392. For similar reasons, we find it appropriate to reduce the number of portfolios that require a linear emissions reduction. Requiring a constant pace of emissions reduction disregards potential future step-changes such as market participation. At the same time, however, we stop short of eliminating the linear reduction constraint entirely given that it promotes additional interim emissions reductions by requiring the model to acquire additional wind, solar, and storage resources. Accordingly, we retain the linear reduction constraint for Portfolio 9, which helps ensure the Commission has an aggressive emissions reduction option. Public Service shall remove the linear constraint from all other portfolios. For these portfolios without the linear constraint, the Company will keep all other emissions constraints (*e.g.*, the 2030 and 2050 requirements) but will remove intervening constraints, including the Carbon Caps set forth in Section 2.11 of the technical appendix.

393. In sum, Public Service shall model the following Phase II portfolios:

No.	Name	JT Credits[334]	SCC	Emissions pathway[335]	Comp. ownership	Additional emissions constraint
1	No new Company-owned gas	Yes	SCC	80/30	50%	None
2	Business as usual	Yes	SCC	80/30; no 100% by 2050 constraint	0%	None
3	Least cost portfolio	No	No	80/30	0%	None
4	Least cost portfolio	Yes	No	90/33	0%	None
5	Company ownership	Yes	No	80/30	50%	None
6	Company ownership	Yes	SCC	80/30	50%	None
7	Company ownership	Yes	No	90/33	50%	None
8	Accelerated emissions reduction	Yes	SCC	86/30 & 90/33; no 100% by 2050 constraint[336]	50%	None
9	Accelerated emissions reduction	Yes	SCC	86/30 & 90/33	50%	Linear
10	Accelerated emissions reduction	Yes	SCC	86/30 & 90/33	50%	None
11	Lower Comp. ownership	Yes	Match PP[337]	Match PP	40%	Match PP
12	Low New Gas	Yes	Match PP	Match PP	50%	Match PP
13	PP with no JT Modeling Credits	No	Match PP	Match PP	Match PP	Match PP
14	Accelerated emissions with no JT Modeling Credits	No	SCC	86/30 & 90/33	50%	None

394. We note that if the Company advances Portfolio 10 as the preferred portfolio, then Portfolio 13 becomes duplicative of Portfolio 14. Therefore, in the event Portfolio 10 is the preferred portfolio, then Portfolio 14 should be adjusted to mimic Portfolio 9's inclusion of the

[334] For purposes of this Table, just transition modeling credits is abbreviated as "JT Credits."

[335] For purposes of this Table, the 80 percent by 2030 emissions constraint is abbreviated as "80/30," the 86 percent by 2030 constraint is abbreviated "86/30," and the 90 percent by 2033 is abbreviated "90/33." Unless otherwise specified, all portfolios have the 100 percent by 2050 emissions reduction constraint.

[336] Although this portfolio does not have the 100 percent by 2050 constraint, in this portfolio gas-fired facilities would still be subject to early depreciation as well as the higher costs associated with hydrogen fuel.

[337] For purposes of this Table, preferred portfolio is abbreviated as "PP."

linear emission constraint. In other words, if Portfolio 10 is the preferred portfolio, then Portfolio 14 shall be modified to include the linear emission constraint.

395. Although we reject the Public Service's proposal to model the checkpoint portfolios, the Commission approves the Company's plan to address the CEP Rider baseline development based on the presented portfolios in the base RFP Phase II process.

396. Consistent with Conservation Coalition's recommendation and our discussion above,[338] we reject the 50 percent Company ownership target in the supplemental RFP. While the level of utility ownership will likely continue to be an important consideration given the differences between Company-owned projects and PPAs, we see no basis to maintain a 50 percent ownership target. Eliminating the 50 percent ownership target would make Portfolio 4 duplicative of Portfolio 7, so the Company would be able to eliminate either one. In order to test the impacts of varying amounts of utility ownership, Public Service shall run two variations on the supplemental RFP preferred portfolio. The first would set a utility ownership constraint of at least 50 percent, and the second would set a utility ownership limit of 40 percent.

N. Conforming Bid Policy and Modifications to PPA Provisions

397. Public Service recommends the Commission adopt a conforming bid policy under which developers can only submit bids that conform to the model PPAs approved in the Phase I decision. In other words, in response to the RFP, bidders would be required to provide a proposal and associated firm non-conditional bid price that is fully compliant with the Company's model agreements without markup or exceptions. Public Service argues this new approach will help the

[338] See ¶ 119 *supra*.

Company complete project evaluation and contract negotiations in a timely manner, as well as to ensure projects are compared on a like-for-like basis.[339]

398. The Company argues its conforming bid policy supports three objectives: first to ensure a fair, transparent and competitive RFP; second, to protect customers against bidders trying to shift risk and costs to customers through redlined bids and during post-selection negotiations; and finally, to improve the efficiency and effectiveness of the solicitation, selection and procurement process in Phase II. On this last point, the Company argues that a conforming bid policy will help prevent extended periods of bid evaluation and negotiation.[340] The Company notes that negotiation of specific language details will still occur at arms-length. The conforming-bid policy simply prohibits developers from submitting bids that rely on the assumption that fundamental aspects of the Model PPA will be modified.

399. To finalize a conforming model PPA, the Company in its SOP suggests a series of procedural steps that would allow for the submission and ultimate approval of a redlined PPA. For instance, within 14 days after the Commission issues a decision adjudicating the disputed issues with the model PPAs, the Company would file updates of each model PPA. Intervenors would then have 14 days to file comments, including redlined versions of the updated PPAs. Then the Company would have 14 days to file reply comments and updated PPAs. The Company contemplates that the Commission would issue a decision on the final model PPAs within 21 days of reply comments and possibly after a technical conference.[341]

400. CIEA, CEI, and Interwest all urge the Commission to deny the conforming bid policy. CIEA recommends bidders be allowed to provide commercially reasonable redlines to the

[339] Hr. Ex. 104, Bornhofen Answer, Vol. 2, p. 214.
[340] Hr. Ex. 120, Bornhofen Rebuttal, p. 9, 20.
[341] Public Service's SOP at p. 29.

model PPA with bids such that Public Service is aware of proposed edits. Public Service would have discretion to review bidder redlines, to reject bids under certain conditions, and to provide negative non-price factors for either excessive redlines or redlines that say "TBD."[342] CIEA argues there is a "striking absence in the record" showing the effectiveness of a conforming bid policy anywhere else.[343] Regarding the Company's assertion that the conforming bid policy allows for an apples-to-apples comparison, CIEA notes that approximately half of the approved generation projects may be owned by the Company, and such utility-owned projects are not required to comply with the model PPA terms but are allowed to submit bids with redlines to the term sheet.[344] CIEA further asserts that the risk of delay of the RFP and the resulting costs to ratepayers far outweighs the hypothetical value of extra litigation to arrive at a model PPA. CIEA argues the RFP cannot and should not be delayed to continue contract mediation. In the alternative, if the Commission decides to delay the RFP to decide PPA language, CIEA requests the Commission adopt the positions of CEI and Interwest.[345]

401. CEI recommends the Commission reject the proposed new model PPA and the conforming bid policy and by default adopt the model PPA approved in the last ERP—Proceeding No. 21A-0141E. If the Commission chooses to convene a process to develop an agreed-upon model PPA, CEI argues it should be aimed at the supplemental RFP only.[346] Throughout the Proceeding, CEI submitted considerable testimony regarding the unreasonableness of the Company's proposed PPA terms. CEI argues that when the proposed terms are reviewed and taken together, it presents a one-sided agreement that dramatically favors the Company.[347]

[342] CIEA's SOP at pp. 7-8.
[343] CIEA's SOP at pp. 14.
[344] CIEA's SOP at pp. 18-19.
[345] CIEA's SOP at pp. 22.
[346] CEI's SOP at pp. 6-7.
[347] *See* Hr. Ex. 2202, Pierce Answer, p. 61.

CEI asks the Commission not to leave this issue up to the Company to decide, arguing that even after the Company's concessions in Rebuttal, the parties remain far apart on key PPA terms. CEI warns that the Company's proposed terms are unreasonably burdensome to IPPs and that adopting a one-sided model contract shifts risk to IPPs, which is likely to increase the cost of bids and reduce participation.[348]

402. Interwest similarly recommends that the Commission reject the conforming bid policy in its entirety in favor of negotiability. Interwest asserts the conforming bid policy reduces flexibility in one of the most uncertain moments in electricity generation acquisition and makes IPPs bear much of the risk associated with this uncertainty.[349] Interwest acknowledges that there "are some benefits to having at least some contract terms be non-negotiable" such as quicker processing time.[350] However, Interwest argues that it is better for the whole contract—or at least specific provisions—to be negotiable. Similar to CEI, Interwest goes through numerous problems with the proposed PPA terms and recommends they remain negotiable or be modified.[351] Interwest argues that if the Commission chooses to accept any portion of the conforming bid policy, it should explicitly incorporate all of the positions put forth by Interwest, CEI, and CIEA.[352]

403. Pivot Energy also recommends rejecting the conforming bid policy.[353]

404. We largely agree with Public Service regarding the need for, and potential benefits of, a conforming bid policy. The bid evaluation process in the 2021 ERP/CEP took much longer than the Commission's Rules anticipate, and Public Service had to seek multiple extensions of the deadline to file the 120-Day Report. One of the proffered reasons for these delays was the difficulty

[348] CEI's SOP at pp. 5-6.
[349] Interwest's SOP at pp. 7-8.
[350] Hr. Ex. 500, Sanger Answer, p. 22.
[351] *See* Hr. Ex. 500, Sanger Answer, pp. 25-52.
[352] Interwest's SOP at pp. 8-9.
[353] Pivot Energy's SOP at p. 18.

Public Service had evaluating numerous bids with proposed modifications to the model PPA contracts. In the Commission's Phase II Decision in the 2021 ERP/CEP, we observed that having the Company and IE attempt to determine on an *ad hoc* basis during the bid evaluation process which terms of the PPAs are negotiable is a challenging situation, especially considering that the Commission already addresses many core issues of the model PPAs in Phase I and the fact that in Phase II the Company and IE are called upon to equitably evaluate numerous bids.[354] Even after a final portfolio of resources was approved, there were significant delays in the negotiation and execution of most PPAs. These delays contributed to the need for the CEP Delivery Decision. Even after the CEP Delivery Decision, however, the process of negotiating and executing PPAs remained relatively slow.

405. Adopting a conforming bid policy will simplify the process of evaluating and modeling numerous bids because Public Service and the IE will not need to evaluate the impacts of various redlines to the PPAs. Moreover, the conforming bid policy will likely prevent a protracted negotiation process in which Public Service and the respective IPPs go back and forth on fundamental contract terms such as the amount of security or the definition of *force majeure*. We acknowledge arguments from various intervenors that a conforming bid policy will reduce flexibility at the same time that the challenges and uncertainties regarding developing new resources is increasing. Based on our experience in the 2021 ERP/CEP, however, a fully negotiable PPA was insufficient to avoid issues associated with changing conditions.

406. To facilitate the development of minimally negotiable PPAs,[355] we find it appropriate to resolve several of the key disputed issues, including provisions regarding security

[354] Phase II Decision at ¶¶ 292-293 issued in the 2021 ERP/CEP (Jan. 23, 2024).

[355] Consistent with the Company's proposal, post-selection parties may still negotiate minor issues in the PPAs, so long as doing so is not inconsistent with our directives on the key substantive issues.

requirements, events of default, *force majeure*, and transfer limitation. Within 14 days of this Decision, Public Service shall submit updated versions of each PPA that incorporates our directives. The Company must include both clean and redline versions. Intervenor comments on the revised PPAs, including redlined versions with proposed language, are due within 14 days of the Company's submission of the revised PPAs.[356] Any reply comments and updated PPA language from Public Service are due within 14 days after intervenor comments. The Commission will target issuing a decision within 21 days of the reply comments and may convene a technical conference, as necessary. This will result in a final set of PPAs to which bids must conform for the base RFP.

407. Our resolution of the key disputed issues are set forth below. As set forth above, the Company shall fully incorporate our below directives into the revised PPAs it files within 14 days of this Decision. Additionally, to ensure fair competition and to maximize ratepayer protections, the Commission will endeavor to ensure that utility-owned generation meet standards equivalent to those expected for PPAs.

1. Market Changes

408. The Model PPAs contain provisions that requires the IPP and Company to cooperate in good faith if Public Service enters a market that impacts the deployment of the resource. For instance, Section 5.3 in Volume 3, Appendix D2 (also present in Section 5.2 of Volume 3, Appendix D1) sets forth the following:

> a. If at any time during the Term, the Transmission Authority changes or the facilities at the Point of Delivery cease to be subject to the Transmission Tariff, the Parties shall cooperate in good faith to

[356] The Commission recognizes that potential requests for rehearing, reargument, or reconsideration ("RRR") may be concurrent with this proposed timeline. While a RRR request does not automatically stay a Commission decision, appropriate filings may request revision to this timeline, including through concurrently filed or included motion to extend timelines if needed or appropriate through resolution through RRR resolution.

facilitate the delivery of Energy, at the least possible cost to the Parties, consistent with this PPA to the extent possible.

b. If at any time during the Term, the Transmission Authority, the ERO or any other Governmental Authority with jurisdiction imposes an organized market or Company elects to join a regional transmission organization, or participate, or change its participation in, an organized market that changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation of the Facility accordingly, at the least possible cost to the Parties, consistent with this PPA to the extent possible.[357]

409. At a high level, Interwest argues that language should be added to this provision that limits the costs imposed on the IPP and requires a dispute resolution or mediation process if a disagreement arises. CEI argue for language that provides clarity to ensure that the project developer does not incur additional material costs as a result of the Company electing to join a regional transmission organization.[358]

410. In Rebuttal, the Company agrees to add a deductible concept in which the Company will reimburse required capital expenditures if they exceed a deductible equal to $25/KW of nameplate capacity, subject to Company approval.[359] More generally, Public Service argues that "[t]he developer's risk to meet its commitments despite changes by the Federal Energy Regulatory Commission, a market operator, or reliability entity as it relates to its facility or equipment, remains with the bidder to bear."[360]

411. In Surrebuttal, however, CEI continues to object even with the Company's offered compromise. CEI asserts that costs that are unknown and unable to be negotiated when the contract is signed are the responsibility of Public Service, including material costs that do not constitute

[357] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D2, pp. 18-19.
[358] *See* Hr. Ex. 2207, Att. JFP-2, p. 11.
[359] Hr. Ex. 2207, Att. JFP-2, p. 11.
[360] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 4.

capital expenditures. CEI asserts that joining a regional market is to the benefit of the Company and its customers, and those costs should not be imputed after the fact on the IPP project.[361]

412. We agree with the Company's proposal to create a cap on the developer's capital obligations regarding market changes. This approach is responsive to Interwest's request to limit the IPP's costs and provide bidders additional certainty. Given IPPs have little, if any, control over whether the Company enters a market, however, we find that the Company's proposed deductible amount is too high. Instead, to the extent any changes required in connection with market changes as set forth in the PPA require capital expenditures within the Facility, such reasonable expenditures will be reimbursed if they exceed a deductible equal to $10/KW of nameplate capacity. With the exception of capital expenditures, each party otherwise will bear its own costs.

2. Security Requirements

413. Article 11 covers the IPP's security requirements and Section 11.1(B) dictates the amount and timing of security as follows:

> Seller shall establish and fund the Security Fund in the amount of [insert $200/kW] multiplied by the number of kW in the Facility Nameplate Capacity], no later than thirty (30) Days following the Effective Date. Within five (5) Business Days following COD, the amount of the Security Fund shall be reduced to [insert $75/kW multiplied by the number of kW in the Facility Nameplate Capacity].[362]

414. Interwest argues the pre-COD security is excessive and should be reduced to $100-$125/kW, and that the Seller should only be required to replenish the Security Fund post-COD. CEI argues that alternative commercially reasonable approaches to security, such as performance bonding or a letter of credit, should be used instead of the proposed security requirements.[363]

361 Hr. Ex. 2207, Att. JFP-2, p. 11.
362 Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 29.
363 Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 27.

415. In Rebuttal, the Company makes certain concessions but generally maintains its position, arguing that the security amounts cannot be changed after bid selection as that would undermine the integrity of the RFP. As for the amount, Public Service states it can agree to reduce the Pre-COD security from $200/kW to $150/KW and can also agree to modify the contract so pre-COD replenishment is only required when security falls to 50 percent or below the initial level. The Company notes that the model contract as written already allows Letters of Credit as an acceptable form of security.[364]

416. In its Surrebuttal, CEI continues to oppose the security provisions, characterizing them as "a major issue."[365] CEI argues the Company's concessions are insufficient to account for the other problematic liquidated damages language in Section 12 and that it is impossible to negotiate these components individually.

417. We agree with Public Service that the security provisions in the PPAs should be nonnegotiable. Security provisions have significant implications for many other portions of the PPAs. Developers incur costs to maintain the security fund, and the size of the security fund also changes the amount of risk a developer assumes when it executes a PPA. Conducting an apples-to-apples comparison of bids for new-build projects would be difficult if those bids assume significantly different security provisions.

418. While we agree Article 11 should be nonnegotiable, we disagree with the Company's proposal for a pre-COD security of $200/kw. Instead, the initial Security Fund in Section 11.1(B) shall be reduced to $125/kw, consistent with the recommendation from Interwest. This level also matches the amount used in the model PPAs in the 2021 ERP/CEP.[366] We adopt the

[364] Hr. Ex. 120, Att. JLB-2, Rev. 1, pp. 28-29.
[365] Hr. Ex. 2207, Att. JFP-2, pp. 20-21.
[366] Hr. Ex. 2212, p. 130.

Company's post-COD Security Fund of $75/kw. We further adopt the concession Public Service made in Rebuttal that pre-COD replenishment is only required when security falls to 50 percent or below the initial level.

419. Finally, Public Service shall make corresponding changes throughout the PPAs to reflect the lower security amount. For example, in Section 12.2(D), the liquidated damages amount is set at $100/kw. In Rebuttal, the Company acknowledges that if the security fund is reduced to $150/kw, the liquidated damages in Section 12.2(D) would change to $75/kw. Because we set the pre-COD security fund to $125/kw, the liquidated damages in Section 12.2(D) must be modified to $62.5/kw.

3. Events of Default

420. Section 12.1(A) lists several events that could cause default if not cured. These include events like if the IPP declares bankruptcy, fails to obtain and maintain insurance, or if any of the representations the IPP makes in the contract are materially false.

421. Public Service argues that it expects developers to perform and is unwavering in protecting its customers given the likely consequences if they do not. The Company asserts that the default provisions in Section 12.1(A) are reasonable and are designed to ensure competent, effective, and diligent development and operations. [367]

422. Interwest and CEI argue the Company has overly aggressive definitions of default and specifically flag provisions concerning breach of the interconnection agreement, committed energy requirements, and availability factor.

[367] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 4.

423. In Rebuttal, Public Service offers concessions on certain of these provisions but maintains its position on others.[368] In Surrebuttal, CEI asserts that Section 12 "remains a major issue," even after the Company's concessions and that "the Company has very aggressive definitions of default."[369]

424. While we agree that Section 12.1(A) should be nonnegotiable, we direct the Company to make several changes to the PPAs. First, Section 12.1(A)(4) states the following:

> Any representation or warranty by Seller that materially affects its ability to perform this PPA (a) is proven to have been false in any material respect when made or, (b) ceases to remain true in all material respects during the Term, provided however, that a representation or warranty that ceases to remain true due to a change in Applicable Law shall not be considered an Event of Default.[370]

425. Public Service shall strike Section 12.1(A)(4)(b) from the PPAs such that Section 12.1(A)(4) reads: "Any representation or warranty by Seller that materially affects its ability to perform this PPA is proven to have been false in any material respect when made." We find 12.1(A)(4)(b) unreasonable in that representations and warranties that cease to be true over the course of the contract (*e.g.* 15-20 years) could result in a default. Moreover, the model PPAs from the 2021 ERP/CEP do not include this future-looking default provision,[371] and Public Service has not met is burden of showing why this concept is now necessary.

426. We further direct changes to the provisions in Section 12.1(A) establishing the availability requirements. Interwest raised concerns with the Company's proposal to measure the capacity availability factor for an event of default over 12 months. Interwest instead argues the industry standard is to measure the capacity availability factor over 24 months.[372] In its Rebuttal,

[368] Hr. Ex. 120, Att. JLB-2, Rev. 1, pp. 29-31.
[369] Hr. Ex. 2207, Att. JFP-2, p. 22.
[370] Hr. Ex. 101, Att. JWI-3, Appendix D2, p. 44.
[371] Hr. Ex. 2212, p. 134.
[372] Hr. Ex. 2207, Att. JFP-2, p. 22.

the Company asserts the PPAs do provide developers 24 months because developers have a year to cure before the capacity availability factor would trigger a default.[373]

427. We direct Public Service to revise the PPA provisions regarding availability requirements (including for renewables, hybrid, and storage-only PPAs) to match the equivalent availability requirements that were included in the model PPAs from the 2021 ERP/CEP. For solar and wind availability requirements, we specifically direct Public Service to use the availability requirements agreed upon as part of the 2021 ERP/CEP USA.[374]

4. Specific Performance

428. Section 12.1(D) entitles the Company to specific performance, in addition to its other contractual remedies: "In addition to the other remedies specified herein, upon any Event of Default of Seller under this Section 12.1, Company may elect to treat this PPA as being in full force and effect and Company shall have the right to specific performance."

