Decision No. C17-0316

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 16A-0396E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2016 ELECTRIC RESOURCE PLAN.

**PHASE I DECISION GRANTING,
WITH MODIFICATIONS, APPLICATION FOR
APPROVAL OF 2016 ELECTRIC RESOURCE PLAN**

Mailed Date: April 28, 2017
Adopted Date: March 23, 2017

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I. BY THE COMMISSION

A. Statement

1. This Decision approves, with modifications, the 2016 Electric Resource Plan (2016 ERP) filed by Public Service Company of Colorado (Public Service or Company) on May 27, 2016.

2. Consistent with the discussion below, we authorize Public Service to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need during an eight-year resource acquisition period extending from 2016 through 2024. We also approve the process for evaluating bids to the competitive solicitation and establish the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in compliance with this Decision.

3. In addition, we adopt procedures for the consideration of new clean energy and energy efficient technologies pursuant to § 40-2-123, C.R.S. We further direct Public Service to propose an Independent Evaluator for the forthcoming bid evaluation and selection process.

B. Discussion

1. Electric Resource Planning

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

that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives, such as the Renewable Energy Standard (RES) at § 40-2-124, C.R.S.

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

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

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

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

8. Phase II begins after the Commission issues its Phase I decision. Public Service will issue its RFPs, receive competitive bids and utility-owned proposals, and file a report in this

Proceeding no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) (120-Day Report). The report will present an evaluation of all proposed resources, based on the criteria established in the Phase I decision (*e.g.*, the base modeling inputs and assumptions to be used in developing optimized resource portfolios and the sensitivities that "re-price" optimized portfolios using alternative values for selected inputs and assumptions).

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

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

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

2. Procedural Background

11. On May 27, 2016, Public Service filed an application for approval of its 2016 ERP (Application). Public Service filed the Application pursuant to the ERP Rules. The Application filing initiated Phase I of this ERP proceeding. Public Service requests that the Commission approve its 2016 ERP and the accompanying assumptions and studies incorporated in this 2016 ERP. The Company submitted Direct Testimony of five witnesses in support of the Application.

12. On July 15, 2016, the Commission set the Application for hearing and established the parties in this Proceeding.[1] Parties include: Public Service; Staff of the Colorado Public Utilities Commission (Staff); the Colorado Office of Consumer Counsel (OCC); the Colorado Energy Office (CEO); the City of Boulder (Boulder); the Colorado Energy Consumers Group (CEC); Climax Molybdenum Company (Climax); Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Colorado Solar Energy Industries Association (CoSEIA); the International Brotherhood of Electrical Workers, Local No. 111; Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly, RMELC and CBCTC); Holy Cross Electric Association, Inc., Yampa Valley Electric Association, Inc., Intermountain Rural Electric Association (IREA) and Grand Valley Rural Power Lines, Inc.; Invenergy Wind Development North America, LLC; Sustainable Power Group, LLC (sPower or Sustainable Power); Southwest Generation Operating Company, LLC (SWGen); Western Resource Advocates (WRA); and Vote Solar. The Commission also granted the Air Pollution Control Division of the Colorado Department of Public Health and Environment (CDPHE) leave to participate as an *amicus* in this Proceeding.

[1] Decision No. C16-0663-I, issued July 15, 2016, Proceeding No. 16A-0396E.

13. On September 23, 2016, the Commission established a procedural schedule for Phase I of the proceeding.[2]

14. On October 14, 2016, sPower filed a Motion for Waiver of Commission Rule 3902(c), requesting that the Commission waive the rule indefinitely, claiming it does not comply with the requirements of the Federal Public Utility Regulatory Policies Act of 1978 (PURPA) and the regulations promulgated by the Federal Energy Regulatory Commission (FERC) to implement PURPA. Sustainable Power also requested that the Commission establish an alternative methodology to calculate avoided costs for the purchase of electricity from Qualifying Facilities within this Proceeding.

15. On December 9, 2016, Staff, the OCC, CIEA, WRA, SWGen, sPower, CoSEIA, and Interwest filed Answer Testimony.

16. On December 19, 2016, the Commission denied sPower's Motion for Waiver, finding that the motion was procedurally improper and the relief, as requested, is beyond the scope of this Proceeding.[3]

17. On January 17, 2017, Public Service filed its Rebuttal Testimony, and the OCC, sPower, and WRA filed Cross-Answer Testimony.

18. On January 20, 2017, we established procedures for the evidentiary hearing before the Commission *en banc* and scheduled a public comment hearing for February 1, 2017.[4]

[2] Decision No. C16-0867-I, issued September 23, 2016, Proceeding No. 16A-0396E.
[3] Decision No. C16-1156-I, issued December 19, 2016, Proceeding No. 16A-0396E.
[4] Decision No. C17-0053-I, issued January 20, 2017, Proceeding No. 16A-0396E.

19. On January 26, 2017, we granted Staff's motion to allow parties to submit written Surrebuttal Testimony regarding the Company's proposal in its Rebuttal Testimony to address three levels of resource need in the Company's 120-Day Report.[5]

20. On January 30, 2017, Staff and the OCC filed Surrebuttal Testimony.

21. We conducted a public comment hearing in this matter on February 1, 2017. Nearly 40 speakers provided oral comment on several issues, including the acquisition of renewable energy resources, the development of energy storage, fossil fuel consumption and its associated emissions, and electricity market design.

22. An evidentiary hearing was conducted February 1, 2017 through February 6, 2017. Hearing Exhibits 1 through 33 correspond to the pre-filed Direct Testimony, Answer Testimony, Rebuttal Testimony, Cross-Answer Testimony, and Surrebuttal Testimony. Hearing Exhibits 1 through 33 were offered and admitted into the evidentiary record in this Proceeding. Hearing Exhibits 34 through 75 were offered during direct examination, cross-examination, and redirect examination of witnesses. Hearing Exhibits 34 through 65 and 67 through 75 were admitted. Hearing Exhibit 66 was marked for identification, offered, but not admitted.

23. Parties filed Statements of Position (SOPs) on February 24, 2017, including Public Service, Staff, the OCC, CIEA, WRA, CEC, SWGen, Vote Solar, sPower, CoSEIA, Interwest, RMELC and CBCTC, and Boulder. CDPHE also filed an SOP.

C. Plan to Acquire New Utility Resources

24. Public Service proposes a competitive, all-source solicitation to acquire resources to meet its future resource need. The Company's proposal is consistent with 4 CCR

[5] Decision No. C17-0082-I, issued January 26, 2017, Proceeding No. 16A-0396E.

723-3-3611(a) that states: "It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource plan (*i.e.*, an all-source solicitation)."

25. Rule 4 CCR 723-3-3604(a) requires Public Service to include in its ERP:

> A statement of the utility-specified resource acquisition period and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of the needs of the utility system.

26. Public Service proposes a resource acquisition period (RAP) extending from May 2016 through May 2024. The Company further proposes to evaluate the bids to the competitive solicitation over a Planning Period extending from June 1, 2016 through June 1, 2054.

27. Public Service explains that several factors will influence the mix and timing of the supply-side resources the Company eventually may acquire. These include: (1) historic low natural gas prices; (2) underutilized natural gas generation facilities in the region; (3) the extension of the federal production tax credit for new wind generation and the investment tax credit for new solar generation; (4) a downward sloping cost curve for solar generation; (5) enhancements to the distribution grid allowing for new grid related services; and (6) the U.S. Supreme Court's stay of Environmental Protection Agency's (EPA) proposed Clean Power Plan regulating carbon dioxide emissions from power plants.

28. We approve Public Service's plan to issue RFPs for an all-source, competitive bidding process to meet its resource need during the RAP. We also approve the proposed RAP extending from May 2016 through May 2024 and the proposed Planning Period from 2016

through 2054. These fundamental elements of the 2016 ERP are consistent with the Commission's ERP Rules.

D. Determination of Future Resource Need

1. Resource Need Scenarios

a. Positions of the Parties

29. Public Service describes the determination of the Company's incremental resource need be the "paramount finding" required in the Commission's Phase I Decision.

30. In its initial Application filing of May 2016, Public Service projected a need of approximately 284 MW in 2022 and a need of 615 MW in 2023. However, in its Annual Progress Report filed October 31, 2016 pursuant to Rule 4 CCR 723-3-3618(a), the Company projects no net generation need in 2022 and a net generation need of 389 MW in 2023.

31. In its Rebuttal Testimony filing submitted on January 25, 2017, Public Service argues that there are significant uncertainties that affect the determination of its future resource need during the RAP, such as uncertainty surrounding future oil and gas loads and uncertainty surrounding the outcome of pending Commission proceedings and the associated impacts on the Company's electric demand for customers. The Company also points to uncertainty surrounding both future environmental regulations and current opportunities to procure renewable energy resources with the benefit of the federal Production Tax Credit and Investment Tax Credit. Public Service further states that it is now operating in an environment where generation technologies are rapidly changing, renewable energy resource technologies are cost competitive, and storage technologies are more cost-effective.

32. To account for this uncertainty and to provide more flexibility to the Phase II process, Public Service proposes to present in its 120-Day Report three scenarios for its

future resource need in 2023, each based on a different level of resource requirements (*i.e.*, low, medium, and high). As shown in Table JFH-4,[6] each level of need would be based on: an updated assessment of system peak demand; demand reductions that are expected in response to rate design changes; savings from the Integrated Volt-VAr Optimization project;[7] load growth from the oil and gas industry; and load growth from electric vehicles. Public Service proposes to use its Strategist computer model to build separate sets of bid portfolios that meet each of the three levels of resource need, consistent with the Commission's Phase I decision.

33. Public Service states that, until such time as Boulder is authorized to serve customers as a municipal utility, the Company has the obligation to plan its system and resources including and accounting for Boulder's load. The Company's three proposed scenarios therefore do not reflect a net reduction in need as a result of Boulder potentially serving customers as a municipal utility.

34. Public Service acknowledges that its proposal for presenting bid portfolios for three levels of resource need differs from the Company's two prior ERPs where a single MW estimate of resource need was used for the presentation of modeled portfolios of bid resources. The Company therefore proposes additional review procedures as part of Phase II. Public Service would file updated levels of low, medium, and high need in early May, 2017. Intervening parties then would have two weeks to file comments on the updated need amounts, and the Company would have another two weeks to respond to those comments. The Company proposes that the Commission then consider the updated calculations of need, the parties'

[6] Hearing Exhibit 4, Hill Rebuttal, p. 24.

[7] The Integrated Volt-VAr Optimization Project is a proposal put forth by the Company in Proceeding No. 16A-0588E.

comments, and the Company's response and render a decision on the low, medium, and high need calculations to support the issuance of an RFP by July 1, 2017.

35. In accordance with the low, medium, and high need amounts established by the Commission, Public Service would present three sets of bid portfolios in its 120-Day Report, which would be submitted in early February, 2018, based on the proposal that bids to the RFPs are due on or around October 1, 2017. Public Service states that the Company will recommend, based on its updated demand forecast in its 120-Day Report, both a preferred resource need and a preferred portfolio to fill the applicable need.

