Decision No. C13-0094

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 11A-869E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2011 ELECTRIC RESOURCE PLAN.

DOCKET NO. 12A-782E

IN THE MATTER OF THE APPLICATION OF PSCO FOR APPROVAL OF THE ACQUISITION OF THE BRUSH 1, 3, AND 4 GENERATION FACILITIES AND IN CONNECTION THEREWITH THE GRANT OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY IF REQUIRED AND THE APPROVAL OF COST RECOVERY THROUGH A GENERAL RATE SCHEDULE ADJUSTMENT.

DOCKET NO. 12A-785E

IN THE MATTER OF THE VERIFIED APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE POWER PURCHASE AGREEMENT FOR 118.8 MW OF NATURAL GAS GENERATION, EARLY RETIREMENT OF ARAPAHOE UNIT 4, AND A GAS SALES AGREEMENT.

PHASE I DECISION GRANTING APPLICATION FOR APPROVAL OF 2011 ELECTRIC RESOURCE PLAN; DENYING APPLICATION FOR ACQUISITION OF THE BRUSH GENERATING FACILITIES; AND GRANTING APPLICATION TO RETIRE ARAPAHOE UNIT NO. 4 AND ENTER INTO A TRANSACTION WITH SOUTHWEST GENERATION OPERATING COMPANY IN PART

Mailed Date: January 24, 2013
Adopted Date: December 18, 2012

INTRODUCTION

By this Decision, the Colorado Public Utilities Commission (Commission) concludes the first phase of an Electric Resource Plan (ERP) by which competitive bidding will be used to acquire additional utility resources needed to serve the customers of Public Service Company of Colorado (Public Service or Company). Competitive bidding will foster cost discipline while also creating an opportunity for Public Service, independent power producers (IPPs), and other providers to propose technologies whose public interest benefits will be examined by the Commission in the second phase of the ERP.

Competitive bidding is consistent with the Commission's long-standing policies and practices. The form of competitive bidding adopted by this Decision will also bring forward new and clean energy technologies as the Commission fulfills its obligations under § 40-2-123(1)(a), C.R.S. As demonstrated below, the Commission is committed to examining the benefits of qualifying projects whose implementation is shown to be cost-effective.

To further the benefits of competition, the Commission also takes steps by this Decision to ensure fairness in the bid solicitation and bid evaluation processes. The approved competitive solicitation comes at a time when certain IPPs are seeking to renew purchased power contracts with Public Service, and the supply of existing generation may exceed the need due to limited system load growth. Public Service also expects to participate in the competitive bidding with its own proposals to build and operate additional generation facilities to be constructed at the Company's existing stations with sufficient capacity to meet the entire resource need. Due to the Company's interest in competing against IPP bids, the Commission directs Public Service to engage an Independent Evaluator to oversee the bid evaluation process primarily for the purpose of calling attention to any deficiencies that may compromise fair and reasonable outcomes from the competitive solicitation.

This ERP follows the Commission's approval of Public Service's emission reduction plan pursuant to the Clean Air Clean Jobs Act set forth at §§ 40-3.2-201 through 40-3.2-210, C.R.S. The Commission sought to study in the context of this ERP the availability of cost-effective alternatives to repowering two generation facilities on natural gas while preserving or exceeding the emission reductions resulting from the switch from coal to natural gas. It now appears no longer necessary for those base load facilities—unit 4 at the Arapahoe Station and unit 4 at the Cherokee Station—to operate as must-run resources during summer months for system stability. Instead, the units can be dispatched economically as natural gas-fired peaking facilities with lower emissions than previously contemplated due to low expected capacity factors. This Decision directs Public Service to provide an analysis for determining in the second phase of this ERP whether the retirement of those units is preferable as compared to their repowering as approved pursuant to the statute.

This ERP also follows Public Service's acquisition of 2,100 MW of wind facilities and over 80 MW of utility-scale solar photovoltaic facilities. This level of intermittent generation requires substantial flexibility in the Company's fleet of resources, and any additional renewable resources will also likely require that Public Service obtain additional utility resources that can satisfy future load requirements and help the overall system accommodate intermittent resources more efficiently.

Finally, by this Decision, the Commission denies the approval of Public Service's proposed acquisition of Brush Power LLC and its generation facilities whose output is presently purchased by the Company under contracts expiring in either 2017 or 2022.

The Commission concludes that Public Service's ownership of those facilities has not been shown to be in the public interest due, in part, to the risks inherent in the expected operation of relatively old equipment. However, the Commission approves Public Service's proposed contracting for the output from the facilities at the Arapahoe Station owned and operated by Southwest Generation Operating Company, LLC. The Commission determines that, despite initial questions surrounding the means by which Public Service and Southwest Generation entered into the proposed transaction, the result is a cost-effective, ten-year purchased power agreement with additional savings for customers from the associated natural gas sales agreement between the Company and Southwest Generation.

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I. BY THE COMMISSION

A. Statement

1. On October 31, 2011, Public Service Company of Colorado (Public Service or the Company) filed an Application for Approval of its 2011 Electric Resource Plan (ERP) in Docket No. 11A-869E (Application).

