Decision No. C24-0634

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 22A-0230E

IN THE MATTER OF THE APPLICATION OF BLACK HILLS COLORADO ELECTRIC, LLC FOR (1) APPROVAL OF ITS 2022 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN, AND (2) APPROVAL OF ITS 2023-2026 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN.

COMMISSION DECISION ADDRESSING PHASE II RESOURCE SELECTION AND APPROVING MODIFIED CLEAN ENERGY PLAN, ESTABLISHING PERFORMANCE INCENTIVE MECHANISMS FOR BID 245-01, REQUIRING AN ADVICE LETTER COMPLIANCE FILING, AND ADDRESSING RELATED MATTERS

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I. **BY THE COMMISSION**

A. Statement

1. In accordance with § 40-2-125.5(4), C.R.S., the Electric Resource Plan ("ERP") filed by Black Hills Colorado Electric, LLC ("Black Hills" or the "Company") on May 27, 2022, includes a Clean Energy Plan ("CEP") to reduce the Company's carbon dioxide ("CO_2") emissions by a target of 80 percent by 2030 as compared to 2005 levels. As set out in Decision No. C23-0193

("Phase I Decision"),[1] the Commission granted, in part, with modifications the Unanimous Comprehensive Settlement Agreement that Black Hills filed on January 13, 2023 ("Phase I Settlement") and approved with modifications the Company's 2022 ERP.

2. Some of the key additions and clarifications the Commission made to the Phase I Settlement stem from our efforts to ensure that any approved CEP results in reasonable costs to customers. Based in part on concerns that utility-owned generation projects have fewer protections against cost increases as compared to power purchase agreement ("PPA") projects that independent power producers ("IPPs") own,[2] we required the parties to engage in a stakeholder process for the development and submission of performance incentive mechanisms ("PIMs") for utility-owned generation.[3] The Phase I Decision explains the costs of a utility-owned project could significantly increase in a follow on certificate of public convenience and necessity ("CPCN") proceeding. The Phase I Decision states: "To ensure that the Company is held to its estimated costs in its Phase II bid, it is necessary for the utility-ownership PIM to be developed and applied in this Proceeding, as opposed [to] a later CPCN proceeding."[4] We further authorized Black Hills to implement the statutory requirements for approval of its CEP such that the Commission could continue evaluation of, among other things, the additional CEP activities, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I) and (3)(a)(II), C.R.S., and whether the CEP is in the public interest and consistent with the clean energy target in § 40-2-125.5(3)(a)(I), C.R.S.

3. Throughout the course of Phase II, Black Hills has advanced portfolios of resources with high costs and high percentages of utility-owned projects. In the Preferred Portfolio that Black

[1] Issued March 8, 2023.
[2] Phase I Decision, ¶ 62.
[3] As discussed later, we also directed the parties to develop an emissions reduction PIM.
[4] Phase I Decision, ¶ 62.

Hills initially advanced in the 120-Day Report, Black Hills would have owned 62.5 percent of the new generating and storage resources.[5] For reference, in the Phase I Settlement, the Settling Parties agreed that "the Company may propose to own *up to* a target of up to 50 percent of generation acquisitions."[6] Similarly, Black Hills' Preferred Portfolio was more expensive than other available portfolios, such as the CEP Portfolio.[7]

4. Despite our findings in the Phase I Decision regarding the necessity to establish PIMs for utility-owned resources in this Proceeding given the risk that costs could significantly increase, in Phase II, and during the subsequent construction process, Black Hills requested that the Commission allow the Company to delay submitting a proposed utility-ownership PIM until after the Commission issued a Phase II decision authorizing specific resource acquisitions. Moreover, Black Hills questioned the applicability of a utility-ownership PIM, arguing that as to the specific utility-owned generating projects included in the various portfolios, "the Company will have little control over the construction cost of a project."[8]

5. Consistent with our efforts throughout this Proceeding to ensure that any approved CEP results in reasonable costs to customers, and after consideration of the statutory and public interest factors, we find that modifying Black Hills' proposed CEP[9] is necessary to ensure the plan is in the public interest. In the CEP that we approve through this Phase II Decision, Bid 114-05a (a 200 MW solar build transfer agreement ("BTA"))[10] is replaced with Bid 114-08 (the same

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[5] Black Hills' Response Comments, p. 17.

[6] Phase I Settlement, ¶ 6 (emphasis added).

[7] 120-Day Report (Rev. 1), pp. 53, 56.

[8] Black Hills' Second Motion for Extension, p. 9.

[9] In Black Hills' Supplemental Comments, the Company indicates that its preferred portfolio of resources is the Local Economic Development Portfolio, which consists of Bid 114-05a, Bid 248-01, and Bid 245-01. (Black Hills' Supplemental Comments, pp. 4, 29).

[10] BTA projects are developed and constructed by an IPP but then sold to the utility to own and operate. Thus, BTA projects are ultimately utility-owned projects.

underlying 200 MW solar PPA),[11] and Bid 248-01 (a 100 MW solar PPA) is replaced with Bid 334-03 (a 150 MW solar PPA). The 50 MW storage BTA project (Bid 245-01) is unmodified. Thus, Bid 114-08, Bid 334-03, and Bid 245-01 are the resources included within the Commission's Modified Local Economic Development Portfolio ("Modified LED Portfolio").

6. The Modified LED Portfolio exceeds Colorado's goals in emission reductions and protects reliability of the electrical system. At the same time, Modified LED Portfolio, which has fewer utility-owned resources, greatly reduces the risk that customers will bear significant cost increases based on construction and operational cost overruns and thus helps ensure that the plan will result in reasonable cost and rate impacts to customers.

7. We therefore direct Black Hills to pursue this Modified LED Portfolio and its backup resources with further due diligence and contract negotiations and to file a CPCN application for the Company-owned resources arising from the Modified LED Portfolio. We further direct that Bid 245-01 from the approved CEP is subject to the cost-to-construct PIM set forth below.

8. In addition, we make several directives regarding Black Hills' next ERP (the 2026 ERP) and require the Company to file an advice letter relating to cost recovery and the CEP Rider ("CEPR").

B. Background

1. Electric Resource Planning

9. 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

[11] PPA projects are developed, constructed, owned, and operated by IPPs.

assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

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

11. 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.[12] In Phase II, the Commission issues a final decision regarding the utility's preferred cost-effective plan for pursuing the acquisition of particular resources.

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

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

13. At the end of Phase II, the Commission issues a final Phase II decision that approves, conditions, modifies, or rejects the utility's preferred cost-effective resource plan pursuant to Rule 3613(h). Upon issuance of this Phase II Decision, and consistent with Rule 3613(h), Black Hills will continue its due diligence and contract negotiations, as appropriate, and file an application for a CPCN in accordance with § 40-5-101, C.R.S., for any Company-owned project arising from the approved CEP. Per Rule 3617(d), any utility actions consistent with the approved CEP are entitled to a presumption of prudence.

2. Clean Energy Plans Pursuant to SB 19-236

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

15. SB 19-236 enacts § 40-2-125.5(1), C.R.S., that declares the statewide importance of promoting cost-effective clean energy and new technologies and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." Specifically, § 40-2-125.5(3), C.R.S., creates the following clean energy targets:

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

16. The statute further requires that the first ERP that a qualifying retail utility files following January 1, 2020, must include a CEP that "will achieve the clean energy target set forth in subsection (3)(a)(I)" and will "make progress toward the [100 percent] clean energy goal set forth in subsection (3)(a)(II)."[13] Subsection 4 further specifies what a CEP must include (*e.g.*, a plan of actions and investments projected to achieve compliance with the clean energy targets set forth in subsection (3)(a)(I) and (3)(a)(II), the projected costs of the CEP's implementation, and workforce transition and community assistance plans).

17. Black Hills does not constitute a qualifying retail utility under the statute because it does not provide electric service to more than 500,000 customers.[14] However, per § 40-2-125.5(3)(b), C.R.S., Black Hills has voluntarily opted into the terms of § 40-2-125.5, C.R.S., and the parties to this Proceeding support this voluntary election.[15]

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

> Reductions in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
>
> The feasibility of the clean energy plan and the clean energy plan's impact on the reliability and resilience of the electric system. The commission shall not approve any plan that does not protect system reliability.
>
> Whether the clean energy plan will result in a reasonable cost to customers, as evaluated on a net present value basis….[16]

[13] § 40-2-125.5(4)(a).
[14] § 40-2-125.5(2)(c)(I).
[15] Phase I Settlement, ¶ 1.
[16] § 40-2-125.5(4)(d).

19. If the Commission approves a CEP that achieves an emission reduction of at least 75 percent from 2005 levels, then the relevant utility is provided with a "safe harbor" from any additional emission reduction regulations that the Air Quality Control Commission ("AQCC") might develop for the power sector through 2030.[17]

20. As a general matter, the Colorado Department of Public Health and Environment ("CDPHE") is tasked with calculating whether a proposed CEP will meet these clean energy targets. In particular, the division of administration in the CDPHE must describe the methods of measuring CO_2 emissions and verify the projected CO_2 emission reductions of the CEP.[18] The statute goes on to state that the division of administration, in consultation with the AQCC, must determine whether the CEP will meet the 2030 clean energy targets, and will report to the Commission the division's calculation of CO_2 emission reductions attributable to any approved CEP.[19]

21. SB 19-236 also sets forth accounting requirements to track the costs of the CEP. For instance, § 40-2-125.5(4)(a)(III), C.R.S., states the utility must "clearly distinguish" between the set of resources necessary to meet customer demands in the resource acquisition period ("RAP") and the additional CEP activities that may be undertaken to meet the clean energy target of 80 percent emission reduction by 2030. Moreover, the CEP must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions.[20] Likewise, the CEP must list the "actions and investments" necessary to meet the clean energy

[17] § 25-7-105(1)(e)(VIII)(C), C.R.S.
[18] § 40-2-125.5(4)(b).
[19] § 40-2-125.5(4)(c)(1).
[20] § 40-2-125.5(4)(a)(VI).

target and describe the effect of such actions and investments on the safety, reliability, renewable energy integration, and resiliency of the electric system.[21]

22. The statute goes on to direct the utility to collect revenues for the additional CEP activities through a CEPR assessed on a percentage basis on all retail customer bills.[22] This CEPR is limited to a maximum electric retail rate impact of 1.5 percent of the total annual electric bill for each customer for implementation of the approved additional CEP activities and "may be established as early as the year following approval of a clean energy plan by the commission."[23]

23. The statute requires the utility to use a competitive bidding process to procure any resources to fill the cumulative resource need derived from the ERP and CEP. In addition, per § 40-2-125.5(5)(b), C.R.S.:

> The commission shall allow the qualifying retail utility… to own a target of fifty percent of the energy and capacity associated with the clean energy resources and any other energy resources developed or acquired to meet the resource need, as well as all associated infrastructure, if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact.[24]

24. The statute goes on to clarify, however, that the provisions in § 40-2-125.5(5)(b), C.R.S. in no way alter the Commission's authority to approve or modify the utility's CEP pursuant to § 40-2-125.5(4)(d), C.R.S.

25. As discussed in our Phase I Decision, certain statutory findings required for an approved CEP could not be made in the Phase I Decision but must wait until Phase II. We further noted in our Phase I Decision that we will continue to consider the cost concerns raised by various parties and "will strive to avoid any set of bids that results in unnecessary or unreasonable rate

[21] § 40-2-125.5(4)(a)(IV)-(V).
[22] § 40-2-125.5(5)(a)(II)
[23] § 40-2-125.5(5)(a)(I).
[24] § 40-2-125.5(5)(b).

impacts."[25] The Phase I Decision permitted Black Hills to issue the RFP and proceed to Phase II and established the framework in which bids will be evaluated and selected, setting important Phase II assumptions and ensuring that the 120-Day Report contains the information required to make the statutory findings necessary to reach an approved CEP.[26]

26. The Commission did not anticipate, and no party requested, a fully litigated hearing in Phase II. Rather, through its usual Phase II process together with the supplemental filings Black Hills provided, the Commission can address the necessary statutory findings in this Phase II Decision (*e.g.*, upon consideration of the 120-Day Report, the parties' comments to the 120-Day Report, and the Independent Evaluator ("IE") Report). SB 19-236 might change the objectives of the ERP process, but it does not direct any changes to the process itself.