36. Staff states that it conferred with Public Service after reviewing its proposal to present bid portfolios for three levels of need as set forth in Table JFH-4 and sought agreement, prior to the hearing, of a workable procedure for the parties to follow prior to the issuance of the RFPs. Staff explains that this procedure was described in the Surrebuttal Testimony of Staff witness Erin O'Neill. Staff argues that modeling a range of load outcomes provides a more complete picture of the future and allows for the examination of how different combinations of resources perform across a range of demand levels. Staff asserts that a presentation of low, medium, and high need scenarios will alleviate the need for the parties to agree on a single point forecast for the load associated with various technologies, regulatory proceedings, and industries.

37. WRA, CIEA, and Interwest support the three-scenario approach set forth in Table JFH-4. SWGen states that the proposed procedure for establishing the three levels of need is a reasonable way to address the issues. Public Service also states that the approach is supported by CEO, sPower, Vote Solar, Climax, RMELC, and IREA.

38. The OCC opposes the three need scenarios proposed by Public Service, arguing that the Company has failed to present evidence demonstrating the methods, formulas, and

assumptions it relied upon to develop values presented in Table JFH-4. The OCC argues that only through increased transparency on the methods used to determine the levels of need will the Commission be able to determine the appropriateness of the bid portfolios presented in the Company's 120-Day Report.

39. CEC also objects to Public Service's proposed three-scenario approach for determining resource need in this ERP. CEC instead favors the establishment of a single point of need, contending that such a point is necessary for determining whether a proposed resource portfolio is cost-effective. CEC argues that over-developing resources inappropriately commits ratepayers to funding unnecessary and imprudent investments without corresponding value, whereas under-developing resources jeopardizes the Company's ability to safely and reliably provide service to customers, and any capacity shortfall also puts ratepayers at risk for funding additional capacity at excessive and avoidable cost.

40. CEC further argues that the review process for the need determination in Table JFH-4 provides inadequate protections for ratepayers and that it should be modified by the Commission if it is not rejected. CEC suggests that the Commission should, at a minimum, provide parties the opportunity for limited, yet expedited, discovery, as well as an abbreviated evidentiary hearing to examine the low, medium, and high need calculations. CEC further states that it supports the OCC's position that a flexible resource acquisition process administered under the Commission's ERP Rules will afford Public Service sufficient flexibility to adapt to changing circumstances and address the uncertainty the approach in Table JFH-4 is intended to address.

41. Boulder argues that its gradual departure as a user of the Company's generation should be included in Table JFH-4 as a variable for the determination of need in 2023.

Without any supporting evidence or testimony, Boulder recommends that the calculated resource need in 2023 should be decreased by 50 MW. Boulder adds that if the Commission approves "Boulder's concept of [the Company] using Boulder's released energy and capacity to meet [the Company's] growing native load, Boulder will likely present a detailed gradual departure plan proposal in the 2019 ERP proceeding."[8]

b. Findings and Conclusions

42. We are not persuaded that the degree of uncertainty surrounding the resource need in this 2016 ERP requires the three scenarios proposed in Table JFH-4. All of Public Service's calculations for a resource need during the RAP reflect a planning reserve margin of 16.3 percent, which corresponds to roughly 1,000 MW of utility resources. This amount of resources is intended to address uncertainty surrounding the determination of a future resource need[9] and comes at a significant cost to ratepayers.

43. We also share CEC's concerns about the risk of acquiring potentially superfluous generation resources, and we are particularly concerned about resource portfolios for a high need scenario that is 530 MW greater than the low need scenario. We further find that the evidentiary record in this Proceeding fails to support some of the adjustments to the demand forecast proposed in Table JFH-4, and we are not inclined to adopt CEC's request to have a hearing on the final resource need calculation.

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[8] Boulder SOP, p. 7.

[9] Rule 4 CCR 723-3-3609(b) states, in part: "The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks."

44. We therefore direct Public Service to develop two scenarios for presenting portfolios in its 120-Day Report instead of the three proposed in Table JFH-4.

45. The first scenario shall correspond to a zero-need of ("0 MW") in 2023, which reflects the possibility that the Company will have only a minimal need to acquire new utility resources during the RAP. Given the substantial reserve margin of approximately 1,000 MW and recognizing that any need would likely be in the last year of the RAP, which could be addressed in Public Service's 2019 ERP, it is reasonable to examine resource portfolios that correspond to a zero-need scenario. We agree with Public Service witness Jim Hill's testimony at hearing that zero-need portfolios could be comprised of wind resources (and perhaps solar resources) and would not preclude the potential acquisition of low cost gas-fired resources.[10]

46. The second scenario shall be based on the Company's updated demand forecast, but unadjusted as proposed in Table JFH-4. We order Public Service to file this need calculation, in the form of a Loads and Resources Table,[11] prior to the issuance of its RFPs. Because the resource need amount for the 2016 ERP will be established consistent with this Phase I decision, we find that no additional comments, discovery, or hearings are required for the determination of need to be addressed in Phase II.

47. Consistent with Rule 4 CCR 723-3-3613(d), Public Service shall identify in its 120-Day Report a single preferred resource portfolio that meets the Company's resource need during the RAP. However, because it is the Commission's preference to consider resource acquisitions in an ERP context, we permit Public Service to present in its 120-Day Report an alternative portfolio that includes additional resources in excess of the calculated resource

[10] Transcript, February 2, 2017, pp. 199-200.
[11] Hearing Exhibit 1, p. 2-267.

need. Proposed acquisitions in excess of the need must be shown to benefit customers over the Planning Period.

48. We also approve the inclusion of Boulder's full amount of projected load in Public Service's native load calculation for the eight-year RAP. The timing of Boulder's possible departure from Public Service's system remains unclear. If litigation surrounding Boulder's municipalization plans continues, there likely will be more adjudicated proceedings beyond the case presently before the Commission in Proceeding No. 15A-0589E. We agree with Public Service that such future cases could take several more years to complete, given the numerous and complex issues at stake. Based on this current status of Boulder's plan to pursue municipalization, inclusion of the full amount of projected load attributable to Boulder is appropriate.

49. Finally, we direct Public Service to file an updated reserve margin study with its 2019 ERP filing.[12]

2. Early Coal Plant Retirements

50. CIEA requests that the Commission direct Public Service to model the acquisition of sufficient additional resources to permit the early retirement of a portion of its existing coal-fired generation resources, if doing so would create savings for customers. CIEA argues that the Company has used Strategist modeling to examine accelerated retirement coal units in previous ERP proceedings.

51. CIEA clarifies that it is not advocating for any particular accelerated retirement. CIEA also explains that the Commission need not decide whether a unit may be retired in

[12] Transcript, February 2, 2017, p. 190.

Phase II or how such retirement and replacement might occur. CIEA argues that the Commission would benefit from the information presented by modeling potential accelerated coal plan retirements during the RAP.

52. Public Service responds with legal arguments, countering that CIEA's proposal raises constitutional issues and is contrary to the Commission's ERP Rules. Public Service also argues that the extent of Strategists' capabilities to conduct the analyses proposed by CIEA is unknown and potentially "fairly crude."[13]

53. We will not require Public Service to conduct CIEA's proposed analysis of early coal plant retirements in this ERP. While we agree with CIEA that the resource modeling done in an ERP proceeding may provide relevant information on the costs and benefits of early plant retirements, the record in this case does not provide adequate detail to establish how the coal retirements could be modeled in this ERP, particularly given the level of cost inputs required for early retirement and the questions about the ability of Strategist to be used for this purpose. We also decline to address Public Service's legal objections to CIEA's proposal at this time.

54. As discussed elsewhere in this Decision, we intend to open a rulemaking to modify the ERP Rules. We may examine potential changes to the provisions for evaluating existing resources pursuant to Rule 4 CCR 723-3-3607 with respect to plant retirements and replacement capacity based on the experience gained in recent ERPs and other proceedings such as the Clean Air-Clean Jobs Act proceedings in 2010.[14] The future rulemaking will provide Public Service and others a chance to present relevant legal arguments, and we will have the opportunity to clarify the Commission's policies and authorities.

[13] Public Service SOP, p. 68.

[14] Proceeding No. 10M-245E for Public Service and Proceeding No. 10M-254E for Black Hills/Colorado Electric Utility, LP.

3. Load Forecast

55. In the Application filing, Public Service's base case native peak demand, including retail and firm wholesale requirements, was projected to increase at a compounded annual growth rate (CAGR) of 1.6 percent through 2023. The Company's Base Case native sales were projected to increase at a CAGR of 1.5 percent through 2023. Public Service developed these growth rates using economic indicators for the entire State of Colorado obtained from IHS Global Insight, Inc. Public Service states that the economic outlook for its service territory through the RAP ending in 2023 indicates that Colorado will experience similar growth compared with the previous five years.

56. Staff argues through the Answer Testimony of Erin O'Neill that Public Service's service area is growing faster than the state.[15] Staff recommends that the Company develop its load forecast using service-area specific measures of economic growth and not on statewide measures of growth.

57. In its SOP, Staff maintains the economic growth in Public Service's electric service territory has and may continue to be stronger than the State of Colorado as a whole. While acknowledging that the Company's forecast for economic growth in the state may now be similar to the forecast for Public Service's own territory, Staff argues that there is no guarantee that the forecasts will be similar at such time as the load forecast is updated prior to the Phase II competitive solicitation. Staff recommends that the Commission direct Public Service to use the best available economic forecast information that most closely resembles its service territory on a going forward basis when the Company updates its load forecasts, including updates within this ERP process.

[15] Hearing Exhibit 14.

58. In response, Public Service argues that it is appropriate to continue to use statewide economic indicators for sales and peak demand forecasting in this ERP and going forward into its next ERP. The Company argues that this approach is appropriate due to the absence of significant differences in forecasts derived using statewide figures and forecasts derived using data posited to be more specific to its service area (*i.e.*, data for certain Metropolitan Statistical Areas (MSAs) contained with the Company's electric service areas including Boulder, Denver-Aurora-Lakewood, Grand Junction, and Greeley). Public Service explains that it compared the results of a peak demand forecast using the aggregated MSA economic indicators to the results of a forecast using state data and found only a statistically insignificant difference.

59. We adopt Staff's recommendation and direct Public Service to derive its demand and sales forecasts using MSA-aggregated data that is more tailored to the Company's service area.[16] Staff's analysis convinces us that the demand and sales forecasts used for the Public Service's resource planning should be based on the MSA-aggregated data, because the Company's service area has stronger economic growth indicators as compared to the indicators for the State of Colorado as a whole.

E. Base Modeling Assumptions and Modeling Sensitivities

1. Carbon Adder

a. Position of the Parties

60. Public Service states that a carbon proxy cost demonstrates the potential value that zero and low-emitting resources bring to the Company's system as compared to the use of other resource options. The Company argues, however, that due to the uncertainty facing the

[16] Commissioner Wendy M. Moser does not join in these conclusions and findings.

federal Clean Power Plan and other types of carbon regulation, it is reasonable to use a proxy cost of $0 per ton for carbon as the base modeling assumption. Public Service recommends comparing the base modeling results to two sensitivities, arguing that this approach will allow the Commission to evaluate portfolios under a broad range of carbon compliance costs. The first sensitivity would apply a Low Clean Power Plan cost of carbon (Low Carbon Cost Case), which the Company states represents the potential costs for implementing the federal emissions regulations based on the EPA's and other's modeling of those costs. The Company proposes that the Low Carbon Cost Case start at $1.86 per ton in 2022 and increase to roughly $25 by the end of the Planning Period.[17] The Company proposes a second sensitivity, or High Carbon Cost Case, apply a cost for carbon based on the values adopted by the Commission when it approved the Company's 2011 ERP.[18] The Company proposes imputing a cost for carbon starting in 2022.