429. Interwest and CEI oppose this provision, arguing that it is not a reasonable, market term for the Company to be able to force the Seller to perform.[375] In Rebuttal, the Company agreed to remove Section 12.1(D) so long as the remedies in Section 12.1(B) remain unchanged.[376] Under Section 12.1(B), the Company can seek actual damages, offset payment due to the Seller, and draw damage from the security fund.[377] In Surrebuttal, CEI argues it is unreasonable to condition the removal of Section 12.1(D) on maintaining the damage provisions in Section 12.1(B), especially given the "extreme amounts" of liquidated damages.[378]

[373] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 29.
[374] *See* 2021 ERP/CEP USA, Att. 3.
[375] Hr. Ex. 2207, Att. JFP-2, p. 23.
[376] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 33.
[377] Hr. Ex. 101, Att. JWI-3, Appendix D2, p. 47.
[378] Hr. Ex. 2207, Att. JFP-2, p. 23.

430. We direct Public Service to remove Section 12.1(D). We agree with CEI and Interwest that specific performance is an out-of-market remedy in this context. While we are not directing Public Service to modify the language in Section 12.1(B), we note that our prior directives lowering the amount of required security impacts the force of Section 12.1(B).

5. Default Option

431. Section 12.1(E) provides another remedy to Public Service if the Company determines that there has been an event of default under Section 12.1. As opposed to obtaining a portion of the security deposit or seeking additional monetary damages, Section 12.1(E) provides Public Service with a default option in which it can unilaterally purchase and own the project:

> If Company terminates this PPA under this Section 12.1 following COD, then, at any time within ninety (90) Days following such termination, Company may give notice to Seller of Company's intent to purchase the Facility from Seller (a "Default Option Preliminary Exercise Notice").[379]

432. Interwest and CEI both strongly oppose the Default Option in Section 12.1(E), arguing that it is unreasonable and not aligned with market terms. They assert this provision would incentivize Public Service to terminate PPAs so that the Company could use Section 12.1(E) to takeover and own the facility.[380] In Rebuttal, the Company maintains its support for Section 12.1(E). Public Service asserts that the provision simply provides the Company with an alternate path to offset damages. The Company further asserts 12.1(E) does not provide an improper incentive because the Company is not in control of Seller defaults.[381] In Surrebuttal, CEI asserts the default option under Section 12.1(E) is new to the Colorado marketplace and is extremely anti-competitive in favor of the Company.[382] During the evidentiary hearing, Company witness Mr.

[379] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 35.
[380] Hr. Ex. 2207, Att. JFP-2, p. 24.
[381] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 33.
[382] Hr. Ex. 2207, Att. JFP-2, p. 24.

Bornhoffen acknowledged the model PPAs in the 2021 ERP/CEP did not have a similar default option. Mr. Bornhoffen continued to defend the default option, however, arguing that lenders appreciate these types of provisions.[383]

433. We agree with Interwest and CEI and direct Public Service to strike the default option provisions from the PPAs. At the very least, the default option increases the risk that Public Service would be incentivized to determine that an event of default under Section 12.1 has occurred. This would allow the Company to acquire the project outright instead of seeking monetary damages from the IPP. Public Service acknowledges this is a "new" provision that it did not have in the 2021 ERP/CEP Model PPA, but the Company has not established why a default option is now necessary.

434. We are unpersuaded that the risk of losing IPP resources justifies the default option. The PPAs already provide Public Service a Right of First Offer ("ROFO") in Section 19.2. More generally, if Public Service was concerned about losing the project it could allow the PPA to remain in effect but pursue any appropriate monetary damages.

6. Construction and Development Milestones

435. In addition to the events of default listed in Section 12.1, Section 12.2(A) provides that the IPP will be in default if it fails to meet the COD target date or if the project fails to achieve any Critical Path Development ("CPD") Milestones. In addition, Section 12.2(A) allows Public Service to collect liquidated damages of $250/MW of nameplate capacity for each day of delay.[384] The CPD milestones are defined in Section 4.1 and include acquisition of necessary permits, execution of all construction contracts, and closing of project financing. [385]

[383] Hr. Tr. June 17, 2025, pp. 236-38.
[384] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 36.
[385] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 9.

436. Interwest and CEI both object to the addition of CPD Milestones and the associated risk of default and liquidated damages. For instance, Interwest argues that damages should not be imposed for missing milestones, unless the milestone is the target COD. [386]

437. In Rebuttal, the Company argues that the CPD Milestones include only those milestones that if not achieved by a certain date puts the project COD in serious jeopardy. Public Service asserts knowing whether a project is sufficiently correcting the issue is imperative to the Company's near-term planning efforts. However, the Company states it would be willing to combine the milestones to be a single milestone whereby the bidder must have executed their supply contracts, obtained their construction permit, and closed on construction financing no less than 30 days following the date designated in Seller's construction schedule. [387] More generally, the Company argues that a firm and reliable construction schedule is necessary to ensure timely delivery of a project. Milestones allow the Company to identify and act when projects are behind schedule and at risk of delayed in-service. [388]

438. In Surrebuttal, CEI disagrees with the Company's concession to combine milestones and maintains that missing early milestones should not risk triggering a full default. CIE asserts that, even if eventually refunded, paying liquidated damages will impact projects security, replenishment, and potentially its financing requirements.[389]

439. We agree with Interwest and CEI and direct Public Service to remove the CPC development milestone concept from the PPAs. The PPAs set strict penalties if developers do not meet their COD. In addition, the PPAs require developer to set out several construction milestones and requires the developer to "use Commercially Reasonable Efforts to achieve the milestones set

[386] Hr. Ex. 2207, Att. JFP-2, p. 7.
[387] Hr. Ex. 120, Att.JLB-2, p. 9.
[388] Hr. Ex. 120, Att. JLB-2, p. 4.
[389] Hr. Ex. 2207, Att. JFP-2, p. 7.

forth in Exhibit B - Construction Milestones and shall notify Company promptly following achievement of each such Construction Milestone."[390] Given this existing requirement, it is unclear how the new CPD Milestones are necessary for the Company to be able to identify when a project is falling behind. In addition, the CPD Milestones concept provides for a finding of default and the imposition of liquidated damages, which a developer does not face if it fails to meet a regular construction milestone. Public Service has not established, however, how terminating the PPA or imposing significant liquidated damages for missing CPD Milestones will help the project complete construction, especially given that the penalties for missing the COD would seem to properly incentivize a developer for finishing construction on time. This concept was not included in the 2021 ERP/CEP Model PPA, and Public Service has again failed to establish why it should be a required provision in the current Model PPA.

440. While we eliminate the CPD Milestones concept, this does not alter the penalties for missing the COD. In addition, going forward we intend to hold Company-owned projects to similar standards as PPA projects both in terms of economics and timing. In other words, given there are strict consequences for IPPs if their projects fail to meet their target COD or budget, Public Service should likewise face strict consequences if utility-owned projects are delayed or over budget.

7. Exit Clauses

441. Section 12.2(D) states that failure to cure a COD Delay will be an event of default that would allow Public Service to terminate the PPA and collect a certain amount of liquidated damages:

[390] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 9.

> Failure to cure a CPD Delay or COD Delay within the applicable cure period set forth in Section 12.2(B) shall be an Event of Default by Seller. Upon such an Event of Default, Company may (i) terminate this PPA immediately upon notice to Seller, without penalty or further obligation to Seller except as to costs and balances incurred prior to the effective date of such termination, and (ii) in connection therewith, in addition to accrued Liquidated Delay Damages but in lieu of Actual Damages for the balance of the Term, collect from Seller liquidated damages therefor in the amount of [*insert $100/kW x Facility Nameplate Capacity*].[391]

442. As with the other portions of Section 12, CEI argues that this provision does not reflect the market and should be removed. CEI asserts the liquidated damages called for in other parts of the agreement should be adequate if structured correctly. [392]

443. The Company characterizes this provisions as a convenience exit in which if the developer chooses to abandon the project, the Seller must reimburse the Company and forego 50 percent of its security. The Company argues that it cannot agree to eliminating the damages associated with the provision as that would give the developer a free exit clause or rights to walk away from the contract. [393]

444. We agree with Public Service that IPPs should not be allowed to default on the PPA and walk away with little consequence. In this vein, the Company's suggestion that liquidated damages equal to 50 percent of the security deposit (in addition to costs/damages accrued prior to the termination date) is a reasonable consequence for failing to meet the COD. We note a substantially similar provision was contained in the 2021 ERP/CEP model PPA

445. To be clear, however, we do not approve Section 12.2(D) verbatim. As discussed above, Public Service must eliminate the CPD Milestones concept from the PPAs,

[391] Hr. Ex. 101, Att. JWI-3, Appendix D1, p. 37.
[392] Hr. Ex. 120, Att. JLB-2, p. 36.
[393] Hr. Ex. 120, Att. JLB-2, p. 36.

and our directive to reduce the amount of necessary security impacts the level of liquidated damages in Section 12.2(D).

446. Finally, we reiterate our intent that PPA and utility-owned projects will meet similar expectations. Given that IPPs face significant consequences if they are no longer able or willing to move forward with a project under the terms of an executed PPA, Public Service should likewise not be able to freely walk away from utility-owned projects.

8. Force Majeure

447. The PPAs provide the following definition of force majeure:

> For purposes hereof, "Force Majeure" means an event or circumstance that prevents a Party from performing its obligations under this PPA, which event or circumstance (i) was not anticipated as of the Effective Date, (ii) is not within the control of or the result of the fault or negligence or failure to follow Good Utility Practices of the Party claiming excuse, and (iii) which by exercise of due diligence and foresight could not reasonably have been avoided….[394]

448. Section 14.1 then goes on to list several items that expressly do *not* constitute force majeure. These include failure to obtain permits, supply chain disruptions, and changes to applicable law.

449. Interwest and CEI both oppose the current force majeure language. CEI, for example, notes that FM currently does not recognize change in law risks. CEI states that force majeure is a critical PPA term and should be further negotiated by the parties. Interwest argues the phrase "unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this Section 14.1" should be added to subsections 14.1(A), 14.1(C), and14.1(D).

[394] Hr. Ex. 101, Att.JWI-3, Appendix D1, pp. 42-43.

Interwest also recommends extending the time within which parties have to claim force majeure and including labor strikes or other labor disruptions in the definition of force majeure. [395]

450. In Rebuttal, Public Service largely opposes the various suggested revisions to the force majeure language, arguing that force majeure should only include only those circumstances that are truly unpredictable or unforeseeable. However, the Company does agree to modify the notice requirement to start the clock on the date when Seller "was aware or should have been aware" of the Force Majeure event, so long as the period of delayed awareness is no longer than 90 days after the date of occurrence.[396]

451. In Surrebuttal, CEI maintains that that impacts to the supply chain should constitute force majeure, reasoning that it is unrealistic in this national and global environment to attribute all of the supply chain risk to sellers. [397] CEI similarly argues that placing all change-in-law risk on Sellers is unreasonable in the current environment.

452. Similar to the exit clause concept discussed above, we agree with Public Service that the PPAs should strictly limit when a developer can be excused from performance by reason of force majeure. Nevertheless, we direct Public Service to make several modifications to the force majeure definition. First, we adopt Interwest's recommendations and add the following language to subsections 14.1(A), 14.1(C), 14.1(D): "unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this Section 14.1." We also adopt Interwest's recommendation that the period within which notice is required under Section 14.2 starts when the party becomes aware of the force majeure event not when it occurs. We deny the Company's suggestion in Rebuttal that such period of delayed awareness cannot be

[395] Hr. Ex. 2207, Att. JFP-2, p. 29.
[396] Hr. Ex. 120, Att. JLB-2, pp. 39-40.
[397] Hr. Ex. 2207, Att. JFP-2, p. 1.

longer than 90 days after the date of occurrence. In the 2021 ERP/CEP the relevant provision simply required "prompt notice." In addition, Public Service shall strike Section 14.1(L), which carves out labor strikes, slowdowns, work stoppages, or other labor disruptions from the definition of force majeure. Interwest has put forth evidence that other utility PPAs, such as PacifiCorp's 2022 RFP, include these types of events as force majeure.[398] The Company's argument that work stoppages within a developer's supply chain are the developer's responsibility is unpersuasive.

453. Moreover, we disagree with Section 14.1(H)'s exclusion of delays or failure of the transmission authority: "any delay or failure by the Transmission Authority to perform its obligations under the Interconnection Agreement or any curtailment or reduction in deliveries by the Transmission Authority."[399] Even by the Company's own standard, it is difficult to see why delays from the transmission authority (likely Public Service) would not be unpredictable or unforeseeable to a developer. This concept was not included in the force majeure definitions in the 2021 ERP/CEP PPAs.[400] The Company has failed to explain why developers should be liable under the PPA for delays and failures on the part of the transmission authority. Not only do we disagree with Section 14.1(H)'s exclusion of these types of events, we direct Public Service to modify the PPAs such that "any delay or failure by the Transmission Authority to perform its obligations under the Interconnection Agreement or any curtailment or reduction in deliveries by the Transmission Authority" expressly constitutes an event of force majeure.

454. We empathize with CEI's arguments that by excluding change in law from the definition of force majeure, the Company places the risk of future tariffs and changes in federal law on IPPs. At the same time, we are reluctant to endorse such a broad expansion of force majeure

[398] Hr. Ex. 500, Sanger Answer, p. 50.
[399] Hr. Ex. 101, Att. JWI-3, Appendix D1, p. 43.
[400] Hr. Ex. 2212, p. 142.

by including as events of force majeure changes of federal law or tariff policy. Instead, we direct Public Service to include in the revised PPAs language that would enable Sellers to avoid pre-COD default, liquidated damages, and other seller obligations if there was a Commission-recognized change in law. This language should propose a notice and comment process where parties could request a change-in-law finding or notify the Commission that the parties agree that a change in law has occurred. This process for recognizing changes in law will not include changing tariffs, which we address separately below in Section P.

9. Transfer Limitations

455. Under Section 19.3 of the Model PPA, whenever an IPP wants to sell a project after the COD but before then end of the PPA term, it must offer Public Service a Right of First Offer ("ROFO"). After notice of the ROFO, the Company has 60 days to agree to purchase the project. If the Company does not agree to purchase the project, then the IPP can sell the project to a third party, but only "on terms that a reasonable person would determine are not more favorable to such buyer than the terms offered to the Company in the ROFO Notice."[401]

456. Under Section 19.4, the IPP must give Public Service at least 90 days' notice of any Pending Facility Transaction ("PFT Notice") that does not otherwise trigger Company's ROFO rights under Section 19.3. At a high level, the PFT Notice requirement is triggered by events such as the IPP attempting to sell to its equity interests to a third party. If the IPP fails to timely provide the PFT Notice, the Company is entitled to liquidated damages in the amount of $5/kw. [402]

457. Interwest argues that ROFO or any similar provision are disfavored by developers and financers and can thus limit the pool of potential buyers and can delay sales. Interwest adds

[401] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 47.
[402] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, pp. 47-48.

that every developer is different regarding what it is willing to accept related to these ROFO provisions.[403]

458. CEI similarly opposes the ROFO provision, arguing that it is more commercially reasonable to require a right of last offer ("ROLO") as the Seller can price the project for the benefit of the Seller. CEI argues that if a ROFO is included, it should set a period of time by which parties must agree or execute any transaction. CEI adds the "not more favorable" provision in Section 19.3 is undefined and should be struck.[404]

459. In Rebuttal, Public Service argues that while the PFT and ROFO provision may not align with the IPP's business model, they align with the Company's business model to serve its customers reliably. Public Service asserts it needs to be made aware when a project is going to be sold to a third-party buyer for reliability and planning reasons. The Company states the Model PPAs in 2016 and 2021 contained PFT and ROFO terms, and IPPs were able to successfully bid in those solicitations. According to the Company, these are reasonable and practical requirements that in no way lessen the developer's opportunity to seek the highest and best offer for its project.[405]

460. In Surrebuttal, CEI maintains its opposition to the ROFO and PFT provisions.[406]

461. We find persuasive the Company's point that the ROFO and PFT provisions have been included in the Model PPA of the last two ERPs. Neither Interwest nor CEI contests this point in Surrebuttal. We thus direct that the ROFO and PFT concepts be included in the PPAs, but bidders are allowed to negotiate the details of certain modifications. Specifically, the ROFO provisions must include a period of time by which parties must agree to execute any transaction. In addition, the ROFO provision must be converted to a ROLO. Alternatively, the ROFO must

[403] Hr. Ex. 500, Sanger Answer, p. 47.
[404] Hr. Ex. 2202, Pierce Answer, pp. 54-55.
[405] Hr. Ex. 120, Att. JLB-2, pp. 34-35.
[406] Hr. Ex. 2207, Att. JFP-2, p. 31.

require the use of third-party appraisals to ensure fair valuation of the project. These modifications are responsive to CEI's concerns about the "not more favorable" language. Bidders should be allowed to negotiate the specific wording that implements these concepts.

462. Similarly, for the PFT provisions in Section 19.4, the PFT Notice concept shall be included in the PPAs, but bidders and the Company may negotiate the exact instances in which the PFT Notice requirement is triggered and whether a breach of Section 19.4 entitles the Company to liquidated damages.

463. In addition to the transfer limitations currently included in the PPAs, we direct Public Service to include in the revised PPAs an additional provision creating a ROLO to renew PPAs at the expiration of their terms. After Public Service customers have supported PPA projects over the course of the PPA term, Public Service should have an opportunity to renew the PPA rather than having the project sign a new PPA with a different utility.

10. Existing PPAs

464. Onward Energy urges the Commission to reject Public Service's plans to apply the conforming bid policy to existing PPA resources. Onward argues that when applied to existing facilities the conforming-bid policy does not provide any significant benefit to Public Service's customers and instead increases costs, transactional complications, and uncertainty. Onward asserts Public Service's model PPA is simply not structured with an existing facility in mind. Onward asserts numerous provisions in the model PPA are intended to address pre-operational risks that are inapplicable to an existing facility.[407]

465. Rather than applying the conforming bid policy to existing resources, Onward argues that such existing resources should be allowed to offer a bid based on updates to the existing

[407] Onward's SOP at p. 5.

PPA. Onward acknowledges that existing resources should be required to compete with other generation options on price and reliability metrics but maintains that Public Service should not be erecting unnecessary barriers to re-contracting with existing resources.[408]

466. In Rebuttal, the Company opposes arguments from Onward that there should be an exception to the conforming bid policy for existing PPAs. The Company acknowledges that existing resources can provide significant benefits but asserts that many of the original provisions of a pre-existing PPA may be outdated. The Company further argues that certain provisions in pre-existing PPAs, if maintained, would be unfair to the new construction bidders. For example, the Company states it is not uncommon to find lower security requirements in older PPAs, and that bidder with less security can submit lower bids. The Company asserts it is unfair to grant one bidder a more favorable term without offering the same to every bidder as a part of the RFP.[409] The Company also asserts that Onward's arguments that numerous sections or exhibits of the model PPA would require significant modifications are exaggerated.[410]

467. In its SOP, Onward asks the Commission to expressly state that Public Service is free to deviate from the model PPA terms when accepting bids from and negotiating with existing resources, where such terms either reflect an attempt to mitigate risk associated with pre-operational projects, where such terms either reflect an attempt to mitigate risk associated with pre-operational project development.[411]

468. For the reasons set forth by Onward, we reject the Company's proposal to apply the conforming bid policy to existing resources. Instead, we direct Public Service to make clear in the RFP that existing resources may use their existing PPA as a baseline for crafting their bids.

[408] Hr. Ex. 1100, Spurgeon Answer, pp. 9-10.
[409] Hr. Ex. 120, Bornhofen Rebuttal, pp. 28-29.
[410] Hr. Ex. 120, Bornhofen Rebuttal, pp. 26-27.
[411] Onward's SOP at pp. 5-6.

While IPPs of existing resources and Public Service can negotiate certain necessary updates, the baseline for such negotiations should be the existing PPA. Existing PPA resources may have unique benefits, especially in comparison to new Company-owned fossil generation, which could carry concerning stranded asset risk, which warrants a thoughtful approach to such negotiations and terms. The additional flexibility will hopefully encourage existing projects to bid into the solicitations.

O. Phase II Modeling Methodologies and Assumptions and Processes

1. Best-in-class and Phase II Modeling Updates

a. Party Positions

469. The Company proposes to keep the same best-in-class process for reducing the number of bids that proceed to computer-based modeling as was used in the 2021 ERP/CEP. The Company explains it will evaluate each technology class separately by utilizing the partial unit optimization feature of EnCompass to solve for the least-cost portfolio comprised solely of that technology class. Projects will be selected to be advanced further in this "best in class" initial selection process by determining if the model selected any partial amount of a project as part of a least-cost solution.[412]

470. In its Answer, Staff raises concerns regarding the use of the best in class process and recommends Public Service be required to notify Staff of all modeling changes/challenges encountered in Phase II, update Staff if the company decides to use the best-in-class process in Phase II, and consult with Staff should further due diligence eliminate more bids after the best-in-class process.[413] More broadly, Staff recommends that the Commission require the

[412] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 60.
[413] Hr. Ex. 2604, Abiodun Answer, p. 12.