3. Procedural Background

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

28. The parties in this Proceeding consist of the following: Black Hills, Staff of the Public Utilities Commission ("Staff"), Office of Utility Consumer Advocate ("UCA"), Colorado Energy Office ("CEO"), the Board of County Commissioners of Pueblo County ("Pueblo County"), the City of Pueblo ("Pueblo City"), the City of Cañon City ("Cañon City"), Walmart Inc., Energy Outreach Colorado, Western Resource Advocates ("WRA"), Colorado Independent Energy Association ("CIEA"), and Interwest Energy Alliance.

[25] Phase I Decision, ¶ 38.
[26] Phase I Decision, ¶ 19.

29. In Decision No. C22-0494-I,[27] the Commission granted the Motion for Limited Participation that CDPHE filed on June 24, 2022. As such, CDPHE is participating in this Proceeding as a neutral verifier.

30. On March 8, 2023, the Commission issued the Phase I Decision approving in part, and with modifications, the Phase I Settlement. Among other things, the Phase I Decision directed Black Hills to issue RFPs for an all-source, competitive bidding process to meet its resource need.[28] The Commission further required the parties to engage in a stakeholder process for the development and submission of an emissions-reduction PIM and a utility-owned generation PIM. We found that developing and applying a utility-owned generation PIM in this Proceeding is necessary to ensure that the Company is held to the cost estimates in its Phase II bids.[29]

31. In Decision No. C23-0501,[30] the Commission approved Accion Group, LLC ("Accion") as the IE for Phase II of this Proceeding.[31]

32. On July 31, 2023, Black Hills issued its 2023 all-source RFPs, including a Company ownership RFP, a dispatchable resources RFP, and a renewable resources RFP. Bids were due by October 20, 2023.

33. On November 20, 2023, Black Hills filed the Unopposed Motion for Partial Waiver of Rules 3613(a) and 3613(d)-(h) to Provide an Extension of Time to Notify Bidders of Bids Advanced to Computer-Based Modeling and File its 120-Day Report. In this Motion, the Company argued that, due to the volume of bids received in response to the RFP, it needed an additional

[27] Issued August 18, 2022.
[28] Phase I Decision, p. 34.
[29] Phase I Decision, ¶ 62.
[30] Issued July 31, 2023.
[31] Under the Commission's ERP rules, Staff, UCA, and the relevant utility jointly propose an IE to oversee the Phase II RFP and bid evaluation process and generally facilitate the administration of the Phase II solicitation. (*See* Rule 3612; Phase I Decision, ¶ 460).

15 days to conduct eligibility reviews, due diligence, and economic screening, and then notify bidders of advancement to computer-based modeling per Rule 3613(a). For similar reasons, Black Hills requested an additional 60 days to file the 120-Day Report under Rule 3613(d).

34. In Decision No. C23-0807,[32] the Commission granted the Unopposed Motion that Black Hills filed on November 20, 2023. Among other things, this extended the deadline for Black Hills to file the 120-Day Report from February 17, 2024, to April 17, 2024.

35. On April 17, 2024, the Company filed its 120-Day Report setting forth the Company's Preferred Portfolio of generation resources as well as several other alternative resource portfolios. On May 10, 2024, Black Hills filed a revised version of the 120-Day Report, and a supplement on May 16, 2024.[33] As contemplated in the Phase I Settlement, the Company held a technical conference on May 1, 2024, to provide an overview of its 120-Day Report and to answer questions from parties.

36. On May 14, 2024, the APCD filed its Phase II CEP Verification Report. In its Verification Report, APCD confirms that the CEP Guidance and associated verification workbooks were properly used to calculate the emissions reduction percentages and that the 2005 baseline was appropriately used.[34] Importantly, APCD states that—with the exception of the two ERP portfolios—all of the Phase II portfolios Black Hills presents in the 120-Day Report are "expected to meet the minimum requirements under the statutes to qualify as a CEP and for the Safe Harbor."[35]

[32] Issued December 5, 2023.

[33] The 120-Day Report Supplement provides a securitization analysis consistent with the Phase I Decision and § 40-2-137, C.R.S. and the Company's proposed early retirement of the Pueblo Diesel units. The Pueblo Diesel Units only have a book value of approximately $527,000, and Black Hills opined that attempting to securitize the Pueblo Diesel Units would likely increase the cost of the Preferred Portfolio by at least $7 million.

[34] Phase II Verification Report, pp. 3-4.

[35] Phase II Verification Report, p. 5.

37. On May 17, 2024, Accion filed its IE Report, generally concluding that "a fair solicitation was conducted, that all bidders had access to the same information at the same time, and that all bids were evaluated using the same criteria and standards."[36]

38. On June 3, 2024, several intervenors in this Proceeding filed comments on the Company's 120-Day Report, including Staff, CEO, UCA, CIEA, Pueblo County, and Cañon City.

39. On June 10, 2024, Black Hills filed an Unopposed Motion for Extension of time to File a PIM and Motion for Waiver of Response Time. In this Unopposed Motion, Black Hills requested a 45-day extension of the deadline to file a stakeholder PIM proposal.

40. By Decision No. C24-0407,[37] the Commission granted the Unopposed Motion filed on June 10, 2024, and extended the deadline for Black Hills to file its stakeholder PIM proposal from June 17, 2024, to August 1, 2024.

41. On June 18, 2024, Black Hills filed its Response Comments and associated attachments responding to the intervenor comments filed on June 3, 2024.

42. The Commission commenced its Phase II deliberations on July 10, 2024.

43. In Decision No. C24-0509-I,[38] the Commission raised concerns with the substantial costs projected for the portfolio of resources Black Hills advanced. Noting that Black Hills' ratepayers pay some of the highest electricity rates in the state, we found it would be unconscionable to move forward unless and until we had more confidence the proposed resource investments will result in a reasonable cost to customers.[39] Accordingly, we required supplemental

[36] IE Report, p. 18.
[37] Issued June 12, 2024.
[38] Issued July 16, 2024.
[39] Decision No. C24-0509-I, pp. 3-4.

information from Black Hills regarding the Phase II bid evaluation and selection process including "whether there are more cost effective means to achieve the state's emission reduction targets."[40]

44. In addition, in Decision No. C24-0509-I we waived the 90-day deadline under Commission Rule 3613(h) to issue a Phase II Decision to ensure the Commission has sufficient time to reach the appropriate outcome.[41]

45. On July 22, 2024, Black Hills filed a Second Motion for Extension of Time to File a PIM and Request for Clarification ("Second Motion for Extension"). In this Second Motion for Extension, Black Hills requested an additional extension of time of 45 days, or 30 days following the Commission's final Phase II decision (whichever is later) for the Company to file its stakeholder PIM proposals. Black Hills also requested clarification of certain requirements for the emissions-reduction PIM and the utility-ownership PIM set forth in the Phase I Decision.

46. Pursuant to Decision No. C24-0509-I, on July 30, 2024, Black Hills submitted Supplemental Comments along with several attachments and exhibits.

47. In Decision No. C24-0553,[42] the Commission granted, in part, and deferred, in part, the Second Motion for Extension that Black Hills filed on July 22, 2024. The Commission vacated the August 1, 2024 deadline for Black Hills to file its stakeholder PIM proposal but deferred setting new deadlines or issuing the requested clarifications. The Commission expressed concern over several of the arguments and suggestions Black Hills made in its Second Motion for Extension, and we expressed our intent to establish the appropriate next steps for the stakeholder PIMs in a future decision.

48. The Commission concluded its Phase II deliberations on August 7, 2024.

[40] Decision No. C24-0509, ¶ 11.
[41] Decision No. C24-0509, ¶ 29.
[42] Issued July 31, 2024.

C. Phase II Filings

1. 120-Day Report

49. In the 120-Day Report, Black Hills advances its Preferred Portfolio of resources that consist of the following three projects: (1) a 150 MW PPA wind project (Bid 248-02) located in Kit Carson County, (2) a 200 MW BTA solar project (Bid 114-05a) located in Pueblo County, and (3) a 50 MW BTA battery storage project (Bid 248-19) located in Pueblo County.[43] The wind project is the only additional resource that the Preferred Portfolio has compared to the baseline ERP portfolio (*i.e.* the ERP with Social Cost ("SC")-Greenhouse Gas ("GHG") Portfolio). Thus, Black Hills characterizes the wind project as the additional CEP activities.[44]

50. Although Black Hills advances the Preferred Portfolio in the 120-Day Report, Black Hills also constructed six other resource portfolios for consideration in the 120-Day Report: (1) ERP – No SC-GHG, (2) Base ERP with SC-GHG, (3) CEP, (4) 40 Percent Ownership, (5) Geographic Diversity, and (6) Local Economic Development. The alternative portfolios were modeled such that varying amounts of wind, solar, storage, and market purchases were acquired during the RAP.[45]

51. In addition to the resources in the Preferred Portfolio, the Company proposes backup bids for each project proposed in the Preferred Portfolio (*i.e.*, the wind project, the solar project, and the storage project). The Company explains that Commission approval of backup bids is important given the risk that an approved project in the Preferred Portfolio fails to perform. In such an event, the Company could then replace the project from the Preferred Portfolio with a recommended backup bid.[46] In the 120-Day Report, Black Hills asserts that "[t]he Company's

[43] 120-Day Report (Rev. 1), p. 7.
[44] 120-Day Report (Rev. 1), p. 69.
[45] 120-Day Report (Rev. 1), pp. 47-48.
[46] 120-Day Report (Rev. 1), pp. 63-64.

approach to recommending the back-up bids is to present the next most competitive bids by resource type and recommend those bids."[47]

52. Pursuant to the requirements in the Phase I Decision, in the 120-Day Report, Black Hills provides four different scenarios for recovering cost associated with the proposed CEP. Although the Company presents different scenarios, it advances Scenario 4 in which cost recovery occurs through the Renewable Energy Standard Adjustment ("RESA"), Electric Cost Adjustment ("ECA"), and CEPR, with the RESA decreasing to 1.5 percent and 50 percent of the RESA balance transferred to CEPR at the end of 2026.[48]

53. More generally, throughout the 120-Day Report, Black Hills describes the bids it received in response to the RFP, how the Company conducted the Phase II bid evaluation, and the modeling that was used to construct the various resource portfolios.

2. Intervenor Comments

54. In the various intervenor comments, several concerns were raised including the manner in which Black Hills modeled the Phase II resource portfolios. In its Comments, Staff notes that in the 120-Day Report the Company's Preferred Portfolio is the only portfolio that was run through both Resolve and Plexos. Black Hills does not provide dispatch modeling (Plexos) for any of the other portfolios. Staff argues this makes comparing the Preferred Portfolio to the other six portfolios challenging.[49] Staff recommends in its responsive comments the Company provide Plexos modeling results for the CEP Portfolio and the Local Development Portfolio.

55. CEO raises similar concerns, noting that because the Preferred Portfolio was the only portfolio modeled in Plexos, the system costs, social costs, and GHG emissions of the

[47] 120-Day Report (Rev. 1), p. 64.
[48] 120-Day Report (Rev. 1), pp. 70-71.
[49] Staff's Comments, pp. 14-16.