61. WRA, Vote Solar, CoSEIA, SWGen, and Interwest support the inclusion of a carbon proxy cost, but recommend it be included as a base case Phase II modeling assumption.

62. WRA agrees with Public Service that the base case modeling assumptions should represent "the most likely future the Commission foresees" over the Planning Period.[19] WRA argues that it is nearly certain that Public Service will face regulation of carbon during the Planning Period and that it therefore is unreasonable for the Company to assume no carbon costs in the base modeling case in the Phase II evaluation of portfolios. First, WRA takes the position that it is premature for Public Service to conclude the Clean Power Plan will not be upheld by the courts and implemented. Second, WRA maintains that the implementation of carbon regulation

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[17] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, pp. 2-262 - 2-266.

[18] Decision No. C13-0094, issued January 24, 2013, Proceeding Nos. 11A-869E, 12A-782E, and 12A-785E.

[19] WRA SOP, p. 9.

during the Planning Period may not depend on the Clean Power Plan. WRA argues that the likelihood of some future regulation of carbon is greater today than it was in 2007. WRA argues that United States Supreme Court precedent and EPA findings since 2007 support its conclusion that "abandoning all regulation of greenhouse gases from the electric power sector would require a substantial change in both agency policy and Supreme Court jurisprudence."[20] WRA notes that Public Service recognizes this greater likelihood in witness Jim Hill's Direct Testimony when he states, "there will be some form of future carbon regulation" during the Planning Period.[21]

63. Given its assessment that some form of carbon regulation will occur during the Planning Period, WRA recommends the Commission direct Public Service to model an adjusted version of the Company's proposed Low Carbon Cost Case in the base modeling. WRA recommends increasing the price of carbon at an annual rate of $1.65 per ton from 2030 through the end of the Planning Period because it is "reasonable to assume carbon regulations will become more stringent over the course of the planning period" and therefore the cost of carbon emission will rise.[22]

64. CoSEIA does not recommend a specific carbon price, but maintains that Public Service's proposed carbon proxy values do not take seriously the potential impacts of carbon. CoSEIA also disagrees with the Company about the potential for carbon regulation in the near future and recommends the Commission assume a price on carbon starting in 2017.

65. Vote Solar suggests that imputing carbon costs are necessary for the Commission to have sufficient evidence to give the fullest possible consideration to the benefits of renewable

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[20] WRA SOP, p. 17 (citing *Massachusetts v. EPA*, 549 U.S. 497, 521(2007) and Endangerment and Cause of Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66496).

[21] *Id.* (citing Hearing Exhibit 3, p. 19).

[22] WRA SOP, at 23.

energy resources and maintains that none of Public Service's arguments against using carbon cost as a base modeling assumption have merit. Vote Solar rejects Public Service's contention that the Clean Power Plan will not be implemented, noting that efforts by past presidential administrations to "undo" rules have failed in the courts. Consistent with its view about the importance of putting a price on carbon emissions, Vote Solar supports WRA's recommendation to use an adjusted Low Carbon Cost Case in the base modeling.

66. In contrast, CEC recommends that Public Service's base modeling not include a carbon proxy price. CEC argues that parties that support the inclusion of carbon price as a base modeling assumption rely on the implementation of the Clean Power Plan to justify their position, an assumption that CEC holds is unwarranted in the current political climate. CEC also agrees with Public Service that using a $0 per ton carbon price provides more transparency about the cost of renewable resources.

67. The OCC states that it also opposes the inclusion of a carbon price as a base modeling assumption due to its concerns about the impact that assumption will have on the rates customers will pay for electricity. The OCC argues that, in the absence of any current state or federal regulation on carbon emissions, imputing a cost to carbon is speculative and that the Commission should not require customers "to pay speculative costs."[23] While the OCC opposes using a proxy price for carbon as a base modeling assumption, it does support the use of a carbon cost in sensitivity analyses as a way to show effects of potential future regulation.

68. In response to the parties, Public Service acknowledges the Commission has required the Company to assume a cost for carbon as a base modeling assumption in prior ERP

[23] OCC SOP, at 15-16.

proceedings. However, the Company argues that in reaching this conclusion, the Commission relied on both § 40-2-123(1)(b), C.R.S., and an assumption that the regulation of carbon emissions was a potential likelihood. Public Service argues that in the 2011 ERP, the Commission did not require the assumption of a proxy cost for carbon as a base modeling assumption, because it found that "there is not sufficient indication at this time that Congress will enact legislation that would attach a price to carbon emissions, and the impact on carbon pricing from the adoption of a federal clean energy standard is unclear."[24] Public Service takes the position that the absence of foreseeable carbon regulation in the current political climate makes this ERP most like the 2011 ERP.

69. Public Service further argues that imputing a cost to carbon has impacts on the model price of resources and that, without the $0 per ton base modeling results, the Commission has no point of comparison for how carbon proxy prices impact the revenue requirements calculated for particular portfolios.[25]

b. Findings and Conclusions

70. The purpose of resource planning is to develop cost-effective portfolios of resources to meet the utility's demonstrated resource need while giving the fullest possible consideration to the cost-effective implementation of new clean energy resources. To aid the Commission in assessing the relative costs and benefits of resource portfolios, Rule 4 CCR 723-3-3604(k) requires the utility to propose a range of input sensitivities "for the purpose of testing the robustness of the alternative plans under various parameters."

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[24] Decision No. C13-0094, issued January 24, 2013, Proceeding No. 11A-869E, at ¶ 182.

[25] Hearing Exhibit 72.

71. In prior ERP proceedings, the Commission's determination of whether to apply a cost to carbon emissions as a base modeling assumption has depended, in part, on the political climate and the potential for carbon regulation during the applicable RAP and Planning Period. Based on the current political climate addressed by the parties, we conclude that there is little likelihood of federal carbon regulation in the near term. We also conclude that it is not necessary to apply a proxy price for carbon as a base modeling assumption in order to assess the cost and benefits of potential resource acquisitions, provided that we require Public Service to present sensitivity analyses under alternative pricing assumptions for carbon emissions. We are persuaded that establishing a base modeling case with a $0 value for carbon, when combined with sensitivity analyses of substantially higher prices for carbon, provides the Commission with the most useful comparative data for decision-making. Therefore, we approve Public Service's proposal to use a $0 per ton price for carbon as the base modeling assumption and require sensitivities in which costs are applied to carbon emissions and the various resource combinations are re-priced accordingly. Such sensitivities will provide us with the necessary information for determining which resource combinations are the most robust with respect to carbon emission reductions in the future.

72. While WRA presented evidence in support of a change to the value of the Low Carbon Cost Case in the later years of the Planning Period, no party opposed the use of the carbon proxy prices presented by the Company for the purpose of sensitivities. We find that both the Low Carbon Cost Case and the High Carbon Cost Case values are reasonable for such sensitivities. We also find it reasonable for the Company to assume carbon prices starting in 2022. We therefore direct the Company to use the carbon price values presented in Table 2.11-4

of Volume 2 of the 2016 ERP[26] for the carbon cost sensitivities and to present the results in its 120-Day Report.

2. Social Cost of Carbon (SCC)

a. Positions of the Parties

73. WRA, CoSEIA, Vote Solar, and Boulder support applying the federally developed Social Cost of Carbon (SCC) in the Phase II evaluation of resources as a sensitivity. The SCC is intended to represent the externality costs of carbon.

74. WRA argues that the goal of portfolio modeling in the ERP is to provide the Commission with information that will allow it to select a portfolio of generation resources that performs well across a range of different possible futures, including costs for carbon that are not strictly based on implementation of regulations. WRA also states that in past ERP proceedings the Commission has considered costs for externalities related to climate including the impacts on public health and the environment. WRA maintains that the low carbon price recommended for use in the base case, which reflects the cost of compliance with regulations, does not include all the costs Public Service customers will face from the impacts of carbon emissions. WRA argues that climate change is not only a global threat, but that it poses specific threats to Colorado, some of which are described in the Colorado Climate Plan and are being felt now across the state. WRA concludes that using the SCC captures these broader impacts and risks from carbon emissions and it therefore recommends using the social cost of carbon as a sensitivity analysis in the Phase II modeling.

[26] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, Table 2.11-4, p. 2-265.

75. WRA further contends that Public Service, in its 2015 annual report filed with the Securities and Exchange Commission, acknowledges that climate change has several effects on the Company.

76. CoSEIA and Vote Solar both argue in their respective SOPs that climate change negatively impacts Colorado communities, Colorado's long-term economic viability and by extension, impacts Public Service customers.

77. Public Service argues during cross-examination[27] that while the costs that are estimated in the SCC do not necessarily come through the utility bill, there is the potential for customers to incur such costs.

78. In comments filed in Proceeding No. 14M-0235E, Public Service "notes that externalities such as environmental impacts are already and more appropriately considered through the Electric Resource Plan ("ERP") process."[28]

79. Vote Solar accepts Public Service's claim that compliance costs are distinct from externalized costs, but argues that customers are already paying those external costs, including for such things as increased air conditioning in the summer, decreased revenue for winter-related industries as a result of shorter seasons, and impacts from floods and wildfires. Vote Solar recommends the Commission direct Public Service to include an analysis of portfolios using the SCC so that it "has a complete picture of how its decisions on PSCo's electricity generation portfolio will cost all Coloradans in the long term" and that "understanding these costs is crucial to inform the Commission's policy decisions as it chooses between resource portfolios."[29] Vote

[27] WRA cross-examination of Alice Jackson; February 2, 2017 Hearing Transcript; p. 112
[28] Hearing Exhibit 50, p. 5-6.
[29] Vote Solar SOP, p. 13.

Solar further argues that there is no meaningful difference between the cost-benefit analysis conducted by a federal agency and sensitivity modeling in an ERP, because both processes quantify uncertain future costs and provide a range of data to assist decision makers as they select an outcome.

80. CEC recommends that the Commission not require Public Service to perform a sensitivity analysis using the SCC. CEC contends that the SCC reflects "an estimate of monetary damage for potential global climate change" and that Public Service customers will not pay the damages estimated by these costs.[30] Further, CEC takes the position that the sensitivities proposed by Public Service in its initial filing are sufficient to demonstrate potential regulatory costs of a carbon policy.

81. Public Service opposes inclusion of the SCC within modeling. The Company argues its proposed High Carbon Cost Case exceeds the expected price of carbon under the Clean Power Plan and is thus already higher than expected regulatory costs. The Company further maintains that a third carbon price sensitivity is unnecessary and that the SCC does not reflect costs that would appear on a customer's bill. At hearing, Public Service also raised the issue of whether requiring a modeling sensitivity using the SCC exceeds the Commission's authority under. § 40-3-102, C.R.S.

b. Findings and Conclusions

82. We first review whether the Commission has authority to consider externalities within resource planning. The Commission has "broad authority to regulate public utilities in this state." *City of Montrose v. Pub. Utils. Comm'n*, 629 P.2d 619, 622 (Colo. 1981) (citing

[30] CEC SOP, p. 24.