2. On July 5, 2012, Public Service filed two applications in two separate dockets related to changes in its resource need and to specific proposals to meet that need. First, Public Service filed a Verified Application in Docket No. 12A-785E requesting to retire the Company's Arapahoe Unit No. 4 coal-fired plant (Arapahoe 4) by the end of 2013 and to enter into a multi-element transaction with Southwest Generation Operating Company, LLC (SW Generation) and its affiliates SWG Arapahoe, LLC, and SWG Fountain Valley Gas, LLC. Second, the Company filed a Verified Application in Docket No. 12A-782E seeking Colorado Public Utilities Commission (Commission) approval to acquire Brush Power LLC's (Brush) Units 1, 3, and 4 in a transaction in which the Company purchases the corporate entities that currently own those generation assets.

3. By Decision No. C12-0882-I, issued on August 1, 2012, the Commission determined that it was appropriate to consider the proposed transactions set forth in Docket Nos. 12A-782E and 12A-785E pursuant to the ERP process set forth in Commission rules. Further, the Commission found that the applications in those dockets significantly overlap and affect the issues in Docket No. 11A-869E concerning the Company's ERP. The Commission therefore consolidated all three proceedings into the Company's ERP proceeding and designated Docket No. 11A-869E as the primary docket.

4. Hearings on the Application, including the Brush and Arapahoe 4 applications, commenced on October 29, 2012 as scheduled by Decision No. C12-0882-I, with processes clarified in Decision No. C12-1178-I issued October 12, 2012. Hearings continued on October 30 and November 1, 2, 5, 6, and 8, 2012.

5. Prior to hearings, parties were invited by Decision No. C12-0975-I, issued on August 17, 2012, to file comments regarding the use of an Independent Evaluator and by Decision No. C12-1001-I, issued on August 24, 2012, to file comments regarding the consideration of new clean energy technologies or demonstration projects under § 40-2-123(1)(a), C.R.S.

6. Following hearings, statements of position were filed by the following parties:[1] Public Service; Staff of the Colorado Public Utilities Commission (Staff); Colorado Independent Energy Association, Colorado Energy Consumers, and Thermo Power & Electric LLC (Thermo) (collectively, CCT); the Colorado Office of Consumer Counsel (OCC);[2] the Colorado Energy Office, previously the Governor's Energy Office; Interwest Energy Alliance (Interwest);

[1] As set forth in Decision No. C11-1391, issued January 3, 2012, notices of intervention by right were filed by: Staff of the Colorado Public Utilities Commission (Staff), the Governor's Energy Office, and the Colorado Office of Consumer Counsel (OCC). Requests for intervention were timely filed by the following: Blanca Ranch Holdings, LLC and Trinchera Ranch Holdings, LLC; Interwest Energy Alliance (Interwest); EnCana Oil & Gas (USA) and Noble Energy, Inc. (collectively, Gas Producers); City of Boulder; Colorado Renewable Energy Society; Colorado Solar Energy Industry Association; Holy Cross Electric Association, Inc.; Intermountain Rural Electric Association (IREA); Colorado Mining Association; American Coalition for Clean Coal Electricity; Climax Molybdenum Company and CF&I Steel, LP; Ratepayers United of Colorado (RUC); Colorado Energy Consumers (CEC); Ms. Leslie Glustrom; Colorado Independent Energy Association (CIEA); C12 Energy, Inc. (C12); Vote Solar Initiative; SolarReserve, LLC; Coal Mine Methane Coalition; Thermo Power & Electric LLC (Thermo); Southwest Generation Operating Company, LLC (SW Generation); TradeWind Energy, LLC; Western Resource Advocates (WRA). All parties' requests for intervention with the exception of RUS and Ms. Glustrom were granted by Decision No. C11-1391. By Decision No. C12-0138, issued February 9, 2012, the Commission granted permissive intervention to RUS and granted Ms. Glustrom's intervention for the limited scope of addressing the issues of coal costs and coal supply. CIEA, CEC and Thermo often filed jointly and are collectively referred to herein as "CCT."

[2] OCC filed a Motion to Accept a Late Filed Statement of Position on October 23, 2012. The Commission granted the motion at the November 15, 2012 Commissioners' Weekly Meeting. This Order serves as the written decision granting the motion.

EnCana Oil & Gas (USA) and Noble Energy, Inc. (collectively, Gas Producers); City of Boulder (Boulder); Intermountain Rural Electric Association (IREA); Climax Molybdenum Company and CF&I Steel, LP; Ratepayers United of Colorado (RUC); Ms. Leslie Glustrom; C12 Energy, Inc. (C12); SolarReserve, LLC (SolarReserve); SW Generation; TradeWind Energy, LLC (Tradewind); and Western Resource Advocates (WRA).[3]

B. Electric Resource Planning

7. Every four years, regulated electric utilities, including Public Service, file an ERP for review and approval in accordance with the Commission's Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* 723-3-3600, *et seq*. (ERP Rules).