Company to keep Staff apprised of any modeling changes after the Phase I decision is made. Staff recounts that in the 2021 ERP/CEP the Company modified the Phase II modeling in ways that were not agreed upon in the 2021 ERP/CEP USA and did so without informing the Commission.[414] In its SOP, Staff maintains its recommendations in Answer that the Company should be required to inform Staff of modeling changes between Phase I and actual Phase II modeling.[415]

471. Similar to Staff, CIEA argues the Company should be required to notify the Commission and parties if the EnCompass model will not "solve" during the bid evaluation process. CIEA recommends the Commission order Public Service to submit status reports if the bid evaluation effort encounters difficulties to ensure that the Commission and parties are aware if the bid evaluation efforts are "coming off the rails."[416] CIEA also argues for two modifications to the Company's best-in-class process to include consideration of transmission costs. The first would be to conduct partial optimization runs among projects located inside the Denver constraint, ensuring that some subset of these pass on to computer modeling. The second modification would be to sort projects not only by lowest PVRR, but also by transmission costs, so that some projects that do not have the lowest costs could still be forwarded on to computer modeling if they have lower interconnection or delivery costs.[417]

472. In Rebuttal, Public Service specifically opposes CIEA's recommendation to notify the parties and Commission if EnCompass fails to solve during the bid evaluation process. The Company states it will resolve problems and solutions in the Phase II modeling process with oversight from the IE as it has in previous ERPs. Public Service argues that, not only does it expect to avoid many of the challenges it faced during the 2021 ERP/CEP, such a notification process

[414] Hr. Ex. 2604, Abiodun Answer, pp. 5, 12.
[415] Staff's SOP at p. 18.
[416] Hr. Ex. 700, Monsen Answer, Rev. 1, pp. 82-83.
[417] CIEA's SOP at p. 29.

would slow down the Phase II process.[418] Public Service does not appear to address Staff's related suggestion or CIEA's recommended changes to the best-in-class process.

b. Findings and Conclusions

473. The best-in-class process was one of the unvetted changes Public Service made to the Phase II modeling in the 2021 ERP/CEP after the CEP Phase I Decision. While we agree with Public Service that such a process may be necessary to timely model numerous bids, eliminating bids through the best-in-class process does come with risks. We agree with CIEA's recommendations to incorporate transmission and locational considerations into the best-in-class process. Even if these additional considerations slow down the Phase II modeling, we believe this is worth the risk of suboptimal portfolio results. For example, under the current approach Public Service may evaluate all storage bids at once under the best-in-class process and thereby eliminate all but a small group of the lowest-cost storage bids. Storage bids within the Denver Metro constraint may be eliminated at this step if such bids have higher siting costs compared to storage bids farther away from the Denver area. This example demonstrates why additional guardrails and transparency in best-in-class process are appropriate.

474. Accordingly, we adopt CIEA's recommendations and direct Public Service to ensure that the best-in-class modeling process (1) includes partial optimization runs among projects located inside the Denver constraint, ensuring that some subset of these pass on to computer modeling, and (2) sorts projects not only by lowest PVRR, but also by interconnection transmission costs.

475. Regarding arguments from Staff and CIEA that Public Service should be required to provide certain modeling updates, it is important to the Commission that there is more

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[418] Hr. Ex. 118, Landrum Rebuttal, p. 72.

transparency and integrity in the Phase II modeling process. As both Staff and CIEA note, in the 2021 ERP/CEP the Company made several unvetted modeling changes after the CEP Phase I Decision. These include introducing the best-in-class process, the reliability rubric, and assertions that no portfolio could meet reliability requirements unless the portfolio included new thermal generation at specific locations.[419] These unvetted changes caused certain parties to question the validity of the Phase II modeling and allege the Company's Phase II modeling was inconsistent with the Commission's CEP Phase I Decision.

476. Learning from the CEP process, here we grant Staff's recommendations and direct Public Service to inform Staff of the following modeling updates in Phase II as they occur: (1) Modeling changes and challenges encountered between this Decision and actual modeling in Phase II; (2) the Company's modeling decisions regarding application of the best-in-class modeling to manage the pool of bids; and (3) the elimination of bids caused by due diligence after the best-in-class process. Public Service does not seem to address these recommendations, although the Company opposes similar, but more stringent, recommendations from CIEA because they may slow down the Phase II process. The Commission is also wary of slowing down the Phase II modeling but trust that Staff can appropriately discern which modeling updates and changes are necessary and appropriate and which modeling updates require party and Commission feedback.

477. In addition to Staff's recommendations, if Public Service is or becomes aware of any specific system requirements that could relate to types of generation or geographical preferences, the Company shall make that information available to all bidders immediately. If the RFP has already issued, then the Company must notify Staff immediately. We are concerned

[419] Public Service's Response Comments on the 120-Day Report, p. 29, in the 2021 ERP/CEP.

about a Phase II process in which the Company is the only bidder that understands where there is a need or preference for a certain specific resource.

478. We reject CIEA's related request to require Public Service to notify all parties and the Commission or submit status reports if the bid evaluation effort encounters difficulties. Given the numerous intervenors active in this Proceeding and the other demands on the Commission's time and resources, such a process would likely cause damaging delays.

2. Assumptions regarding Existing and Planned Thermal Units

a. Party Positions

479. In its Phase II modeling, Public Service must make certain assumptions regarding a planned CT (*i.e.*, the 200 MW Fort Lupton CT proposed as part of the 2021 ERP/CEP) as well as the Plains End unit gas-fired resource. The Company also seeks Commission approval to extend the life of Cherokee 4 from the end of 2027 to the end of 2028. According to Public Service, Cherokee 4 provides critical energy capacity, reserves, and significant system operations benefits, particularly related to reliability and relieving transmission congestion in the Denver metro area.

480. In its SOP, Staff recommends the Commission direct the Company to include the 200 MW Fort Lupton CT as part of its Phase II modeling assumptions and similarly assume that the resource acquisition of the Plains End unit is successful and reflect the longer asset life past the 2033 extension date in the Phase II modeling. Staff also recommends the Commission approve the Company's proposed delay in the retirement date of Cherokee Unit 4 from 2027 to the end of 2028.[420]

481. UCA largely mirrors Staff's recommendations and specifically requests in its SOP for the Company to include in the Phase II modeling the third CT from the CEP, the continuation

[420] Staff's SOP at pp. 17-18.

of Plains End, and the delayed retirement of Cherokee 4. Regarding Cherokee 4, UCA reiterates its recommendation that two CTs at that location would not only take advantage of the locational reliability and transmission benefits but could also help avoid the $1.8 billion Harvest Mile Chambers-Sandown-Cherokee ("HCSC") and the $379 million New Substation A at issue in Proceeding No. 24A-0560E.[421]

482. EJC recommends the Commission reject the Company's request to extend the life of Cherokee Unit 4 by one year and reject the UCA's proposals to build new gas units at the Cherokee site.[422] According to EJC, the Cherokee gas plant is located in a DI community in the north Denver area, near Elyria, Swansea, Globeville, and Commerce City. In addition to the gas plant, the Suncor oil refinery, I-25 and I-70, and several Superfund sites also pollute and harm the nearby communities. EJC asserts a 2021 Sierra Club report highlighted how the Cherokee gas plant contributes to environmental injustice. Because Cherokee Unit 4 emits large amounts of pollution into nearby DI communities, EJC asserts the Company should retire the unit as planned and not extend its life by a year. [423]

483. EJC also argues that Public Service should be prohibited from accepting gas bids for projects located in Pueblo County. EJC argues that this type of prohibition would provide equity, minimize impacts, and correct historical inequities for Pueblo. EJC suggests that developing bids for a gas plant in Pueblo would be inconsistent with the Commission's equity obligations. [424]

484. In Rebuttal, Public Service agrees with Staff's recommendations on Cherokee 4 and the new Fort Lupton CT. However, the Company disagrees regarding Plains End. The

[421] UCA's SOP at p. 23.
[422] EJC's SOP at pp. 25-26.
[423] Hr. Ex. 1700, Valdez Answer, pp. 33-35.
[424] Hr. Ex. 1700, Valdez Answer, pp. 29-30.

Company argues the extension of Plains End beyond 2033 could impact the final resource mix selected, especially units that would achieve COD in 2031. In addition, under the Phase II Framework, the extension of the Plains End unit would occur during the Supplemental RFP RAP. Public Service thus argues that the Plains End unit should compete with other bids in the JTS Supplemental RFP to ensure an optimal resource portfolio is acquired moving forward.[425]

b. Findings and Conclusions

485. We grant Staff's recommendations, which UCA mirrored, regarding the inclusion of the 200 MW Fort Lupton CT, the one-year extension of Cherokee Unit 4, and the assumption that the resource acquisition of the Plains End unit is successful and the unit continues past the 2033 extension date.

486. The only recommendation that the Company contests is the assumption that Plains End will continue. We find both of the Company's arguments to be unpersuasive. The Phase II modeling must make an assumption either way about whether Plains End remains on the system past 2033. Given the attractiveness of extending existing gas-fired units versus building new gas plants, the noted cost increases and supply issues with new CTs, and the projected need for new capacity, the best assumption is that Plains End continues past 2033.

487. Regarding delaying the retirement date of Cherokee Unit 4 from 2027 to the end of 2028, we reject EJC's request to deny the one-year life extension. The Commission acknowledges EJC's points about Cherokee Unit 4 being located in a DI community. Nevertheless, the record contains considerable evidence that, looking at a system as a whole, including potential impacts to reliability and ratepayers, extending the life of the existing plant is the best available option.[426]

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[425] Hr. Ex. 118, Landrum Rebuttal, p. 81.
[426] *See* Hr. Ex. 105, Siebenaler Direct, Rev. 1, pp. 71-78.

488. We similarly reject EJC's request to prohibit gas bids in Pueblo County. It would be premature for the Commission to determine in Phase I that DI impacts associated with any gas project in Pueblo County outweigh the potential benefits of a gas project, including helping to ensure the Pueblo community is afforded a just transition.

3. Depreciation of Gas Units, Hydrogen Conversion Costs, Etc.

a. Party Positions

489. Consistent with Phase II of the 2021 ERP/CEP, for modeling purposes the Company assumes that natural gas fired units will have a book life of 25 years. In general, the Company's Phase II modeling also requires the model to reach 100% clean energy by 2050, which assumes new gas assets will convert to hydrogen or cease operating.[427] Public Service explains that it allows the EnCompass model to build electrolyzers to produce hydrogen, store hydrogen, and build the generation and transmission required to power the electrolyzers. The model can then burn the hydrogen it produces in the thermal fleet.[428] The Company does not, however, include inputs or assumptions for hydrogen transportation. Public Service argues the need for hydrogen pipelines is outside the scope of generation planning (noting that transportation might be negligible if electrolyzers are located adjacent to thermal units). The Company further asserts estimates for hydrogen transportation costs would be too vague and would not add value to the modeling process.[429]

490. The Company encourages all thermal generation resource (*e.g.*, natural gas-fired) proposals to provide for the resource to be capable of burning, at a minimum, 30 percent hydrogen (by volume), while meeting emission permit requirements. Bidders should provide the maximum

[427] Hr. Ex. 1300, Att. CV-9.
[428] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 81
[429] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 82.

percent of hydrogen (by volume) the generator is capable of consuming while meeting emission permit requirements.

491. CEO argues that all gas-only bids in Phase II should have a useful life of no later than 2050 and for the unit depreciation timelines to reflect that retirement date. CEO asserts Public Service misinterprets the USA from the 2021 ERP/CEP when the Company argues that limiting depreciation of gas units to 2050 would shorten the time period allowed by the USA. CEO argues it is illogical to assume that all of the modeling inputs in the 2021 ERP/CEP set forth in the USA will apply equally to the JTS. Further, CEO asserts there is good cause to update the modeling assumptions because the intent was for the 25-year depreciation timeframe to align with a 2050 target, consistent with State policy goals for zero emissions by 2050.[430]

492. CEO similarly argues Public Service should be required to model the extension of existing gas units so long as they do not need to be retired due to the Colorado State Implementation Plan and to provide an analysis on which existing units with PPAs have contracts that can be extended, for how long those contracts could be extended, and whether the unit was bid into Phase II.[431] In addition, CEO recommends the Company model an annual firm gas supply cost escalator sensitivity for each resource portfolio that it develops in Phase II.[432]

493. CEO also puts forth several recommendations regarding the modeling assumptions surrounding hydrogen. CEO asks the Commission to direct Public Service to require hydrogen capable-bids and bids that will rely on carbon capture to specify information such as the year by which the unit will convert to 100 percent hydrogen, the estimated cost for completing that hydrogen conversion; the estimated cost for adding 100 percent carbon capture capability, whether

[430] CEO's SOP at p. 24.
[431] Hr. Ex. 402, Hay Cross-Answer, pp. 23-24; CEO's SOP at p. 26.
[432] Hr. Ex. 401, Ottesen Answer, p. 15.

hydrogen production would occur onsite, the estimated cost of onsite hydrogen production, and the estimated cost to procure hydrogen from another site, including infrastructure such as distribution networks or transportation.[433]

494. Regarding its hydrogen recommendations, CEO argues the Company failed to adequately address in Rebuttal or at hearing recommendations to require developers of hydrogen-capable bids to specify the estimated costs for completing hydrogen conversion, onsite hydrogen production or the cost of hydrogen infrastructure. CEO acknowledges the Company's argument that future electrolyzers may likely be located near hydrogen capable units to minimize transportation costs. CEO argues, however, that because there is no requirement for hydrogen electrolyzers to be located near hydrogen capable units in this Proceeding, assuming zero costs for hydrogen transportation is overly optimistic and could lead to the selection of bids that may ultimately prove to be more expensive than estimated. CEO makes similar arguments regarding the Company's position not to include conversion costs.[434]

495. Like CEO, WRA and SWEEP argue the depreciation lives of new gas units should be limited to 2050. Rather than rely on the assumption that plants will be able to convert to zero-emissions options, WRA and SWEEP argue the most conservative option is to assume that new gas units retire by 2050. WRA and SWEEP further assert the capacity factor of new gas units should be limited to 40 percent, consistent with current EPA power plant rules. In addition, they request that Public Service be required to model short-term life extensions to existing gas units, reasoning that extending current PPAs reduces risks of stranded assets.[435]

[433] Hr. Ex. 401, Ottesen Answer, p. 15.
[434] CEO's SOP at pp. 24-26.
[435] WRA and SWEEP's SOP at pp. 26-28.

496. To ensure that the Company is accounting for the full costs of hydrogen resources, WRA and SWEEP argue the Commission should direct the Company to include hydrogen transport and conversion costs in Phase II modeling, at a level of at least $1 per kilogram.[436]

497. Conservation Coalition similarly recommends that the Phase II modeling be required to fully depreciate the costs of each new gas bid by no later than 2050, except where a bid contains both a plan for the gas resource to be zero-emitting by 2050 and the costs of such plan are included in the modeled cost for the resources. Conservation Coalition adds that this requirement would be for Phase II modeling only; the depreciable life for ratemaking purposes would then be set in the next rate case or in a CPCN, as applicable.[437]

498. Mirroring CEO, CC4CA argues that new gas resources should have a useful life constrain of 2050.[438] CC4CA also asks the Commission to direct Public Service to present an analysis on which existing gas units with PPAs have contracts that expire during the RAP and whether they can be extended, the costs and feasibility of any upgrades that are needed to extend the lives of Company-owned units, and any existing units that are unable to be extended.[439] Finally, CC4CA asks that Public Service include information regarding projected PM2.5 emissions for each of the portfolios it presents in the 120-Day Report so that the Commission can consider any anticipated PM2.5 emission reductions and related benefits, as contemplated by SB 19-236.

499. Onward takes issue with recommendations from WRA and SWEEP to impose artificial modeling constraints on term extensions. Onward asserts that applying any sort of 10-year (or similar) limit to bids for existing gas-fired projects operating under PPAs would be

[436] WRA and SWEEP's SOP at pp. 27-28.
[437] Conservation Coalition's SOP at p. 26.
[438] CC4CA's SOP at p. 5.
[439] CC4CA's SOP at p. 7.

short-sighted and could lead to unintended consequences. For example, Onward warns that artificially constraining the term length of new PPAs would likely lead to less cost-effective bids, which could in turn make bids for new gas-fired resources look more attractive.[440]

500. In Rebuttal, Public Service opposes the recommendations to limit depreciation to 2050, arguing that it is premature to assume that the assets are unable to be useful beyond 2050. Regarding the proposed capacity factor constraint, the Company asserts that adding such constraints can significantly contribute to longer model run times, and the Company's preferred approach is to start without constraints and then go back and add and remodel with them added later only if necessary, such as seeing the capacity factors actually be above the EPA limits.

501. The Company also opposes the various recommendations regarding hydrogen assumptions in Phase II. Public Service argues that, consistent with the 2021 EPR/CEP, bidders should be required to provide as much information as possible about clean-fuels combustion capability in their bids. The Company asserts, however, that future conversion and supply estimates provided by hydrogen-capable bids must be treated as informational only. The Company opposes requiring bidders to provide such estimates in order to bid. On the other hand, Public Service confirms that any bid proposing to combust hydrogen at COD within the RAP or produce hydrogen within the RAP should clearly outline assumptions and costs related to hydrogen production and transportation. [441]

502. Regarding the extension of existing gas-powered units, the Company argues that after accounting for Cherokee 4, which cannot be extended beyond 2028, and those units that are dependent on 2021 ERP/CEP resources, there is such a small amount of potential capacity that the

[440] Onward's SOP at p. 7.
[441] Hr. Ex. 118, Landrum Rebuttal, p. 77.

impact of an extension would likely be minimal. Additionally, Public Service asserts that a directive to force gas units to re-bid is completely inappropriate without detailed testimony regarding the feasibility and costs of such extensions.[442]

b. Findings and Conclusions

503. Starting with the assumed life of new gas plants, we direct that the Phase II modeling assume that new gas-fired units will have a maximum book life of 22 years. This is shorter than the period proposed by Public Service and reflects the legitimate concerns of intervenors such as CEO, Conservation Coalition, CC4CA, and WRA and SWEEP that gas plants will become stranded assets after 2050 given the state's zero emissions goal. At the same time, we decline to adopt a cutoff of 2050 as these intervenors request. With a 2050 cutoff, a thermal unit acquired in 2030 will appear less expensive in the Phase II modeling than the same thermal unit acquired in 2032. This might unintentionally result in the model selecting more thermal generation earlier in the RAP.

504. Any gas plants the model retains after this 22-year period must assume the generic hydrogen conversion costs set forth in Section 2.11 of the Company's Volume 2 (technical appendix).[443] This modeling restriction shall not apply to gas units within the business as usual portfolio. This portfolio does not include the 100 percent by 2050 emissions constraint. To be clear, the 22-year modeling constraint is only for purposes of Phase II modeling. It would be inappropriate in this ERP proceeding to set the depreciable life of new gas units for ratemaking purposes.

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[442] Hr. Ex. 118, Landrum Rebuttal, p. 75.
[443] Hr. Ex. 102, Landrum Direct, Rev. 1, pp. 80-83.

505. Regarding hydrogen conversion costs, we share concerns of CEO and WRA and SWEEP that the Company's current assumptions may not fully capture the full costs of converting the Company's gas fleet so that it can burn 100 percent hydrogen. Nevertheless, we agree with Public Service's position that developers should not be mandated to include hydrogen conversion costs for any gas project bid into the JTS. Requiring developers to estimate how much it would cost to convert a gas CT to burn 100 percent hydrogen in 2050 could discourage PPA gas bids and result in widely varying and unreliable estimates. Consistent with the Company's position, estimates provided by hydrogen-capable bids should be treated as informational only, and bidders should not be required to provide estimates in order to bid. On the other hand, any bid that is proposing to combust hydrogen at COD within the RAP or produce hydrogen within the RAP must clearly outline assumptions and costs related to hydrogen production and transportation.

506. While we adopt the Company's proposal regarding hydrogen conversion assumptions, we are unconvinced these assumptions capture the full costs of converting the Company's gas fleet to 100 percent hydrogen. The Commission continues to see considerable risk that new-build Company-owned gas facilities may become stranded as the state transitions to a zero emissions system. This risk underlies our other determinations regarding Company-owned gas units, including our directive that Public Service model a Phase II portfolio that contains no Company-owned new-build gas units.

507. Consistent with requests from CEO and CC4CA, Public Service shall present an analysis in the 120-Day Report that evaluates (1) which existing PPA gas units have contracts that expire during the RAP and whether they can be extended and for how long; (2) the costs and feasibility of any upgrades that are needed to extend the lives of Company-owned units; and (3) information about any existing units, whether IPP or Company-owned, that are not able to be

extended. This requirement is appropriate in light of the Company's failure to include a discussion of the Plains End PPA extension in Phase II of the 2021 ERP/CEP and is similar to the Company's commitment in the 2021 ERP/CEP USA to rebid any existing gas units that are scheduled for retirement in the RAP so long as the retirement is not required pursuant to the Colorado State Implementation Plan and the unit can reasonably be expected to perform in a manner that balances the Company's system. We acknowledge, however, the Company's point that the amount of capacity that could potentially be extended appears to be small.

508. We reject various recommendations that the Company should be required to model the extension of existing gas units. There could be instances in which a PPA does not submit a bid to extend a gas unit or the Company is unable to extend the life of an existing Company-owned gas unit.

509. We reject WRA and SWEEP's recommendation to limit the capacity factor of new gas units to 40 percent, consistent with current EPA power plant rules. Such a constraint may have unintended consequences in the modeling, such as acquiring more gas units that are used less frequently. Further, there is a significant concern that current EPA power plant rules may change. We further reject CC4CA's request that Public Service include information regarding projected PM2.5 emissions for each of the portfolios in the 120-Day Report. The general knowledge that gas plants emit pollutants, including particulates, is uncontested and will be considered by the Commission in our Phase II evaluation, but a detailed analysis of the impacts of specific types of pollutants is better left to the Colorado Air Quality Control Commission when it evaluates the required air permits.