Preferred Plan portfolio cannot be directly compared with the system costs, social costs, and GHG emissions of the other portfolios.[50] CEO recommends the Company explain in its Response Comments how and why production cost modeling impacts the system costs, social costs, and GHG emissions of a portfolio. In addition, CEO recommends the Company conduct production cost modeling in Plexos for the Local Economic Development Portfolio and provide the results of the modeling in its Response Comments, including the net present value revenue requirement ("NPVRR") of system costs, net present value of the social cost of emissions, and annual emissions.[51]

56. In addition to the difficulty comparing the Preferred Portfolio against any other portfolio, Staff raises other concerns with how Black Hills conducted Phase II. For instance, Staff notes the Company did not consistently disallow seasonal firm market purchases ("SFMP") across all portfolios;[52] the sensitivities on the Preferred Portfolio were modeled over very limited years within the RAP, with no information provided regarding the cost impacts of those varied assumptions;[53] the IE reports that the Company did not actually model Portfolio 4 (the 40 Percent Ownership Test) and Portfolio 5 (the Geographic Diversity Portfolio);[54] and the Company's modeler (*i.e.*, E3) removed the planning reserve margin ("PRM") constraint for model years 2026 and 2027 to ensure that the PRM constraint did not bias the model towards bids with earlier online dates.[55]

57. In addition, several intervenors questioned the Company's decision to include Bid 248-19 (a 50 MW storage facility) in its Preferred Portfolio instead of Bid 245-01 (a different

[50] CEO's Comments, p. 12.
[51] CEO's Comments, pp. 14-15.
[52] Staff's Comments, p. 16-17.
[53] Staff's Comments, p. 17.
[54] Staff's Comments, pp. 17-18.
[55] IE Report, p. 11.

50 MW storage facility). Staff notes that the model selects Bid 245-01 (*e.g.*, in the CEP Portfolio, Bid 245-01 is used). Staff recommends that the Company provide additional support for the substitution of storage Bid No. 248-19 in its Response Comments. Staff argues that if the Company does not provide this additional support, the Commission should reject Black Hills' preferred storage bid.[56] CEO similarly recommends the Company explain in its Response Comments how the system costs of the CEP Portfolio and Preferred Portfolio differ due to the different battery storage bids selected in each portfolio.[57] UCA argues the lowest-cost bid in a competitive solicitation should be selected and that switching back to Bid 245-01 will save customers approximately $700,000 per year.[58] In line with UCA's position, Pueblo County argues that the Commission should order Black Hills switch to the lowest-cost storage bid (Bid 245-01).[59]

58. Certain parties also argue against the inclusion of Bid 248-02 (a wind project) on the basis of costs. UCA argues that with the significant wheeling fees the wind project (Bid 248-02) incurs to deliver power from Kit Carson County, the price of the energy from the wind project "is substantially above [Black Hills'] generation costs" meaning that the wind bid will substantially increase cost to customers.[60] Pueblo County likewise asks that the Commission remove the high-cost 150 MW wind project (Bid 248-02) and replace it with the lowest cost solar project.[61] Similarly, Cañon City asks that the Commission reject the wind project (Bid 248-02) and replace it with a lower cost solar bid, arguing that Bid 248-02 is too expensive compared to other solar bids.[62] CEO does not argue for the rejection of the wind bid but does recommend that the Company

[56] Staff's Comments, p. 21.
[57] CEO's Comments, p. 14.
[58] UCA's Comments, p. 8; *see also* Black Hills' Response Comments, p. 18.
[59] Pueblo County's Comments, p. 6.
[60] UCA's Comments, p. 6.
[61] Pueblo County's Comments, pp. 6-7.
[62] Cañon City's Comments, p. 1. Cañon City does not advocate for a particular solar bid.

provide information regarding the additional benefits the wind bid can provide or greater clarity about the benefits.[63]

59. UCA and Pueblo County further argue that instead of replacing the wind project (Bid 248-02) with Bid 248-01 (a solar project) as the Local Economic Development Portfolio contemplates, the Commission should amend the Local Economic Development Portfolio to include an alternative solar project—Bid 334-03. UCA argues that Black Hills unnecessarily adds transmission costs to Bid 334-03 but that once these transmission costs are removed, Bid 334-03 is "by far the lowest-cost solar bid."[64]

60. There were also concerns regarding the backup bids Black Hills advanced. To start, Staff argues that in the Phase I Settlement, Black Hills committed to identifying three backup bids in each technology.[65] In the 120-Day Report, however, Black Hills only identifies one backup for the wind project and one storage backup. While there are technically three solar backup bids identified, Staff notes that two of them are 100 MW projects that Black Hills proposes to combine into a single backup option.[66] Staff further criticizes the Company's selection of backup projects. Despite the Company's assertions in the 120-Day Report that the backups are the next most competitive bids by resource type, Staff notes the Company only identifies BTA solar backups, despite the availability of lower-cost PPA bids.[67] Staff argues that Black Hills provides no explanation for selecting more expensive BTA resources.

61. More generally, the intervenors had mixed reactions to the Company's Preferred Portfolio. Although Staff argues the Phase II modeling process was "less than ideal," ultimately

[63] CEO's Comments, p. 20.
[64] UCA's Comments, p. 7; *see also* Pueblo County's Comments, p. 6.
[65] Staff's Comments, p. 12.
[66] Staff's Comments, p. 12-13.
[67] Staff's Comments, pp. 12-13.

Staff agrees with the Company that the Preferred Portfolio is a viable approach and achieves the clean air target at a reasonable cost.[68] Nevertheless, Staff considers the CEP Portfolio (Portfolio 3R) to be preferable to the Company's Preferred Portfolio.

62. In addition, Staff opines that the Local Economic Development Portfolio (Portfolio 6R) has several advantages over both the CEP Portfolio and the Company's Preferred Portfolio. Namely, the Local Economic Development Portfolio appears to be less expensive and have incremental benefits for local communities.[69] Staff acknowledges that the Local Economic Development Portfolio has lower emissions reductions than the Preferred Portfolio, but Staff notes the Local Economic Development Portfolio still achieves more than an 80 percent reduction in emissions. In addition, on a system as small as Black Hills, Staff argues that percentage-based emission reductions are ultimately small in terms of total tons of emissions, so over-compliance with the CEP standard coming at a higher cost is hard to justify.[70]

63. In contrast, CEO recommends the Commission approve the Company's Preferred Portfolio and the Company's requested backup bids. CEO argues that by doing so the Company could make a best effort to secure bids that achieve the highest level of emissions reductions (the Preferred Portfolio) but could switch to the bids that comprise Local Economic Development Portfolio if necessary.[71]

64. UCA recommends that a modified version of the Local Economic Development Portfolio be selected because it would be the lowest-cost portfolio and would achieve the required

[68] Staff's Comments, p. 28.
[69] Staff's Comments, p. 29.
[70] Staff's Comments, p. 29.
[71] CEO's Comments, p. 20.

emissions reduction.[72] Specifically, UCA argues that the Commission should modify the Local Economic Development Portfolio by replacing Bid 248-01 with Bid 348-03.

65. Pueblo County requests the Commission prune and modify the Preferred Portfolio so that Black Hills meets only the statutory goal of an 80 percent reduction in emissions. Specifically, and in line with UCA's position, Pueblo County asks that the Commission remove the high-cost 150 MW wind project (Bid 248-02) and replace it with the lowest cost solar project (Bid 334-03). In addition, Pueblo County argues the Commission should order Black Hills to switch to the lowest-cost storage bid (Bid 245-01).[73]

66. Cañon City likewise asks the Commission to prioritize cost-effective generation over other factors such as geographic diversity.[74]

3. Black Hills' Response Comments

67. In Black Hills' Response Comments, the Company responds to many of the concerns and recommendations the intervenors raised. For instance, in response to the concerns of Staff and CEO, Black Hills worked with its modeler, E3, to complete Plexos modeling for certain portfolios.[75]

68. Regarding Staff's other modeling concerns, Black Hills explains that Portfolio 2 (Base ERP with social cost of carbon ("SCC")) and Portfolio 3 (the CEP Portfolio) were restricted from selecting SFMP. Of the remaining portfolios, however, only Portfolio 1 (the Base ERP without SCC), Portfolio 4 (40 Percent Ownership), and Portfolio 5 (Geographic Diversity) selected SFMP during the RAP.[76] As for the IE's statements about Portfolio 4 (the 40 Percent Ownership)

[72] UCA's Comments, pp. 9-10.
[73] Pueblo County's Comments, pp. 6-7.
[74] Cañon City's Comments, p. 1.
[75] Black Hills' Response Comments, pp. 5-6.
[76] Black Hills' Response Comments, p. 8.

and Portfolio 5 (Geographic Diversity), Black Hills states it used the results of earlier model runs for Portfolio 3 (CEP Portfolio) as the basis for Portfolios 4 and 5. This earlier modeling demonstrated that Portfolios 4 and 5 would produce the same results, so to save time and cost, the Company decided not to perform the additional model runs.[77] Responding to Staff's questions regarding the PRM constraint, Black Hills asserts that this constraint was removed from the modeling for 2026 because the earliest bid available would come online in December 2026 and thus could not contribute to meeting the 2026 PRM. While the PRM constraint was also removed for 2027, Black Hills notes that both the CEP Portfolio and the Local Economic Development Portfolio satisfy the PRM in 2027 because the battery and solar projects in those portfolios come online prior to the summer 2027. The Company notes that the PRM constraint was removed in 2027 "to give the model more flexibility in selecting the most cost-effective bids as many bids come online after summer 2027."[78]

69. Regarding the concerns about the Company's preferred storage bid, Black Hills maintains the storage project should be located at the Company's preferred location.[79] Aside from the location, however, Black Hills states that it "does not oppose reordering the storage bids."[80] Responding to the opponents of the Company's proposed wind bid (Bid 248-02), Black Hills acknowledges that the $/MWh cost of Bid 248-02 is greater than other available solar projects. The Company argues, however, that the wind project allows for a lower dispatch cost of the remaining system resources and reduces social costs.[81]

[77] Black Hills' Response Comments, p. 8.
[78] Black Hills' Response Comments, p. 9.
[79] The Company does not provide additional detail regarding the benefits of the preferred location as Staff requests.
[80] Black Hills' Response Comments, p. 11.
[81] Black Hills' Response Comments, p. 11.

70. In its Response Comments, Black Hills opposes the arguments from UCA and Pueblo County that Bid 334-03 is actually the lowest cost solar project once unnecessary transmission upgrades are removed. Black Hills argues that the Company was intentional in identifying necessary transmission system upgrades so as to avoid later transmission cost "surprises." Black Hills asserts that removing these transmission costs for just Bid 334-03 as UCA argues "would be discriminatory to all other bids that were modeled with estimated transmission upgrade costs."[82] The Company further asserts that under UCA's proposal to treat the transmission line as a gen tie in order to avoid transmission upgrades, customers would be at risk financially for lost production from the project due to a transmission outage that trips the generating project.[83]

71. Turning to Staff's concerns with the Company's proposed backup bids, in its Response Comments, the Company provides additional information that it marked as highly confidential regarding certain backup bids Staff advanced. Black Hills does not, however, directly address Staff's concerns that the Company is passing over more economical PPA projects in favor of BTA projects.

72. As for the portfolio selection in general, in its Response Comments Black Hills continues to advance its Preferred Portfolio but notes the Company "is amenable to [the Local Economic Development Portfolio] if the Commission so chooses."[84]

73. Black Hills notes that while preparing the additional analysis for its Response Comments, it discovered an error in the cost calculations in the 120-Day Report. Whereas Black Hills initially reported the Preferred Portfolio would have a NPV of $976 million,[85] in its

[82] Black Hills' Response Comments, p. 12.
[83] Black Hills' Response Comments, p. 12.
[84] Black Hills' Response Comments, p. 21.
[85] 120-Day Report (Rev. 1), p. 7.

Response Comments Black Hills revises this estimate to $1,306 million[86]—an increase of $330 million. A similar error appears to affect all of the portfolios.

4. Black Hills' Supplemental Comments

74. In Response to Decision No. C24-0509-I, Black Hills submitted Supplemental Comments addressing a variety of issues. For example, in Decision No. C24-0509-I, we required additional information regarding Bid 248-09 and Bid 248-12, and specifically why the levelized price of these bids is relatively high compared to other factors such as their construction price and fixed PPA price.[87] In its Supplemental Comments, the Company explains that the previously disclosed construction costs for Bid 248-09 was erroneously low due to a formula error. Black Hills maintains, however, that "the correct price for Bid 248-09 was used in the modeling performed by the Company and E3."[88] For Bid 248-12, the Company explains that the bid contemplates joint ownership between the utility and the IPP and confirms that the cost estimates were calculated using bidder-supplied data, consistent with all other bids.[89]

75. In addition, in Decision No. C24-0509-I, the Commission critiqued Black Hills selection of backup bids, which seemed to be restricted to like-for-like replacements (*e.g.*, only utility-owned bids could be backups for a utility-owned project). The Commission required Black Hills to identify "the three most competitive backup projects by technology type, regardless of ownership."[90] In its Supplemental Comments, Black Hills advances a revised list of backup bids for solar projects that includes a mix of BTA and PPA projects. The Company also provides a revised list of backup bids for the storage project.[91]

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[86] Black Hills' Response Comments, p. 6.
[87] Decision No. C24-0509, ¶ 17.
[88] Black Hills' Supplemental Comments, p. 14.
[89] Black Hills' Supplemental Comments, p. 15.
[90] Decision No. C24-0509, ¶ 27.
[91] Black Hills' Supplemental Comments, pp. 27-28.