Colo. Const. Art. XXV). This broad authority may be limited by the General Assembly. *OCC v. Mountain States*, 816 P.2d 278, 283 (Colo. 1991). The Commission is authorized by the General Assembly "to do all things, whether specifically designated in [the Public Utilities Law] or in addition thereto, which are necessary or convenient in the exercise of such power." § 40-3-102, C.R.S. Further, every public utility is charged with furnishing, providing, and maintaining service, instrumentalities, equipment, and facilities "as shall promote the safety, health, comfort, and convenience of its patrons, employees, and the public…." § 40-3-101(2), C.R.S.

83. Within § 40-2-123(1)(a), C.R.S., the Commission is required to give the "fullest possible" consideration to cost-effective implementation of new clean energy and energy-efficient technologies "bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, insulation from fuel price increases, and environmental protection…." Directly following this provision, § 40-2-123(1)(b), C.R.S., states: "The commission may give consideration to the likelihood of new environmental regulation and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire resources."

84. WRA and Public Service disagree on the interpretation of § 40-2-123(1)(b), C.R.S. WRA opines that the language permits the Commission to consider two distinct categories: (1) the likelihood of new environmental regulation; and (2) the risk of higher future costs associated with the emission of greenhouse gas pollution. Public Service interprets the language to mean that externalized damages from carbon emissions alone "read(s) out" the "likelihood of new environmental regulation."[31] Public Service contends that higher future costs must therefore be tied to the likelihood of new regulation. Therefore, Public Service urges the

[31] Public Service SOP at 53.

commission to include only "regulatory costs" in its consideration. Notably, both WRA and Public Service recognize that the Commission's resource planning rules have evolved over time to include more than simple "least cost planning."

85. The Commission has broad authority to regulate public utilities and the General Assembly has not limited that authority regarding consideration of externalities within resource planning. We agree with WRA's reading of § 40-2-123(1)(b), C.R.S., particularly when considering the Public Utilities Law and statutes as a whole. Reading the statutes such that the Commission may consider both regulatory costs *and* the risk of other potential costs gives each word meaning; is consistent with, and provides harmony within, the Public Utilities Law; and avoids absurd results. For example, reading the language as proposed by WRA is consistent with statutory and constitutional authority that requires the Commission to consider safety and health impacts, and recognizes the complexities in resource planning under current Colorado statutes. By contrast, we find that Public Service's reading of the statute creates contradiction with statutory language, which encourages broader considerations than least cost planning when the Commission considers proposals from utilities for resource acquisition.

86. We find that the Commission has the authority to consider externalities in resource planning proceedings, regardless of whether the associated costs flow directly to customers as utility revenue requirements recovered through rates. Pursuant to § 40-2-123(1)(b), C.R.S., the Commission may, but is not required to, include externalities within resource planning considerations.

87. In this resource planning proceeding, parties proffered that the Commission consider the SCC as a proxy for carbon externality costs. We find that including a proxy for carbon externality costs is consistent with the Commission's consideration of "environmental

protection" and "risk mitigation" when considering generation acquisitions, as directed in § 40-2-123(1)(a), C.R.S. We also find that the SCC is a reasonable quantification of the potential cost of externalities for the purpose of model portfolios in Phase II.[32] By re-pricing the portfolios presented in the 120-Day Report using the SCC as the value for the carbon adder, we can test the robustness of the portfolios and assess the impact to customers of a broader range of costs from carbon emissions. We also conclude that the full costs for externalities are not in the modeling assumptions presented by Public Service. We therefore direct Public Service to run a third carbon price sensitivity using the SCC as presented in Table A1 (Column 3.0 percent Avg.) in Attachment RLF-1 to the Answer Testimony of CoSEIA witness Roger Freeman.[33] These values start at $43 per ton in 2022 and increase to $69 per ton in 2050. For the period 2051 through 2054, Public Service shall assume the same escalation rate it proposes for its High Carbon Cost Case.

88. Based on the evidence in this Proceeding, the SCC serves as a modeling tool to "incorporate the social benefits of reducing [carbon] emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions" and "is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year."[34] The EPA also states that the SCC is "a comprehensive estimate of climate change damages and includes changes in net agricultural productivity, human health, property damages from

[32] Commissioner Wendy M. Moser joins in the Commission's decision that the statutes allow the Commission to consider externalities within resource planning, but does not join in the majority's conclusions and findings that the SCC should be considered within this ERP.

[33] Hearing Exhibit 26, Att. RLF-1, p. 17.

[34] Hearing Exhibit 26, Att. RLF-1, p. 2.

increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning."[35]

89. We find Public Service's argument that "running an additional sensitivity using the SCC is burdensome" to be without merit. Staff, in suggesting the Commission could order the Company to run different sensitivities than those proposed by the Company, notes that Public Service witness James Hill testified that "sensitivities typically aren't that difficult to run" and "[t]hey can be run fairly fast."[36]

3. Discount Rate

90. Public Service proposes to use a discount rate of 6.78 percent in calculating net present values (NPVs) cost calculations associated with each modeled resource portfolio. The 6.78 percent value corresponds to the Company's current Commission-approved after-tax weighted average cost of capital (WACC).

91. CoSEIA argues that the Commission must require Public Service to model future fuel costs using different discount rates in its bid evaluation and resource selection, because relatively high discount rates (such as the Company's after-tax WACC) can make fossil fuels look less expensive in the future. CoSEIA requests that the Commission order Public Service to run its bid evaluation models using the current Commission-approved after tax WACC and using at least two lower discount rates (*i.e.*, 6.78 percent, 3 percent, and 0). CoSEIA explains that as the discount rate becomes lower, the projected cost of fuels becomes higher over time, and that as the discount rate increases, fuel and other costs are devalued into the future. According to

[35] Hearing Exhibit 34, p. 1.
[36] Transcript, February 2, 2017, p. 241.

CoSEIA, a higher discount rate hides significant economic benefits from the acquisition of cost-effective renewable energy resources as compared to fossil fuel costs.

92. In response, Public Service argues that the same 6.78 percent discount rate should apply to both fossil fuel-fired and renewable resources because the Company's customers pay for these resources through mechanisms like the Electric Commodity Adjustment, including the majority of wind and solar costs incurred by the Company just as fuel costs. The Company argues that if the Commission were to change the discount rate for the Company's fuel costs, it would also need to change it for renewable resources to have an apples-to-apples comparison and a balanced approach to the NPV calculations. Public Service further states that it is unclear if a lower discount rate would actually change the cost rankings of the bid portfolios, since all resources would be evaluated pursuant to the same lower discount rate.

93. Public Service also argues that there are means to examine benefits of acquiring renewable energy resources other than reduced discount rates as applied in its modeling, such as the natural gas price and carbon cost sensitivities. Nonetheless, Public Service states that it is willing to model a sensitivity case using a lower single discount rate that is applied to all portfolio cost streams in the Strategist model and recommends a single 3 percent discount rate sensitivity.

94. We agree with Public Service that it would not be appropriate to apply different discount rates for different types of generation resources, because ratemaking conventions for utility owned renewable resources and pricing conventions for Power Purchase Agreements (PPAs) with renewable energy resources cause future revenue requirements for those resources to follow the same cost patterns as future fuel costs. We direct Public Service to use its after tax WACC in calculating NPV values as a base modeling assumption. We also direct the Company

to present sensitivity runs for the most prominently featured portfolios in its 120-Day Report using the two alternative discount rates as suggested by CoSEIA: zero and a 3 percent discount rate.

4. Gas Price Volatility Mitigation (GPVM) Adder

a. Positions of the Parties

95. Public Service proposes a GPVM adder to represent gas volatility costs, as it has included in its last two ERP proceedings.

96. Staff recommends excluding the GPVM adder from Phase II modeling, because it does not represent an actual cost to the Company's system. Staff provides information showing that the GPVM adder is expensive, effectively raising the gas price forecast by $0.61 per MMBtu each year and adding as much as $1 billion in NPV revenue requirements for certain resource portfolios. Staff further argues that the use of high gas price and low gas price sensitivities in Strategist modeling will address the level and potential impact of gas price risk for different modeling portfolios.

97. The OCC also recommends excluding the GPVM adder as a base case modeling assumption. The OCC argues that gas price volatility is lower than it was in previous years, thus making a GPVM adder in today's gas market less justifiable. The OCC further questions the basis for the proposed $0.61/MMBtu GPVM value, alleging that it was the result of a single phone call in July 2015 and arguing that the Company failed to present verification with evidence in this Proceeding.

98. In response, Public Service argues that, while high and low gas cost sensitivity cases are useful when examining the impact on NPV calculations, they do not provide a measure of the impact of gas price volatility in the base gas cost forecast. Public Service agrees that gas

price volatility levels are lower than they were previously, but suggests that such lower volatility is reflected in the reduced level of the premium for an at-the-money call option as compared to the GPVM values used in previous proceedings.

99. To help alleviate Staff's concerns as to the transparency of the impacts of the GPVM adder, Public Service proposes to provide in its 120-Day Report information on the impact of the GPVM on each portfolio and a comparison of the relative impact of each portfolio to the least cost portfolio, just as the Company did in its 120-Day Report for the various sensitivities evaluated in the last ERP. The Company also proposes to remove the GPVM adder from the high and low gas price sensitivity runs.

b. Findings and Conclusions

100. We require Public Service to eliminate the GPVM adder as a base modeling assumption. While higher gas prices and greater price volatility may have justified the application of a GPVM adder in past ERP proceedings,[37] the evidence provided by Staff and the OCC in this Proceeding demonstrates that these circumstances have changed. We agree with OCC that gas price volatility is significantly reduced from past ERP proceedings. We also agree with Staff that the costs resulting from the GPVM adder are very expensive in light of today's more stable gas prices.

101. The GPVM adder does not represent actual costs to the system. We further question whether the "single phone call" methodology used to establish the GPVM adder is

[37] In Hearing Exhibit 37, the Phase I Decision in Public Service's 2007 ERP, the Commission stated: "Numerous parties took issue with the gas prices that result from the forecasts, most recommending that a much higher forecast gas price be used. Many parties point to supply-and-demand factors that indicate a tightening of supply, and likely increased prices." ¶ 251.

appropriate and whether the high level of the resulting GPVM costs are a reasonable proxy to represent current volatility impacts on customers.

102. Nevertheless, we require Public Service to include a sensitivity case with the GPVM adder. We find this sensitivity appropriate to provide an upper bound of these potential costs to assist in overall considerations made by this Commission.

5. Surplus Capacity Credit

103. Public Service proposes a modeling credit for portfolios that exceed the system capacity requirements. The proposed surplus capacity credit accounts for situations where resource combinations do not fit exact system requirements.