510. We grant CEO's request to require the Company to model an annual firm gas supply cost escalator. Rather than requiring this sensitivity for each resource portfolio, however,

the Company only needs to model the sensitivity on its preferred portfolio. This limitation should again limit Phase II modeling burdens and help eliminate delays. In its Supplemental Direct, Public Service explains that the current firm gas cost assumption for a generic CT is $21.14/kW-yr, remaining flat throughout the analysis. For the sensitivity, the Company shall use an escalator at the generic inflation rate of 2.5 percent instead of keeping the firm gas cost constant, consistent with the Company's proposal in Supplemental Direct.[444]

511. We find this additional sensitivity modeling starts to address our concern that, given the State's goal of reducing local gas distribution utility emissions from the distribution and end-use of gas, retail sales of natural gas may decline going forward. This could result in large firm customers like gas-fired plants bearing a higher percentage of system costs. The higher cost associated with maintaining gas infrastructure that fewer customers need is not represented in the modeling. The firm gas supply cost escalator sensitivity we establish through this Decision starts to address this issue, but we encourage parties in the 2028 ERP to evaluate and propose more robust methods for recognizing this risk.

512. Relatedly, we are concerned the bid prices for new gas-fired facilities fail to include the costs of the gas infrastructure necessary to supply the new facilities. Required upgrades to the natural gas system are real costs of new gas-fired facilities. Accordingly, Public Service shall evaluate whether bids for new gas-fired facilities will require upgrades to the natural gas system over the planning horizon for that utility. We likewise encourage parties in the 2028 ERP to evaluate and propose more robust methods for including the costs of any necessary upgrades to the natural gas system.

[444] Hr. Ex. 111, Landrum Supplemental, p. 38.

4. Generic Prices

a. Party Positions

513. In Rebuttal, Public Service raises the concern that the generic prices proposed in Phase I are significantly below current market expectations and current activities in Congress present significant risk in future project pricing, especially around tax credit opportunities. Based on current ongoing RFP prices in other Xcel Energy jurisdictions, the cost pressures seen in Proceeding 21A-0141E, and the Company's current experience with 2021 ERP/CEP projects, Public Service argues the Phase I generics are significantly below market prices, in some cases maybe as much as half the reasonable expectation for JTS bid prices. The Company recommends using the revised generic prices for Phase II it included in its Rebuttal. [445]

514. The Company also proposes a mechanism in Phase II to automatically adjust generic pricing based on the actual pricing of the bids. If the median bid pricing analysis presented to the Commission in the 30-day Report is more than 20 percent higher or lower than the generic pricing for a given technology, the Company recommends adjusting the generics to have the 2030 generic price, by technology, match the median bid price and then escalate into the future using the price escalation curve of these new generics. The Company would then re-run the locked tails with the updated pricing.[446]

515. Staff opposes the Company's proposal to update generic pricing. Staff asserts the proposed method is not transparent, verifiable, or an appropriate basis for price updates that would apply in the post-RAP period. Instead of the Company's proposal, Staff argues the Commission should order the Company to use public and verifiable sources such as the Lazard Levelized Cost

[445] Hr. Ex. 118, Landrum Rebuttal, p. 69.
[446] Hr. Ex. 118, Landrum Rebuttal, p. 69.

of Energy Study or the National Renewable Energy Laboratory Annual Technology Baseline for its generic pricing assumptions. Staff reasons these types of public sources are driven by long-term trends and are less impacted by year-over-year volatility.[447]

516. Staff also requests the Company be required to confer with Staff and the IE to discuss the appropriate update for all generic pricing prior to the Phase II modeling. Staff notes this would be similar to the process that the Company followed in the last ERP.

b. Findings and Conclusions

517. We approve the Company's proposed mechanism to automatically adjust generic pricing based on the actual pricing of the bids. While we agree with Staff that using public and verifiable sources such as the Lazard Levelized Cost of Energy Study is generally preferable, such sources may not capture the recent impacts to pricing caused by federal legislative changes and tariff uncertainty. Given the dynamic, uncertain environment, we are concerned that looking at the long-term trends presented by public sources could underplay or ignore recent developments.

518. While we disagree with Staff's primary recommendation, we grant its second request and direct Public Service to confer with Staff and the IE to discuss the appropriate update for all generic pricing prior to the Phase II modeling. To be clear, while we welcome Staff's conferral and observation, we adopt the Company's proposed mechanism to base generic pricing on the bids received in the RFP.

5. Modeled Production Costs for Existing Resources

519. In its Answer, Staff notes that Public Service's cost assumptions for its resources may form the basis for future performance evaluation and thus the Company should be required conduct resource planning with reasonably accurate cost projections. Staff put forth analysis,

[447] Staff's SOP at pp. 16-17.

however, showing that the Company's cost assumptions for many existing resources raise many questions. Staff recommended that Public Service explain in Rebuttal the discrepancies observed between modeled future production costs and past reported costs for certain generation resources. Staff warned that if Public Service's Rebuttal leaves cost deviations inadequately explained, the Commission should consider ordering an independent investigation and audit of the Company's processes for developing cost assumptions for resource planning.[448]

520. In its SOP, Staff notes the Company provided no additional information in Rebuttal to explain the significant discrepancies Staff identified between the modeled production costs for existing resources and the costs reported in historical filings with this Commission and the Federal Energy Regulatory Commission.

521. Accordingly, Staff asks the Commission to order an independent review of the Company's processes for developing modeling cost assumptions for existing resources. As an alternative to an immediate investigation, Staff suggests the Commission could require the Company to file a benchmark comparison of its existing resources' historic and future modeled costs in future Phase I ERP filings, similar to the benchmarking analysis provided in Staff's answer testimony. Staff argues the Commission should also require the Company, as part of future ERP proceedings, to identify and explain any material discrepancies between historic and future modeled costs to enable the Commission and parties to review and question the reasonableness of modeled cost assumptions.[449]

522. We agree with Staff and order an independent review of the Company's processes for developing modeling cost assumptions for existing resources. The performance assumptions

[448] Hr. Ex. 2600, Dahlke Answer, p. 78.
[449] Staff's SOP at pp. 36-37.

for Company-owned facilities can have far-reaching impacts, and Staff's assertions that there are significant discrepancies between the current assumptions and those that the Company reported elsewhere are troubling.

523. To initiate this independent review, we direct Staff and Public Service to confer and file a notice in this Proceeding no later than December 31, 2025, detailing the results of the conferral. This should include whether the independent review will take place via an M-docket, I-docket, standalone application, or some other procedural path.

P. Miscellaneous Resource Acquisitions Issues

1. Short List and Best-and-Final Offer

a. Party Positions

524. CIEA urges the Commission adopt a best-and-final-offer ("BAFO") process in Phase II that would allow a subset of bids to refresh their prices. More specifically, CIEA argues that the size of the solicitations, the inflationary environment, and the delays witnessed in the 2021 ERP/CEP justify a new approach in which the bids in the approved portfolio plus the incremental need pool bids (the short list) are allowed a 10 percent price refresh opportunity after the Phase II decision (the BAFO). Public Service would re-rank the projects based on the updated pricing, which CIEA argues would retain competitive tension and increase the chances that the final portfolio would succeed. The Company would then provide a Notice of Final Portfolio and offer the remaining Short List bids the option to join the incremental need pool.

525. To justify the need for the new process, CIEA notes the Phase II process in the 2021 ERP/CEP took 13 months. CIEA asserts that bids that are submitted in Q1 2026 for the JTS RFP have at least the same, if not an increased risk, as in the 2021 ERP/CEP of holding their price for more than a year from the Phase II process. CIEA argues that the BAFO should be adopted given

that the uncertainties in the generation and transmission market globally will make holding prices from Q1 2026 into Q2 2027 difficult if not impossible for both utility and IPP bidders. CIEA asserts other Western utilities have implemented a Short List/BAFO process, so this is not a novel concept.[450]

526. CIEA draws a comparison to the incremental need pool process in which the pool of backup bids are allowed a limited price refresh. CIEA asserts it is illogical that backup bids in the incremental need pool are allowed to reprice but the initial winning bids do not.

527. Interwest also supports the BAFO concept. Similar to CIEA, Interwest asserts cost drivers for all types of generation are rapidly changing. Given the uncertain economic and federal landscape, Interwest argues it is unreasonable to expect a bidder to hold a bid price for any extended period without a BAFO pricing refresh.[451]

b. Findings and Conclusions

528. We reject the BAFO proposal for purposes of this JTS. It is unclear whether there would be sufficient competitive tension during the "final offer" price refresh to prevent gaming. If bidders knew that they would have a 10 percent price increase opportunity after being selected, this might encourage unreasonably low prices in the initial bid. In addition, it is far from certain that the unexpected cost increases and delays that occurred in the 2021 ERP/CEP will repeat in the JTS. While cost pressures have increased since the 2021 ERP/CEP, bidders may be less surprised by such cost pressures and might better be able to accurately incorporate them into their bid prices. Our decisions to adopt a modified version of Staff's tariff passthrough mechanism and incorporate change in law language into the PPAs will help address future uncertainty.

[450] CIEA's SOP at pp. 31-32.
[451] Interwest's SOP at pp. 6-7.

529. Moreover, the modified Phase II Framework and its incremental need pool concept that we adopt already allows a limited price refresh for backup bids. This is directionally consistent with CIEA's BAFO proposal and is a good next step in evolving Colorado's ERP process. Despite CIEA's arguments, it is appropriate for winning bidders to be ineligible for the price refresh opportunity that incremental need pool bids have. Unlike incremental need pool bids, which must wait for a project failure or a material increase in load, winning bids have the opportunity to sign PPAs and begin development shortly after the Phase II Decision.

530. In addition, the BAFO process may not alleviate the risk of delays and project failures. Although the Phase II Decision in the 2021 ERP/CEP took longer than anticipated, the delays experienced in the PPA negotiations were also problematic. CIEA's BAFO proposal ignores this issue. Simply put, even after the price refresh, re-ranking process, and notice of final portfolio, there is no guarantee that the selected projects would be able to quickly sign PPAs and move forward with project development. Thus, the risk of delays and project failures persists.

531. Nevertheless, the Commission is intrigued about the BAFO concept and direct Public Service to confer with CIEA prior to the 2028 ERP about a modified BAFO approach. Specifically, the conferral should examine whether PPA execution could be a component of the BAFO process (*e.g.*, only those projects that execute a contingent PPA would be eligible for the price refresh opportunity). Public Service shall address this concept as part of its direct case in the 2028 ERP.

2. Bid Fees

a. Party Positions

532. Public Service does not propose increasing the bid fees from what was required in the 2021 ERP/CEP but recommends removing most of the options for bidding multiple variations

of a project under a single bid fee. The Company asserts this will help reduce the administrative burden of managing the complexity of multiple options.[452] The Company has maintained two single bid fee options related to backup fuel and the prospective MVLE transmission line segment of the Colorado Power Pathway.[453] In addition, any bid selected to begin PPA negotiation is also required to pay a Second Bid Fee of $1/kW (*e.g.*, 100 MW Project * $1/kW = $100,000) to the Company prior to commencement of negotiations. Upon execution of a PPA the Second Bid Fee is refunded to the bidder. Under the Company's proposal, however, if the bidder and the Company fail to execute a PPA due in part to the bidder's actions that do not reflect bidder's representations or commitments during the RFP bidding process, the Company can retain the Second Bid Fee.[454]

533. Interwest argues that bid fees should not be required for the following variations: (1) CODs, (2) capacity sizes, (3) commercial structures, or (4) tenors (*i.e.*, allow variation of the PPA term and COD; and allow capacity size variations that do not require varying specifications for the collection substation, generator tie-line, or any other generator interconnection information).[455] Interwest characterizes the Company's proposal as "overly aggressive" and argues that it will lead to fewer bids and higher costs. Interwest argues that bidders are not in a good position to evaluate the benefits of variations for the Company and are left to utilize imprecise analysis to select what they think Public Service will find to be the most attractive and cost effective options.[456]

534. Interwest also opposes the Company's plan to impose a second bid fee to negotiate with the utility, which is refundable if PPA is executed. Interwest argues bidders should not be

[452] Hr. Ex. 102, Landrum Direct, pp. 55.
[453] Hr. Ex. 111, Landrum Supplemental, pp. 17-18; Hr. Ex. 101, Att. JWI-2 Vol. 2, Rev. 2, p. 214.
[454] Hr. Ex. 101, Att. JWI-2 Vol. 2, Rev. 2, p. 214.
[455] Hr. Ex. 501, Wilson Answer, p. 7.
[456] Interwest's SOP at p. 6.

required to pay this second bid fee.[457] Interwest asserts there is nothing in the record to indicate that these bid fees after selection are designed to cover RFP administrative costs or have any other legitimate basis.[458]

535. Conversely, CIEA seems to agree with Public Service that the large number of bid variations (especially compared to the actual number of projects) contributed to the modeling issues and delays in the 2021 ERP/CEP. CIEA reasons that limiting bid variations makes sense based on what Public Service can reasonably model. CIEA recommends that bid variations allowed under the same bid fee be limited to variations of the project connecting to the MVLE (if a CPCN is filed in time) and a Company-owned option in addition to a PPA bid. CIEA recommends establishing a per project bid limit of 10, and prohibiting variations for free curtailment, energy-only hybrid PPA pricing, and levelized versus fixed cost pricing.[459]

536. In Pivot's SOP, it recommends the Commission should (1) direct the Company to eliminate its proposed second bid fee; and (2) direct Public Service to charge a bid fee of $750 for projects sized between 100 kW and 2 MW.[460]

b. Findings and Conclusions

537. We adopt the bid fees put forth by Public Service,[461] including the second refundable bid fee for projects that begin PPA negotiations. Public Service has raised legitimate

[457] Hr. Ex. 500, Sanger Answer, p. 15-16.
[458] Interwest's SOP at p. 6.
[459] Hr. Ex. 700, Monsen Answer, Rev. 3, pp. 13; CIEA's SOP at p. 10.
[460] Pivot's SOP at p. 18.
[461] On September 24, 2025, Public Service, Staff, CEO, and UCA ("Joint Movants") made a filing in Proceeding No. 21A-0141E that pertains to the bid fees required in the JTS base RFP. In that filing, the Joint Movants propose discounting the JTS bid fees for certain bids that were also submitted into the Near-Term Procurement ("NTP") RFP process in Proceeding No. 21A-0141E. Specifically, for developers with bids in the NTP that are not ultimately selected as part of the NTP, and who then submit bids into the JTS Base RFP, the $2,000 NTP bid evaluation fee for each non-selected NTP bid will be treated as a credit and allowed to offset the associated JTS bid evaluation fees. Our decisions in this JTS Proceeding regarding bid fees in no way alter the Joint Movants' proposal to discount JTS bids that were also bid into the NTP.

concerns, echoed by CIEA, that evaluating numerous variations of the same projects increases complexity and the risk of delays in the Phase II modeling. Other than variations regarding the MVLE and backup fuel for thermal bids, developers shall be required to put forward their best bid or pay a second bid fee. The Commission likewise supports the Company's second bid fee for projects that begin PPA negotiation. This second fee both reflects the additional resources the Company expends negotiating PPAs and hopefully further incentivizes developers to quickly come to an agreement.

538. There is insufficient record to determine that the level of bid fees, including for small projects, is too high, especially because the Company has not increased the fees since the 2021 ERP/CEP.

3. RFP Requirements

a. Party Positions

539. Interwest recommends several specific changes to the RFP, which sets forth the rules with which bidders must comply to have their bid evaluated. Interwest first opposes the RFP's prohibition on out of state company ownership bids. Interwest argues that the most cost-effective bids should win, regardless of where they are located. Interest's second challenge is to the 15-year maximum term for hybrid PPA projects, such as solar plus storage resources. Interwest argues that the term-limit on hybrid projects should match 25-year limit on other PPAs or should at least match the 18-year limit from the 2021 ERP/CEP's RFP. Interwest's third objection concerns the RFP's exclusivity requirement. Interwest argues that developers should be able to bid the same project into multiple RFPs or otherwise sell a project that has been bid. In addition, Interwest notes that, based on discovery, Public Service plans to set the due date for Company-owned bids one day

before PPA bids. Interwest supports this plan and states it is important that Company-owned bids not be allowed to come in after PPA bids.[462]

540. Finally, Interwest argues that the non-price scoring analysis in the RFP is vague and subjective. Interwest recommends the Company develop a detailed non-price scoring matrix in this RFP so that bidders are able to self-score and design their bids according to what the Company expects. CIEA similarly offers a recommendation regarding the non-price factor analysis. CIEA argues the bidder qualifications should be prioritized over other non-price factors to increase viability of bids.[463]

b. Findings and Conclusions

541. We grant Interwest's first request regarding out-of-state Company ownership bids and direct the Company to remove this prohibition from the RFP. We find persuasive Interwest's arguments that the most cost-effective bids should win. At the same time, however, we reiterate that the Company retains discretion with its development and submission of Company-owned bids.

542. We also grant Interwest's second request to remove the 15-year maximum term for hybrid projects. In the 2021 ERP/CEP, there was considerable adjudication over the treatment of hybrid resources such as solar plus storage. Public Service raised concerns that, without certain restrictions, hybrid resources could be viewed as finance leases. IPP interests raised concerns about the lack of capacity payments and unnecessarily short-term limits. In the Phase I RRR Decision, the Commission found that allowing hybrid projects to receive capacity payments but limiting the term length of the storage component to 18 years "strikes an appropriate balance between addressing the finance lease concern and allowing IPP solar plus storage bids to be more

[462] Hr. Ex. 500, Sanger Answer, pp. 8-14.
[463] CIEA's SOP at p. 10.

competitive."[464] We are unclear why Public Service shortened the term length for hybrid projects to 15 years in this JTS Proceeding.[465] Regardless, we adopt the approach from the 2021 ERP/CEP and allow hybrid projects to receive capacity payments but limit the term length of the storage component to 18 years.

543. We reject Interwest's third proposed modification to the exclusivity requirement. The Company, parties, and the Commission should not spend time evaluating bids that are not fully committed. Allowing bids to leave the solicitation process if they receive a better offer in a separate solicitation could increase the difficulty of bid evaluation and selection. In addition, the exclusivity requirement to which Interwest objects was also present in the 2021 ERP/CEP.[466] This requirement did not seem to unduly restrict bidders in the 2021 ERP/CEP.

544. As for the Company's plan to set the due date for Company-owned bids one day before PPA bids, we agree with Interwest about the importance of this deadline. Instead of letting this simply be the plan for the deadline, we clarify that all Company-owned bids shall be submitted one day prior to the deadline for PPA bids.

545. Regarding the non-price scoring analysis, consistent with Interwest's recommendation, Public Service shall develop and make available to bidders a detailed non-price scoring matrix in this RFP so that bidders are able to self-score and design their bids according to what the Company expects. Given that the Company already has (or is at least developing) some way to apply the non-price scoring to bids, it is reasonable to provide this plan to bidders beforehand. Providing this scoring matrix to bidders significantly increases transparency. Moreover, to further increase transparency, Public Service shall notify Staff any time a bid fails

[464] Decision No. C22-0559 at ¶ 44 issued in the 2021 ERP/CEP (Sept. 21, 2022).
[465] *See* Hr. Ex. 101, Att. JWI-3, Vol. 3, Rev. 1, p. 16.
[466] Hr. Ex. 101, Att. AKJ-3.2-1, p. 18 in the 2021 ERP/CEP.

the non-price factor analysis. The notification to Staff must include a detailed description of why the bid should not be advanced to computer-based modeling. Staff can raise any concerns it has with the Commission, at its discretion. We reject CIEA's related request to prioritize bidder qualifications. We are unconvinced that such an approach is an appropriate way to increase the viability of bids in the approved portfolio.

546. Going forward, in the 2028 ERP, Public Service shall present its proposed non-price scoring matrix as part of its direct case for parties to evaluate during the course of the proceeding. As part of this non-price scoring matrix, the Company shall propose as an additional consideration of whether a developer has backed out of an approved bid in the JTS. If a bid is selected as part of the JTS bid evaluation and selection process but the developer subsequently withdraws the bid, the developer's bids may be viewed less favorably in the 2028 ERP.

4. Solar Regulating Reserve Penalty

a. Party Positions

547. In its Direct, the Company proposed a Solar Regulating Reserve ("SRR") penalty of $8/kW-year for solar projects located within a 37-mile radius of Pueblo to account for increased regulation costs associated with high ramp rates of the concentration of solar facilities in the area. Solar bids proposing to locate in the area would also be ineligible for the just transition modeling credits. To conduct its SRR analysis, the Company developed a regression model using five-minute 2022 plane-of-array ("POA") irradiance at the Neptune solar plant outside of Pueblo to predict the plant's measured 2022 AC generation. It then used this model to convert irradiance data at other locations to generation estimates for not-yet-built solar generators by scaling the resulting generation to match the AC installed capacity of the new solar generators.