8. The Commission's ERP Rules serve two primary functions. First, the periodic examination of the utility's energy sales and demand forecasts and the assessment of its existing resources (demand side and supply side) help the Commission ensure that sufficient generation will be available to meet customer needs in the future. Second, the review and approval of an ERP help the Commission ensure that the utility procures the best mix of additional resources given the costs and benefits of various alternatives consistent with the state's public policy objectives, such as the Renewable Energy Standard set forth at § 40-2-124, C.R.S.

9. If an ERP identifies a future resource need, the utility will explain how it expects to meet that need. It is the Commission's preference, however, that the utility use competitive bidding to procure additional resources. An ERP must therefore include requests for proposals (RFPs) and other information and documents needed to support the approval of a competitive acquisition process.

[3] Filings, exhibits, and comments in this docket are voluminous. Some party positions and comments shall be reiterated in this Decision as relevant in the various sections below; however, exclusion of a party filing or comment does not indicate that the party's presented information was not considered.

10. The ERP also describes how the utility expects to evaluate bids and proposals. In anticipation of these bid evaluation activities, the utility will often ask the Commission to approve certain inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, coal prices, carbon costs, discount rates, integration costs for intermittent resources). In some instances, these inputs are specific values, while in other instances the Commission is asked to approve a method or approach for developing and for updating inputs and assumptions at a later date.

11. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources. This Decision concludes Phase I of Public Service's ERP.

12. In Phase II, the Commission ultimately determines which bids and utility proposals for new resources should be approved. At the start of Phase II, Public Service will modify the components of its ERP to be consistent with the Commission's Phase I order. The Company will then issue the RFPs, receive bids and proposals, and evaluate them for bid selection. Public Service will have 120 days after it receives the bids and proposals to evaluate the resources and to file a report with the Commission. Parties in this proceeding will then have an opportunity to submit comments on the 120-day report, and the Commission will deliberate and issue a Phase II decision identifying the resource portfolios found to be in the public interest.

13. After Phase II, Public Service will negotiate with selected bidders and pursue its utility-owned facilities as established in the Phase II decision. The implementation of a Phase II decision is expected to be complete within 18 months after receipt of bids.

C. Competitive Bidding and Alternative Proposals for Resource Acquisition

14. Public Service has selected a seven-year resource acquisition period (RAP). In its initial ERP filing on October 31, 2011, the Company determined that it needs an additional 292 MW in 2018. Public Service explained in subsequent filings that, based on updated energy sales and demand forecasts and other proposals for the acquisition of new utility resources, the resource need could range from 345 MW to 432 MW in 2018.

15. Consistent with the ERP Rules, Public Service proposes to use a competitive solicitation process to acquire the new utility resources necessary to meet its projected needs. Specifically, the Company proposes to issue RFPs for an all-source solicitation in which supply-side electric generation resources with a nameplate electric rating of 10 MW (AC) or larger would be eligible for consideration. The Company states that the solicitation will seek both short-term and long-term power supply proposals.

16. In support of this approach, Public Service filed three RFPs: one for dispatchable resources (such as natural gas combined-cycle or simple cycle facilities), one for renewable resources (such as wind or photovoltaic solar facilities), and one for semi-dispatchable renewable resources (such as concentrating solar power with storage). Each proposed RFP accommodates projects seeking consideration as "Section 123 resources" as discussed later in this Decision. The Company also filed proposed model contracts for each of these three types of resources. Furthermore, Public Service sets forth in its ERP a proposal for initial bid due diligence, bid screening, bid selection for computer modeling, and portfolio development using computer modeling.

17. We generally approve the Company's proposed framework for acquiring utility resources. However, during the course of the proceeding, parties have made various proposals

and suggestions regarding the elements of the all-source solicitation, and the Company has also proposed modifications to specific components of its ERP since the October 2011 filing. We adopt the approach proposed by Public Service with certain modifications, as described in this Decision.

1. Brush Proposal

a. Background Summary

18. Public Service seeks Commission approval to acquire Brush Power LLC and its generation facilities, Brush Units 1, 3, and 4, whose output is presently purchased by the Company under purchase power agreements (PPAs).

19. Brush 1 is a 60 MW combined cycle unit with one combustion turbine (CT) and one steam generator, Brush 3 is a 30 MW simple cycle CT, and Brush 4 is a 147 MW combined cycle unit with two CTs and one steam generator. The PPA for Brush 1 and 3 expires in April 2017, and the PPA for Brush 4 expires in 2022. Public Service proposes to purchase the Brush assets for $75 million in place of continuing the PPAs, resulting in the addition of 237 MW at an overall cost of approximately $316 per kW.

20. In support of its proposal, Public Service performed a spreadsheet analysis and computer-based portfolio modeling. For both studies, the Company proposes a 45-year useful life of each unit beginning from the date the equipment was reconditioned and installed in Colorado.[4] The Company estimates that the purchase of the Brush assets will result in savings of about $11.3 million through 2022 and $62 million over the life of the facilities.

[4] Accordingly, the Company proposes to retire Brush 1 in 2034, Brush 3 in 2043, and Brush 4 in 2046.