104. Staff and CIEA raise concerns regarding surplus capacity credit amounts and pricing, which allow a credit for portfolios that include more generation capacity than that needed to meet the reserve margin target. Staff proposes reducing the level of surplus capacity from 200 MW to 100 MW for the years within the RAP and from 500 MW to 100 MW for all years beyond the RAP (*i.e.*, 2024-2054). In contrast, CIEA proposes increasing the level of surplus capacity during the RAP from 200 MW to 500 MW and maintaining the level at 500 MW for all years beyond the RAP. CIEA also recommends a 10 percent increase in the value from $2.79/kW-mo. to $3.06/kW-mo. be approved for modeling purposes.

105. Public Service agrees with Staff's position and supports the recommendation that the surplus capacity within and beyond the RAP be reduced to 100 MW. Public Service thus proposes a surplus capacity credit of up to 100 MW at a rate of $2.79/kW-month for four months of each year within the RAP and for 12 months of each year beyond the RAP based on the cost of a generic combustion turbine.

106. We agree with Staff that it is appropriate to proceed with caution when valuing excess capacity. We thus adopt the positions advocated by Staff and Public Service and allow credits for surplus capacity up to 100 MW within and beyond the RAP.

6. Gas Price Forecast

107. Public Service proposes to use a blend of four sources of market information to represent gas prices at the Henry Hub trading location (*i.e.*, New York Mercantile Exchange (NYMEX) future contract prices combined with commercial, proprietary price forecasts developed by Wood Mackenzie, Cambridge Energy Research Associates, and Petroleum Industry Research Associates). The Company applies basis differentials to the blended Henry Hub forecast values to produce a natural gas price forecast representative of costs at a Colorado Interstate Gas trading location. This is the same methodology and same four sources of natural gas price forecasts that the Commission approved in the Company's 2011 ERP. Public Service proposes to update its four-source natural gas forecast blend in advance of the Phase II competitive solicitation.

108. The OCC recommends that the Commission order the Company to rely solely upon the NYMEX futures price instead of the proposed four-source blend. The OCC argues that there is a significant difference between Public Service's four-source blend gas price forecast and the NYMEX gas price forecast and that the Company's proposed gas price forecast fails to reflect gas prices that are likely to be incurred in the next few years.

109. In response, Public Service recommends that the Commission reject OCC's proposal and direct the Company to utilize its four-source methodology. Public Service states that the first 29 months of its four-source blend forecast are, in fact, the NYMEX monthly futures prices. Public Service also argues that blending multiple sources to create the forecast

provides stability without abrupt changes due to a single source forecast change. Further, while the NYMEX pricing extends out approximately 12 years, the vast majority of the trading volume occurs within the first few months, so the prices published for the later years are not based on this level of market data.

110. We adopt Public Service's proposed four-source blend natural gas forecast methodology as a base modeling assumption. We agree with Public Service that it is reasonable to use a blend of four established forecasting services, particularly when the majority of NYMEX trading volumes occur within the first few months.

111. We also approve Public Service's proposal to run sensitivities for a High Gas Price scenario and Low Gas Price scenario, where the growth rate for the base four-source blend is adjusted up and down by 50 percent starting in year 2018.[38]

7. Point Costs for Capital and O&M in Utility Proposals

a. Positions of the Parties

112. CIEA recommends that bids for utility-owned generation, including build-transfer arrangements, should be provided as a point cost for comparison to bids from independent power producers (IPPs) in Phase II. CIEA also argues that future cost recovery should be capped at the proposed capital and operating and maintenance (O&M) cost levels. CIEA asserts that Public Service's plan to use a bid price that is plus-or-minus 20 percent is not consistent with prior Commission treatment of the capital component of utility proposals bid in Public Service's last two ERPs. CIEA states that if an IPP bid is accepted, then the IPP is bound by the terms of the

[38] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, p. 2-181.

PPA. Such changes in IPP contract terms typically require a renegotiation of the PPA, with the IPP being required to make concessions to maintain the benefit of the bargain for both parties.

113. With respect to O&M costs, CIEA states that an IPP must bid its all-in costs for the lifetime of the contract. CIEA notes that in the Company's last ERP, the Commission did not require a point cost for estimated O&M costs but nevertheless expected the issue to be addressed in the future. CIEA alleges that Public Service did not provide adequate responses to discovery to compare recent O&M costs to estimates. Therefore, if the Commission does not cap future O&M cost recovery to the bid amount, CIEA recommends opening an additional phase in this proceeding or to conduct and conclude a separate proceeding to compare actual utility performance to previous expectations before issuing its Phase II decision in this Proceeding.

114. For capital costs, Public Service agrees in Rebuttal Testimony to provide a point cost. However, the Company objects to the CIEA assertion that the point cost should be a hard cost cap that cannot be exceeded under any circumstances. For O&M costs, Public Service asserts that it generally follows CIEA's proposed methodology for bid comparison, but it objects to limiting future cost recovery to this level.

115. Public Service argues that CIEA's proposals do not account for the regulatory compact, where the Company should have the opportunity for recovery of its actual project costs that are found to be prudent in a subsequent rate recovery proceeding. Public Service argues that if its actual costs come in lower, then customers benefit from these lower costs. In contrast, Public Service argues that IPPs build profit into their bids, and if their actual costs are lower, the IPPs keep the difference as additional profit.

116. Further, Public Service states that IPPs can abandon a project if there are unanticipated increases in project costs that render the project uneconomic. As a regulated

utility, Public Service has the legal obligation to provide reliable service. While acknowledging that there is a benefit in considering both IPP and utility projects, Public Service argues that CIEA's proposal will chill the offering of both utility-self-build and build-transfer structured bids. Public Service further argues that CIEA provides no evidence that there is any problem for which its proposal would serve as a remedy. Public Service asserts that it has a strong track record in delivering projects on time and at or under budget.

b. Findings and Conclusions

117. With respect to capital costs, we adopt Public Service's position in Rebuttal Testimony that the Company will provide a point cost for its utility proposals, without a 20 percent variance, consistent with past ERP practice. Public Service reserves the right to make a request with the Commission to recover costs that exceed this point level under extraordinary circumstances.[39]

118. With respect to O&M costs, we deny CIEA's proposed limitations on future cost recovery. We also deny CIEA's proposed study of past O&M costs. We instead require Public Service to provide, as a part of any utility proposal, detailed information on its O&M estimates, consistent with the types of information the Company requires for IPP bids. Public Service shall track the actual O&M costs for a utility facility acquired pursuant to this ERP and explain any differences between actual and estimated costs in any rate recovery proceeding where the facility is at issue, within ten years of the date the facility commences operation. Such information collection and reporting will enable parties to the future cost recovery proceedings to investigate the reasonableness of such costs.

[39] Decision No. C08-0929, ¶ 189, Proceeding No. 07A-447E issued September 19, 2008.

8. Annuity Backfilling

a. Positions of the Parties

119. PPA contracts generally have terms that are shorter than the useful life of any utility-owned resource. Base modeling assumptions regarding the extension or replacement for PPAs after contract expiration are necessary to address the treatment of unequal lives of resources in order to calculate the NPV costs for each resource portfolio.

120. The Commission addressed this issue at length in Public Service's last ERP and established a "bookend" approach for base modeling purposes, where the two sides are based on alternative market views on the cost of future replacement resources.[40] On one end, Public Service's "replacement method" represents a market where demand exceeds supply, and expiring contracts are bid at or near the cost of new construction, either for new utility resources or for existing projects. On the other end, the annuity method represents future market conditions where supply exceeds demand, and bidders approach the competitive solicitation faced with the possibility that anything other than the lowest possible price could result in a stranded asset. Thus, under the annuity approach, the bidders representing expiring contracts should be in a position to offer pricing that is similar to the pricing under the expiring PPA.

121. As required by the Commission in Public Service's 2011 ERP proceeding, Public Service proposes to apply in its 2016 ERP a version of the annuity backfilling method. However, Staff and CIEA raise concerns with the Company's proposed method. Staff asserts that the annuity calculation methodology proposed by the Company is contrary to the Commission directives in Decision No. C13-0323 in Proceeding No. 11A-869E issued March 15, 2013.

[40] Decision No. C13-0094, issued January 24, 2013, Proceeding Nos. 11A-869E, 12A-782E, and 12A-785E, pp. 67-68.

According to Staff, Public Service calculates the annuity tail by taking the bid price in the first year then escalating it by inflation to fill in the first year of the tail. Then, the second year of the bid is escalated to fill in the second year of the tail repeating the methodology for each year of the bid term.

122. Staff argues that such calculations do not follow the annuity approach required by the Commission. CIEA also asserts that the Company has misapplied the annuity method, and provides examples of IPP contract extensions that are significantly less than the original bid price in support of its argument to use the proper annuity method.

123. In response, Public Service argues that the Company implemented the annuity backfilling in a manner that best fits the original intent for the annuity approach as argued by CIEA in the 2011 ERP. Public Service asserts that the annuity method the Company implemented in the 2011 ERP improperly extended the IPP bid out to the end of the Planning Period, rather than simply extending the bid to match the competing utility resource as the annuity method was designed to do. According to the Company, this approach of extending the bid to match the competing utility resource solves the potential problem of IPP bids being extended beyond a reasonable facility life.

b. Findings and Conclusions

124. We require Public Service to implement the annuity backfilling method as advocated by Staff and CIEA and therefore deny Public Service's proposed alternative method for calculating an annuity tail. We agree with Staff and CIEA that Public Service has misapplied the annuity method in its proposal for the 2016 ERP. As discussed in detail by Staff and CIEA, the Commission required the annuity bid backfilling method in Public Service's 2011 ERP as one part of two "bookends" representing high and low pricing that might result in future resource

solicitations after the IPP bid at issue expires. The annuity method is a proxy for potential lower-cost resource proposals that could result if there is excess generation available in the market at the time the IPP bid expires and is re-contracted.

125. Although Public Service raises several issues with the annuity method that was used in its last ERP, we are not persuaded by the Company's arguments. First, we disagree with Public Service's assertion that the annuity method cannot be used if it would extend the IPP facility pricing past the expected facility life for that facility. The annuity extension is a proxy for possible low price future bids, and is not intended to represent a precise calculation of how that specific IPP facility will be used in a future market. It is possible that an aged IPP facility will no longer be viable in 25 to 40 years, and, in that case, the replacement method tail (*i.e.*, the high-cost bookend) as Public Service proposes may be appropriate. However, it is also possible that, at the time of re-contracting, the IPP facility costs will be well depreciated such that the facility is available at a significantly low price to warrant extension, even beyond the average life expectancy for that type of facility. For example, Public Service proposed in its 2011 ERP to acquire the Brush facilities and to extend their lives significantly, claiming that these old gas turbine generator facilities would run infrequently but provide inexpensive peaking capacity.[41] Certain components of an older IPP facility also could be upgraded or replaced, warranting a longer extension of the facility while still maintaining a lower cost than an entirely new facility.

126. We also disagree with Public Service that the annuity tail should increase with inflation. CIEA provided examples where re-bid prices may be less than the original bid. As a

[41] Decision No. C13-0094, issued January 24, 2013, Proceeding Nos. 11A-869E, 12A-782E, and 12A-785E. Paragraph 21 states: "The CTs were built in 1969 and reconditioned in 1990. The steam turbines were built in 1947. Therefore, according to Staff's calculations, Public Service is proposing to run the steam turbines for 87 to 100 years and to run the CTs for 66 to 78 years."

proxy to represent the lower range of future bids, we find that the annuity pricing should not be escalated for inflation.