548. The Company used this method to develop generation profiles for two 1-GW solar portfolios. One portfolio was composed of four bids from the 2021 ERP located in the Pueblo area; the other portfolio was composed of two existing and two fictional solar plants located in the Craig and Keenesburg areas. Where the Company did not have POA irradiance data (from existing plants) it used location-specific solar data obtained from NREL. Using the Neptune regression model and the local solar data, the Company generated five-minute generation estimates for each of the unbuilt solar plants, which, together with the measured data from the operational plants, were aggregated into annual Pueblo-area and non-Pueblo-area one GW generation profiles with five -minute resolution. These profiles were then added to the 2028 net load profile. The Company then used these data sets to identify the largest 15-minute up and down ramp rates throughout the year. From this, the Company determined that an incremental one GW of solar in the Pueblo area would require 691 GWh of regulation reserve more than an incremental one GW of solar located in areas distant from Pueblo. Finally, the Company applied the average of regulating reserve costs per MWh from MISO, SPP and CAISO to the 691 GWh difference, and calculated that the additional regulating reserve cost for solar in the Pueblo area amounted to $7.68/kW-year, which it proposes to round up to the $8/kW-year penalty for Pueblo-area solar.[467]

549. In its Answer, CEI alleges a fundamental flaw in the Company's analysis that resulted in the proposed value of the penalty.[468] In Rebuttal, the Company agrees with CEI and proposes a revised penalty of $2.59/kW-year based on the CEI corrections. However, the Company contests all other arguments posed by CEI and other parties. Among these were that the SRR penalty is unnecessary because even relatively minor geographic distances between solar resources

[467] Hr. Ex. 102, Att. JTL-2.
[468] Hr. Ex. 2200, Lucas Answer, pp. 36-46.

create substantial diversity in the timing of ramps due to passing clouds;[469] that the Company failed to make a parallel analysis of wind ramp rates;[470] that there are no incremental regulation costs because the Company already owns or will own sufficient regulating capacity;[471] that solar + storage resources can inherently limit their ramp rates and so should not be subject to the penalty and remain eligible for the Just Transition credit; and that the Company's use of regulation costs from three ISOs to estimate its incremental regulation costs was improper or inaccurately applied.[472]

550. Interwest notes the Company's agreement during the hearing that both storage and gas facilities provide regulating reserves, and that these resources are likely to be added to the system in and around Pueblo. Interwest contends that as a result, the system around Pueblo may be materially different after a Phase II portfolio is approved, so excluding solar from the just transition modeling credits and applying the SRR penalty are unwarranted. Instead, Interwest recommends the Commission require the Company to select resources in and around Pueblo that achieve the necessary reliability and operational requirements when taken in conjunction with each other and the current system. Interwest argues that pre-determining a reasonable quantity of each resource type without knowing what other resources will be added is unreasonable, particularly since some resources in the portfolio could diminish the need for regulating reserves.[473]

551. In addition to citing the flaws described by CEI, EJC contends the SRR Study was flawed in that it ignored how pairing solar with storage could address the ramping needs alleged by the Company. EJC contends further the SRR penalty would discourage construction of clean

[469] Hr. Ex. 2200, Lucas Answer, pp. 46-50.
[470] Hr. Ex. 2200, Lucas Answer, pp. 54-57.
[471] Hr. Ex. 2200, Lucas Answer, pp. 63-64.
[472] Hr. Ex. 2200, Lucas Answer, pp. 57-60.
[473] Interwest's SOP at pp. 11-12.

resources in the Pueblo area, which would be contrary to the Commission's equity obligation to prioritize benefits to DI communities. EJC argues this is particularly troubling given the modeling credits for gas plants to locate in Pueblo. EJC recommends that the Commission reject the SRR penalty and require that solar bids in the Pueblo area be eligible for the just transition modeling credits.[474]

552. In Rebuttal, the Company proposes applying the SRR penalty of $2.59/kW-year to solar bids within 37 miles of Pueblo and excluding such bids from eligibility for the just transition modeling credits.

b. Findings and Conclusions

553. We find the intervenor arguments against the SRR penalty to be valid. It is inaccurate not to incorporate the impact of wind resources when assessing the need for regulating reserves. CEI's criticisms of the way in which the Company estimate the cost of regulating reserves appear well founded. EJC is correct that the Company's proposed penalty has no exemption for combined solar + storage resources that have the inherent capacity to limit ramp rate. The SRR penalty would discourage emission-free generation in an area that has a high concentration of DI communities, while the just transition modeling credits would encourage siting gas-fired generation there. And Interwest's point that it is premature to judge the need for regulating reserves when the approved portfolio may include gas and storage resources in the Pueblo area that can provide this service is also well taken. Additionally, we note CEI's point that even limited geographic diversity of multiple solar resources will attenuate their aggregate ramp rate, as it takes time for clouds to move from one array to another.

[474] EJC's SOP at pp. 11-13.

554. Accordingly, we find the proposed SRR penalty is neither conceptually well-founded nor methodologically accurate and so reject both the SRR penalty and the Company's proposal to exclude solar resources in the Pueblo area from eligibility for the just transition modeling credits.

5. Curtailment of PTC-Qualified Facilities

a. Party Positions

555. In its Direct, Public Service initially proposed to discontinue reimbursing IPPs for lost PTCs due to compensable curtailments. Public Service made the same proposal in the 2021 ERP/CEP, but in the USA the Company ultimately agreed to reverse course and allow for compensable curtailment (*i.e.*, bidders are reimbursed for lost PTCs due to compensable curtailments). Although the Company maintained its Direct position in Rebuttal, Public Service argued in the alternative that if the Commission continues compensation for compensable curtailments the Commission should expressly allow the Company to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate and regardless of whether the project is a UOG project or IPP owned. [475]

556. During the hearing, the Company reversed course and offered to continue reimbursing IPPs for lost PTCs due to compensable curtailments. Public Service reiterated its request, however, that the Company be allowed to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate.[476]

557. The IPP interests such as CIEA and Interwest agree with the Company's most recent proposal to continue compensating for compensable curtailments. CIEA, however, argues

[475] Hr. Ex. 120, Bornhofen Rebuttal, p. 37.
[476] *See* Hr. Tr. June 17, 2025, pp. 252-55.

the Commission should reject the Company's related request to allow the Company to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate. Instead, CIEA argues that the model PPA curtailment language in the 2021 ERP/CEP that was agreed upon in the USA should be maintained.

558. CIEA argues the Company has failed to meet its burden of showing why the PPA should be modified to allow curtailments regardless of individual tax rates. CIEA argues there is "scant" information in the record on this point and characterizes Public Service's proposed modification as "a last-minute change." CIEA states:

> Public Service offered one question and answer to this proposal in its pre-filed testimony. Public Service at hearing could not explain what the tax rate selected would be, and its witness explained that he was not an expert in the tax issues for which he was the sole Company witness discussing.[477]

b. Findings and Conclusions

559. The Commission expressly approves the language in the 2021 ERP/CEP that was agreed upon in the USA regarding compensable curtailments. In addition, the Commission rejects the Company's request to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate.[478] The Commission agrees with CIEA that the Company failed to put forth sufficient evidence to justify modifying how the Company currently curtails PTC-eligible projects. Public Service did not make this request is Direct. No parties filed Answer testimony on it. The testimony in Rebuttal and at hearing is sparse and leave many questions unanswered.

560. For instance, the Company has argued that the monetary impact is relatively small per year for an individual project. The Company has not, however, explained how much money

[477] CIEA's SOP at p. 36.

[478] Chair Blank dissents and would grant the Company's request to curtail PTC-qualified facilities on an equal basis.

this change would likely cost ratepayers in the aggregate (*i.e.*, throughout the Company's system and over the entire period in which projects are eligible for PTCs). The Company has also provided little information about why the current approach for curtailments must be changed. The Company references a desire to curtail projects equitably. If certain projects cost more money to curtail than other projects, however, it seems appropriate to reflect this cost difference in the Company's curtailment decisions.

6. Tariff Passthrough

a. Party Positions

561. In its Answer, CIEA argues that a project bidding in 2026 would be "throwing darts at a board" as to tariffs on equipment delivered in 2029 or 2030.[479] CIEA notes it is possible that tariffs in place during the RFP will be lifted when equipment is received in 2029 or 2030, potentially resulting in a windfall for the developer. CIEA recommended the Commission allow limited repricing for all projects or pass-through via the ECA of the actual costs of any tariffs incurred.

562. In Rebuttal, Public Service expresses openness to a modified version of CIEA's proposal. The Company states it is evaluating an approach where bidders provide anticipated supply chain/country of origin(s) for critical components, quantifying these assumptions as part of their bid packages.[480]

563. In Cross Answer, Staff opposes CIEA's specific approach to pass through tariff-based costs but puts forth a modified approach to accomplish the same result. Staff opposes CIEA's approach because removing all tariff risk from bid pricing could result in poor decisions in the face

[479] Hr. Ex. 700, Monsen Answer, Rev. 1, pp. 98-99.
[480] Hr. Ex. 117, Ihle Rebuttal, p. 61; Hr. Ex. 120, Bornhofen Rebuttal, pp. 24-25.

of tariff risks that could be avoided or hedged. For example, Staff argues the model may over select a resource that is highly susceptible to future tariff costs instead of less risky resources.[481]

564. Under Staff's proposed tariff mechanism, bidders would be required to separate bid prices into two components: a base project cost and a current and known tariff estimate ("CKTE"). Bidders would support their CKTE by submitting a sourcing plan. The IE and Public Service would flag any questionable or incomplete CKTEs and sourcing plans in initial screening for potential clarification or disqualification. Selected projects would be required to file updates on CKTE's and sourcing plans if tariff rates change prior to project delivery and completion. In any event, tariff-caused prices increases would be limited to less than 20 percent of overall project costs and projects would be required to provide actual tariff cost documentation for verification through an Independent Auditor process prior to cost remuneration.[482]

565. During the hearing, Public Service admitted Hearing Exhibit 131, which summarizes the main components of Staff's tariff passthrough proposal, states the Company's position on each component, and provides specific comments and suggested modifications. Overall, Public Service states that it supports Staff's tariff passthrough proposal with the Company's modifications as reflected in Hearing Exhibit 131. Public Service characterizes the tariff passthrough mechanism as another important concept to drive the JTS forward and capture the best bids possible while managing substantial uncertainty.[483]

566. In its SOP, Staff states it is supportive of the clarifications and modifications that Public Service makes to the proposal in Hearing Exhibit 131, with two exceptions. First, Staff states it cannot agree to limit the CKTE to an amount that is "reasonable" in comparison to the

[481] Hr. Ex. 2605, Dahlke Cross Answer, p. 12.
[482] Hr. Ex. 2605, Dahlke Cross Answer, p. 30.
[483] Public Service's SOP at pp. 29-30.

overall bid cost. Staff argues the purpose of the CKTE is to get an accurate picture of projected costs based on tariff rates in effect at the time of the bids, regardless of the reasonableness of such rates. Second, Staff agues the term “major equipment” should be more clearly defined to prevent differing interpretations among the Company and bidders. At a minimum, Staff argues “major equipment” must consist of the following: (1) wind: tower, blades, and nacelle assembly; (2) solar PV: panels, inverters, and mounting structures; (3) gas: turbine and generator; and (4) battery: battery modules and power conversion system.[484]

567. Regarding the cap on price increase, Staff sticks with its original proposal for a 20 percent cap on price increases. Rather than terminating a project if it exceeds the 20 percent cap, however, Staff recommends the Commission conduct a notice and review process to reconsider whether to proceed with the project or seek alternative options.[485]

568. CIEA generally supports Staff’s passthrough proposal, as modified by Public Service, but suggests additional modifications. For instance, CIEA argues that if tariffs cause prices to rise above the 20 percent price cap, that should trigger a Commission review of the update rather than automatic withdrawal. For any projects that must withdraw due to exceeding the CKTE cap, CIEA argues Public Service should be prohibited from charging a termination payment or loss of security as such costs are out of the developer’s control.[486]

569. CEI supports the passthrough concept but argues the information bidders provide to substantiate tariff cost claims and support a CKTE passthrough should be minimized to avoid revealing any pricing information that would give the Company a competitive advantage. CEI recommends the Commission approve the CKTE process in Hearing Exhibit 131, with a

[484] Staff’s SOP at p. 20.
[485] Staff’s SOP at pp. 20-21.
[486] CIEA’s SOP at pp. 33-34.

commitment to further modification in a stakeholder process between the Phase I decision and the Phase II RFP.[487]

570. Climax supports Staff's tariff passthrough, with Public Service's adjustments, and urges the Commission to adopt it.[488]

571. CEC generally supports Staff's tariff passthrough concept, as modified by Public Service in Hearing Exhibit 131. CEC opposes, however, the 20 percent cap as being too high. CEC recommends the Commission should instead approve a more reasonable ceiling for CKTE increases that qualify for automatic pass-throughs such as 5-10 percent of overall project costs.[489]

b. Findings and Conclusions

572. We adopt Staff's tariff passthrough proposal, as modified by Public Service in Hearing Exhibit 131 and further modified by Staff in its SOP. The one deviation we make from the proposal Staff advances is to grant CEC's request and lower the price cap from 20 percent to 10 percent. This lower price cap reduces the risk of bidders attempting to game the passthrough mechanism.

573. Other than the reduced price cap, we note that Staff's tariff passthrough concept has broad party support. However, we reject CIEA's request that bidders be able to walk away from their project if the tariff impact exceeds the price cap. We fear such a mechanism would incentivize bidders to claim a more than 10 percent tariff impact whenever the bidder wanted to leave the PPA.

574. We similarly recommend denying CEI's request for a stakeholder process between the Phase I decision and the Phase II RFP to determine how to ensure that the information bidders

[487] CEI's SOP at p. 26.
[488] Climax's SOP at p. 6.
[489] CEC's SOP at p. 16.

provide does not give Public Service a competitive advantage. First, in Hearing Exhibit 131, Public Service opposes the proposition that it and the IE would flag any questionable or incomplete CKTEs and sourcing plans. Instead, the Company recommends that this be "a completeness review only, by an outside consultant, without focus on substantive content or accuracy of CKTE assumptions."[490] Staff does not challenge this modification in its SOP. Thus, under the modified tariff passthrough, Public Service would not be reviewing the CTKEs and sourcing information that bidders provide. Secondly, we are concerned about the timing impacts of requiring additional process prior to the submission of bids.

7. Demand Response and Aggregated Distributed Energy Resources

a. Party Positions

575. The Company explains that it conducted its resource adequacy study with its existing portfolio of DR programs including the Saver's Switch, SolarRewards, and ISOC programs.[491]

576. With respect to additional distributed energy resources, Public Service modeled 900 MW of ADERs starting in 2028 in a subset of portfolio scenarios.[492] The Company modeled ADERs as a four-hour storage device with essentially unlimited flexibility. However, the Company concluded "our testing resulted in minimal differences in sizing of the portfolios … [which] leave[s] us with the conclusion that while helpful, ADERs will not be enough to get us to our overall emissions reduction objectives and carbon-free goal."[493]

577. WRA and SWEEP argue the cost assumptions of generic advanced technology resources are speculative and the Company's cost assumptions for the ADER generic resource are

[490] Hr. Ex. 131, Public Service's Position on Staff's Tariff Risk Recommendation, p. 1.
[491] Hr. Tr. June 17, 2025, pp. 28-29.
[492] Hr. Ex. 102, Landrum Direct Rev. 1, p. 89.
[493] Hr. Ex. 102, Landrum Direct Rev. 1, p. 105.

overestimated as Public Service can access ADER capacity lower than the full cost of residential or commercial battery storage.[494] They note that Public Service provides an incentive of $350/kW, up to $5,000 per application, plus $100 per year for continued participation in the demand management program. WRA and SWEEP also suggest that the Tesla Powerwall 3 costs around $15,000 for battery plus installation, and determines that the Company can utilize the storage capacity of customer assets at about one third the total installed cost and possibly lower as technology improves.[495]

578. In its SOP, WRA and SWEEP argue the Company should update the cost modeling of generic ADERs in its next Phase I Electric Resource Plan based on the Company's Renewable Battery Connect ("RBC") and virtual power plant ("VPP") tariff options as well as ADER bids received through any administered competitive solicitations, such as the VPP program. WRA and SWEEP also contend the Company should expand generic resource modeling to reflect distributed energy resources beyond battery storage, including consideration of energy efficiency, demand management, and distributed generation, and to represent the opportunity of these resources via an inclining supply curve.

579. CEI argues that the Company conflates the total cost of storage assets for the costs it pays through RBC and other ADER programs. CEI utilized values from a Brattle Group report to determine that ADER programs offer storage capacity at approximately $85/kW-year, a value substantially lower than the Company's assumed value of $475/kW-year.[496] CEI also asserts the Company ignored likely non-system wide benefits of ADERs including distribution system value.

[494] Hr. Ex. 1300, Valentine Answer, p. 84.
[495] Hr. Ex. 1300, Valentine Answer, p. 85.
[496] Hr. Ex. 2201, Turner Answer, p. 12.

They point to a list of studies that indicate the value of avoided distribution investment that range from $60/kW-yr to $87/kW-yr.

580. However, CEI notes that because Public Service is not proposing any action in this Proceeding, the Commission need not take any action in its Phase I order on these issues; instead, it should examine them closely in related proceedings.[497]

581. In Rebuttal, Public Service asserts the reality of many existing DER programs today is that they are deployed for direct participant benefits that would limit the use of the asset from a system operations perspective.[498] Thus, the Company argues it is inappropriate to model utility-only costs with the full range of battery benefits. Public Service argues the Company's modeling approach, including total costs and total benefits, is at least closer to accurate. With respect to the RBC program, the Company explains the terms and conditions of the program only allow it to dispatch up to 60 events per year.[499] These limitations mean the capacity available from RBC is not a like-for-like replacement of larger-scale battery storage resources that do not have these limitations.

b. Findings and Conclusions

582. The Commission recognizes that contractual limitations associated with DR and ADER participation inherently reduce some of the flexibility of those resources (relative to fully-owned or -controlled resources). However, we believe that, with continued improvement in program design and management, DR and ADER resources offer the potential to meaningfully facilitate the Company's ability to meet its peak load obligations, especially considering that many of those contractual limitations are either set by the Company or in adjudications before the

[497] CEI's SOP at p. 27.
[498] Hr. Ex. 125, Pollock Rebuttal, pp. 8-9.
[499] Hr. Ex. 125, Pollock Rebuttal, p. 10.

Commission. We agree with WRA and SWEEP that more should be expected of the Company in its next ERP. Specifically, we require Public Service to update the cost assumptions in its 2028 ERP, informed by: (1) the Company's relevant programming, such as RBC and VPP tariff options, and (2) ADER bids received through any administered competitive solicitations. We also require Public Service to address in its Phase I filings whether generic resource modeling should or should not reflect DERs beyond battery storage, and to provide thorough evaluation of leveraging such resources to serve its system peak requirements as well as reduce the need for transmission and distribution infrastructure.

Q. Miscellaneous Transmission Issues

1. Financing Transmission Projects via the Colorado Electric Transmission Authority ("CETA")

583. WRA and SWEEP assert there is an unprecedented need to expand and upgrade the nation's transmission infrastructure to maintain grid reliability, improve resilience, and meet climate goals. They state that by offering lower costs compared to traditional investor-owned utility financing, public financing for transmission can minimize upward rate pressure. Such a financing pathway could also reduce the risks of sole dependency on private sector banks which often carry higher interest rates for financing. WRA and SWEEP argue that a utility has a fundamental duty to minimize costs. If public financing can demonstrably lower the cost of a necessary transmission project, then a utility has a responsibility to pursue that option. Given the potentially significant rate impacts of traditional transmission financing, they argue, exploring public-private partnerships is a prudent step to mitigate those impacts. Accordingly, they recommend that the Commission require Public Service to partner with CETA to identify and

evaluate which planned or potential transmission projects could be suitable candidates for utilizing CETA's revenue bond financing.[500]

584. The Company states that it and CETA already engage through CCPG, and the Company actively participated in CETA's Transmission Expansion Study. The Company remains interested in working with CETA in the future but asserts CETA is still in policymaking stages for its revenue bonding. As CETA becomes more equipped to provide the services identified in its statutory authority, the Company states it is willing to discuss how those authorities may complement the Company's transmission planning.[501]

585. We agree that CETA financing of transmission projects offers potential ratepayer savings. We therefore direct the Company to engage actively with CETA to either propose CETA financing of all transmission projects needed to support the approved JTS portfolios or provide detailed explanations of why it is not doing so in all relevant future CPCN applications.