21. Staff raises concerns about the cost risks associated with Public Service's proposal for a useful life of 45 years after the Brush facilities were reconditioned and installed in Colorado. 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.[5]

22. Staff asserts that the cost savings projected by Public Service could be offset easily by unanticipated costs or a shorter service life. Staff further contends that the Company essentially is asking for a presumption of prudence such that the Company will be allowed in the future to recover all costs even if they are higher than the Company now anticipates or if the facilities are retired earlier than planned. Staff recommends that the Commission deny the Brush acquisition.[6]

23. In response to Staff's concerns, Public Service argues that, with only a couple of exceptions, the natural gas generation units in its fleet do not have approved useful lives less than 40 years.[7] Public Service also argues that starts and operating hours are more important than equipment age, and the Brush units have a relatively low number of starts and operating hours. Because the Brush units will be operated as peaking units, their starts and operating hours should continue to be low.[8] Public Service further asserts that the first years following the acquisition of the Brush units are the most beneficial to ratepayers, saving them from $46 to $92 million over the full depreciation periods.[9] Public Service also performed a "break-even analysis" showing

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[5] Supplemental Answer Testimony of Staff witness Camp, at 19 (Hearing Exhibit 77).
[6] *Id.* at 20.
[7] Supplemental Rebuttal Testimony of Public Service witness Perkett, at 5 (Hearing Exhibit 40).
[8] Supplemental Rebuttal Testimony of Public Service witness Hess, at 3-4 (Hearing Exhibit 37).
[9] Second Corrected Supplemental Rebuttal of Public Service witness Hill, at 13 (Hearing Exhibit 15).

that ratepayers would benefit under the acquisition if the units are retired in the 2023 to 2028 range, depending on specific cost assumptions.

24. OCC recommends approving the Brush acquisition with the condition that the prudence of the acquisition can be challenged in the future. CCT recommends deferring the Brush acquisition to Phase II, where the $75 million purchase price can be compared with other bids.

b. Commission Findings and Conclusions

25. We agree with Staff that the expected cost savings of Public Service's proposed purchase of the Brush facilities do not outweigh the potential risks of the acquisition. We therefore deny Public Service's proposal.

26. We find that extending the expected useful lives of the facilities 45 years past the reconditioning date, as Public Service proposes, presents a significant cost risk to ratepayers. Reconditioning to "new and clean" does not remove prior damage to the material such as fatigue, fretting, creep, or wear that is within specified tolerances.[10] Although the operating hours of the Brush units are expected to be relatively low, the Company makes no specific allowance for cost risks associated with known flaws or the age of the equipment. The flaws already found highlight the risk that these or other potential problems may require significant investment in the future, particularly if the equipment lives are extended as long as Public Service plans.

In addition, owning facilities that are now uncommon due to their advanced age also raises concerns about parts availability or other difficulties, potentially resulting in higher maintenance and repair costs.

[10] *See* Transcript, Vol. 5, from November 5, 2012 Evidentiary Hearing, at 39-41.

27. We also agree with Staff and CCT that Public Service's cost assumptions are overly optimistic. For example, the Company estimates eight labor positions to operate the facilities compared with the equivalent 9.7 existing personnel who are experienced with the equipment. Public Service also estimates that the eight positions will be reduced to six with additional automation. Staff raises concerns that this older equipment may need the same number of people to operate, even with the additional automation.[11] In addition, we agree with CCT that the costs the Company used to represent future replacement power costs for the Brush units beyond PPA expiration may not represent bids that we will likely see in response to the all-source solicitation.

28. Further, we are concerned that the Brush units have higher heat rates than comparable facilities.[12] While fuel costs are not significant when operated only a few days per year, this low efficiency limits their operation to a narrow service capability. If other units are down for an extended period, or system load increases faster than projected, these inefficient units could be called upon to operate more than the projected 1 to 3 percent of the time. Because of their low efficiencies, the Brush facilities are not good candidates for conversion to base load or other higher load factor service, limiting future optionality. It is also reasonable to expect heat rates for new, more flexible generation units to continue to improve,[13] so the disparity between Brush and other unit heat rates will likely increase over time.

[11] *Id.*, at 78 ln. 6-20.

[12] *See* Supplemental Answer Testimony of Staff witness Camp, at 24 (Hearing Exhibit 77); Confidential Hearing Exhibit 140.

[13] *See, e.g.,* Volume 2 of Public Service's Application, Table 2.8-1, *Generic Dispatchable Resource Cost and Performance* (Hearing Exhibit 1(B))(assuming a 5 percent improvement in heat rate every ten years).

29. We are also not convinced that the Brush units will provide Public Service the flexibility required to integrate additional intermittent resources on its system. We conclude that it is preferable for the Company to invest in more efficient and more responsive facilities for operational benefits as opposed to facilities whose "optionality" might derive principally from retirement as early as 2022.

30. We note that OCC's recommendation to approve the Brush purchase with the condition that the prudence of the acquisition may be challenged in the future creates an unclear standard and we will not adopt it. While in certain circumstances the Commission may, and should, reconsider the appropriateness of previously approving an application if new information comes to light,[14] accepting the OCC's recommendation would, in effect, continuously call into question the prudence of the Brush acquisition. This condition would make it difficult, if not impossible, for Public Service to rely on approval of the application subject to this condition. Further, as OCC contends by including this condition, the information before the Commission indicates concern that, if approved, future events would lead to the conclusion that the proposed Brush acquisition is imprudent. We therefore find that, in these circumstances, approval of the Brush acquisition subject to condition is inappropriate.