127. Finally, we disagree with Public Service that the annuity evaluation of IPP bids is only necessary if there is a competing utility-owned proposal in the portfolio at issue. The comparison between IPP bids also warrants the annuity approach.

128. In sum, we require Public Service to model, as a base modeling approach, both the annuity method, as advocated by Staff and CIEA, and the Company's proposed replacement method as bookends for the range of backfilling costs. The annuity method shall extend from contract expiration through the end of the 39-year Planning Period. For the annuity run, at a minimum, the Company shall apply the annuity method to all IPP bids, and at its option, we authorize the Company to apply the annuity method to utility-owned proposals as well. If there is no utility proposal in a portfolio, all the IPP bids shall be backfilled using the annuity method. Further, Public Service shall perform modeling optimization runs based on the annuity method to analyze the proposed resources, and, at its option, the Company may also perform optimization runs based on its proposed replacement method.[42]

9. Updated Modeling Parameters

129. Prior to issuing the all-source RFPs, Public Service shall file a complete list of the Strategist modeling inputs and assumptions consistent with its presentation on pages 2-181 through 2-195 of Volume 2 of the 2016 ERP.[43] The list shall indicate which parameters have been updated for bid evaluation and selection purposes. To the extent that any parameters are

[42] If Public Service has questions about the implementation of the annuity method upon bid evaluation and selection in Phase II, we authorize the Company and the Independent Evaluator to reach out to Staff and CIEA for clarification. Or, in the alternative, Public Service may file a written pleading with the Commission for clarification.

[43] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, pp. 2-181 – 2-195.

still to be updated after the RFPs are issued but prior to the Phase II resource evaluation,[44] the Company shall identify the parameters in the list which needs to be updated and provide the updated values in its 120-Day Report.

10. Summary of Portfolio Optimizations and Sensitivities

130. Public Service shall perform bid eligibility screening, initial economic screening, and computer modeling to evaluate the bids and utility proposals received in response to its all-source solicitation RFPs, consistent with the procedures identified in Volume 2 of the 2016 ERP in Section 2.9 Phase II Competitive Acquisition,[45] as modified by the directives in this Decision.

131. The modeling shall include optimization of the two resource need scenarios discussed above: (1) a "0 MW" need; and (2) a level of need based on the updated demand forecast to be filed prior to the issuance of RFPs in Phase II. These modeling optimization runs shall use base modeling assumptions, as modified by this Decision, to calculate the NPV of revenue requirements or costs. The base modeling shall apply the Annuity Method for backfilling PPAs. At its option, the Company may perform additional optimizations based on its preferred Replacement Method backfilling, or determine these based on a sensitivity analysis.[46]

132. Consistent with the directives in this Decision, Public Service shall re-price the optimized portfolios as sensitivities based on the following:

- High Gas Price
- Low Gas price
- GPVM Adder
- Low Carbon Cost Case

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[44] Transcript, February 2, 2017, pp. 191-194.

[45] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, pp. 2-215 – 2-229.

[46] *See* Annuity Backfilling section, above.

- High Carbon Cost Case
- SCC Case
- Zero Discount Rate
- 3 Percent Discount Rate

F. Studies and Reports

1. Flex Reserves Study

a. Positions of the Parties

133. Public Service sponsors an Expanded Study of 30-Minute Flex Reserves (4.0 GW Flex Reserves Study) as Exhibit DTB-1 to the Direct Testimony of Drake Bartlett. The purpose of this study is to determine how much wind can be reliably added to the Company's system.

134. Public Service explains that flex reserves are comprised of excess Contingency Reserves, as well as online and offline generation available within 30 minutes that are not already included in the Contingency Reserve calculation: (1) offline flex reserve capacity; (2) excess Contingency Reserve capacity; and (3) greater than ten-minute ramp capability from online or unloaded generation. The Company's flex reserve analysis assesses levels of wind generation on Public Service's system and how other system resources have been used to address large wind generation "down ramps."

135. The OCC concludes that Public Service has sufficient flex reserves to accommodate a considerably larger amount of wind capacity than is currently on its system. The OCC therefore recommends that special efforts to acquire flex reserves in the Phase II solicitation should not be undertaken. The OCC also recommends that the Company undertake a study, prior to the next ERP, of available system resources during wind ramp down events.

136. In contrast, SWGen asserts that Public Service's 12-month dataset used for the 4.0 GW Flex Reserves Study is insufficient and excludes significant downward wind ramping events. SWGen also argues that flex reserve resources should be able to reach full load within 15 or 20 minutes as opposed to the 30-minute requirement used by the Company. SWGen concludes that Public Service's system requires, at a minimum, between 92 MW and 433 MW of additional 20-minute flex reserve, increasing to between 207 MW and 618 MW with the Rush Creek Wind Project.

137. Public Service disagrees with SWGen's analysis that additional flex reserves are necessary. First, Public Service argues that SWGen improperly applied high wind generator tripping, as FERC guidelines cover such events under contingency reserves, not flex reserves. Public Service also disagrees that a 12-month dataset is inadequate, and states that SWGen's examples of extreme ramping events are either high wind tripping or bad data. With respect to SWGen's recommendation to reach full load in 15 to 20 minutes, the Company asserts that large wind ramp events occur over a period longer than 30 minutes, such that operators have adequate time to implement the 30-minute flex reserves.

138. WRA proposes a 5 GW and 6 GW flex reserve study, and recommends the Commission order the Company to convene at least one meeting of a technical working group in advance of filing the 2019 ERP and before the 2019 ERP Flex Reserves Study is performed. However, Public Service disagrees with WRA's proposal and instead proposes an Expanded Flex Reserves Study available for Phase II that is limited to 4.5 GW. Public Service states that a flex reserves study beyond 4.5 GW is appropriate for filing with the next ERP. Further, the Company argues that for a 6 GW flex reserves study, the wind integration cost study, coal cycling and wind

curtailment study, and the Wind Effective Load Carrying Capability Study would also need to be expanded up to a 6 GW level.

139. Staff recommends that the Commission order Public Service to revisit and to revise, as necessary, its conclusions on the system's flex reserves prior to submitting its next ERP in 2019. Specifically, Staff argues that the 4.0 GW study is largely untested and heavily reliant on limited data totaling 2,566 MW that is extrapolated to evaluate the impact of an additional 1,800 MW of wind generation. While Staff acknowledges that there is insufficient data for an exclusively empirical study, Staff recommends that the Commission direct the Company to revisit the underlying operational parameters on a real time basis with additional empirical data if the Commission wants to move forward with the acquisition of additional wind resources beyond Staff's recommended 1,000 MW. Staff also recommends that the Commission require Public Service and Staff work together in forming a panel that would reach out to industry experts from such organizations as National Center for Atmospheric Research (NCAR) and the National Renewable Energy laboratory (NREL) to set a scope of work for any subsequent revisions necessary to establishing flex reserve capacity.

140. Despite its reservations with the 4.0 GW Flex Reserves Study, Staff concludes that it can be relied upon to acquire up to 1,000 MW of additional wind in this ERP, in addition to the 600 MW Rush Creek Wind Project approved in Proceeding No. 16A-0117E.[47]

141. In response to Staff, Public Service agrees that the Flex Reserves Study should be updated prior to the 2019 ERP filing but opposes the proposed panel approach, arguing it is not

[47] Decision No. C16-0958, issued October 20, 2016, Proceeding No. 16A-0117E.

the Company's practice to share decision-making authority with entities such as NCAR or NREL on studies related to real-time operations or which implicate system reliability. Public Service further states that the flex reserves requirement should be updated once there is a full year of data from new wind farm generation.

142. At hearing, Staff expressed concerns with Public Service's rebuttal proposal to expand the Flex Reserves Study from 4.0 GW to 4.5 GW prior to the upcoming Phase II solicitation. Staff states that its criticisms of the 4.0 GW study would be magnified for a 4.5 GW study, since the 4.5 GW study would use the same basic data and further extrapolate the results. Staff also reasserted that acquiring an incremental 1,000 MW[48] of wind in Phase II as proposed in the 4.0 GW Flex Reserves Study is tolerable, since Public Service has some flex reserve headroom associated with the installation of additional Load Commutated Inverters (LCIs). However, according to Staff, acquiring an additional 1,500 MW will not allow Public Service to undertake the increased wind operations in reasonable increments.

b. Findings and Conclusions

143. We approve Public Service's 4.0 GW Flex Reserves Study to be used in the Phase II evaluation of wind bids. As recommended by Staff, we deny the 4.5 GW study as proposed by Public Service in its rebuttal case. We agree with Staff that, although a high degree of extrapolation was necessary to perform the 4.0 GW Flex Reserves Study, the findings of the study are reasonable, since there is additional headroom for flex reserve capacity on the Company's system as a result of additional LCI installations. However, to further extrapolate and extend the analysis to a 4.5 GW level is not reasonable, particularly since Public Service has not

[48] The 1,000 MW is in addition to the recently approved 600 MW Rush Creek proposal.

filed the 4.5 GW study and the Phase I discovery, testimony, and hearings process is now complete.

144. Further, we are concerned that Public Service has largely presented the 4.0 GW Flex Reserves Study from an economic perspective through a witness with experience in Public Service's trading group. We did not hear testimony from the Company's operations and generation dispatch personnel, which is necessary to support findings that reliability in service will continue upon the acquisition of such substantial increments of additional wind energy resources.

145. We direct Public Service to complete an updated Flex Reserves Study and file this study with the Company's 2019 ERP filing. The updated study shall present a full analysis of empirical data available at that time and shall include a back-cast of historical wind data for verification and modification of the results, as Staff has suggested here.

146. We find that it is appropriate for Public Service to retain the right to make decisions regarding the reliability of its system. However, other parties and outside experts should have input into the Company's flex reserve analyses, including the amount of additional wind resources that should be examined. We therefore require Public Service and Staff to work together in forming a panel that would reach out to industry experts from such organizations as NCAR and NREL for the completion of the updated study.

2. Other Wind-Related and Solar-Related Studies

147. In addition to its Flex Reserves Study, Public Service seeks approval of the following studies to be used in Phase II for bid evaluation and selection.

148. The Wind and Solar-Induced Coal Plant Cycling and Curtailment Costs Study evaluate the costs to vary coal generation to allow additional renewables.[49] The study is primarily for wind, providing a range of wind integration costs to be used in resource modeling, which vary from $0.54 to 1.14 per MWh based on location and system wind penetration. For solar, the study provides a range of integration costs to be used in resource modeling, which vary from $0.26 to 0.36 per MWh based on location, fixed or tracking panels, and system solar penetration.

149. The Wind Effective Load Carrying Capability (ELCC) Study evaluates the percentage of wind capacity that will be available to meet peak system demand.[50] The Company's analysis shows an average ELCC value of 16 percent for wind generation, which is an increase from the 12.5 percent value in previous studies.

150. The Solar Effective Load Carrying Capability Study evaluates the percentage of solar capacity that will be available to meet peak system demand.[51] The Company's analysis shows an average ELCC value of 35 percent for fixed systems and 50 percent for tracing systems. The study also concludes that higher installation levels of solar lead to a decline in load carrying capability.