2. Evaluation of Dynamic Line Ratings

a. Party Positions

586. Public Service evaluates the applicability of dynamic line ratings ("DLR") in resolving reliability issues identified in its JTS Transmission Study. The Company states that in the base forecast study it reviewed 23 circuits for the ability to apply DLR and in the low forecast study it reviewed eight circuits. The Company asserts that in many cases circuits were not good candidates because, for example, they include underground segments or their capacities are limited by substation elements that would require costly upgrades. The Company argues that applying DLR to the remaining viable candidate circuits alone would be insufficient to resolve all the system

[500] Hr. Ex. 1302, Richardson Answer, pp. 19-20.
[501] Hr. Ex. 121, Martz Rebuttal, p. 71.

violations identified in the JTS Transmission Study. Public Service states that following approval of a portfolio in Phase II, the Company will evaluate transmission overloads on the existing system caused by the portfolio and determine whether any indicated transmission upgrades could be avoided by DLR.[502]

587. UCA notes that in conducting its evaluation of DLR, the Company explicitly excluded the Colorado Power Pathway. UCA contends that this was inappropriate, given that the Colorado Power Pathway will be carrying substantial wind generation, and thus could benefit from increased rating when the lines are cooled by wind. UCA argues that DLR should be applied specifically to Segment 1 of the Colorado Power Pathway from Ft. St. Vrain to Canal Crossing, but that it should not be applied to Segment 5 (from Sandstone to Harvest Mile) because it claims that doing so would trigger the need for the expensive Harvest Mile-Chambers-Sandown-Cherokee upgrade project. UCA also proposes that DLR be evaluated on the Rush Creek gen tie between the Pronghorn and Missile Site substations, which was also built to carry wind generation.[503]

588. The Company disagrees with UCA, stating that the fact that a transmission line is used to interconnect wind generation is not sufficient evidence of meteorological conditions to alone support the deployment of DLR as UCA suggests. The Company also notes that the lines UCA would like DLR installed on are limited to the 3,000-amp breaker capacities in substations. It states that while these breakers could be upgraded, there is substantial incremental cost to upgrading substation elements that more than likely outweighs the incremental benefits of DLR, particularly since FERC Order No. 881 requires that these lines use ambient adjusted ratings (thus reducing the potential incremental benefit of DLR).[504]

[502] Hr. Ex. 111, Martz Supplemental Direct, pp. 32-43.
[503] Hr. Ex. 305, Neil Answer, pp. 58-59.
[504] Hr. Ex. 121, Martz Rebuttal, pp. 73-75.

b. Findings and Conclusions

589. Public Service claims the application of DLR might require breaker upgrades in substations and so could be much more costly than just installing DLR on its lines. However, the Company has not demonstrated that DLR would actually necessitate such breaker upgrades, nor that if required, these upgrades would render DLR non-cost effective. We agree with UCA that these lines were built to carry large volumes of wind power and that it is reasonable to investigate whether DLR could cost-effectively increase volume of wind energy they transport.

590. Therefore, we direct that the small stakeholder group established as part of the Phase II Framework, supported by the ITA, discuss the potential benefits of DLR on the lines recommended by UCA. If the stakeholder group finds that further analysis of DLR is warranted, we direct the Company to model and report on the application of DLR to the lines recommended by UCA as part of the assessment of proactive projects contemplated in the Phase II Framework.

3. Investigation of Interconnection with the PacifiCorp Gateway South Line

a. Party Positions

591. As discussed in Section 2.15 of the Technical Appendix, per the USA from the 2021 ERP/CEP, the Company studied the "Gateway South-Northwest Colorado 500 kV Interconnection Project." This project posits a 500 kV connection between either the Craig or Hayden substation to a substation on Pacificorp's Gateway South line. The Company explains that:

> The study attempted to understand how generation dispatch between Public Service's area in Eastern Colorado and the PACE area in Wyoming impacts the amount of flow possible on these two alternative lines. The results of the analysis showed that power transfers between the PACE area via the conceptual connection are possible, but do not alleviate existing limitations related to the existing transmission paths within Colorado. Further, the

> result of this analysis shows a redistribution of flows between the TOT3 and TOT5 paths, depending on direction of transfer. While the addition of either of these alternatives was found to relieve post-contingent loading level in some areas, other areas saw loadings in excess of their ratings. Additional study is required to assess the costs and capabilities of such a connection compared to the value provided.[505]

592. The Company cautions that interstate transmission is subject to several layers of national, state, and local regulation as well as the potential for stakeholder opposition. It also states that "[e]ven before those challenges are encountered, insufficient intra-state transmission capability stands as the primary hurdle to realizing the value of interstate expansion," but states that it continues to work with state, regional and national partners to understand the potential for interstate transmission.[506]

593. WRA and SWEEP contend that this project would increase the Company's access to other power markets and increase the geographic area (and thus resource diversity) in which it can utilize renewable energy resources. They assert the Company's study of the line was incomplete in that it looked only at reliability impacts, failing to investigate the costs and benefits of the project. WRA and SWEEP refer to a discovery response in which the Company states that it is assessing potential next steps but does not know when additional studies will be conducted. WRA and SWEEP recommend the Commission direct Public Service to conduct detailed studies that fully assess two key aspects of a potential interconnection with Gateway South: first, the potential net benefits, and second, the necessary system upgrades – and associated costs – required to facilitate such an interconnection. WRA and SWEEP envision that this study would quantify environmental, reliability and resilience, and economic benefits for Colorado customers and provide estimates of the cost and timeline for any necessary upgrades to the Company's existing

[505] Hr. Ex. 105, Siebenaler Direct, pp. 87-88.
[506] Hr. Ex. 105, Siebenaler Direct, pp. 87-88.

transmission system. They recommend further that the Commission direct the Company to report its findings within 18 months of the Phase I decision .[507]

594. The Company does not respond to WRA and SWEEP's recommendation.

b. Findings and Conclusions

595. In the 2021 ERP/CEP, the Commission required Public Service to provide supplemental direct testimony reporting on the reserve margin and other potential benefits from a 400 MW increase in the bi-directional transfer capability between Public Service and "Pacificorp East" starting in 2028.[508] In response, the Company conducted a capacity expansion modeling run simulating the expected impacts of an approximately 60-mile long, 500 kV transmission line running from its Hayden substation due west to a new 500 kV switching station on the Pacificorp Gateway South project, where it would interconnect. The Company estimated the cost of this project at $269 million and estimated $700 million in net benefits. Public Service suggested that these results provided a sense of the potential but cautioned that the cost estimate was at a very high level and that the modeled benefits were highly dependent upon the assumed reduction in planning reserve margin that this connection would enable and the assumption of a liquid and organized market on the Pacificorp side of the interconnection.

596. WRA and SWEEP are correct in noting that the study submitted in this Proceeding regarding the transmission link to the Pacificorp Gateway South project focuses exclusively on reliability impacts, providing no insight into other costs or benefits the project might provide. Indeed, the Company states that "[a]dditional study is required to assess the costs and capabilities of such a connection compared to the value provided."[509] While the information provided in the

[507] Hr. Ex. 1302, Richardson Answer, pp. 14-18.
[508] Decision C21-0395-I at ¶ 9 issued in the 2021 ERP/CEP (July 2, 2021).
[509] Hr. Ex. 105, Siebenaler Direct, Rev. 1, p. 89.

2021 ERP/CEP is indicative of the potential benefits of interregional transmission, the analysis underlying that information cannot be considered a rigorous assessment of the likely costs and benefits of such a project.

597. We note that in July 2025, the CETA Board of Directors approved a shortlist of six priority transmission projects, among which was a 38-mile transmission link between the Company's Craig power plant and the same Pacificorp Gateway South line. This indicates that CETA has found there to be considerable benefit to forging a link nearly identical to the one that has been a focus of both this JTS Proceeding and the 2021 ERP/CEP. In sum, the Company's own analysis indicates this transmission link could be highly beneficial for ratepayers, and CETA strongly endorses such a line as one of the few potential transmission projects it intends to prioritize. What we lack is (1) rigorous modeling to determine the potential for economically advantageous trades across such a line; (2) an assessment of costs and benefits rigorous enough to determine whether it is sensible to move forward with project development; and (3) a comprehensive understanding of the regulatory approvals from FERC, relevant state utility Commissions, and the Moffat and Hayden County Commissions that would be needed if a decision were made to build the line.

598. Given the positive indicative results from the 2021 ERP/CEP, we require the Company to rigorously develop the information identified as missing in the previous paragraph. We therefore direct the Company to work with CETA and its contractors to develop a consensus optimal route for a high voltage transmission link to the Pacificorp Gateway South line and to develop the modeling parameters necessary to accurately quantify the potential costs and benefits of this link. We further direct the Company to submit a report in this Proceeding within 18 months

presenting both its cost-benefit analysis of this line and any unique process-related issues that developing the line might pose.

4. Large Load Transmission Study

599. At hearing, Chair Blank discussed with the Company the possibility of evaluating the transmission impacts of locating much of the large loads the Company is forecasting on the high side of the 345 kV system, and thus outside of the Denver Metro Constraint. The Company indicated a willingness to conduct this modeling at hearing.[510] In its SOP, the Company recommends several modifications to the study Chair Blank outlined, which it states align with ongoing market developments, trends and studies already in progress. The Company recommends the following parameters:

- An EnCompass run based on the Company's Rebuttal Testimony Updated Base Forecast, with updated generic pricing assumptions, including tax reform impacts. The EnCompass run will also include several topology sensitivities, all focused around Data Center Row and the Smoky Hill and Spruce substations;
- Power flow analysis that includes (1) updated generation portfolio and dispatch assumptions; and (2) updated load forecasts.

600. The Company proposes to conduct these analyses under three load scenarios: a no large load scenario; a scenario assuming the large loads in the updated base forecast (about 950 MW); and a high large load forecast (ranging from about six to ten GW) based on the status of the Company's queue and anticipated demand in early third quarter 2025. The Company suggests that these scenarios will enable the Company and Commission to better understand the magnitude of potential system costs that future large loads may drive. The Company states that it can commit to

[510] Hr. Tr. June 20, 2025, pp. 210-213.

filing this "Large Load Transmission Study" in conjunction with its Large Load Tariff filing in January 2026 if the Commission approves its proposed approach.[511]

601. While we appreciate the Company's proposal, we find that it will not adequately identify the transmission costs that could be imposed on ratepayers by allowing developers to site new large loads within the Denver Metro constraint as opposed to assuming that these facilities are constructed outside of the constraint or on the high side of the 345 kV transformers that serve Denver.

[511] Public Service's SOP at pp. 24-25.

602. Accordingly, we require the Company to conduct the following modeling studies:

- A revised EnCompass run based on the Company's Low Load Forecast as adjusted by the Commission's decision in this case regarding EV and BE loads and with updated generic resource cost and tax reform assumptions.
- A second EnCompass run that includes an additional 2,000 MW of large data center load over and above what's included in the first Encompass run above. This additional load is to ramp up in alignment with the ramping assumptions the Company used in its original Base forecast.
- Power flow and transmission capacity expansion analysis for the following three scenarios: (1) assuming that the new large loads are limited to existing customers as in the low load forecast; (2) that the 2,000 MW of additional load in the second Encompass run comes online around Data Center row within the transmission-constrained Denver Metro area on the 230 kV system or below; and (3) the 2,000 MW of new load comes online outside the Denver Metro area on the 345 kV system or on the high-voltage side of the Daniles Park and Smoky Hill substations.

603. These modeling studies are to be completed, and their results filed in this Proceeding no later than the January 31, 2026 Large Load Tariff filing date. We expect that these modeling results will be reflected in the direct testimony the Company files in support of that tariff.

R. Performance Incentive Mechanisms

1. Cost-to-Construct ("CtC") and Operational PIMs versus Three-Party PIM

a. Party Positions

604. In Phase II of the 2021 ERP/CEP three parties (Staff, UCA, and CEC) advanced a new type of PIM for utility-owned generation in which Public Service would be required to recover the costs of Company-owned renewable generation assets entirely through the ECA as opposed to base rates. Under this Three-Party PIM, cost recovery increases in direct proportion to the amount of renewable energy the assets produce while also tying cost recovery to Public Service's Phase II bids. Likewise, the PIM would account for both capital construction costs and performance of the assets. While the Commission declined to adopt the Three-Party PIM in the 2021 ERP/CEP, we

opined that the approach offered a potential avenue to engage in performance based regulation on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking. The Commission expressed an intent to further evaluate the Three-Party PIM in the JTS.[512]

605. In this Proceeding, Public Service vehemently opposes the Three-Party PIM. The Company argues the PIM would compensate the utility strictly based on production, breaking the cost of service ratemaking construct entirely, and essentially deregulating cost recovery for impacted generation projects.[513] In Rebuttal, the Company even opposes Staff's request to provide additional reporting in subsequent proceedings that may help evaluate whether the future implementation of the Three-Party PIM is appropriate. The Company argues it already has numerous reporting obligations and that adding a hypothetical calculation to the reporting mix is unnecessary, burdensome, and likely confusing.[514]

606. Instead of the Three-Party PIM, Public Service recommends the Commission continue to develop the CtC and operational PIMs for any utility-owned generation projects arising from the JTS.[515] The Company argues the exact mechanics of such PIMs should be considered in a separate future proceeding in which the parties can iterate on and evolve the approach recommended in the unopposed settlement agreement in Proceeding No. 24A-0417E.[516]

607. Staff argues the Commission should order cost-to-construction and operational PIMs for Company-owned projects in this JTS consistent with the 2021 ERP/CEP and does not recommend approving the Three-Party PIM at this time. Staff explains, however, that it continues

[512] Phase II Decision at ¶¶ 196-98 issued in the 2021 ERP/CEP (January 23, 2024).
[513] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 92-94.
[514] Hr. Ex. 117, Ihle Rebuttal, p. 92.
[515] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 92-94.
[516] Public Service's SOP, Attachment A.

to remain interested in such an approach moving forward. If the Commission is also interested, Staff recommends the Commission order the Company to provide an annual calculation comparing the (1) the as-bid project revenue requirement and unit performance with (2) the actual performance of the generating asset and actual cost recovery. Staff argues the Company could provide this comparison in the annual ECA prudence review proceeding or another proceeding where the Company reports the results of on-going operational PIMs.[517]

608. Staff disagrees with the Company's arguments that such a reporting requirement would be "unnecessary, burdensome, and likely confusing," arguing instead that such reporting would provide the Commission a straightforward and transparent comparison of both the Company's actual performance compared to its ERP bidding and the Company's cost recovery compared to PPA projects.[518]

609. UCA continues to advocate for the Three-Party PIM, arguing that it would put Public Service on equal footing with other entities bidding into the ERP process such as IPPs. If the Commission is not inclined to do adopt the three-party PIM, then UCA suggests that any consideration of PIMs should be left to CPCN proceedings stemming from this ERP for any Company-owned generation.[519]

610. Climax argues that PIMs for utility-owned projects should not be set or considered in this Proceeding. Instead, Climax argues that such PIMs should be considered in associated CPCN proceedings guided by the same parameters applied to Colorado Power Pathway projects.[520]

[517] Staff's SOP at p. 28.
[518] Staff's SOP at pp. 27-28.
[519] UCA's SOP at p. 32.
[520] Climax's SOP at p. 6.

b. Findings and Conclusions

611. Given the capital bias that exists in current cost-of-service regulation, where utility earnings growth is directly linked to capital spending and rate base expansion, we continue to have serious concerns with the projected growth in Public Service's rate base and the potential impacts on customer bills and rates, all in the context of customer service failings. In this context, we are committed to finding ways to move towards more performance-based regulation in which the Company prioritizes performance over capital spending. In short, this Commission continues to see a need to align customer and Company incentives. The CtC and operational PIMs in their current form, while very helpful in partially aligning certain construction and performance-related risks as between customers and the utility, do not fully address these concerns.

612. Turning to the three-party PIM, we continue to find this PIM intriguing because it offers a potential avenue to engage in performance based regulation on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking. Although much of the Company's opposition to the three-party PIM appears to be overstated, we agree with Public Service that shifting to the three-party PIM would mark a major shift in how the Commission regulates Company-owned generation. Given the likely magnitude of its impact and the relatively thin record in this Proceeding, we agree with Staff that the Commission should not attempt to implement the three-party PIM in this Proceeding.

613. To continue evaluating this PIM, however, we adopt Staff's suggested reporting requirements in which the Company provides an annual calculation in the ECA comparing (1) the as-bid project revenue requirement and unit performance with (2) the actual performance of the generating asset and actual cost recovery. For the reasons set forth by Staff, we find the Company's arguments against this reporting to be unpersuasive. Such reporting could provide critical

information if the Commission decides to adopt the three-party PIM in the 2028 ERP. In this vein, Public Service shall provide this reporting on utility-owned assets not just from this JTS but also on the utility-owned assets arising from the 2021 ERP/CEP.

614. We further grant Staff's recommendation and direct that the CtC and operational PIMs will apply to Company-owned projects arising from this JTS. Although the Commission can continue to address the details of these PIMs in subsequent CPCNs (directionally consistent with recommendations from UCA, Climax, and the Company), we reaffirm that the Company's Phase II bids[521] will set the baselines for the PIMs, unless the Company can show the existence of extraordinary circumstances. As such, for purposes of the PIM calculation, Public Service shall file as part of the 120-Day Report the capital construction cost and associated AFUDC for each utility-owned bid as well as the capacity factor and levelized cost of energy for each utility-owned renewable bid. Regardless of whether the CtC and operational PIMs change going forward to better address our desire to shift toward performance based regulation, the baselines for these PIMs will be the bid metrics Public Service uses in the Phase II bid evaluation and selection.

615. The Commission disagrees with suggestions from UCA, Climax, and the Company that the CtC and operational PIMs should be entirely deferred to future proceedings. These PIMs may change the level of risk the Company assumes for utility-owned projects. The Company should be able to incorporate this risk into its Phase II bids.

2. Emissions PIM

616. In its Direct, Public Service also puts forth a proposed emissions reduction PIM that it previously discussed with stakeholders (*i.e.* Staff, WRA, and CEO). The Company notes, however, that the Company and parties have not reached a consensus recommendation for an

[521] To be clear, this includes both Company-built assets and build-transfer-own assets.

emissions reduction PIM. Ultimately, Public Service does not endorse the emissions reduction PIM. The Company states that the intent of such a PIM is laudable, but the practical application of an emissions PIM that utilizes the as-modeled emissions reductions as the threshold for earning an incentive may be unworkable.[522] Public Service recommends the Commission defer consideration of an emissions PIM to a future proceeding.[523]

617. Regarding the emissions reduction PIM, Staff recommends against approving the PIM in this Proceeding. Given concerns about the complexity and viability of an emissions PIM, risks of higher costs to ratepayers, and the lack of consistency with the Commission's prior PIM guidance, Staff states that it agrees with the Company, UCA, WRA and SWEEP, and CEO that an emissions PIM should not be adopted at this time.[524]

618. WRA and SWEEP recommend that, instead of approving the emissions PIM, the Commission should approve a set of Phase II portfolios and solution sets that will allow for robust evaluation of accelerated decarbonization in Phase II.

619. We agree with the parties that the Commission should refrain from attempting to implement an emissions reduction PIM in this Proceeding. We reiterate, however, that one of our primary policy objectives is to achieve cost-effective emissions reductions. The fact that the parties were unable to bring forward a holistic emissions reduction PIM does not lessen the importance of this objective, especially as we endeavor to focus more directly on the Company's performance in rate making.

[522] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 107.
[523] Public Service's SOP, Attachment A.
[524] Staff's SOP at p. 27.

S. 24/7 Carbon Free Energy Community Programs

1. Party Positions

620. In its Direct, Public Service puts forth a "program concept" for a 24/7 Carbon Free Energy ("CFE") acquisition strategy that aims to match a participating customer's electricity consumption with carbon-free generation on an hourly basis. The Company requests the Commission approve its proposed strategy to acquire resources for future 24/7 CFE programs from its RFPs that are higher in the bid stack than (*i.e.*, incremental to) the resources selected to meet the rest of its future customers following an approved ERP.

621. Staff argues that the Commission should deny as premature the Company's proposed plan for acquiring resources for a yet-to-be developed 24/7 CFE. Staff asserts zero emissions community programs face growing challenges, including a lack of customer interest and are "purely hypothetical at this stage."[525] Staff argues the Commission should not approve how resources for these programs will be acquired until the Company introduces actual, well-defined programs for approval.

622. CEO is generally supportive of the CFE program but has the following five recommendations: (1) ensure that the program is tariff-based so 24/7 CFE program participants bear the entire cost of the program; (2) acquire CFE resources from the Phase II bids that remain after the approved and backup bid portfolios are developed; (3) expand the CFE offering to new large loads; (4) at least for new large loads, the CFE should include minimum contract lengths, walk-away penalties, and minimum billing demand to reduce the chance of those large customers

[525] Staff's SOP at p. 36.

leaving the program; and (5) subtract the projected load for the 24/7 CFE program from the ERP forecast before allowing the Company to acquire incremental 24/7 CFE resources.[526]

623. CC4CA argues the Commission should direct the Company to require hourly renewable energy credit ("REC") tracking of all eligible energy resources acquired via the JTS. CC4CA argues that current voluntary renewable products are designed for customers to "offset" consumption with renewable electricity but renewable production is not intentionally matched with customer consumption. Tracking RECs on an hourly basis supports development of the next generation of voluntary renewable products so that customers do not claim to be "100% renewable" while still consuming fossil fuel electricity.[527]

624. CC4CA opposes the Company's proposal that CFE resources be acquired only as incremental resources to the ERP resources. CC4CA asserts it is premature to find that this is the only or most effective pathway to 24/7 CFE. CC4CA suggests, for example, that a CFE program could pay for any incremental cost of zero emissions resources to include the bids in the approved portfolio. CC4CA recommends the 120-Day Report include discussion of three scenarios: (1) the potential for a CFE product to lead to the selection of a portfolio that provides additional emissions reduction compared to the Preferred Portfolio; (2) the potential for the capacity of one or more renewable bids included within the Preferred Portfolio to be expanded to serve CFE customers, as reflected in bid variations submitted in the competitive solicitation; and (3) the potential for innovative clean technology bids to be developed by CFE customers in lieu of the CFFD proposal.[528]

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[526] Hr. Ex. 400, Hay Answer, pp. 62-64.
[527] CC4CA's SOP at p. 13.
[528] CC4CA's SOP at p. 14.

625. CC4CA further requests the Commission require Public Service to convene a stakeholder group to refine a CFE product that could develop CFE resources through the incremental need pool or to solicit them through the supplemental RFP. CC4CA asserts that at the evidentiary hearing Public Service expressed a willingness to continue conversations with customers and communities regarding 24/7 CFE.