76. In its Supplemental Comments, Black Hills no longer advocates for the wind bid that was included in the Preferred Portfolio and now recommends the storage bid (Bid 245-01) that several of the intervenors supported. Moreover, Black Hills states that "upon further review and consideration" the Company is now amenable to Bid 334-03 (a 150 MW solar PPA) that UCA and Pueblo County advance.[92] This change stems from "new interconnection information for Bid 334-03" that eliminates the substantial network upgrades Black Hills previously assumed for this project.[93]

77. Black Hills' Supplemental Comments address several other topics, including estimated curtailments, potential impacts of future markets on transmission costs, the capacity factors for solar bids, and a revised rate impact analysis that examines estimated rates through 2040.

D. Modification of the CEP's Resource Portfolio

78. As described above, the statute prescribes when the Commission must approve a CEP and when the Commission may modify the CEP. Specifically, the Commission may modify the plan if the modification is necessary to ensure the plan is in the public interest. In evaluating whether a CEP submitted to the Commission is in the public interest, the Commission shall consider (1) emissions reductions, (2) the CEP's impact on reliability and resilience of the electric system,[94] and (3) whether the CEP will result in a reasonable cost to customers. The statute also permits the Commission to consider "other relevant factors." In this instance, we find that the risk of the cost of the CEP rising above the bid prices modeled in Phase II bid evaluation and selection is another relevant factor we must consider to determine whether the CEP is in the public interest.

[92] Black Hills' Supplemental Comments, p. 3.
[93] Black Hills' Supplemental Comments, pp. 3, 16.
[94] The statute makes clear that the Commission "shall not approve a plan that does not protect system reliability." (§ 40-2-125.5(4)(d)(III), C.R.S.)

79. Black Hills' proposed CEP would use the portfolio of resources in the Local Economic Development Portfolio.[95] This Portfolio results in significant reductions in carbon dioxide and other emissions that will allow Black Hills to meet the 80 percent reduction by 2030 clean air target and work towards the goal of 100 percent clean energy by 2050. The Local Economic Development Portfolio likewise reduces both the social cost of carbon and the social cost of methane.[96] Moreover, no parties, including Black Hills, have raised concerns that pursuing the Local Economic Development Portfolio will negatively impact the reliability and resilience of the electric system. Thus, the statutory factors regarding emissions reductions and reliability support the Local Economic Development Portfolio.

80. The more difficult factor for us to weigh is whether a CEP that uses the Local Economic Development Portfolio will result in "a reasonable cost to customers."[97] It is no secret that "there has long been community outrage about [Black Hills'] high electric rates,"[98] and throughout this Proceeding certain parties consistently have directed our attention to the profound impact this Proceeding will have on customers.[99] Black Hills' ratepayers already pay some of the highest electricity rates in the state,[100] and in the Company's recently filed electric rate case—which does not include costs associated with acquiring additional resources in this Proceeding—the Company asks for an almost 20 percent increase in residential rates.[101] Moreover, the communities in Black Hills' service territory have lower median income levels than other parts

[95] Black Hills' Supplemental Comments, pp. 4, 29 (The Local Economic Development Portfolio consists of Bid 114-05a, Bid 248-01, and Bid 245-01. The Company indicates, however, that it is willing to replace Bid 248-01 with 334-03. Black Hills requests the ability to negotiate with the developers of both projects (Bid 248-01 and Bid 334-03) to secure the best outcome for customers but recommends Bid 334-03 be the first solar backup bid).

[96] Black Hills' Response Comments, pp. 5-7.

[97] § 40-2-125.5(4)(d)(III), C.R.S.

[98] Hr. Ex. 600 (Ortiz Answer), p. 6.

[99] *See, e.g.*, Pueblo County's Comments, p. 6; Cañon City's Comments, p. 1.

[100] Pueblo County's Comments, p. 2.

[101] *See* Proceeding No. 24AL-0275E, Hr. Ex. 100 (Advice Letter No 871) p. 6 (noting an estimated monthly change in residential bills of 18.4 percent).

of the state, and the Company serves relatively few customers.[102] This ultimately means that cost increases are spread over fewer customers who are already impacted by high electricity rates.

81. Our concerns about customer costs led to a critical addition to the Phase I Settlement in which the parties were required to develop and submit a utility-ownership PIM. The Phase I Decision explains how IPPs could be at risk for losing their security if PPA projects cannot go forward in accordance with the price the IPP included in its Phase II bid. For utility-owned projects, however, the cost of the project could increase significantly from the Phase II bid in the follow on CPCN proceeding.[103] Hence, we directed the development of a utility-ownership PIM to incentivize Black Hills to submit accurate bids in Phase II and to "control the costs on any utility-owned project that is selected."[104] In other words, the utility-ownership PIM is intended to be a customer protection mechanism that incentivizes the Company to ensure that its utility-owned projects are built on or below budget, whether bid by the utility or by an IPP for a BTA. In this context, the "budget" is the costs of construction and level of operation that the bidder assumed in its Phase II bid. The Commission was clear that to be effective, the utility-ownership PIM must "be developed and applied in this Proceeding, as opposed [to] a later CPCN proceeding."[105]

82. Although Black Hills did not challenge any part of our Phase I Decision—including the requirement for a utility-ownership PIM—and has had approximately 18 months to consider the PIM concept, the Company now indicates that it cannot develop a meaningful utility-ownership PIM. Specifically, Black Hills now argues the Commission's concerns about cost increases for

[102] For example, Pueblo County's per capital personal income of $43,196 ranks in the lowest quartile in the state. (Pueblo County's Comments, p. 2).
[103] Phase I Decision, ¶ 62.
[104] Phase I Decision, ¶ 61.
[105] Phase I Decision, ¶ 62.

utility-owned projects appear to have "less applicability" in BTA projects because "the Company will have little control over the construction cost of a [BTA] project other than through the BTA contract itself."[106] The Company further argues that without having the details of the specific projects that are typically set forth as part of a CPCN application, the design of any PIM must be based more on theory. Black Hills thus requests that the Commission consider deferring the PIM issue until the later CPCN proceedings.[107]

83. It is concerning that Black Hills indicates that it has little control over BTA construction costs because approximately 63 percent to 71 percent of the resources in the Company's Local Economic Development Portfolio are BTAs and would ultimately be owned by the utility.[108] For comparison, in the Phase I Settlement, the Settling Parties agreed that "the Company may propose to own *up to* a target of up to 50 percent of generation acquisitions."[109] Thus, Black Hills is proposing a much higher percentage of utility ownership than was approved in the Phase I Settlement while at the same time indicating the required customer protection mechanisms for utility-ownership generation are not feasible, and that it lacks the ability to control construction costs.

84. Contrary to Black Hills' assertions, the Commission's concerns regarding cost increases of utility-owned projects are exceedingly applicable to BTA projects. In a BTA project, an IPP submits the bid for a project with the understanding that it will transfer the project to Black Hills, and the Company will ultimately own and operate it. The IPP is incentivized to submit a low-priced bid so that the project is selected in the Phase II modeling. Compared to a PPA

[106] Second Motion for Extension, pp. 8-9.
[107] Second Motion for Extension, p. 9.
[108] If Bid 248-01 is included in the Local Economic Development Portfolio instead of Bid 334-03, the Company's ownership percentage is 71.4 percent. If the Bid 334-03 is included instead of Bid 248-01, the Company's ownership percentage is 62.5 percent.
[109] Phase I Settlement, ¶ 6 (emphasis added).

context, however, the IPP might have fewer consequences if the project fails to perform as expected given that the utility will be operating the project.[110] Similarly, the consequences, if any, an IPP bears for cost overruns during construction of the project will largely depend on the terms and enforcement of the BTA contract. The specific terms and enforcement of the BTA contract are largely controlled by Black Hills, who negotiates and enters into the BTA contract with the IPP. All else being equal, the Company would likely benefit from an increase in construction costs as this would increase the Company's rate base that Black Hills recovers from customers.[111]

85. Under these circumstances, we find that modifying Black Hills' proposed CEP is necessary to ensure the plan is in the public interest. Specifically, we modify the Local Economic Development Portfolio such that Bid 114-05a (a 200 MW solar BTA) is replaced with Bid 114-08 (a 200 MW solar PPA). Bid 114-05a and Bid 114-08 are identical in that they are the same technology, same size, same estimated energy production, same interconnection point, and the same IPP submitted both bids.[112] Bid 114-08 differs in that it has a later construction date, has a slightly higher price, and is a PPA instead of a BTA. In our view, the later construction date and the somewhat higher price are more than justified because the Bid 114-08 shields customers from substantial construction cost overrun and underproduction risks. Despite a clear Commission directive and ample time for the Company to provide a proposal to mitigate these risks, the Company declined to do so. In light of this, we refuse to ignore the risk that approval of

[110] On this point, we are concerned that the Company has merely adopted the construction cost and production estimates from the bidders and conducted no real independent project-specific analysis despite the considerable costs of the projects. For instance, in its Supplemental Comments, Black Hills states that "[g]iven the large number of bids received, the Company relied on capacity factors provided by bidders and did not make any adjustments to the capacity factor." (Black Hills' Supplemental Comments, p. 12.).

[111] Black Hills is subject to the risk that cost increases would be disallowed in a follow-on rate case if the Company fails to establish that it acted prudently. This possibility, however, does not fully ameliorate our concerns that customers will likely pay for cost increases of utility-owned projects.

[112] *See* 120-Day Report (Rev. 1) (Appendix A).

Bid 114-05a will ultimately result in customers paying unreasonable costs because the BTA project's construction costs are substantially more than expected or its energy projection is less than anticipated. With the selection of Bid 114-08, these risks are placed on the IPP, not customers, which allows us to find that the approved CEP will result in reasonable cost to customers.

86. We acknowledge that replacing Bid 114-05a with Bid 114-08 will reduce Black Hills' ownership of the energy and capacity resources associated with the CEP below the 50 percent ownership target in § 40-2-125.5(5)(b), C.R.S. To be clear, the Commission is not opposed to utility ownership. We are opposed to customers bearing the significant risk of large potential cost increases associated with the Local Economic Development Portfolio. Given the economic realities of Black Hills' service territory as established in this record, we cannot accept the risk inherent in the Local Economic Development Portfolio while at the same time finding that the CEP will result in a reasonable cost to customers. The statute makes clear that the ownership target in § 40-2-125.5(5)(b), C.R.S. does not alter the Commission's authority under § 40-2-125.5(4)(d), C.R.S. to modify a CEP if the modification is necessary to ensure the plan is in the public interest.[113]

87. Likewise, the risk of cost increases prevents us from finding that the proposed level of utility ownership in the Local Economic Development Portfolio comes at a reasonable cost and rate impact. This is consistent with our Phase I Decision in which we clarified paragraph no. 7 of the Phase I Settlement. Paragraph no. 7 states:

> To the extent a portfolio includes up to a 50 percent ownership target by the Company, 50 percent ownership shall only be allowed if it can be accomplished at reasonable cost, per Colorado law. Reasonable cost should be bound by the range of bids advanced to modeling.[114]

[113] § 40-2-125.5(5)(b) ("Nothing in this subsection (5)(b) alters the commission's authority under subsection (4)(d) of this section.").

[114] Phase I Settlement, ¶ 7.