151. The 4 GW Wind Integration Cost Study, evaluates the cost to add wind to the system.[52] The study provides a range of integration costs to be used in resource modeling, which vary from $1.87 to 9.18 per MWh based on gas costs and system wind penetration.

[49] Hearing Exhibit 7, Att. KLS-5.
[50] Hearing Exhibit 7, Att. KLS-4.
[51] Hearing Exhibit 5, Att. KLS-2.
[52] Hearing Exhibit 6, Att. KLS-3.

152. The Solar Integration Cost Study evaluates the cost to add solar to the system.[53] The study provides a range of integration costs to be used in resource modeling, which vary from $0.01 to 0.74 per MWh based on gas costs and system solar penetration.

153. We approve these proposed wind and solar-related studies. The updates generally use the same method that was used in previous studies but reflect current costs of natural gas and other inputs as well as higher levels of renewable energy resources on the Company's system. Staff states that it investigated the studies to ensure they would not have a negative impact on system reliability and would not distort the proposed Phase II competitive acquisition process. Staff reports that it found no reason to contest the conclusions reached in each of these studies for the purposes of this Proceeding. No party contested these studies.

3. Future Coal Supply Report

154. The OCC recommends that the Commission require Public Service to provide annual reports on the status of its coal supplies for its power plants given the recent bankruptcies of several major coal companies. The annual reports would assess the financial condition of the companies providing the coal and would analyze in detail whether those companies can profitably produce the required amount of coal at reasonable prices. For instance, the report would analyze such factors as whether the existing coal mines supplying the Company's generating stations are approaching the limit of their reserves, the availability of new areas to mine, the cost of opening those new mines, and whether the companies have the financial ability to open the new mines. The annual reports would also provide the projected stripping ratios at the mines and how the stripping ratios will impact the cost of coal.

[53] Hearing Exhibit 5, Att. KLS-1.

155. Public Service asserts that such reporting is not necessary. While numerous bankruptcies have occurred in the coal industry, the Company states that coal suppliers continue to provide services and will emerge from bankruptcy. Public Service details three major coal companies that have emerged or are in the process of emerging from bankruptcy and reports that the operations that supply coal to Public Service are profitable and have continued to operate normally during the bankruptcies.

156. Given the turbulence in the coal market, we find it necessary for Public Service to provide the Commission an assessment of the status of its coal supply and coal suppliers. We therefore direct the Company to provide two reports: the first to be filed on or before October 31, 2018, and the second to be filed at the time when it files its 2019 ERP. Each report shall provide a market-based assessment of Public Service's suppliers along with the coal production industry in general. Public Service is not required to determine the future cost structures and profitability of individual suppliers or mines. Instead, the Company may use commercially available resources and professional services that provide assessments of the financial health and future viability of the coal industry as relevant to Public Service. Each report shall also include a detailed discussion of the factors which affect the future coal cost and supply.

G. Section 123 Resources

157. Section 40-2-123, C.R.S., requires the Commission give the fullest possible consideration to the cost-effective implementation of new energy technology or demonstration projects. In an ERP context, the Commission defines such projects as "Section 123 Resources" as set forth in Rule 4 CCR 723-3-3602(q).

158. For its 2016 ERP, Public Service proposes using the same process for evaluating Section 123 Resources that the Commission adopted in its approval of the Company's 2011 ERP.[54] Specifically, the RFP documents filed by the Company in this Proceeding explain that a bidder that seeks for its proposal to be considered a Section 123 Resource must indicate, as part of the bid submission, why the resource qualifies as both "clean" and "new."[55] Public Service will list all bids that claim Section 123 Resource status in the bid report filed pursuant to Rule 4 CCR 723-3-3618(b)(I) and will state any opposition by the Company to a claim of that status. Public Service also will provide the Commission a copy of any disputed bids under seal. The Commission then can determine whether the disputed bids qualify for further evaluation in the modeling as a Section 123 Resource.

159. At hearing, CoSEIA's witness argued that there is no specific "vehicle" in this ERP to address the selection of a Section 123 Resource in Phase II and asks that the Commission initiate a process.[56] CoSEIA argues that the Commission should use § 40-2-123, C.R.S., to give solar thermal electric generation resources "explicit attention and encouragement," because solar thermal technology is excluded from the RES statute, from other state programs, and has received virtually no utility encouragement in prior ERPs.[57] CoSEIA does not propose a specific process or approach that the Commission should take in considering solar thermal a Section 123 Resource.

160. Public Service takes the position that to the extent that CoSEIA's proposal can be construed as seeking designation of solar thermal generators as a Section 123 Resource in

[54] Decision No. C13-0094, issued January 24, 2013, Proceeding Nos. 11A-869E, 12A-782E, and 12A-785E.

[55] Hearing Exhibit 1, Att. AKJ-3.

[56] Transcript, February 6, 2017, p. 109.

[57] Hearing Exhibit 26, pp. 15-16.

Phase I, the Commission should reject this request, but adopt instead the process proposed in the Company's ERP plan.

161. We find that the approach recommended by the Company will allow us to evaluate bids for Section 123 Resources in the context of bids for other resources in Phase II. No party, including CoSEIA, objects to the approach to designating and evaluating Section 123 Resources that Public Service proposes for its 2016 ERP filing. We therefore approve the proposed process for evaluating the status of Section 123 Resources consistent with Decision No. C13-0094 from the Company's most recent ERP, Proceeding No. 11A-869E. Accordingly, we will determine, as necessary, whether a particular bid for a solar thermal resource qualifies for Section 123 Resource consideration as part of this process in Phase II.

162. Consistent with those same procedures in Decision No. C13-0094, we also direct Public Service to present a group of resource portfolios in its 120-day Report where each portfolio is differentiated by the inclusion of a single proposed Section 123 Resource. This type of presentation will assist us in evaluating the costs and rate impacts of each proposed Section 123 Resource. As in Decision No. C13-0094, this approach deviates from the presentation of Section 123 Resources contemplated in Rules 4 CCR 723-3-3604(k) and 3613(d) and we therefore waive those provisions to the extent they conflict with this Decision.

H. SPS Diversity Exchange

163. Public Service can access up to 101 MW of capacity from its affiliate Southwestern Public Service (SPS) pursuant to a capacity exchange agreement by using a tie-line between the two systems (*i.e.*, the Lamar DC Tie) and associated transmission, which are collectively called the "SPS Diversity Exchange." As its name indicates, the SPS Diversity Exchange allows Public Service to take advantage of the load diversity that exists between the

two systems whenever the Company has acquired sufficient transmission service. The benefit of the agreement is a reduced need for other forms of generation capacity, while the cost is primarily associated with the underlying transmission service.

164. The OCC recommends that the SPS Diversity Exchange be subject to competitive bidding as part of the Phase II process of this 2016 ERP. Subject to the limitations of transmission contracting, Public Service agrees with OCC's recommendation and will evaluate it as a 101 MW resource in Phase II.

165. WRA recommends the Commission reject the Company's proposal to evaluate the SPS Diversity Exchange, as the SPS system is approximately 49 percent coal and therefore is inconsistent with the Company's commitment not to acquire any coal-based generation resources in this ERP. In response, Public Service explains that it is expected to be a capacity resource and would not likely be called upon to provide energy. Further, any such energy would be during high load periods when the incremental generation would consistent predominantly of gas-fired generation.

166. We grant OCC's recommendation and direct Public Service to model the SPS Diversity Exchange as a resource bid.

I. Transmission Injection Capabilities

167. The OCC argues that Public Service's ERP filings do not include a comprehensive representation of the injection capability on the entire Public Service transmission system and recommends that an injection capability table in the form of Table 2.5-3 in Volume 2 of the 2016 ERP should be continuously updated until the RFPs are issued for the Phase II competitive

solicitation.[58] The OCC further recommends that this updated table also include the cost to expand injection capability, the higher injection capability that results from such expense, and the combined injection capability where multiple projects have been proposed.

168. In response, Public Service asserts that Table 2.5-3 was not intended to represent the injection capability on the entire Public Service transmission system. However, the Company states that updated injection capabilities based on Large Generator Interconnection Procedure transmission study results and on the completion of new transmission projects likely to be in-service during RAP will be communicated in a format similar to Table 2.5-3 in the final RFP documents and through publicly available documents.

169. We find Public Service's proposal to provide updated transmission injection points to bidders as a part of the final RFP documents to be reasonable and adopt this approach. We deny the OCC's request to require the Company to update the information more frequently and to expand the information provided.

J. Qualifying Facilities (QFs)

170. Sustainable Power, through the Answer Testimony of witness Hans Isern,[59] requests that the Commission order Public Service to implement a "viable" program to acquire capacity and energy from Qualifying Facilities (QFs). Sustainable Power claims that such a program would: offer an accurate avoided cost rate for purchases from QFs; provide PPAs or other legally enforceable obligations with term lengths of at least 20 years; treat QF interconnections non-discriminatorily; and include a fair queuing process, including indicative pricing and timeframes for action on the part of the utility and the QF developer. Sustainable

[58] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, p. 2-167.

[59] Hearing Exhibit 32.

Power suggests that the QF program for Colorado could be modeled after the queuing process for Rocky Mountain Power's Schedule 38 in Utah. Schedule 38 allows a QF to request indicative avoided cost pricing from the utility at any time pursuant to the Commission-approved methodology. If the QF decides to move forward with its planned project, Schedule 38 establishes a timeline of required actions on the part of the utility and the QF developer, such that, if the QF meets each of the milestones, the QF will be able to enter into a PPA with the utility at the indicative pricing rate.

171. In its SOP, however, sPower acknowledges that its proposal that the Commission adopt a methodology for determining avoided cost rates will not be addressed in this Proceeding, based, in part, on Decision No. C16-1156-I, in which the Commission determined that setting a QF methodology for determining avoided costs as requested by sPower amounted to the promulgation of rules of general applicability and, consistent with Colorado's Administrative Procedure Act, must be decided through an appropriate rulemaking procedure. Sustainable Power recommends that the Commission make several policy findings related to QF procurement. These include findings that a QF procurement program would: allow Public Service to procure additional renewable energy resources and the associated environmental benefits at no additional cost or at a savings to ratepayers; allow resource developers to drive down the cost of renewable energy resources to the benefit of ratepayers; serve as a tool for evaluating the cost effectiveness of other renewable resources; and be compatible with Public Service's existing competitive bidding process.

172. Public Service filed its plan to implement a competitive resource solicitation in which QFs may participate, consistent with the Commission's current rules governing Public Service's potential purchases from QFs, 4 CCR 723-3-3900, *et seq*. As discussed below, we

intend to open a rulemaking to modify its ERP Rules by separate decision. Sustainable Power, and other parties or interested persons, are not precluded from proposing QF avoided cost methodology rule changes or policy implementations for Commission adoption through appropriate rulemaking proceedings.

K. Rulemaking

173. Public Service states that it supports a potential rulemaking to modify certain provisions of the Commission Rules Regulating Electric Utilities to improve the integration of the Commission's ERP Rules (4 CCR 723-3-3600 through 3619) with its RES Rules (4 CCR 723-3-3650 through 3668). Public Service argues that there are inconsistencies as between the requirements of the two sets of rules and suggests that some streamlining of the rules can be achieved prior to commencement of its next ERP cycle. Public Service states that no formal action with respect to this future rulemaking needs to be taken by the Commission in this Proceeding.