626. In sum, CC4CA ultimately recommends the Commission require (1) hourly REC tracking of acquired eligible energy resources; (2) convene stakeholders to continue development of a 24/7 CFE product; and (3) consider development of CFE product based on CFFD technology bids received in Phase II.[529]

627. In Rebuttal, Public Service agrees that additional development will be necessary for a CFE program and recommends this additional development occur in a future filing. Public Service reiterates its initial recommendation, however, that the Commission affirm that CFE-serving resources should be "next in line" after approved and backup bids in an ERP-type solicitation.[530]

2. Findings and Conclusions

628. We reject Public Service's request to determine at this stage that CFE resources be acquired only as incremental resources or "next in line" to the approved ERP resources. We agree with CC4CA that it would be premature to find that that this is the only or most effective pathway to 24/7 CFE. For instance, resources developed through the CFFD or VPP resources should not be precluded from future 24/7 CFE community programs. We grant CC4CA's request and require Public Service to convene a stakeholder group to further refine the details of a CFE product.

[529] CC4CA's SOP at p. 30.
[530] Hr. Ex. 117, Ihle Rebuttal, p. 98.

629. We reject the remaining requests from CC4CA and CEO. The specifics of how a future CFE program should be designed and tracked (including through hourly REC tracking) are best left for the stakeholder group or a future filing when there is a concrete proposal.

T. Mapping

1. Party Positions

630. In the 2021 ERP/CEP, the Company provided maps showing the location of various bids as well as heatmaps showing things like net load and curtailments. In this Proceeding several intervenors argue that Public Service should be required to provide similar data in the Phase II of this Proceeding. For example, CEO requests public maps of bids relative to DI communities, including a web-based GIS map that shows generalized locations of all bids included in Phase II portfolios, the geographic areas of DI Communities, and the geographic areas where bids receive modeling credits or adders. [531]

631. CC4CA and Healthy Air and Water both support CEO's mapping requests and ask for additional information concerning the location of bids and the Denver Metro/North Front Range Ozone Nonattainment Area ("NAA"). CC4CA specifically requests one map illustrating the relationship between bids and the NAA and another map showing an overlay of the NAA in a cost-free, web-based GIS map that can be accessed by parties with signed NDAs that shows specific locations of bids included in portfolios in relationship to DI communities and locations of bonus credits. CC4CA argues that such maps will help show the burden that new gas plants may have on the NAA.[532] Healthy Air and Water similarly recommends CEO's requested maps also show new generation facilities proposed within the NAA. Healthy Air and Water argue that this

[531] CEO's SOP at p. 9.
[532] CC4CA's SOP at p. 8.

Commission and stakeholders should have a straightforward and accessible way to understand which new generation facilities are proposed to be located within the NAA.[533]

[533] HAWC's SOP at p. 17.

632. CRES/PSR requests that the Company should again provide heat maps showing things like net load and curtailment, but CRES/PSR requests that such heat maps provide additional information such as the modeled fossil fuel dispatch and modeled storage discharge. CRES/PSR argue that the heat map data provided in the 120-Day Report were useful in subsequent proceedings to represent the trends in the hourly profiles of load, net load, and renewable curtailment.[534] For purposes of the JTS, CRES/PSR request the following heat map information, in the same 24 x 12 format as the 2021 ERP/CEP:

a. Modeled average CO_2 emissions intensity (lbs/kWh or similar intensity metric)
b. Modeled load (MW)
c. Modeled storage discharge (positive) and charge (negative), (MW)
d. Modeled available renewables without curtailment (MW)
e. Modeled fossil fuel dispatch (MW)
f. Modeled net load = (Modelled load – renewables without curtailment) (MW)
g. Modeled curtailment of solar (MW);
h. Modeled curtailment of wind (MW), and
i. Modeled hours with curtailment. (Hours)[535]

633. Public Service does not appear to respond to these various requests in its SOP or Rebuttal.

2. Findings and Conclusions

634. We grant CEO's mapping requests and direct Public Service to include the following in the 120-Day Report: (1) a public PDF map of bids relative to DI communities (2) a public PDF map of bids relative to geographic locations where bids receive modeling credits or adders as approved by the Commission in Phase I; and (3) a web-based GIS map that shows

[534] CRES/PSR's SOP at p. 11.
[535] CRES/PSR's SOP at p. 28.

generalized locations of all bids included in Phase II portfolios, the geographic areas of DI Communities, and the geographic areas where bids receive modeling credits or adders.

635. Similar mapping regarding DI communities was provided in Phase II of the 2021 ERP/CEP, and these requests from CEO are supported by CC4CA and Healthy Air and Water.

636. We reject, however, requests from CC4CA and Healthy Air and Water for maps showing bids in relation to the Denver Metro/North Front Range Ozone NAA. Regardless of the portfolio of resources the Commission approves in Phase II, projects will need to obtain all applicable permits, including air quality permits. Analyzing projects based on their presumed impacts on the ozone NAA is better left to the air permitting authorities.

637. Finally, we grant CRES/PSR's request for heat map information, including, among other things, data on modeled net load, modeled available renewables without curtailment, and modeled curtailment of wind and solar. The Company committed to providing similar information in the 2021 ERP/CEP and we agree with CRES/PSR regarding the usefulness of such information.

U. Best Value Employment Metrics

1. Party Positions

638. In light of the passage of SB 23-292, Public Service proposes to fashion the RFP bidding documents such that bidders are required to acknowledge and adhere to labor standards set forth in the Commission's rules regarding BVEM and abide by SB 23-292 and the apprenticeship utilization law and prevailing wage law, unless otherwise covered by a Project Labor Agreement.[536]

639. Similar to the 2021 ERP/CEP, Public Service has retained a labor economist to provide a BVEM score for all bids advanced to computer-based modeling based on the BVEM

[536] Hr. Ex. 104, Bornhofen Direct, pp. 36-37.

information provided. As part of its Phase II Bid Evaluation Report, the Company will provide the labor economist's cumulative BVEM score for each portfolio presented based on the BVEM scores of the bids in the portfolio. [537] The Pueblo Intervenors support the Company's labor scoring proposals, arguing that a bidding process that only advances "least cost" projects is counterproductive to our community and undercuts good labor practices.[538]

640. In a public comment, Laborers' International Union of North America Local 720 ("Local 720"). Local 720 urges the Commission to require Public Service to adopt the same union labor provisions for PPAs in Colorado that its Minnesota subsidiary uses.

2. Findings and Conclusions

641. In all decisions involved in ERPs § 40-2-129(1)(a)(I), C.R.S. requires the Commission to consider best value regarding employment of Colorado labor and positive impacts on the long-term economic viability of Colorado communities. To this end, we must require utilities to obtain and provide to the Commission information regarding "best value" employment metrics. The precise information that is required is defined by statute.

642. Public Service has put forth a reasonable approach to ensuring that the Commission has the necessary information to consider BVEM, including the Company's proposal to procure a labor economist to calculate a BVEM score for each portfolio presented in Phase II. Conversely, there is insufficient evidence on this record to require Public Service to adopt the union labor provisions that Xcel's Minnesota subsidiary uses. Moreover, we note the PPAs already require the Seller to certify they are complying with Senate Bill 23-292 and the associated apprenticeship utilization law and prevailing wage law or are otherwise covered by a Project Labor Agreement.

[537] Hr. Ex. 101, Att. JWI-3, Vol. 3, Rev. 1, p. 33.
[538] Hr. Ex. 1202, Swearingen Answer, p. 8.

643. Thus, we direct Public Service to ensure that provision and presentation of BVEM rules during Phase II of this Proceeding (both the base RFP and supplemental RFP) fully comply with the statutory requirements.

V. Holy Cross's Requests

1. Party Positions

644. In its SOP, Holy Cross seeks to reaffirm its rights under Paragraph 46 of the USA from the 2021 ERP/CEP. Paragraph 46 of the USA states the following:

> Holy Cross, in its sole discretion, shall have the option to select one or more replacement resources owned by or contracted to Holy Cross and interconnected with the Integrated Transmission System (as that term is defined in the PSCo-HCE Transmission Integration and Equalization Agreement) that will be provided appropriate transmission access, capacity accreditation entitlement and equivalent capacity credit associated with the Facility under the PSCo-HCE Power Supply Agreement, to the extent it is still in effect, by the Company following the early retirement of the Facility in an amount not to exceed Holy Cross' existing volumes from the Facility as of the date of this agreement. These may include projects selected by Holy Cross through the Pueblo Just Transition Resource Solicitation after the portfolio necessary to serve the Company's retail customers has been selected.[539]

645. Holy Cross asserts that Commission guidance interpreting paragraph 46 the USA is important for Public Service, Holy Cross, and bidders to effectuate the Unit 3 retirement and replacement process. If the Commission determines that it is not appropriate to provide the guidance requested by this statement in its Phase I decision regarding the Phase II process, then Holy Cross requests that its arguments be allowed to be raised again in Phase II without prejudice.

646. Holy Cross requests the Commission make numerous legal conclusions regarding paragraph 46. For instance, Holy Cross argues that its rights under paragraph 46 apply to the base RFP as well as the supplemental RFP and that Holy Cross has the same ability to review the JTS

[539] 2021 ERP/CEP USA at ¶ 46.

bid packages as the IE, Staff, and UCA. Holy Cross also asserts that it need not wait for both JTS RFPs to be complete before selecting project. Instead, Holy Cross argues it should be allowed to have its replacement capacity contracted and online in a similar manner to the replacement capacity in-service dates required by Public Service, which means it may select from resources after completion of the base RFP. Holy Cross acknowledges that it cannot select its replacement resources until after the Phase II Decision is final but asserts that it should not be required to wait until the Commission resolves applications for RRR or other delays associated with an aspect of the Phase II Decision that does not impact the approved portfolio.

647. To communicate Holy Cross's rights under the USA, Holy Cross and

648. Public Service agree to add the following paragraph to the RFP:

> **1.7 Holy Cross Comanche 3 Replacement Capacity**. After Public Service's resource portfolio is approved by the Commission, Holy Cross Electric Association may select resources from the bids submitted to this RFP to replace some or all of its 60 MW Comanche 3 capacity entitlement. Please see holycross.com/JTSRFP for more information.[540]

649. In addition, Holy Cross asserts that, per the USA, Public Service will provide transmission access sufficient to deliver energy from Holy Cross's replacement capacity to the Holy Cross points of delivery on the Public Service transmission system.

2. Findings and Conclusions

650. As Holy Cross's SOP demonstrates, the development of the Phase II Framework complicates the rights afforded to Holy Cross under paragraph 46 of the USA. Moreover, the issue regarding Holy Cross's rights under paragraph 46 were raised for the first time in Holy Cross's SOP. The Commission does not have the benefit of party feedback. Accordingly, we decline to make the requested legal conclusions in this Decision.

[540] Holy Cross's SOP at p. 8.

651. Rather than attempt to craft a way forward on such a limited record, we direct Public Service to confer with Holy Cross on these issues and come back to the Commission with any proposed solutions. Thus, 30 days prior to the RFP issuance, Public Service must file a notice setting forth the results of its conferral with Holy Cross. The Company may also include updated language in the RFP alerting bidders to the rights that Holy Cross has pursuant to the 2021 ERP/CEP USA.

W. Pueblo Energy Park

1. Party Positions

652. In its Answer, EJC proposes the concept of a renewable energy park in Pueblo. EJC explains that renewable energy parks have the following four components: (1) renewable energy, which is primarily wind and solar; (2) short-duration battery storage; (3) industrial customers with flexible loads; and (4) long-duration energy storage in the form of flexible technologies that can both store energy and reconvert it to electricity.[541] EJC argues a renewable energy park could be critical in achieving a just transition in Pueblo. EJC cites a report from Energy Innovation that studied building a renewable energy park in Pueblo. The Energy Innovation report concludes that such a park would reliably replace the generation from the Pueblo coal plant, 40 percent of the energy generated would flow to Pueblo County, and the park could generate more than $40 million in annual property tax revenue and 350 permanent jobs in Pueblo.[542]

653. EJC urges the Commission to direct Public Service in its Phase I decision to convene a stakeholder process to study the development of a renewable energy park in Pueblo.

[541] EJC's SOP at p. 14.
[542] EJC's SOP at pp. 14-15.

EJC proposes that Public Service would file a report in this Proceeding no later than one year after the Commission's final Phase I decision that discusses and recommends the next steps for building a renewable energy park in Pueblo.[543] EJC warns that simply deferring this issue to the Phase II solicitation is highly unlikely to result in a successful renewable energy park bid because the renewable energy park concept requires components like flexible industrial loads and long duration energy storage.[544]

654. The Commission received numerous public comments discussing a renewable energy park, most of which were strongly supportive of the concept.

655. Public Service opposes the requirement to study the development of a renewable energy park in Pueblo, arguing that doing so would be redundant with the study Public Service conducted in Pueblo following the 2021 ERP/CEP, which resulted in the PIESAC Report. Public Service notes that it will accept all renewable and storage bids proposed in the Pueblo area as part of the Phase II all-source solicitation, including a renewable energy park if such a proposal is bid.[545]

2. Findings and Conclusions

656. The Energy Innovation Report reflects the advantages of co-locating flexible load and generation/storage as well as the potential economic advantages of such a system for Pueblo. This justifies additional evaluation of long duration energy storage and flexible large loads. We reject, however, EJC's primary request to require Public Service to study the concept of a renewable energy park in Pueblo. The Energy Innovation report that EJC submitted into the record already shows the potential benefits and existing challenges with deploying a renewable energy park. The report finds that one of the primary barriers to deploying an energy park is attracting

[543] EJC's SOP at p. 16.
[544] EJC's SOP at pp. 17-18.
[545] Hr. Ex. 118, Landrum Rebuttal, p. 91.

industrial customers to serve the crucial role of flexible load.[546] Similarly, one of the key components of a renewable energy park is the existence of long duration energy storage. For both of these components—industrial customers with flexible load and long duration energy storage—another stakeholder study in Pueblo is unlikely to yield material benefits.

657. Instead, we direct the Company to continue advancing efforts to develop load flexibility for large loads and long duration energy storage. At a minimum, Public Service shall address load flexibility in the new large load tariff filing. This aligns with the Company's inclusion of load flexibility in the commercial principles for large loads. Load flexibility could also be critical in advancing the possibility of a Clean Transition Tariff, which will also be addressed in the large load tariff filing. Regarding long duration energy storage, this technology appears to be a prime candidate for CFFD funding. The Commission therefore encourages Public Service to fully evaluate options to promote long duration energy storage through the CFFD process.

X. Updated Phase I Modeling

658. In its SOP, CEC notes the Company's Phase I modeling does not reflect several revised conditions such as increased generic costs described in the Company's Rebuttal, current tariff estimates, and the accelerated termination of clean energy tax credits. Regarding the increased generic costs, CEC cites Public Service's Rebuttal in which the Company warns that the cost assumptions used in the Phase I modeling may in some cases be half of the costs the Company reasonably expects to see in Phase II.[547] In light of the revised conditions, CEC recommends the Commission require Public Service to rerun its load forecasts, PVRR, long-term rate analysis, and

[546] Hr. Ex. 1701, Att. DS-4, pp. 22-23.
[547] CEC's SOP at p. 14 (citing Hr. Ex. 118, Landrum Rebuttal, p. 68).

capacity expansion models with inputs that reflect the best and most current information available for the increased generic costs, current tariff estimates, and the accelerated termination of clean energy tax credits.

659. We agree with CEC and direct Public Service to provide updated Phase I modeling by December 31, 2025. Consistent with CEC's request, this updated modeling shall include refreshed load forecasts, PVRR, long-term rate analysis, and capacity expansion models and shall use updated assumptions regarding increased generic costs, current tariff estimates, and the accelerated termination of clean energy tax credits. This updated modeling will help establish more accurate expectations for the pricing and resource procurement we may see in Phase II as well as additional context for the large load tariff filing.

Y. Omnibus Motion, IE, and Requested Variances

1. Extension of Phase II Timelines (Rules 3618(b)(I), 3613(a), 3613(d), and 3613(e)-(h))

a. Party Positions

660. Public Service argues in the Omnibus Motion[548] that the resource planning procedures have become increasingly complex over the course of the past several ERP cycles with an unprecedented number of submitted bids resulting in portfolios with several gigawatts of new resources and billions in new clean energy-related investments across the State of Colorado. The Company expects the 2024 JTS to be similarly complex and requests an extension of the Phase II deadlines.[549]

[548] In its Omnibus Motion, the Company requests waiver of Commission Rules 3606(b), 3612(a), 3618(b)(I), 3613(a), 3613(d), 3613(e)-(h), and 3608(c)(III)-(IV). In Decision No. C24-0941-I, issued December 23, 2024, the Commission addressed Rule 3606(b) (regarding load forecasts) and Rule 3612(a) (regarding the motion to approve an IE). All of the other requested rule waivers were deferred to a future decision.

[549] Omnibus Motion at pp. 19-20.

661. In its SOP, Staff argues that the Company's requested waivers of the Phase II deadlines (Rules 3618(b)(I), 3613(a), 3613(d), and 3613(e)-(h)) should all be denied. Staff notes that Public Service has not provided further testimony related to these requests or otherwise shown a need for timing extensions given the evolution of the Phase II Framework. Staff asserts the Phase II Framework and the relatively limited number of modeling portfolios proposed for Phase II should help ease the Company's concerns about deadlines. If the Company determines in Phase II that extensions are needed, Staff argues the Company can seek extensions as it did in the last ERP.[550]

662. CEO likewise opposes the Company's requested extension of the Phase II deadlines CEO still believes it is premature to approve any of the Company's requested waivers regarding Phase II deadlines. CEO acknowledges the complexity of the ERP presents a challenge during Phase II proceedings but maintains that adhering to the ERP regulatory deadlines is important to reducing uncertainty around project deliverability and maintaining the timing of the Framework.[551]

663. CEI also opposes the Company's requested extension of the Phase II deadlines. CEI argues that after the passage of the federal Reconciliation Bill, time is of the essence for Colorado to purchase renewable energy that can qualify for the existing ITC/PTC credits as quickly as possible to maximize savings to ratepayers. In fact, CEI argues that it is critical for the Commission to issue a Phase II Decision before July 4, 2026, to ensure that bidders and Company-owned projects are able to take the steps necessary to safe-harbor projects and increase the chances of qualifying for ITC/PTC tax credits. CEI puts forth a proposal for an expedited Phase II schedule in which the RFP would issue by October 31, 2025, and the 120-Day Report

[550] Staff's SOP at p. 33.
[551] CEO's SOP at p. 12.

would be filed by March 1, 2026. Under CEI's expedited schedule, the Phase II Decision would issue on June 1, 2026.[552]

b. Findings and Conclusions

664. For the reasons set forth by Staff and CEO, we deny the Company's requested waivers regarding extensions of the Phase II timelines (*i.e.*, Commission Rules 3606(b), 3612(a), 3618(b)(I), 3613(a), 3613(d), 3613(e)-(h)). The Commission expects that the decisions made in Phase I (*e.g.* limiting bid variations that do not require a separate bid fee and largely approving the Phase II Framework with a reduced load forecast) make the Phase II bid evaluation and selection process more efficient. In addition, Public Service now has more experience with EnCompass, which should result in fewer unforeseen modeling issues.

665. While agree with CEI that the federal Reconciliation Bill added additional time pressures for the acquisition of renewable energy resources, we decline to adopt CEI's expedited schedule. As Staff notes, if Public Service needs additional time, the Company can file motions for extension of time like it did in the 2021 ERP/CEP.

2. Injection Capacity

a. Party Positions

666. As part of the Omnibus Motion, the Company requests a waiver of Rules 3608(c)(III)-(IV), which require information on injection capacities of all transmission assets. The Company contends that providing a fixed injection capability to any location on the system is misleading because the injection capability determined for a given location in the transmission system is highly dependent on the assumed generation and storage dispatch pattern. Therefore, the maximum injection capability corresponds only to the most favorable system

[552] CEI's SOP at pp. 31-32.

condition expected to occur. Because this system condition rarely occurs, the Company contends, an injection capability number by specific location is not a valid metric for the actual injection capability.

667. UCA argues that injection capability needs to be reported in Phase I so that bidders can determine where to site their projects in Phase II. UCA argues that despite its repeated requests, the Company failed to provide information about injection capability in the discovery process. UCA contends that the absence of this information gives the Company an unfair advantage over independent developers. UCA therefore recommends that the Commission require the Company to provide interconnection capability information prior to the base RFP.[553]

668. Interwest recommends the Commission direct the Company to provide transparent, timely, and actionable information for generation interconnection customers to identify available or low-cost headroom based on recent studies of transmission capability at interconnection points on the Company's system. Interwest also requests that basic technical information about the potential interconnection points, such as the status of terminal bays, presence of fiber options, flowgate data, and any known limiting element(s) at a potential interconnection point should also be made publicly available.[554]

669. Staff supports the Company's requested waiver but notes the Company does have an on-going responsibility to describe the dynamic nature of its transmission system, how it is modeled, and how it changes under different scenarios. Staff states that it "expects the Company to provide complete explanations and responses to discovery requests reasonably calculated to better understand transmission transfer capabilities."[555]

[553] UCA's SOP at p. 30.
[554] Hr. Ex. 501, Wilson Answer, pp. 33, 47.
[555] Staff's Response to Public Service's Omnibus Motion and Decision No. C24-0872-I, p. 4.

b. Findings and Conclusions

670. While we agree with the Company that injection capacity at any location is a very dynamic quantity, UCA's arguments that developers need information on available injection capacity, and that the absence of this information may give the Company a competitive advantage are also valid. Accordingly, we grant the Company's waiver request, but we also direct the Company to utilize historic SCADA data to provide statistical information on interconnection points of interest to developers. Specifically, for each interconnection point at which the Company has received either commercial inquiries or formal requests for interconnection studies from developers over the last two years, the Company shall make the following data available to developers: (1) the maximum capacity available in the most recently completed calendar year; (2) the number of hours in the most recently completed calendar year available capacity fell into each of ten bins, each representing ten percent of the maximum; and (3) the mean, median and standard deviation of available capacity over the most recently completed calendar year.