88. In the Phase I Decision, we approved paragraph no. 7 of the Phase I Settlement subject to the clarification that the provision "does not restrict what the Commission can consider when we determine whether the utility-ownership target comes at a reasonable cost and rate impact per § 40-2-125.5(5)(b), C.R.S."[115] In this Phase II Decision, the current economic realities of Black Hills' service territory and the significant risks of cost increases associated with Bid 114-05a are some of the critical factors we have considered when determining the reasonableness of the cost and rate impact.

89. The second modification we make to the Local Economic Development Portfolio is replacing Bid 248-01 (a 100 MW solar PPA) with Bid 334-03 (a 150 MW solar PPA). In its Supplemental Comments, Black Hills states it is amenable to this replacement and requests the ability to negotiate with the developers of both projects (Bid 248-01 and Bid 334-03) to secure the best outcome for customers. Nevertheless, Black Hills recommends Bid 248-01 as the primary solar bid with Bid 334-03 as the first backup bid.[116]

90. The economics of Bid 334-03 and the fact that it is 50 MW larger than Bid 248-01 are appealing to the Commission. Adding additional solar capacity on Black Hills' system benefits the Company's current system and will likely reap dividends in the future. For example, the additional solar capacity that Bid 334-03 offers positions Black Hills to better utilize future energy storage and transmission investments in its system. The additional solar capacity could similarly offer benefits if Black Hills joins a regional market in the future. Accordingly, we direct Black Hills to use Bid 334-03 as the primary solar bid instead of Bid 248-01. We further encourage the

[115] Phase I Decision, ¶ 73.
[116] Black Hills' Supplemental Comments, p. 28.

Company to pursue negotiations with Bid 334-03 and consider providing timing and other flexibility if doing so helps secure the most economic result for customers.

91. In sum, we find that modifying Black Hills' proposed CEP is necessary to ensure the plan is in the public interest. Instead of the Local Economic Development Portfolio, the CEP we approve shall incorporate the following resources within the Modified LED Portfolio: Bid 114-08, Bid 334-03, and Bid 245-01. As explained above, the Local Economic Development Portfolio is projected to achieve significant emissions reductions and will also significantly reduce the social cost of carbon and social cost of methane compared to the baseline ERP approach. While Bid 114-08 has a later on-line date than Bid 114-05a, it is otherwise essentially the same 200 MW solar project as Bid 114-05a, so the impacts this delay has on interim emissions reduction and the social cost of carbon, and the social cost of methane are relatively minor. Importantly, Bid 114-08 would not impact Black Hills' ability to meet the 2030 clean air target. To be clear, the Modified LED Portfolio is expected to exceed the 80 percent emissions reductions set forth in statute and makes progress toward achieving the goal of 100 percent clean energy resources by 2050. Because Bid 334-03 is 50 MW larger than the solar bid it replaces, this modification will further reduce emissions reductions. Regarding feasibility, the record contains no issues regarding the Local Economic Development Portfolio's reliability, and it is supported by the utility. The switch to Bid 114-08 and Bid 334-03 should have no impact on reliability.

92. As for the statutory factor of reasonable costs to customers and the related Commission-defined factor of risk of the cost of the CEP rising above the bid prices modeled in Phase II, modification of the CEP to include the Modified LED Portfolio is necessary for the public interest. As discussed above, even though Bid 114-08 comes at a higher cost than Bid 114-05a, the Modified LED Portfolio has fewer utility-owned resources and greatly reduces the risk that

customers will bear significant cost increases. This change allows the Commission to find that the approved CEP will result in a reasonable cost to customers and reasonable rate impacts.

E. Backup Bids

93. In the 120-Day Report, the Company proposes backup bids for each project proposed in the Preferred Portfolio (*i.e.*, the wind project, the solar project, and the storage project).

94. As referenced above, Staff does not support the backup bids that Black Hills initially proposed, arguing that Black Hills had not identified enough backups and that the Company was inappropriately limiting solar backups to utility-owned projects.[117] Additionally, Staff recommends a check-in process regarding solar backups. If an approved solar project fails, Staff argues the Company should be required to make a filing explaining its selection of an alternative backup project. Under this proposal, parties would have 30 days to file a protest regarding the Company's backup selection.[118]

95. CIEA suggests the Commission could direct the Company to add PPA projects to the solar and storage backups. CIEA argues having more PPA projects ready to compete with the utility-owned projects in case those cannot move forward could enhance IPP ownership.[119]

96. In its Supplemental Comments, Black Hills reworks its list of backup bids. Black Hills now proposes to the use the following bids for solar backups: Bid 334-03, Bid 223-01b in combination with Bid 223-03b, Bid 248-12, and Bid 190-05a. In addition, the Company now proposes the following bids for storage backups: Bid 248-19 and Bid 193-01.[120]

97. The revised list of backup bids Black Hills puts forth in its Supplemental Comments appears to respond to the concerns Staff raised. We approve this revised list of backup bids for

[117] Staff's Comments, pp. 12-13.
[118] Staff's Comments, p. 23.
[119] CIEA's Comments, pp. 9-10.
[120] Black Hills' Supplemental Comments, p. 28.

storage and solar projects in the order presented by Black Hills, subject to certain modifications. First, consistent with our findings above regarding the Modified LED Portfolio, Bid 334-03 is one of the approved solar projects and can no longer be a backup. Accordingly, Bid 248-01 shall replace Bid 334-03 as the first backup solar bid. Second, the check-in process proposed by Staff will add valuable transparency if Black Hills needs to move to a backup solar bid, and we approve it. If one of the approved solar projects fails (*i.e.* either Bid 114-08 or Bid 334-03), the Company shall submit a filing in this Proceeding explaining the failure and the Company's selected backup project. Parties in this Proceeding shall have 30 days after Black Hills' submission to file a protest regarding the Company's backup selection.

98. Finally, we deny CIEA's proposal to simply add PPA projects to the solar and storage backups. In its Supplemental Comments, Black Hills presents a balanced approach that we find to be more appropriate than CIEA's suggestions.

F. PIMs

99. As referenced above, the Phase I Decision requires the parties to develop and submit a utility-ownership PIM and an emissions-reduction PIM. The Phase I Decision sets specific parameters as to how these PIMs must be structured, particularly regarding the utility-ownership PIM. The Phase I Decision specifies, in part:

> The expected costs that were assumed in Phase II shall be compared to the final cost of the project after construction is complete and it begins operating. The PIM shall incentivize final capital, O&M, and availability costs that are lower than what was assumed in the Phase II bid and disincentivize final costs that are higher than what the Phase II bid assumed.[121]

100. Based on the Company's Second Motion for Extension, we find that it would be more administratively efficiently to simply establish a utility-ownership PIM in this Phase II

[121] Phase I Decision, ¶ 61.

Decision, rather than hoping the stakeholder process will successfully produce a meaningful PIM. We recognize the importance of limiting uncertainty for the bidders and desire that the approved projects can move forward quickly with clarity regarding the utility-ownership PIM.

101. Accordingly, the remaining utility-owned project in the Modified LED Portfolio (*i.e.* Bid 245-01) shall be subject to a cost-to-construct PIM in which the baseline is the construction costs set forth in Appendix A to the 120-Day Report (*i.e.*, the build transfer price). There shall be a five percent deadband around this baseline in which cost deviations from the baseline would earn neither an incentive nor a disincentive. However, if the final construction costs of Bid 245-01 deviate more than five percent above the deadband, then 25 percent of the overage will be borne by Black Hills and not recoverable from customers. Conversely, if the final construction costs of Bid 245-01 come in more than five percent below the deadband, then Black Hills will be allowed to keep 25 percent of the savings as an incentive.

102. Relative to the utility-ownership PIM, the emissions-reduction PIM presents more complexity. Thus, we find it appropriate to maintain the stakeholder PIM process set forth in the Phase I Decision for the development and submission of an emissions-reduction PIM. Given that we vacated the previous deadline for the stakeholder PIM proposal in Decision No. C24-0553, the Commission now requires Black Hills to submit in this Proceeding an emissions-reduction PIM 14 days after the final Phase II Decision, including any decision ruling and applications for rehearing, reargument, or reconsideration. This emissions-reduction PIM must comply with the parameters for the emissions-reduction PIM set forth in our Phase I Decision. After the Company submits its proposed emissions-reduction PIM, the deadlines and process set forth in the Phase I Decision shall govern the stakeholder process.[122]

[122] Phase I Decision, ¶ 58.

G. Cost Recovery

103. In the 120-Day Report, Black Hills compared the Preferred Portfolio to Portfolio 2 (the Base ERP with SC-GHG) to determine a baseline for "additional" CEP resources.[123] The Company states that Bid 248-02 (the 150 MW wind project) is required under the Preferred Portfolio but not under Portfolio 2, which does not meet the 80 percent emissions reduction target. Therefore, Black Hills concludes the costs associated with Bid 248-02 are "additional" CEP costs eligible for CEPR recovery. Black Hills proposes that the revenue requirement associated with Bids 114-05a (200 MW solar) and 248-19 (50 MW storage) would be recovered through the ECA for ten years, at which point Black Hills would file an application to retain or change the method of cost recovery.[124]

104. Black Hills proposed four cost recovery scenarios. In creating these forecasts, it did not forecast changes in base rates or surcharges. Based on this analysis, Black Hills proposes to apply Scenario 4, which would implement a 1.5 percent CEPR surcharge on January 1, 2025, and reduce the RESA surcharge from 2 percent to 1.5 percent. In addition, under Scenario 4, half of the RESA surplus would be transferred to the CEPR balance at the end of 2026.[125] Finally, Black Hills drew on Plexos modeling of the Preferred Plan to conclude that adding renewable energy will reduce gas usage and create more stable bills.

105. The Company's cost scenario approach drew mixed reactions from the intervenors. In its Comments, CEO supports Black Hills' methodology and recommendation for Scenario 4, stating that it appears to provide the best mix of short-, medium-, and long-term rate impacts.[126]

[123] 120-Day Report (Rev. 1), p. 69.
[124] 120-Day Report (Rev. 1), pp. 69, 72.
[125] 120-Day Report (Rev. 1), pp. 70-71.
[126] CEO Comments, p. 22.

106. Pueblo County recommends the Commission order Black Hills to explain anticipated bill impacts clearly and in plain language. Pueblo County recommends the Commission order Black Hills to present a table showing average monthly bills, regardless of which cost recovery mechanisms are used, providing for 2009 to 2035 for average residential, commercial, and industrial customers.[127]

107. UCA asserts that approving the Local Economic Development Portfolio may make it possible to recover all costs in the ECA and avoid the need for a CEPR.[128]

108. Staff raises several issues with Black Hills. For example Staff argues that Scenarios 1 and 2 create large regulatory assets which does not constitute and existing mechanism and thus does not comply with the Phase I Settlement. In addition, Staff asserts that the Company uses an asymmetric carrying cost for the RESA, even though the Phase I Settlement contemplates a symmetric carrying cost.[129] More generally, Staff argues it is difficult to fully understand the cost and rate impacts Black Hills presents in the 120-Day Report because of how the Company only used Plexos modeling with its Preferred Portfolio. Staff notes there is also a lack of clarity on which resources will be approved and no modeling results after 2030.[130]

109. Staff proposes three goals for cost recovery: minimizing customer bill impacts; maximizing intergenerational fairness; and minimizing bill volatility. In addition, Staff proposes three alternative cost recovery scenarios for the Commission to consider: Scenario 5, Scenario 3A, and Scenario 6. Overall, Staff suggests that the Commission consider the Company's Scenarios 3 and 4, as well as Staff's Scenarios 3A and 5. Staff specifically recommends that Scenarios 3A and 5 be the priorities for selection. Staff explains that given potential cost increases from

[127] Pueblo County's Comments, pp. 7-8.
[128] UCA's Comments, p. 2.
[129] Staff's Comments, pp. 32-33.
[130] Staff's Comments, pp. 30-31.

electrification, transmission, and other items, the Commission should try to avoid pancaking on costs to ratepayers.[131]

110. In its Response Comments, Black Hills agrees with the cost recovery objectives set forth by Staff and corrects the carrying cost for the RESA as proposed by Staff for Scenario 4. The Company also presents versions of its cost recovery Scenario 4 and Staff's cost recovery Scenario 5 with the Local Economic Development Portfolio. In response to Pueblo County, Black Hills states it has posted a detailed rate trend report on its website.[132]

111. While Black Hills continues to prefer its existing portfolio, it is amenable to recovery Scenario 4 or 5 if the Local Economic Development Portfolio is chosen. For the Local Economic Development Portfolio, the Company notes Scenario 5 has a slightly higher bill impact due to using the ECA for recovery, but there are no CEPR costs or deferred balance to recover in rates after 2030. Scenario 4 would have the lowest monthly bill impact by 2030, but the highest CEPR deferred balance. Black Hills does not address the merits of Scenario 3A.[133]

112. As an initial matter, we approve Black Hills' general approach for assessing additional CEP activities. While Staff rightly points out that Black Hills' approach does not precisely match the Phase I Settlement, Staff also does not oppose the Company's approach. Moreover, treating a whole resource as incremental will help simplify tracking and reporting.