31. We also disagree with CCT's recommendation to defer the proposed Brush acquisition to Phase II where it can be compared with other bids.[15] Public Service states that a primary benefit of the acquisition results from the renegotiation of the existing PPA, and comparing the current Brush Acquisition proposal to other bids in Phase II

[14] For example, if approved and if, subsequently, it is found that the Company intentionally provided incorrect or false information in presenting the application for approval, such circumstances could later be used to re-open the approval decision.

[15] Corrected Supplemental Answer Testimony of CCT witness Monsen, at 3, 30 (Hearing Exhibit 58).

will not alter this aspect of the Phase I evaluation. However, the owners of the Brush units will have the opportunity to bid its expiring contracts into the all-source solicitation or to bid a different proposal for utility ownership, consistent with the terms of the RFP.

32. In conclusion, we agree with Staff that the Brush units are better suited as IPP assets under the current contracts, and we deny the Brush acquisition.

2. Arapahoe PPA Proposal

a. Background Summary

33. Public Service requests approval to retire its Arapahoe 4 unit by the end of 2013 and, in its place, to enter into a multi-element transaction with SW Generation and its affiliates SWG Arapahoe, LLC, and SWG Fountain Valley Gas, LLC.[16] The deal encompasses two contracts with SW Generation. The first is a ten-year, 118.8 MW PPA to purchase the output from Arapahoe units 5, 6, and 7 from January 1, 2014 through December 31, 2023. The second contract is a natural gas sales agreement with SWG Fountain Valley Gas, LLC, under which Public Service will sell natural gas to fuel the Fountain Valley generation facility.

34. Public Service estimates that the proposed Arapahoe transaction, including the retirement of Arapahoe 4, will save $18 million as compared to operating Arapahoe 4 on gas.[17]

35. To secure the PPA offer from SW Generation, Public Service explains that it determined only two IPPs are in a position to offer electric power in competition against Arapahoe 4. Public Service contacted both IPPs, SW Generation and Thermo, and solicited offers.

[16] We address the question of retiring Arapahoe 4 separately, as discussed below.
[17] Direct Testimony of Public Service witness Hill (Docket No. 12A-785E), at 14 (Hearing Exhibit 13).

36. Staff questions whether Public Service acted appropriately in considering the SWG Fountain Valley Gas, LLC, gas sales agreement as a part of the solicitation. However, Staff takes no position on whether the Arapahoe transaction is in the public interest. Interwest and WRA recommend that the Commission defer consideration of the Arapahoe transaction to Phase II so that wind and solar resources can be included in the comparison.

b. Commission Findings and Conclusions

37. While Public Service's actions in soliciting bids outside of the normal course of an ERP are highly unusual, we find that Public Service's actions were reasonable in this situation. We appreciate Staff's concerns about the overall fairness of the solicitation, and we note that Public Service's targeted solicitation with two bidders normally would not meet the competitive bidding requirements contained in the ERP Rules. However, we find that the solicitation meets the goal of using competition to obtain cost-effective bids from potentially stranded IPP assets. We also find that, despite Public Service's intentions to use this solicitation for the purpose of replacement of Arapahoe 4, the retirement of Arapahoe 4 is not an essential component of the resulting PPA proposal.

38. The Arapahoe PPA proposal is largely unopposed, and due to the attractive bid price, we find that the proposal is in the public interest. We therefore approve the proposed contracts with SW Generation and find that this early resource solicitation constitutes an approved plan for the acquisition of new utility resources under paragraphs 3611(b) and (c) of the ERP Rules. Further, we approve Public Service's request seeking authorization to modify the Company's ECA to accommodate the gas sales agreement with SWG Fountain Valley Gas, LLC.

3. Retirement of Arapahoe 4

a. Background Summary

39. Public Service proposes accelerated retirement of Arapahoe 4 on December 31, 2013. Public Service states that a Commission determination in Phase I to approve the Arapahoe 4 retirement will allow for an orderly shutdown of that unit and the re-deployment of personnel.

b. Commission Findings and Conclusions

40. We decline to approve the retirement of Arapahoe 4 as part of this Phase I decision. First, because Arapahoe 4 is nearly depreciated, the unit provides inexpensive system capacity when operated as a peaking facility. The heat rate of Arapahoe 4 is consistent with other natural gas-fired peaking resources, and the unit may provide additional system flexibility, because it is located within the transmission constrained Denver Metropolitan area.

41. Second, the record contains substantial testimony regarding the benefit of keeping Arapahoe 4 as a viable resource in Phase II to maintain competitive pressure on bidders.[18] We conclude that the competitive environment could be altered significantly by removing a viable generation facility from the overall pool of available resources.