671. Should the above directive prove unduly burdensome, the Company may use alternative, commercially reasonable approaches to characterize available capacity at interconnection points of interest to developers.

3. Motion for IE Approval

672. As part of the Omnibus Motion, the Company requested a waiver of Rule 3612(a)'s timing requirement to file for Commission approval of an IE jointly proposed by Staff and UCA, until two weeks prior to the Phase I hearing. In Decision No. C24-0941-I, the Commission granted this request such that the Company had until two weeks prior to the Phase I hearing to file for Commission approval of an IE jointly proposed by Staff and UCA.[556]

[556] Decision No. C24-0941-I at ¶ 44.

673. Contrary to the Commission's directive in Decision No. C24-0941-I, Public Service has not filed a Motion to Approve an IE. The Company shall file this Motion, with the required conferral, as soon as reasonably practicable, but no later than two weeks prior to the issuance of the base RFP.

4. IE Conferral with Developers

674. Traditionally, the IE's scope of work has focused on ensuring the Phase II bid evaluation and selection process is conducted fairly. We find it necessary, however, to expand the IE's scope of work to include conferral with developers to increase the transparency regarding the negotiation process between Public Service and developers. The Company experienced several challenges negotiating PPAs in the 2021 ERP/CEP, and these challenges contributed to delays, price increases, and a higher likelihood that PPA projects fail during the negotiation process.[557] Despite these challenges, the Commission has relatively little insight into the negotiation process. With limited exceptions, individual developers do not intervene in ERP proceedings. Moreover, developers may be unwilling to openly discuss the challenges experienced in negotiations.

675. To increase transparency regarding the negotiation process, we direct Public Service, with conferral from Staff, UCA, and CIEA, to expand the IE's scope of work to require the IE to create a confidential channel through which bidders have the option to anonymously report their experiences negotiating with Public Service. This shall include both negotiations that resulted in executed PPAs and failed negotiations for which no PPA was executed. The IE will then compile these communications and file regular reports, possibly in the form of anonymous survey results, that stakeholders and the Commission can review. The goal is

[557] *See* Hr. Ex. 104, Bornhofen Direct, p. 15.

to create a more direct communication link between bidders and the Commission that would provide additional insight into the causes of the recent negotiation challenges including lengthy timelines and failed bid negotiations. We acknowledge this increased scope of work will result in higher costs for the IE. It is evident, however, that the negotiation challenges between bidders and the Company have already resulted in significant costs. The additional transparency into the negotiation process will better enable the Commission to enact targeted solutions.

676. In the interest of more quickly obtaining this additional transparency, this new IE task shall cover not just the PPA negotiations arising from this JTS but also the negotiations associated with the 2021 ERP/CEP projects. In other words, the IE must not wait until the JTS bidder negotiations to begin conferring with developers but shall start as soon as reasonably possible collecting information regarding the negotiations for the 2021 ERP/CEP projects.

677. The Commission will review the details of the new IE task when Public Service submits its Motion for IE approval, which shall include the IE scope of work.

5. Variances Needed for Phase II Framework

678. Staff recommends a permanent variance to paragraph 97 of Decision No. C22-0459 to allow for the JTS RAP to extend through 2033 as contemplated under the JTS Phase II Framework, particularly for the JTS supplemental RFP. Given the multiple RFPs provided under the JTS Phase II Framework, Staff argues the RAP extension will ensure more flexibility and allow for greater project participation in Phase II.

679. Staff also requests waiver of the deadline for the ERP following the JTS. In the 2021 ERP/CEP, the settling parties agreed to an October 31, 2026 deadline for filing of the Company’s next ERP but left open the possibility for a variance to this deadline based on future circumstances. In Decision No. C22-0459, we approved this October 31, 2026 deadline.

Here, Staff recommends a permanent variance to paragraph 45 of Decision No. C22-0459 to move the deadline for filing of the Company's next ERP to 2028 consistent with the Phase II Framework. Staff further supports a similar variance to Rule 3603(a) as necessary.

680. For the reasons set forth by Staff, we grant a permanent variance to paragraph 97 of Decision No. C22-0459 to allow for the JTS RAP to extend through 2033. Similarly, we grant a permanent variance to paragraph 45 of Decision No. C22-0459 (and variance to Rule 3603(a), as necessary) to move the deadline for filing of the Company's next ERP to 2028 consistent with the Phase II Framework of the JTS

6. Variance from Rule 3206(b)(I)

a. Party Positions

681. Public Service requests a partial and permanent variance from Rule 3206(b)(I) such that (1) the Company need not request a CPCN for transmission lines that are constructed to serve a single customer which terminates at the customer premise and is paid for entirely, or the costs are directly assigned to, that customer; (2) the CPCN exception not be limited to those transmission facilities that are a "radial feed"; and (3) this variance be granted for all transmission facilities constructed for new large load customers that will take electric service from a "transmission line designed at 230 kV or above that serves a single retail customer and terminates at that customer's premises."[558]

682. The Company explains that under Rule 3206(a), a utility may not commence new construction of transmission facilities until either the Commission notifies the utility that such facilities do not require a CPCN or the Commission issues a CPCN. However, Commission Rule 3206(b)(I) states that a CPCN is not required for a radial transmission line

[558] Public Service's SOP, Att. A, at p. 4.

designed at 230 kW or above that serves a single retail customer and terminates at that customer's premises.

683. Public Service asserts it has a robust pipeline of potential large new customers that will require transmission level service to their facilities. According to the Company, granting this variance will reduce procedural hurdles and will enable the Company to interconnect these customers more quickly. Moreover, Public Service argues that allowing the Company to avoid the need to prepare and litigate such CPCNs will result in cost savings, and administrative efficiencies for the Commission and all parties.[559]

684. Staff argues that the Company's requested CPCN variance is premature, noting that the Company concedes that a decision on this point is not necessary in Phase I. Staff further warns that the Company's request appears to extend well beyond projects needed to implement the JTS. Further, although the Commission found that no CPCN was needed for certain projects serving a single customer in the past, in those instances the Commission had information about the scope, location, estimated costs, and justification for those particular projects. At this time, Staff asserts, the Commission and interested parties lack such information. Thus, Staff recommends the Commission deny the request and that the Company seek variances for specific projects as needed in appropriate future filings.[560]

b. Findings and Conclusions

685. For the reasons set forth by Staff, we deny as premature the Company's request for a partial and permanent variance from Rule 3206(b)(I). As Staff notes, as this point the

[559] Hr. Ex. 123, Bailey Rebuttal, p. 50.
[560] Staff's SOP at pp. 33-34.

Commission and interested parties lack information about the scope, location, estimated costs, and justification for the projects applicable to the Company's requested waiver.

7. 120-Day Timeline for post-JTS CPCNs

686. Public Service proposes that all post-ERP CPCNs should be based on a 120-day timeline, so long as the projects are consistent with the as-bid project.[561] The Company notes its request would still provide four months of process to evaluate projects requiring a CPCN—and more than that if the project is not consistent with the project as-bid. If the project as-bid has won in a competitive solicitation and the material terms of such remain consistent, the Company argues that eight to nine months of regulatory process for a CPCN proceeding is not necessary.[562]

687. Public Service reiterates this request in its SOP, arguing that follow-on CPCN filings are not requirements that IPPs have. In addition, the Company asserts resource adequacy and cost management considerations counsel in favor of the Commission granting this timing tool for use with Company-owned JTS projects in order to improve speed to operation and maximize capture of potential tax benefits.

688. Staff opposes the Company's request for several reasons. Staff notes the CPCN statute contemplates a base timeline of 120 days and that it is unclear what the Company means by "generally consistent" with the Phase II bid. Staff asserts the Company's proposal would make it difficult for parties to provide meaningful oversight and review of Company-owned generation resources. Staff also argues that deciding this issue in Phase I is premature because such decision unnecessary to conduct Phase II and the scope of these CPCN proceedings as well as potential conflicts with other proceedings are not yet known.

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[561] Hr. Ex. 101, Ihle Direct, pp.76-77.
[562] Hr. Ex. 117, Ihle Rebuttal, p. 69.

689. We deny the Company's request as premature. The Company's request risks putting the burden on the Commission to quickly evaluate and determine whether a CPCN application is consistent with the Company's Phase II bid. Given the Commission's constrained resources, a more efficient path is for Public Service to work together with Staff, UCA, and other interested stakeholders prior to filing its CPCN applications. Interested stakeholders could agree in their interventions that the Company's application is consistent with its Phase II bid and there are no other unresolved issues, such as the utility-ownership PIMs. We emphasize that in such a situation where parties agree that an expedited timeline is appropriate, the Commission will work diligently to process the CPCN applications within such timeline.

Z. Adjudication Costs

1. Party Positions

690. The Company requests deferral of expenses related to consultant work, transcripts and hearing costs, and outside legal counsel. The Company also requests deferral of outside legal expenses associated with negotiating PPAs emanating from the approved JTS. Public Service estimates that the costs for consultants and outside witnesses, including for the labor economist and E3, will be $490,000. The Company anticipates incurring an approximate cost of $54,500 for the purchase of transcripts of the hearings and other hearing costs. Outside legal costs, including costs that will be incurred to assist with PPA negotiations, are expected to be $2.2 million.[563]

691. For most of these requests, the Company proposes to track the costs in a non-interest bearing regulatory asset that will be reviewed for recovery purposes in a future rate case

[563] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 126-28.

proceeding. However, Public Service requests to recover the costs of the independent facilitator associated with the CFFD, the labor economist, and IE through the ECA.[564]

692. UCA opposes the request to recover the labor economist fees through the ECA. UCA argues that fees associated with the labor economist should instead be included in the deferred account similar to the deferred account with other outside consultants.[565]

693. UCA also argues the Company should be directed to use any over-collection of bid fees to offset the adjudication costs in the deferred account. UCA suggests this offsetting could be done through accurate accounting of the costs of bid evaluation with bid fee receipts. UCA asserts the Company has not committed to refund excess bid fee collections to ratepayers and that a Commission order requiring this will promote the public interest. [566]

694. Other than the issues with the labor economist fees and the offsets from unused bid fees, UCA does not oppose the Company's deferral request, as long as the regulatory account does not include carrying costs.[567]

695. In Rebuttal, Public Service argues the labor economist fees are necessary for the evaluation of bids in the Phase II process, similar to the costs for the IE. For consistency, the Company asserts these costs should be treated the same and recovered in the ECA. The Company also opposes UCA's request regarding the bid fees, arguing the purpose of bid fees is to offset the Company's costs of evaluating bids during the Phase II process, not to offset the costs of prudently incurred expenses from litigating the JTS proceeding.[568] The Company further argues that UCA's recommendations regarding bid fees fail the acknowledge that bid fees cover real costs of bid

[564] Public Service's SOP, Att. A, at p. 3.
[565] UCA's SOP at p. 33.
[566] UCA's SOP at p. 33.
[567] Hr. Ex. 301, England Answer, pp. 23-24.
[568] Public Service's SOP at p. 31.

evaluation, which is particularly acute given the number of bids the Company receives and has to process in very short order.[569]

2. Findings and Conclusions

696. We grant the Company's request to cover the costs of the independent facilitator and the labor economist through the ECA. The labor economist concept was present in the 2021 ERP/CEP, where the settling parties agreed that the costs should be recovered via the ECA.[570] UCA's arguments do not justify changing this approach for purposes of the JTS. This same rationale supports ECA recovery for costs associated with the independent facilitator. As set forth above, however, the costs associated with the independent facilitator are included in the CFFD's budget cap. Regarding the IE, Public Service has not yet filed the Motion to approve an IE. We thus defer consideration of cost recovery for the IE until the decision ruling on the Motion to approve an IE.

697. In addition, we grant UCA's request that excess bid fees must offset the adjudication costs in the deferred account. It is unclear what costs the Company incurs in evaluating bids that it does not already recover elsewhere. Public Service shall provide an accounting of the costs of bid evaluation along with all bid fee receipts in the Company's next ERP Annual Report. To the extent there are any bid fees that are in excess of the Company's incremental costs of evaluating bids that are not recovered elsewhere, Public Service shall use such excess bid fees to offset the adjudication expenses.

698. In all other respects, we grant the Company's request to track and defer expenses related to consultant work, transcripts and hearing costs, and outside legal counsel costs in a

[569] Hr. Ex. 117, Ihle Rebuttal, p. 104.
[570] Decision No. C22-0459 at ¶¶ 155-56 issued in the 2021 ERP/CEP (Aug. 3, 2022).

non-interest bearing regulatory asset that will be reviewed for recovery purposes in a future rate case proceeding.

AA. Updates to Modeling Inputs and Assumptions

699. Section 2.11 of Volume 2 sets forth the inputs and assumptions Public Service intends to use in Phase II. These inputs and assumptions include capital structure and discount rate, gas price forecasts, inflation rates, and the ELCC and PRM values derived from the RA study. Section 2.11 also includes the inputs regarding the Company's demand and energy forecasts and projected resource capacity need. In Volume 2, Public Service states that, consistent with past practice, the Company will update the modeling inputs and assumptions as necessary.

700. During the hearing, Public Service specifically committed to provide an updated load forecast 30 days before the issuance of the RFP. The Company anticipated that this update would be "a full refresh of the load forecast" and include refinements to the Company's EV and PHEV forecasts.[571]

701. Except as modified in this Decision, the Commission approves the modeling inputs and assumptions outlined in Section 2.11 of Volume 2. In addition, consistent with past practice and the Company's commitments during the hearing, we direct Public Service to file, 30 days prior to issuing the base RFP, a complete list of the modeling inputs and assumptions consistent with the presentation in Section 2.11 of Volume 2 and indicate which parameters were updated for bid evaluation and selection purposes. To the extent that any parameters are still to be updated after the RFP is issued but prior to the Phase II resource evaluation, Public Service shall identify the updated parameters in the 120-Day Report. These updates shall be consistent with the Commission's other rulings in this Decision, including our directives on which large loads to

[571] Hr. Tr. June 23, 2025, pp. 64-65.

include in the load forecast, revisions to the Company's EV and BE estimates, the inclusion of an annual firm gas supply cost escalator, and updates to the costs of generic resources, including any changes made during the Company's rebuttal filing or at hearing to reflect evolving market conditions.[572]

702. Given the various changes we are directing Public Service to make in its RFP, the Commission further directs the Company to file its final RFP in this Proceeding at least 30 days prior to the RFP issuance. Consistent with our decision to adopt the Company's proposed process for reaching a final, non-negotiable PPA prior to the RFP, the Company must file its final, revised PPAs, incorporating all of the Commission's directives, at least 30 days prior to the RFP issuance.

BB. Conclusion

703. In this Phase I Decision, we establish the necessary guardrails within which Public Service may initiate an all-source, competitive bidding process to meet the Company's unprecedented resource need. Through the modified Phase II Framework, Public Service will move forward with a base RFP to acquire resources through 2031, a supplemental RFP to acquire additional resources through 2033, and a new ERP proceeding in 2028. In addition, the Company may use the incremental need pool to quickly respond to changes that the base RFP and supplemental RFP did not anticipate, and the Company can move forward immediately using the strategic reserve funds to begin the process of acquiring necessary transformers and breakers. This novel regulatory framework allows the Company to swiftly respond to the dynamic environment in which we find ourselves.

704. At the same time, the additional customer protections this Decision establishes help protect Colorado ratepayers from the risks associated with new large loads like data centers.

[572] *See. e.g.*, Hr. Ex. 135 (providing updated overnight construction costs for generic CTs).

We specifically reject the notion that existing ratepayers should bear the risk of rate increases if large loads fail to materialize or if the large loads fail to fully pay for their impacts to the electrical grid. This Decision sets clear steps that Public Service and prospective large loads must take to qualify for the streamlined regulatory process for acquiring additional resources through the modified Phase II Framework. If large load customers are willing to take such steps and commit to Colorado, the Commission is eager to support Public Service in acquiring new generation. We are unwilling to make existing customers pay for additional generation before such a commitment.

705. Importantly, this Decision also largely adopts the Company's proposed tools for ensuring a just transition. We maintain the basic framework for community assistance payments established in the 2021 ERP/CEP USA and extend them somewhat to provide payments based on the Company's ownership interests in Craig Unit 2. We also grant the Pueblo Intervenors' request to quantify the community assistance payments to Pueblo County and the underlying methodology and, in-line with the requests from the Routt County Governments, direct Public Service to propose a pathway to the dedication of the Hayden Station Spur Line, the Pumphouse Property, and any unused water rights currently benefiting Hayden Station. We acknowledge our rulings do not go as far as some parties request. Given that community assistance payments are funded by ratepayers, however, we ultimately agree with Staff that further expansion of community assistance payments will have affordability impacts on all ratepayers, including low-income customers.

706. Recognizing the testimony from various parties that capital investments in just transition communities are much more advantageous than temporary community assistance payments, we also largely approve requested mechanisms to drive new investments in these

communities. In addition to continuing the property tax offset modeling approach established in the 2021 ERP/CEP USA, we partly approve the Company's request to introduce new just transition modeling credits. Our decisions help ensure the Phase II modeling recognizes the true value of resources sited within just transition communities and does not simply select the least-cost resources. At the same time, our decision to pare back the full amount of the modeling credits addresses various concerns, including that using the full amount of the requested modeling credits is vulnerable to gaming and could allow developers to inflate the bid price of their projects. Another approved mechanism to drive new investment is the CFFD, which addresses barriers to the development of carbon-free firm dispatchable resources such as advanced geothermal and nuclear energy. An advisory board comprised of a broad group of stakeholders including members representing ratepayer advocates, the environmental community, the OJT, the Hayden community, the Pueblo community, Moffat County, and Morgan County will help determine how the $100 million in CFFD funds will be allocated.

707. In addition to the above, our Decision sets forth numerous rulings that carefully balance the competing interests of numerous intervenors and provide the necessary clarity for an efficient and transparent Phase II process. Some of these rulings include the following:

a. We maintain our initial approach and defer granting an unconditional CPCN for the MVLE until a showing in Phase II that a portfolio including the cost of the MVLE and any related transmission investment in southeast Colorado is in the public interest.

b. We establish a suite of Phase II portfolios that Public Service must model. These Phase II portfolios are intended to provide a wide range of potential pathways, including accelerated emissions reduction portfolios, portfolios with limited amounts of new gas-fired resources, least cost portfolios, and a business as usual portfolio.

c. We largely approve the Company's request for a conforming bid policy and provide guidance and a process to help the parties achieve further agreement on a non-negotiable PPA.

d. We address several Phase II modeling methodologies, such as the best-in-class process, assumptions regarding existing and planned thermal units, and updates to the generic prices of resources.

e. We deny the Company's proposal to use an SRR penalty in the Phase II modeling based on evidence that it would inappropriately discourage the model from selecting solar resources in the Pueblo area.

f. We largely adopt Staff's tariff passthrough proposal that will encourage bidders to participate in the resource solicitation process in the face of substantial uncertainty regarding future tariff impacts.

g. We adopt the Company's BVEM proposals, including for a labor economist to calculate a BVEM score for each Phase II portfolio and direct Public Service to ensure that provision and presentation of BVEM rules during Phase II of this Proceeding (both the base RFP and supplemental RFP) fully comply with the statutory requirements.

708. Through these and many other rulings, this Decision provides the necessary regulatory certainty for Public Service to move to Phase II in which the Company will solicit and evaluate various bids for new generation and storage resources. Consistent with this Decision, Public Service will compile these bids into various Phase II portfolios and ultimately present its plan for acquiring additional resources in the 120-Day Report.

II. ORDER

A. The Commission Orders That:

1. The Verified Application for Approval of a 2024 Just Transition Solicitation filed by Public Service Company of Colorado ("Public Service") on October 15, 2025, is granted, with modifications, consistent with the discussion above.

2. The Omnibus Motion for Extraordinary Protection of Highly Confidential Information, and for Partial Waiver of Rules 3606(b), 3612(a), 3618(b)(I), 3613(a) and 3613(d) and Waiver of Rule 3608(c)(III)-(IV) filed by Public Service on October 15, 2025, is granted, in part, and denied, in part, consistent with the discussion above. The requested waivers of

Commission Rules 3606(b), 3612(a), 3618(b)(I), 3613(a), 3613(d), 3613(e)-(h) are denied. The requested waiver of Rules 3608(c)(III)-(IV) is granted.

3. The Motion to Strike filed on August 4, 2025, by Moffat County and the City of Craig is denied.

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

5. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS AND WEEKLY MEETINGS
August 6, 13, 18, 21, and 27, 2025.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

ATTEST: A TRUE COPY

TOM PLANT

Commissioners

Rebecca E. White,
Director

COMMISSIONERS ERIC BLANK,
MEGAN M. GILMAN, AND
TOM PLANT, DISSENTING,
IN PART