113. As for the precise cost recovery scenario to approve, we agree with Staff that Scenarios 1 and 2 will likely create a significant deferred asset balance, which could result in rate shock after 2030. For this reason, we decline to adopt Scenarios 1 and 2. We also reject Scenario 5, under which costs would be recovered through the ECA and no CEPR would be created.

[131] Staff's Comments, pp. 33-35.
[132] Black Hills' Response Comments, p. 14.
[133] Black Hills' Response Comments, pp. 15-16.

Given the Commission's approval of the Modified LED, there will be "additional [CEP] activities," and the statute directs that revenues for these activities be collected through a CEPR. Thus, Scenario 5, which does not establish a CEPR, is not a viable option.[134]

114. Accordingly, Black Hills shall move forward with cost recovery Scenario 4 as set forth in Black Hills' Response Comments via an advice letter. This includes establishing a CEPR of 1.5 percent to go into effect as of January 1, 2025, and reducing the RESA from 2 percent to 1.5 percent. We further authorize Black Hills to transfer up to 50 percent of the RESA balance at the end of 2026 to recover the incremental costs of the clean energy resources and their directly related interconnection facilities. We do not preclude Black Hills from proposing additional RESA transfers in a future, appropriate proceeding (*e.g.*, the next ERP/RES proceeding) if doing so would help reduce rate shock associated with any deferred balance in the CEPR account.

115. Staff raised three important values as part of considering cost recovery: minimizing customer bill impacts, maximizing intergenerational fairness, and minimizing bill volatility. Scenario 4 as applied to the Modified LED Portfolio strikes the best balance with those values. The CEPR deferred balance that is anticipated to arise under Scenario 4 is manageable, thus addressing concerns regarding intergenerational fairness and reducing bill impacts associated with carrying charges. Moreover, utilizing revenues from both the CEPR and the RESA help minimize bill volatility compared to recovering costs primarily through the ECA.

H. CIEA's Recommendations

1. Percentage of Utility Ownership

116. In its Comments, CIEA urges the Commission to be skeptical of "the nearly 2/3rds ownership division [Black Hills] proposes in favor of its own resources to a generation fleet that

[134] § 40-2-125.5(5)(a)(II).

is already nearly entirely under [the Company] or its affiliates' ownership."[135] CIEA asks the Commission to ensure that "a better ownership balance is achieved to manage ratepayer risks of utility owned generation."[136] CIEA recommends the Commission use the next 2026 ERP and interim resource acquisitions, if any, to course correct and rebalance IPP versus utility ownership in the total capacity mix on Black Hills' system. CIEA asks the Commission to find that the Company's resource mix should have goal of having at least 50 percent PPA resources.[137]

117. In its Response to CIEA's arguments about utility ownership exceeding 50 percent, Black Hills quotes the Public Service ERP/CEP Phase II Decision as follows: "the Commission does not find that SB 19-236 in any way sets a floor or a ceiling for Company-ownership."[138] Black Hills asserts the issue is whether the ownership level comes at "a reasonable cost and rate impact," per the statute and argues that both the Preferred Portfolio and Local Economic Development Portfolio are at a reasonable cost and rate impact.[139]

118. Black Hills argues that CIEA's request for a Commission finding that the resource mix should have a goal of at least 50 percent PPA resources "would violate virtually every tenet adhered to in quasi-judicial proceedings, including 5th Amendment Due Process Clause rights of every party to such proceedings, and that every determination must be supported by the factual record."[140] Future proposed generation acquisitions, Black Hills asserts, must be judged in individual proceedings based on the public interest.

[135] CIEA's Comments, p. 8.
[136] CIEA's Comments, p. 9.
[137] CIEA's Comments, p. 9.
[138] Black Hills' Response Comments, p. 17 (quoting Proceeding No. 21A-0141E, Decision No. C24-0052, issued January 23, 2024, p. 34 fn. 96).
[139] Black Hills' Response Comments, p. 17.
[140] Black Hills' Response Comments, p. 18.

119. CIEA's requests relating to the percentage of utility ownership are denied. We agree with Black Hills that it would be premature and inappropriate for the Commission in this Phase II Decision to set a goal for the percentage of utility ownership acquired in future proceedings.

120. As set forth in Decision No. C24-0509-I, in the Step 1 Deliberations, the Commission granted two requests from CIEA and required Black Hills to (1) provide a breakdown of ownership versus PPA bids that were advanced to computer modeling and (2) provide a detailed explanation as to the assumptions regarding tax credits used in the Phase II modeling. Black Hills provided this additional information in its Supplemental Comments. After reviewing this information, we decline to take additional action on these issues at this time.

2. Information Sharing with the IE

121. CIEA raises concerns that, based on the IE Report, Black Hills and its modeler, E3, might have been less than forthcoming with the IE. CIEA observes that the IE found it concerning that "bid data obtained via the RFP is not readily available in a form usable by the RESOLVE model, the computer-based modeling occurred in two steps."[141] CIEA argues the Commission deserves further explanation as to why the capacity expansion model could not readily use bid data. CIEA also suggests the Phase II modeling conventions might have skewed the selection of resources.[142]

122. CIEA recommends the Commission require more information on the part of Black Hills, the IE, and E3 to discover whether there was any deficiency in information sharing

[141] CIEA's Comments, p. 12 (quoting IE's Report, p. 10).
[142] CIEA's Comments, p. 4.

on the part of the Company and its consultants with the IE, including of the Resolve model if the Company continues to use that model in future ERPs.[143]

123. Black Hills responds that CIEA's allegations in this regard "are entirely speculative and without basis."[144] The Company acknowledges challenges from using a newer modeling process but notes the IE concluded that "a fair solicitation was conducted, that all bidders had access to the same information at the same time, and that all bids were evaluated using the same criteria and standards."[145] Black Hills states the Commission should decline from making a finding that is not based on evidence.

124. We empathize with CIEA's concerns regarding the information sharing with the IE. The IE Report states that there were inconsistencies in the translation of the bid data from the IE Website "that could have been corrected and/or avoided if the input data had been made available to the IE in a timelier manner."[146] The IE also notes that E3 declined to provide certain information to the IE regarding the Bid Cost Translation Tool that converted information from the RFP into the Resolve model because E3 claimed that such data was proprietary. Despite these shortcomings, the IE ultimately concludes that the inconsistencies in the translation of the bid data do not appear to have adversely affected the outcome. Similarly, while additional information regarding the Bid Translation Tool would provide greater assurance, "the IE finds no reason to question the accuracy or reasonableness of the model's results."[147]

125. Accordingly, we deny CIEA's requests to require additional information in this Phase II. CIEA itself does not advocate for redoing the Phase II modeling because of the significant

[143] CIEA's Comments, p. 13.
[144] Black Hills' Response Comments, p. 19.
[145] Black Hills' Response Comments, p. 19.
[146] IE Report, p. 15.
[147] IE Report, p. 15.

pressure this would place on IPPs. Nevertheless, in future ERPs the Company shall be more proactive in ensuring the IE and E3 (or any other modeler it employs) communicate freely. We direct Black Hills to address this issue in its initial filings in its next ERP, including whether the modeler it employs will restrict the IE's access to any data on the grounds that the data is proprietary.

3. Annuity Tail

126. CIEA argues the Commission should find that the annuity tail method of optimization modeling provides a better basis for comparison than the replacement chain tail modeling method and require Black Hills to produce the annuity tail method results for Portfolio 1 (ERP with no SCC Portfolio) that it did not share in its 120-Day Report.[148] On this last point, CIEA cites the IE Report as observing that Portfolio 1 (ERP with no SCC Portfolio) was run using both the replacement chain and annuity methodologies but only the replacement chain methodology was reported.[149]

127. CIEA recounts that the annuity tail method assumes that PPAs are extended with the same generators at the end of the effective or proposed contract terms. Thus, the annuity tail method essentially assumes that PPA contracts are renewed for the same price. The replacement chain tail modeling method, on the other hand, keeps a PPA in place but assumes that facility's price of power is escalated for inflation. The result, CIEA asserts, is the replacement chain method makes PPAs that will expire look more expensive in the tail years of the planning period versus utility-owned generation. CIEA argues the annuity tail method has been proven in the real world, in the Public Service system, and in prior RFPs.[150]

[148] CIEA's Comments, p. 13.
[149] CIEA's Comments, p. 18 (citing the IE Report, p. 14).
[150] CIEA's Comments, pp. 14-15.

128. Nevertheless, CIEA notes the capacity expansion results are the same for the replacement chain and annuity tail methods in terms of resources selected in the CEP Portfolio. For the "Base ERP with SC-GHG" Portfolio, the annuity tail method selects the PPA wind resource and the replacement chain method does not.[151] CIEA concludes the Commission should therefore find that the annuity tail method is valuable and more effective at bid evaluation than using the replacement chain method. CIEA suggests the Commission could also require the continued use and optimization with the annuity tail method to guide the next ERP base case modeling.[152]

129. In its Response Comments, Black Hills reiterates its arguments from Phase I as to why the replacement chain method is superior to the annuity method. The Company further argues the annuity tail method should not be used because the Company is not proposing to extend any existing resources through this Proceeding and because the annuity tail version of the portfolios are "just a sensitivity."[153] Black Hills argues the Commission should not require the annuity tail method result for Portfolio 1 because the Commission could not select this ERP portfolio, and the annuity tail method does not result in any changes in the results of the CEP modeling.[154]

130. CIEA's request to find that the annuity tail method is superior to the replacement chain method is denied. The annuity tail method and the replacement chain method each provide distinct views of the cost of replacing PPA resources. In this Proceeding, however, the annuity tail and replacement chain methods do not alter the resources selected in the CEP Portfolio. Regardless, it is unnecessary and inappropriate for the Commission to find in this Phase II Decision

[151] CIEA's Comments, p. 17.
[152] CIEA's Comments, p. 18.
[153] Black Hills' Response Comments, p. 20.
[154] Black Hills' Response Comments, p. 20.

that either the annuity tail or the replacement chain method is superior to the other and should be used as the primary method in all future ERP proceedings.

131. For similar reasons, the Commission denies CIEA's request to require Black Hills to produce the annuity tail method results for Portfolio 1 (the ERP with no SCC Portfolio). Learning more information about this particular ERP portfolio at this stage does not justify delaying the Phase II Decision. Moreover, the Settling Parties to the Phase I Settlement—which includes CIEA—did not contemplate an annuity tail version of Portfolio 1. Per the Phase I Settlement, Black Hills was to use the replacement chain method and the annuity method as bookend optimizations for: (1) ERP baseline, (2) CEP Preferred, (3) 40 Percent Ownership, and (4) Geographic Diversity.[155] Because the ERP baseline is Portfolio 2 (ERP *with* SCC), the Phase I Settlement does not require both methodologies for Portfolio 1 (ERP with No SCC).