42. Finally, maintaining Arapahoe 4 as an available resource in Phase II is consistent with Staff's suggestion to allow the Company's computer-based portfolio model to select the most economic resources for dispatch, as well as the argument of CCT and OCC that resource selections should be vetted through competitive bidding. Later in this Decision, we address the specific approach for the Phase II portfolio modeling to be used to investigate the potential retirement of Arapahoe 4.

[18] *See* Rebuttal Testimony of Public Service witness Hill, at 8-12 (Hearing Exhibit 14); Corrected Supplemental Rebuttal Testimony of Public Service witness Haeger, at 11 (Hearing Exhibit 6).

4. Resource Acquisition Period, Planning Period, and Timing

43. Public Service takes a relatively short-term perspective in this ERP. The Company asserts that the low resource need combined with various uncertainties surrounding the future state of the economy, natural gas supply, Boulder's municipalization efforts, and other factors together present a situation where short-term resource decisions are currently the best option, and long-term resource decisions should be reserved for a future ERP filing.

44. Public Service therefore proposes a seven-year RAP, from October 2011 through October 2018.[19] The Company also states a preference for short-term PPA bids (8-year maximum) as well as a 25-year maximum term for long-term PPA bids.[20]

c. Background Summary

45. Staff suggests a longer RAP than that proposed by Public Service in order to capture low bid prices that may be available under current market conditions.[21] In support of its position, Staff argues that Public Service will need significant peaking capacity between 2018 and 2021. Because a number of existing PPAs are expiring in that period, resource availability should result in favorable prices for ratepayers. Staff further estimates that 900 MW of stranded generation capacity will be available by 2021. Staff also argues that a ten-year RAP will increase the likelihood that innovative technologies will bid in Phase II of this ERP.[22] As an alternate approach, Staff recommends a ten-year RAP for Section 123 resources.[23]

[19] Direct Testimony of Public Service witness Hill, at 2 (Hearing Exhibit 9).
[20] *Id.*, at 44-46.
[21] Answer Testimony of Staff witness Podein, at 6 (Hearing Exhibit 72).
[22] Corrected Answer Testimony of Staff witness Sigalla, at 10 (Hearing Exhibit 74).
[23] The definition of a Section 123 resource is addressed below.

46. In rebuttal, Public Service disagrees with Staff's analysis regarding the RAP. Public Service argues that there would be more need in 2021 than the available capacity, which likely would result in higher bid prices. Public Service also argues that the Company's revised demand forecast, as well as the impacts of the Brush and Arapahoe transactions discussed above, further reduces the amount of available capacity. Public Service also refutes Staff's argument that a ten-year RAP will increase innovative technologies, arguing that the innovative bids received in Public Service's 2007 ERP, Docket No. 07A-447E (2007 ERP), could be constructed within the Company's proposed seven-year RAP.[24]

47. Staff also raises concerns about Public Service's proposed preference for short-term contracts. Staff asserts that striking Public Service's proposed preference for short-term bids and the 25-year maximum for long-term bids is necessary to create a level playing field compared to the Company's proposed long-term utility-owned resources.[25] Staff suggests that an explicit order from the Commission striking the short-term preference would encourage bidders to offer their best bid.

48. In response, Public Service explains that it stated a preference for short-term contracts in its ERP to discourage the construction of new IPP facilities. Although the Company will encourage short-term bids, it agrees to accept and to consider bids for PPAs with terms up to 25 years.

d. Commission Findings and Conclusions

49. We agree with Public Service that, if a longer RAP results in having more need than available capacity, bid prices would likely be higher. Also, resource needs after 2018 can be

[24] Rebuttal Testimony of Public Service witness Hill, at 2 (Hearing Exhibit 14).
[25] Corrected Answer Testimony of Staff witness Sigalla, at 29 (Hearing Exhibit 74).

adequately addressed in Public Service's 2015 ERP. Consistent with Public Service's rationale for a short-term approach, we also find that the additional information that will become available between now and 2015 will allow for a more accurate consideration of Public Service's resource need going forward.

50. We also agree with Public Service that the seven-year RAP is a reasonable period in which to begin construction of Section 123 resources. We therefore deny Staff's request to include a ten-year RAP for Section 123 resources.

51. With respect to the resource planning period, we find that using a planning period longer than the 25-year maximum PPA term will capture the benefits of long-life resources, such as the utility self-build resources. A 40-year planning period also will allow the Commission to better assess these long-term resources when compared to different methods of projecting costs for years after bid proposals expire. We therefore approve a 40-year planning period rather than Gas Producers' proposal to use a shorter period, consistent with our past practices.

52. Finally, we agree with Staff that the Commission should encourage bidders to offer their best bids. We therefore direct Public Service not to discriminate between short- and long-term bid proposals. If Public Service prefers one bid over another, for timing considerations or otherwise, the Company shall state the basis for such preferences in its 120-day report in Phase II.