174. WRA states that it agrees with Public Service that there are inconsistencies and a lack of clarity between the Commission's RES Rules and the ERP Rules and also suggests that a rulemaking proceeding would provide value in removing confusion among the electric utilities and stakeholders.

175. A rulemaking proceeding to examine potential changes to the Commission's RES Rules and ERP Rules will be useful to all stakeholders. By separate decision, we will set forth a process for developing a Notice of Proposed Rulemaking for that rulemaking proceeding, including various pre-rulemaking activities, such as workshops and information meetings, as necessary.

L. Independent Evaluator (IE)

176. We find that an Independent Evaluator (IE) is necessary for Phase II of this ERP for the limited purposes of fulfilling certain roles contemplated under Rule 4 CCR 723-3-3613. Under this limited scope of work, the IE will perform the following tasks:

- The IE shall provide a report to the Commission, pursuant to paragraph 3613(e) of the ERP Rules, containing an analysis of whether Public Service conducted a fair bid solicitation and bid evaluation process, with any deficiencies specified in the report.
- The IE shall include in the report how Public Service implemented the Commission's Phase I decision in the bid evaluation process. The IE shall independently review the inputs and outputs from the bid evaluation modeling, including in the report an assessment as to whether the resulting outputs are feasible, and alerting the Commission and parties through the report where there may be deficiencies in the outputs.[60] The IE will not provide opinions regarding whether the public interest may be served through the acquisition of any particular resource. Also, the IE will not make any findings of fact or render legal conclusions, as those duties rest solely with the Commission.
- The IE shall also provide a log of contacts with the utility and other parties pursuant to paragraph 3612(d) of the ERP Rules.

177. Ideally, the IE will be engaged before the release of the RFPs for the all-source solicitation. Public Service shall provide the IE with full copies of each bid received and all information used in the bid evaluation process with respect to the Company's proposals for expansions of its owned generation facilities. The interactions between Public Service and the IE shall be governed by the provisions in the ERP Rules.

178. By Decision No. C16-0559-I, the Commission granted Public Service's Motion for Partial Waiver of Rule 3612(a), which requires the utility to file for approval of an IE that is

[60] As discussed further below, the IE's report is not intended for the introduction of new facts into the evidentiary record of this proceeding. The IE's report shall be limited to the matters described above and will serve as a resource for the parties to use for their analyses, inquiries, and any comments that may be filed with the Commission on the issues relevant to the Phase II process.

jointly proposed by the utility, Staff, and OCC.[61] The motion requested additional time for Public Service, Staff, and OCC to jointly propose an IE for this proceeding. However, ten months has passed, and the Company has still not filed for approval of an IE. The Commission therefore directs Public Service, Staff, and OCC to propose an IE to be used in the Phase II proceeding within 30 days of the effective date of this Decision.

M. Additional Approvals

179. Consistent with Rule 4 CCR 723-3-3617(c), we approve: the Company's proposed Contingency Plan set forth on pages 2-175 – 2-179 in Volume 2 of the 2016 ERP;[62] the RFPs and model contracts in Volume 3 of the 2016 ERP; [63] and the proposed bid evaluation process described in Section 2.9 Phase II Competitive Acquisition in Volume 2 of the 2016 ERP,[64] except as modified by this Decision. We also find that implementation of Public Service's ERP, consistent with this Phase I Decision, will satisfy the alternate scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, or Section 123 Resources.

180. Except as modified or rejected by this Decision, we approve the other components of Public Service's ERP as revised, if applicable, by its Rebuttal Testimony.

181. To the extent other specific requests made by Public Service or an intervening party are not addressed in this Decision, they are denied.

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[61] Decision No. C16-0559-I, issued June 21, 2016, Proceeding No. 16A-0396E.
[62] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, pp. 2-175 – 2-179.
[63] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.3.
[64] Hearing Exhibit 1, Att. AKJ-2, 2016 Electric Resource Plan, Vol.2, pp. 2-215 – 2-229.

II. ORDER

A. The Commission Orders That:

1. The Application for Approval of 2016 Electric Resource Plan filed by Public Service Company of Colorado (Public Service) on May 27, 2016 is approved, with modifications, consistent with the discussion above.

2. Public Service shall issue Requests for Proposals (RFPs) for an all-source, competitive bidding process to meet its resource need during the eight-year resource acquisition period of the 2016 Electric Resource Plan, consistent with the discussion above.

3. Public Service shall develop two scenarios for developing resource portfolios for presentation in its report to be submitted pursuant to Rule 4 *Code of Colorado Regulations* 723-3-3613(d) (120-Day Report). Consistent with the discussion above, one scenario shall correspond to a need of "0 MW" in 2023 and the other scenario shall be based on an updated demand forecast. In its 120-Day Report, Public Service shall identify a preferred resource portfolio within one of the two need scenarios.

4. Public Service shall file an updated calculation of its resource needs prior to the issuance of the RFPs, consistent with the discussion above.

5. Public Service shall file an updated reserve margin study with its next Electric Resource Plan.

6. Public Service shall derive its demand and sales forecasts using data tailored to its service area instead of statewide data, consistent with the discussion above.

7. Public Service shall present in its 120-Day Report, resource portfolios using the base modeling assumptions and sensitivities for the same resource portfolios, consistent with the discussion above.

8. Public Service shall provide a point value for capacity costs for its utility proposals to the all-source solicitation, without a 20 percent variance, consistent with the discussion above. Public Service also shall provide, as a part of any utility proposal, detailed information on its estimates of operations and maintenance (O&M) expenditures and shall track its actual O&M costs for an acquired facility and explain any variances between actual and estimated costs in any rate recovery proceeding where the facility is at issue, consistent with the discussion above.

9. Public Service shall model, as a base modeling approach, both the annuity method and its proposed replacement method for the range of costs to backfill Power Purchase Agreements, consistent with the discussion above.

10. Prior to issuing the all-source RFPs, Public Service shall file a complete list of the Strategist modeling inputs and assumptions, consistent with the discussion above.

11. Public Service shall perform bid eligibility screening, initial economic screening, and computer modeling to evaluate the bids and utility proposals received in response to its all-source solicitation RFPs, consistent with the discussion above.

12. Public Service's 4.0 GW Flex Reserves Study is approved for use in the evaluation of wind bids to the all-source solicitation, consistent with the discussion above. Public Service's proposal to complete a 4.5 GW study for use in this Proceeding is denied.

13. Public Service shall complete an updated Flex Reserves Study and file such study with its next Electric Resource Plan proceeding, consistent with the discussion above.

14. Public Service shall prepare and file two reports on the status of its coal supply and coal suppliers, consistent with the discussion above.

15. Section 123 Resources shall be addressed using the same procedures as approved in Decision No. C13-0094, consistent with the discussion above.

16. Public Service shall model the Southwestern Public Service Diversity Exchange as a resource bid to the all-source solicitation, consistent with the discussion above.

17. Public Service shall propose an Independent Evaluator for this Proceeding within 30 days of the effective date of this Decision, consistent with the discussion above.

18. To the extent requests made by intervening parties are not addressed in this Decision, they are denied.

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

20. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING March 23, 2017.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

____

FRANCES A. KONCILJA

____
Commissioners

COMMISSIONER WENDY M. MOSER
CONCURRING IN PART AND DISSENTING IN PART.

III. COMMISSIONER WENDY M. MOSER CONCURRING IN PART AND DISSENTING IN PART

1. I hereby concur in the majority decision except as it relates to the decision to include a sensitivity run in the model reflecting the "Social Cost of Carbon." I dissent as to this aspect of the majority decision for the following reasons:

a. Basically, the Social Cost of Carbon (SCC) is an estimate, measured in dollars, of the long-term damage done by a ton of carbon dioxide emissions in a given year, assuming model impacts at a national, even global, level.[65] The U.S. Environmental Protection Agency (EPA) and other federal agencies use this estimated measure to justify the adoption of a rule or regulation that impacts cumulative global emissions. The Agencies do not use the SCC to justify the selection of resources for utilities. The regulation is said to be "justified" if the Agency can show

[65] Hearing Exhibit 26, Att. RLF-1, p. 2.

that the benefits of the intended regulation justify, *i.e.*, are greater than, its costs. Said another way, the purpose of developing an SCC, was for federal agencies to justify why they adopt regulations, as regulation creates costs, which consumers pay.

b. The purpose of this proceeding, the Electric Resource Plan (ERP), is to select the lowest cost resources available to provide the Company with enough capacity and energy to in turn be able to provide customers with reliable electricity, when needed, at an affordable rate. In contrast, the SCC being proposed is not going to determine which resource will provide a utility with the needed capacity and energy at the most affordable rate to customers. As a sensitivity run, the claim by Western Resources Advocates (WRA), as cited by the majority, is that it will help capture the "broader impacts and risks" from carbon emissions. It cannot capture this accurately, if the data is not accurate, and there is no evidence to prove that the data is accurate. What will happen is that applying a cost due to SCC in the ERP model will discriminate against fossil fuel resources in the bid process. As decision makers, we will not know if the discrimination is justified or not, because we do not know if the SCC numbers are anywhere near accurate.

c. The SCC proposed to be used in the ERP modeling is not based on impacts specific to Colorado. The evidence in the record is very clear that there is no reliance upon state specific data, but rather it is meant to be a "comprehensive" estimate of global climate change data developed at the federal level. Accordingly, we cannot isolate the information to just Colorado data, nor just stationary resources (like power plants), but we would be using federal data (maybe global data) that includes any type of carbon emitting resource, including naturally occurring carbon and moving sources, (*i.e.,* automobiles and cows, etc.). Nothing in the record accounts for variables between states and in fact, the record shows that the models used to develop the SCC estimate are incomplete, due to lack of precise information.[66] Accordingly, by substituting the SCC data from the federal level that is used to justify regulations, as an indication of "actual costs to customers," we are engaging in a "garbage in, garbage out" analysis. Portraying these modeling estimates as the "real cost of carbon emissions" to customers is a dangerous charade. We have no evidence in the record to support the recommended dollar amount for an SCC that customers in Colorado "are actually subjected to" and without such evidence, I cannot condone its use.

d. Customers of Public Service Company of Colorado will not pay the proposed SCC amount, regardless of which resources are ultimately selected in this ERP proceeding. As a result of the ERP process, resources

[66] Hearing Exhibit 34, p. 1.

will be selected and it is the direct costs of those selected resources that are passed on to customers in their utility bill.

e. The carbon proxy price sensitivities that we have ordered, are to represent the potential estimated future costs of compliance with carbon regulations, and admittedly, these may never occur either. Past Commissions have relied upon carbon proxy prices, rather than estimates of climate damage. Without evidence to support why a change is needed or that the change will be more accurate, there does not appear to be grounds for modeling the SCC as an additional sensitivity.

2. In summary, because there is no reliable way to determine a Colorado SCC amount and no evidence in the record to support it, I hereby dissent on this issue.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

WENDY M. MOSER

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Commissioners