4. Technical Conference

132. The Phase I Settlement requires Black Hills to conduct a technical conference with all parties 14 days after the 120-Day Report.[156] CIEA asserts that at the May 1, 2024, technical conference, Black Hills began by announcing the Company could not discuss any confidential information during the conference. Moreover, rather than trying to find a proper venue to discuss confidential topics, the Company stated that the public technical conference would be the only discussion available to parties. CIEA expresses disappointment the Company made no attempt to rectify this error after agreeing to use the technical conference in lieu of answering discovery in Phase II. CIEA requests the Commission note Black Hills' failure to honor the settlement terms

[155] Phase I Settlement, ¶ 33.
[156] Phase I Settlement, ¶ 51.2.

and find that future ERP technical conferences should be made available to discuss confidential information.[157]

133. Black Hills asserts the technical conference needed to be public because at least one party attending the technical conference had not signed the highly confidential non-disclosure agreement. Black Hills states, however, that at the technical conference the Company offered to meet separately with UCA to discuss highly confidential information, and Staff, UCA, and CEO, subsequently asked for a separate, confidential meeting. Black Hills states it met with each of these three parties separately to answer questions based on the highly confidential version of the 120-Day Report. Black Hills argues it also would have met with CIEA about the highly confidential version of the 120-Day Report had CIEA requested such a meeting.[158]

134. Nevertheless, Black Hills does not object to CIEA's recommendation to hold a highly confidential Technical Conference in future ERPs, with the option to hold an additional public conference in the utility's discretion.[159]

135. The Commission denies CIEA's request to find that Black Hills failed to honor the Phase I Settlement. Even aside from the Company's response that it offered to and did meet with parties separately to discuss highly confidential matters, the Phase I Settlement indicates that the technical conference was to concern cost recovery issues. Moreover the Phase I Settlement does not address whether the technical conference can be public.

136. The Commission appreciates the Company's willingness to engage in technical conferences in future ERPs. Given the abbreviated nature of the Phase II process, additional communication between the parties could help improve the quality of Phase II filings. Thus, we

[157] CIEA's Comments, pp. 18-19.
[158] Black Hills' Response Comments, p. 20.
[159] Black Hills' Response Comments, p. 20.

direct Black Hills to include in its initial filings in the next ERP a proposal to hold a highly confidential Technical Conference to discuss the 120-Day Report.

I. Best Value Employment Metrics

137. The Phase I Settlement helps ensures the statutory requirements regarding best value employment metrics ("BVEM") are hardwired into the Phase II bid evaluation and selection process. Specifically, the Phase I Settlement requires that bids be evaluated in part using a 100-point bid scoring process, and a bid's BVEM impacts its 100-point bid evaluation score.[160] Moreover, in the Phase I Settlement, the Company commits to grade each bid on how it complies with BVEM, advancing only those proposals that are compliant with statutory requirements for these metrics. The Company also commits to advising potential bidders of the required metrics and the scoring and ranking system that it will use as well as informing any bidders determined to be noncompliant along with providing the bid BVEM scores. The Company states that it will provide documentation on the compliance metrics and scoring/ranking system in the RFP documents and will make itself available to discuss questions with bidders.[161]

138. In the 120-Day Report, the Company affirms that bids were evaluated on two primary components: (1) economic evaluation criteria (constituting 75 percent of the evaluation) and (2) non-economic evaluation criteria (constituting the remaining 25 of the evaluation). This non-economic evaluation criteria assessed non-price factors of a bid and included five categories of criteria with each having the same weight of five percent, one of which is BVEM.[162]

139. Black Hills provides detailed information regarding BVEM responses and how these responses play into the total non-economic score in Appendix B and Appendix F to the

[160] Phase I Settlement, ¶ 26; Hr. Ex. 112 (Thames Rebuttal), pp. 22-23.
[161] Phase I Settlement, ¶ 27.
[162] 120-Day Report (Rev. 1), p. 31.

120-Day Report. However, the Company has marked this information as highly confidential, which makes it difficult for the Commission to publicly discuss our BVEM considerations. Importantly, the projects comprising the Modified LED Portfolio scored well on BVEM metrics when compared to the other bids, and as a portfolio the Modified LED Portfolio scores higher on BVEM metrics than the Local Economic Development Portfolio that Black Hills advances in its Supplemental Comments.

140. Nevertheless, pursuant to § 40-2-129(1)(a), C.R.S., the Commission has considered BVEM throughout this Proceeding. While the BVEM methodology was adequate for this Proceeding, we direct Black Hills to address in its Phase I filings in the 2026 ERP how it can continue to improve the methodology. The Company shall specifically consider whether it can make BVEM scores publicly available in Phase II and provide additional detail supporting the ultimate BVEM scores. While the legislature has made it clear that BVEM should be a consideration, confidential designations on this information by the Company make it difficult for the Commission to express publicly how BVEM scores factored into decisions, which leaves much to be desired in terms of the transparency of the process. This could be improved by a more critical look by the Company at making as much of this information publicly available as possible in its next ERP.

141. Additionally, BVEM considers the employment of "Colorado labor." However, the Commission is also interested in evaluating the local impacts our ERP decisions have, particularly with a utility such as Black Hills that has a relatively small service territory. Thus, in its Phase I filings in the next ERP proceeding, we require Black Hills to address how the Phase II bid evaluation and selection process can better evaluate local employment impacts in addition to the BVEM statutory considerations.

J. Equity Considerations

142. In all of our proceedings, the parties and Commission must consider how best to provide equity, minimize impacts, prioritize benefits to disproportionately impacted ("DI") communities, and address historical inequities.[163] Similar to BVEM, some of this important equity analysis is already hardwired into the bid evaluation and selection process. Specifically, the Phase I Settlement requires that bids be evaluated in part using a 100-point bid scoring process, and the non-economic portion of this 100-point system includes criteria such as "environmental compliance and status of permitting" and "externality benefits and community." In addition, pursuant to the Phase I Settlement, the Company mapped the location of all bids that advanced to computer-based modeling in relation to DI communities based on the CDPHE's EnviroScreen mapping tool.[164]

143. These non-economic criteria do not comprise the totality of our equity considerations. The Commission has also weighed other factors, including the SCC of the various portfolios as well as how the various portfolios are likely to impact the direct costs that customers in Black Hills' service territory—much of which is comprised of DI communities—must pay for years to come.

144. To be clear, throughout this ERP Proceeding, the Commission has considered how best to provide equity, minimize impacts, prioritize benefits to DI communities, and address historical inequities, and the Phase I Decision and Phase I Settlement already hardwired some of this important equity analysis into the bid evaluation and selection process. Because Black Hills

[163] *See* SB 21-272.
[164] *See* 120-Day Report (Rev. 1) (Appendix L).

marked the non-economic scores as highly confidential, however, it is difficult to publicly discuss our considerations.

145. We direct Black Hills to address in its Phase I filings in its next ERP how it can continue to improve the evaluation of equity issues through the ERP process. The Company must specifically consider how it can provide more granularity in the mapping of bids in DI communities and if there are additional metrics that bidders should report to help the Commission and parties better understand the likely impacts and benefits of the proposed generation projects on DI communities. As with the BVEM scores, Black Hills must also address whether it can make the non-economic scores relating to equity issues publicly available. The Commission has spent significant time and resources working on how to better incorporate equity considerations into our processes, and the people and communities impacted by our decisions should be able to understand how this influences our decisions. This could be improved by a more critical look by the Company at making as much of this information publicly available as possible in its next ERP.

K. Section 123 Resources

146. Pursuant to § 40-2-123(1)(a), C.R.S., the Commission shall "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities." These new clean energy technologies are referred to as Section 123 resources and have become a standard consideration in the Commission's ERP proceedings.

147. In the 120-Day Report, Black Hills notes that it received 14 bids claiming Section 123 status. These bids consisted of the following three technologies: solar (PV), solar (PV) and storage, and storage. [165] Black Hills concludes that none of the bids claiming Section 123 resource

[165] 120-Day Report (Rev. 1), p. 35.

status qualify as a Section 123 resource, stating in part that none of the bids are for new technologies that meet the Commission definition of a Section 123 Resource. Nevertheless, Black Hills states the bids were still evaluated based on their economic value and were included in bid portfolios as a result of their competitiveness.[166]

148. No intervenors questioned the Company's determination that none of the bids were eligible for Section 123 resource status, and the Commission similarly finds no reason to question the Company's conclusion in this regard.

L. Transmission Modeling

149. Staff quotes paragraph no. 17 of the Phase I Settlement as requiring Black Hills to provide in the 120-Day Report the additional transmission needs for each portfolio: "Black Hills will model additional transmission needs and cost estimates on a portfolio basis for each portfolio listed above, consistent with the Company's Direct Case, and consistent with the Company's Federal Energy Regulatory Commission-approved Open Access Transmission Tariff."[167]

150. Staff observes that Black Hills apparently failed to provide this information in the 120-Day Report. Staff is concerned that the lack of portfolio-level transmission analysis leaves the Commission with incomplete information when comparing portfolio costs and creates a risk that additional network upgrades will be identified after a portfolio of resources has been approved. Staff explains the cost to interconnect a new resource extends beyond the physical point of interconnection to how the resource impacts the balance of the system in real time.

151. Staff asks the Commission to direct Black Hills to perform the portfolio transmission analysis for the approved portfolio and to report the detailed results to the

[166] 120-Day Report (Rev. 1), p. 35.
[167] Staff's Comments, p. 25 (quoting Commission Decision No. C23-0193A, Attachment A, ¶ 17) (emphasis added).

Commission in this Proceeding 30 days after the final Commission decision. Staff proposes the lower of the transmission costs associated with the Commission-approved portfolio presented in the Company's 120-Day Report or the costs modeled in the updated portfolio analysis should constitute the baseline for any cost-to-construct PIM.[168]

152. In its Response Comments, Black Hills states that, based on points of interconnection of the bids in the Preferred Portfolio, the estimated transmission upgrade costs will not materially change when evaluated on a portfolio basis. Black Hills does not opine on whether this is also the case for the bids in the Local Economic Development Portfolio or the CEP Portfolio.[169]

153. Black Hills opposes Staff's suggestion that the transmission costs presented in the 120-Day Report serve as the baseline for a future cost-to-construct PIM. The Company argues that its approach was to ensure that transmission upgrade costs were incorporated into the bid evaluation process fairly within the limited time available in Phase II but that the Company never intended these costs to be at the accuracy level appropriate for a PIM.[170]

154. Black Hills does not appear to address the Phase I Settlement's expectation that the Company model additional transmission needs and costs estimates on a portfolio basis for each portfolio.

155. The Commission is disappointed Black Hills apparently did not develop transmission needs and cost estimates on a portfolio basis as the Phase I Settlement contemplates. In the context of the timing restrictions in Phase II, however, it is unclear how feasible it was for

[168] Staff's Comments, p. 27.
[169] Black Hills' Response Comments, p. 13.
[170] Black Hills' Response Comments, p. 13.

the Company to provide transmission estimates that accurately reflect the interaction between the various generation projects.

156. Given the lack of analysis performed regarding the required transmission network upgrades, we expressly find that transmission network upgrades, including any grid strength reinforcements or reactive power/voltage support investments, are not part of the approved CEP and are not entitled to any sort of presumption of prudence. These transmission networks upgrades are distinct from the direct interconnection costs needed for each resource individually as reported in the 120-Day Report, which are properly included in the approved CEP.

157. The Commission agrees with Staff and directs the Company to perform a portfolio transmission analysis for the Modified LED Portfolio and report the detailed results to the Commission in this Proceeding 30 days after the final Phase II Decision. As Black Hills indicates in its Response Comments, it is possible the estimated transmission upgrade costs will not materially differ from the costs of the approved portfolio, but having additional analysis at an early stage could be helpful.

158. However, we reject Staff's suggestion to somehow tie this additional transmission analysis to the cost-to-construct baseline. Black Hills raises a legitimate argument that the portfolio transmission upgrade costs developed for purposes of Phase II were not intended to be at the accuracy level expected for use in a PIM.