5. Opportunistic Renewable Resource Acquisitions

a. Background Summary

53. Public Service seeks authorization to issue before its next ERP, additional RFPs to acquire renewable resources when market conditions appear favorable.[26] Public Service states that the Company needs to be able to react quickly, outside of the quadrennial ERP filings, to take advantage of opportunities as they arise. Public Service raises the Limon II wind PPA as an example of the kind of "opportunistic approach" that would be used. The Company states any and all bid evaluation results and selected winners from such targeted solicitations would be submitted to the Commission for review and approval.[27]

54. Staff contests Public Service's proposed opportunistic approach for acquiring future renewables outside of the ERP. Staff states that Public Service's request for blanket approval of opportunistic solicitations undermines the Commission's authority in the selection of renewable resources and that evaluating additional renewable resources without the contextual framework of an ERP would be difficult. According to Staff, the Company should, if necessary, come to the Commission for approval to pursue resource acquisitions outside of the normal ERP or Renewable Energy Standard (RES) compliance dockets on an individual case basis.[28]

b. Commission Findings and Conclusions

55. While we agree with Public Service that the Company should pursue resources when a significant benefit to consumers is likely to be achieved, Public Service has sought waivers successfully pursuant to the ERP Rules when such opportunities have arisen in the past. Public Service can continue to use this waiver process to acquire resources outside of the

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[26] Volume 1 of Public Service's Application, at 47 (Hearing Exhibit 1(A)).
[27] Public Service Brief Concerning Section 123 Resources filed September 21, 2012.
[28] Corrected Answer Testimony of Staff witness Sigalla, at 56 (Hearing Exhibit 74).

planning process if and when compelling circumstances are present. In addition, there is little, if any, evidence in this proceeding that such opportunities are likely to occur between now and the next ERP filing in 2015. Therefore, we do not grant Public Service the blanket authorization it has requested to issue RFPs to acquire renewable resources in response to market conditions.

6. Level Playing Field: Utility Owned and IPP Generation

a. Background Summary

56. Staff recommends that the Commission require Public Service to provide firm prices for any self-build proposals and to reject the Company's plan to "force" the computer-based model to develop a portfolio comprised entirely of new utility-owned projects. Staff asserts that because the Company is both a "player" and a "referee" in Phase II, and because the Company can earn profit on rate-based assets, the Commission must take steps to address this conflict of interest.[29]

57. CCT also disagrees with aspects of Public Service's plan where utility-owned generation is compared to IPP projects. CCT suggests that utility-owned generation projects should not be allowed to compete with IPP projects except for when there is failure in the RFP process. CCT also recommends that rate recovery for utility-owned generation projects should be set for the first ten years using the cost and performance assumptions from the Company's bid or application; otherwise, according to CCT, the evaluation of bids for utility-owned generation projects and IPP resources should account for the differential in ratepayer risk.[30]

[29] Corrected Answer Testimony of Staff witness Sigalla, at 34 (Hearing Exhibit 74).
[30] *See* Corrected Answer Testimony of CCT witness Monsen, at 21-49 (Hearing Exhibit 57).

58. CCT also noted that, in the Phase I order of Public Service's 2007 ERP, Decision No. C08-0929, Docket No. 07A-447E, issued September 19, 2008, the Commission found that Public Service's proposal of securing between 40 and 60 percent of its peak load needs from utility-owned generation strikes a reasonable balance between utility and IPP ownership. CCT points out that this balance no longer exists, as Public Service currently owns 68 percent and the IPP share is 31 percent.

59. Both Staff and CCT recommend requiring Public Service to use a "point cost" for the capital costs of any utility self-build proposals, as was required in the 2007 ERP, Docket No. 07A-447E.[31]

60. By Decision No. C08-0929 in Docket No. 07A-447E, the Commission determined that:

> We find that a utility rate-based proposal without any form of a cost cap does not meet the competitive acquisition process intended by the ERP Rules. Cost overruns for this rate-based plant would be borne by ratepayers, so a comparison with fixed IPP bids is rendered meaningless. ... With a rate-based proposal the utility has a reduced incentive to make sure the estimate will cover its costs, and it has a weaker incentive to make sure the project stays within budget. The IPP has a large incentive in both cases. We agree with CIEA and CEC that we must take steps to place the utility proposal on equal footing with fixed price IPP bids.
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> * * *
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> Although Public Service typically provides facility cost proposals in the form of a cost plus or minus a certain percentage variance, we direct the Company to establish a point cost in its proposal. This may be a cost without any percentage variance. Alternatively, Public Service can include any such contingency as a part of its proposed cost, but the point cost used in bid comparison will include the full variance amount, and we will not consider a range. We expect this point cost cap level to be the maximum amount that is used in future cost recovery proceedings, absent a showing of extraordinary circumstances.[32]

[31] *See* Decision No. C08-0923 (Hearing Exhibit 104).
[32] Decision No. C08-0929, ¶¶ 187 and 189.

61. Staff and CCT argue that this point cost requirement places the utility and IPPs on equal footing. In addition to the requirements in Docket No. 07A-447E, Staff and CCT recommend applying the point cost requirement to operations and maintenance (O&M) costs as well.