M. Additional Directives for Black Hills' Next ERP

159. Per 4 CCR 723-3-3603(a), Black Hills' next ERP will be filed in 2026. In the Phase I Decision, the Commission issued certain directives for this next 2026 ERP to help ensure a more

robust analysis of demand response ("DR").[171] As noted above, in this Phase II Decision we have directed Black Hills to address certain issues in its initial filings in its next ERP proceeding, including improvements to the BVEM and equity methodologies and more defined plans for sharing information with the IE and a Phase II technical conference. In this Section, we outline additional topics Black Hills must address in its next ERP filing to help improve certain shortcomings that arose in this Proceeding.

1. Consistent Modeling

160. Although Black Hills compiled seven portfolios in the 120-Day Report, only one of the portfolios (the Company's Preferred Portfolio) had dispatch modeling through Plexos. This made it challenging to compare the Preferred Portfolio to the other six portfolios. Staff and CEO both raise concerns with this approach in their Comments.[172]

161. While Black Hills responded to the concerns raised by Staff and CEO and provided the Plexos modeling results for certain additional portfolios in its Response Comments, ideally Black Hills would have provided the Plexos modeling results for all portfolios initially in the 120-Day Report. For the Company's next ERP proceeding, the Commission directs Black Hills to consistently model the various portfolios in its Phase I modeling and to explain in its initial Phase I filings how the Company will ensure that the 120-Day Report allows the parties and Commission to accurately compare the various portfolios.

[171] Phase I Decision, ¶ 54 ("Black Hills shall analyze and fully address the suggestions that Staff and WRA put forth during the hearing about including some type of effective load carrying capability value for DR resources, including incremental generic DR resources in Phase I, and putting forth a proposal for how to analyze varying amounts of DR in Phase II. In addition, Black Hills shall evaluate and incorporate, to the extent feasible, the use of third-party aggregated DR as a potential resource solution.") (footnote omitted).

[172] *See* Staff's Comments, pp. 14-16.

2. Annual Emissions Data

162. In its Comments, CEO argues it is important to consider both the annual and cumulative carbon dioxide and methane emissions for each portfolio and recommends that Black Hills provide a summary table for each unique capacity expansion and production cost modeling portfolio.[173]

163. In its Response Comments, Black Hills responds to CEO's concerns and provides annual emissions data for four of the primary portfolios.[174]

164. We agree with CEO that both cumulative and annual emissions data are informative when evaluating various resource portfolios. While Black Hills eventually provided such data for certain portfolios, this should have been included initially in the 120-Day Report. For the next ERP proceeding, the Commission directs Black Hills to include in its Phase I modeling the annual emissions data for the Company's various portfolios and address whether it plans to provide similar data in Phase II.

3. Model Runs with and without SCC

165. In its Comments, Staff states that it is "troubling" that the Local Economic Development Portfolio has a lower NPVRR than the less constrained CEP Portfolio and the 40 Percent Ownership Portfolio. Black Hills does not expressly address this issue in its Response Comments. However, it appears that this anomaly results from how the model optimizes for the SCC. When factoring in the SCC, the less constrained CEP Portfolio is less expensive than the Local Economic Development Portfolio—as expected. It is only when viewing the direct cost to customers (*i.e.* not accounting for the SCC) where the more constrained Local Economic Development Portfolio is less expensive.

[173] CEO's Comments, pp. 15-16.
[174] Black Hills' Response Comments, pp. 6-7.

166. Including additional modeling runs both with and without the SCC would likely remove the confusion regarding how portfolios are optimized. We are mindful, however, that requiring numerous modeling runs could be costly. Thus, in the next ERP proceeding, the Commission directs Black Hills to address this issue in its initial Phase I modeling and include a discussion in its Phase I filings regarding the feasibility of modeling portfolios both with and without the SCC.

4. Modeling of Sensitivities

167. In its Comments, Staff argues the sensitivities on the Preferred Portfolio were modeled over very limited years within the RAP, with no information provided regarding the cost impacts of those varied assumptions. Staff asserts the default modeling approach for sensitivity analyses should be that the sensitivities cover the same period of time as the base modeling and the Company should make clear in Phase I if it does not intend to follow this default.[175]

168. Black Hills does not expressly address Staff's concerns in its Response Comments.

169. The Commission is sympathetic to Staff's assertion that the default modeling approach for sensitivity analyses should be that the sensitivities cover the same period of time as the base modeling. Likewise, additional information regarding the cost impacts associated with the sensitivities could have been useful. In its next ERP proceeding, we direct Black Hills to address in its initial Phase I filings Staff's concerns and explain how the Company intends to model scenarios in Phase II.

[175] Staff's Comments, p. 17.

5. Phase II Modeling Modifications

170. There were multiple instances in which the Phase II modeling deviated from the intervenors' expectations. For instance, the Phase I Settlement calls for a 20 percent PRM.[176] However, Staff notes in its Comments that E3 removed the PRM constraint for model years 2026 and 2027 to ensure that the PRM constraint did not bias the model towards bids with earlier online dates.[177] Staff states the decision to remove the PRM constraint for early years might be reasonable, but the Company neither reported this modeling modification nor provides an explanation of the factors that necessitate such a drastic deviation from the Phase I Settlement and standard planning processes.[178] Staff asks that, going forward, the Company inform both Staff and the IE before it makes such a significant modeling modification.[179]

171. Staff likewise expresses concern regarding the additional screen on more expensive solar bids that E3 performed to speed up modeling. Staff objects to E3 making the decision to perform an additional screen on solar projects and questions whether bidders were accurately informed of their bid status and unclear why the Company did not inform the IE, Staff, or the Commission of this significant deviation. [180]

172. Staff also expresses concern with statements from the IE that the CEP Portfolio "satisfied the requirements" of Portfolio 4 and Portfolio 5 and thus no Resolve run was performed for those portfolios. [181]

173. Black Hills responds to each of these concerns. To begin, the Company argues the PRM constraint was removed in 2027 "to give the model more flexibility in selecting the most

[176] Phase I Settlement, ¶ 10.1.
[177] IE Report, p. 11.
[178] Staff's Comments, p. 28.
[179] Staff's Comments, p. 28.
[180] Staff's Comments, 18.
[181] Staff's Comments, 17-18; *see also* IE Report, p. 13.

cost-effective bids [because] many bids come online after summer 2027."[182] As to Staff's concerns with the additional screen E3 performed on more expensive solar bids, Black Hills maintains the Company "supplied a Bid Rejection Notification to each bidder for bid(s) that would not be advanced to computer-based modeling."[183] Black Hills also states that as portfolios were being developed, E3 held the more expensive standalone solar bids in reserve and focused on the most economic solar bids to speed up computer modeling.[184] And finally, Black Hills asserts that earlier modeling demonstrated that Portfolios 4 and 5 would produce the same results as Portfolio 3, so the Company decided not to perform the additional model runs to save time and cost.[185]

174. We find that some of the modifications Black Hills made to the Phase II modeling appear reasonable, particularly the removal of the PRM constraint in the initial years of the RAP. However, it is troubling that Black Hills made such modifications in Phase II without informing Staff and other parties and without fully justifying the changes in its initial 120-Day Report. In the next ERP proceeding, we thus direct Black Hills to address in its initial Phase I filings how the Company will respond if it needs to modify the Phase II modeling and whether and how it will alert intervenors and the Commission about any such modifications. This will help develop a record so that the Commission can create a contingency plan for the Company to follow if it needs to make modifications in Phase II.

6. Options to Increase Cost Effectiveness of Bids

175. It is imperative in future ERP proceedings to continue to investigate how Black Hills can acquire more cost effective resources. Especially given the relatively high electricity rates that Black Hills' customers already pay, the Company's relatively small size, and

[182] Black Hills' Response Comments, p. 9.
[183] Black Hills' Response Comments, p. 9.
[184] Black Hills' Response Comments, pp. 9-10.
[185] Black Hills' Response Comments, p. 8.

its lack of transmission resources, the Commission encourages all stakeholders, and directs the Company, to consider creative alternatives that could increase competitive tension in Black Hills' next ERP proceeding, including partnering with existing and proposed storage and generation facilities with other utilities, thereby, driving down costs for generation and storage resources.

176. In addition to this general directive, we specifically require Black Hills in its next ERP proceeding to discuss in its initial Phase I filings whether the Company could provide land rights to bidders to increase competitive tension. Under this concept, Black Hills would proactively acquire the option to purchase land in areas in which the Company's system has available injection capacity. Black Hills could then disclose these locations to potential bidders with the expectation that the winning bidder could acquire the land rights from Black Hills.

N. PAGS Correlated Outage Study

177. The Pueblo Airport Generating Station ("PAGS") is a critical piece of Black Hills' generating fleet, consisting of approximately 400 MW of dispatchable capacity from various gas units.[186] In our Phase I Decision, we expressed concern that a correlated outage at PAGS could have significant impacts to Black Hills' system and that little has been done to analyze this risk. We directed Black Hills to conduct or commission a study to assess the risk and potential mitigation options for gas supply disruptions—including gas shortages—that cause a correlated outage at PAGS. The Commission provided Black Hills 12 months from the Phase I Decision within which to file the correlated outage study.[187]

[186] Hr. Ex. 101 (Wagner Direct) (Rev. 1), pp. 20-21.
[187] Phase I Decision, ¶¶ 71-72.

178. The Phase I Decision issued on March 8, 2023, so the filing deadline for the PAGS Correlated Outage Study passed on March 8, 2024. Black Hills has not filed this study in this Proceeding nor addressed its failure to do so.

179. The Commission remains concerned regarding the potential for a correlated outage at PAGS. It would behoove all stakeholders—not the least Black Hills—to better understand this risk. Thus, the Commission directs Black Hills to file in this Proceeding the PAGS Correlated Outage Study as set forth in the Phase I Decision within 90 days of a final Phase II Decision.

O. AQCC's Calculation of Carbon Dioxide Emissions Reductions

180. Under section 40-2-125.5(4)(c)(I), C.R.S. the AQCC "shall report to the public utilities commission" the division of administration's "calculation of carbon dioxide emission reductions attributable to" the approved clean energy plan. For the sake of administrative efficiency, the Commission requests AQCC file the report in this proceeding.

II. ORDER

A. The Commission Orders That:

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

2. Consistent with the discussion above, we authorize Black Hills to pursue the approved CEP and the acquisition of the resources included in the Modified Local Economic Development Portfolio ("Modified LED Portfolio") and backup bids with further due diligence and contract negotiations. Black Hills shall further file applications for Certificates of Public Convenience and Necessity for any Company-owned generation resources arising from the approved CEP. Black Hills' actions, consistent with this Phase II Decision, shall be presumed to

be prudent at the time of cost recovery consistent with 4 *Code of Colorado Regulations* 723-3-33617(d) of the Commission's Rules Regulating Electric Utilities.

3. Bid 245-01 (a 50 MW storage project) is subject to a cost-to-construct performance incentive mechanism ("PIM"), consistent with the discussion above.

4. Black Hills shall file in this Proceeding an emissions-reduction PIM 14 days after the final Phase II Decision, including any decision ruling and applications for rehearing, reargument, or reconsideration, consistent with the discussion above.

5. On not less than two business days' notice, Black Hills shall file advice letter compliance filings to establish the clean energy plan rider, consistent with the discussion above.

6. Consistent with the discussion above, transmission network upgrades, including any grid strength reinforcements or reactive power/voltage support investments are not part of the approved CEP and are not entitled to any sort of presumption of prudence.

7. Within 30 days, Black Hills shall perform a portfolio transmission analysis for the Modified LED Portfolio and report the detailed results to the Commission in this Proceeding.

8. Within 90 days, Black Hills shall file in this Proceeding the Pueblo Airport Generating Station Correlated Outage Study, consistent with the discussion above.

9. Consistent with the discussion above, in Black Hills' next electric resource plan proceeding, Black Hills shall address several topics, including a more robust analysis of demand response, improvements to best value employment metrics and equity considerations, a more defined plan for information sharing with the independent evaluator, a Phase II technical conference, consistent portfolio modeling, annual emissions data, modeling runs with and without the social cost of carbon, the modeling of sensitivities, Phase II modeling modifications, and

options to increase the cost effectiveness of bids (*e.g.*, by providing land rights to bidders to increase competitive tension).

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

11. This Order is effective immediately on its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING July 10, 2024, and August 7, 2024.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E. White,
Director