62. In contrast, Public Service proposes to use an "expected cost" to evaluate its proposed resources, where this expected cost will be within +/- 20 percent of the actual cost of the project. Public Service asserts that it has a good track record of constructing facilities at the expected cost. The Company also argues that, contrary to Staff's and CCT's position, a "point cost" places utility projects at a disadvantage. Public Service also responds that its proposed all-source solicitation will be designed to allow both IPP and utility generation to compete, consistent with the ERP Rules.[33]

b. Commission Findings and Conclusions

63. We recognize the decreasing level of IPP ownership and understand the other concerns raised by the Company and parties regarding the fairness of bid evaluation in Phase II. We will take these factors into account when comparing utility-owned generation projects and IPP proposals in Phase II. We will not prohibit Public Service from submitting proposals in the competitive solicitation, and we will not limit cost recovery to ten years as CCT suggests. Further, we will not, at this time, develop quantitative measures of the incremental risk from self-build projects for bid evaluation. Comparison of IPP and utility proposals was addressed thoroughly in the 2007 ERP, and the issues raised in this proceeding do not warrant a new debate.

[33] *See* Rebuttal Testimony of Public Service witness Haeger, at 22-42 (Hearing Exhibit 5) (setting forth the details of Public Service's response).

64. Consistent with Decision No. C08-0929, we find that using a point cost for capital costs in utility self-build proposals is appropriate. These issues were addressed at length in the 2007 ERP and arguments raised here do not warrant reversal of that reasoning.

65. We find that this record does not contain enough data to include a point cost requirement for O&M costs at this time in addition to capital costs for utility self-build proposals. However, because of the significant impact of O&M costs on the overall costs associated with proposed facilities, the Commission anticipates further review of projected and actual O&M costs for self-build proposals in future dockets.

7. Portfolio of Utility Owned Resources

a. Background Summary

66. Public Service proposes to submit, in the competitive solicitation, utility self-build resource proposals to meet all of the resource need. Public Service explains that its projects, which will all be brownfield expansions to existing generation plants, will ensure that IPP bid prices are reasonable. The Company also proposes to present a portfolio with all of the resource need met by utility self-build resources in its 120-day report.

67. Staff asserts that it is unnecessary to devote a portfolio to utility self-build resources. According to Staff, resource modeling is expensive and using the limited modeling capabilities on a potentially non-economic portfolio could displace another more viable portfolio. Staff also takes the position that, given the amount of stranded assets available, it is not likely for the utility self-build proposals to be cost effective. Further, Staff raises concerns with the use of utility self-build proposals as a “default portfolio,” since the Commission cannot evaluate or approve these costs in Phase I. Instead, Staff recommends allowing the model to use its normal least-cost analysis to determine the appropriate portfolios in Phase II.

68. In response, Public Service states that the self-build portfolio concept stems from an agreement between the Company and OCC in response to OCC's concerns raised in the 2007 ERP. Public Service clarifies that the self-build portfolio will not represent either a contingency plan or a "default portfolio."[34]

b. Commission Findings and Conclusions

69. We find that Public Service's proposal to develop utility-build resources for the entire resource need is consistent with the ERP Rules and is therefore approved. However, we also take this approach into consideration with respect to the need to engage an Independent Evaluator (IE) for Phase II, as discussed further below.

8. Contingency Plan

a. Background Summary

70. Public Service states that the contingency plan hierarchy as proposed in ERP Volume 1, Table 1.8-1, is the same as the Company's 2007 ERP contingency plan.

71. Staff recommends removing self-build generation from the bid hierarchy for contingency resources. CCT further asserts that Public Service's contingency plan hierarchy could undermine the competitive procurement process and provide an avenue for utility self-build proposals to "leap frog" to the front of the queue. In addition, CCT suggests that if a contingency need arises, bidders should be afforded the opportunity to resubmit and refresh their bids.

b. Commission Findings and Conclusions

72. We find that Public Service must file for approval of its contingency plan if and

[34] Rebuttal Testimony of Public Service witness Hill, at 22 (Hearing Exhibit 14).

when it is needed after receipt of bids in Phase II. Paragraph 3604(e) of the ERP Rules requires the utility to address contingency plans as part of its Phase I resource plan filing for informational purposes. However, subparagraph 3609(c)(2) of the ERP Rules states that the Commission will consider the approval of contingency plans only after the utility receives bids.[35] Therefore Public Service must file for specific approval of a contingency plan, if necessary, after the receipt of bids in Phase II.

73. Further, we neither set forth instructions for bidders to resubmit or revise bids if contingency measures are necessary nor require Public Service to remove self-build generation from the contingency hierarchy. Parties will have the opportunity to address such contingency requirements if the need arises after receipt of bids in Phase II.

9. Standard PPA Contracts and Negotiation Time Limits

a. Background Summary

74. Staff recommends that the Commission approve standard contracts for PPAs as part of the Phase I decision, such that changes to the contract would not be allowed during the negotiations with the winning bidders. Staff also suggests that the Commission set a 90-day limit on contract negotiations. Staff asserts that these recommendations are necessary to provide a level playing field and improve the efficiency of the IPP bidding environment.

75. Public Service disagrees with Staff's recommendation for a non-negotiable standard contract, asserting that there are too many details about the terms and conditions of a PPA for a "one size fits all" approach. Further, Public Service asserts that forcing all bidders to

[35] Rule 3609(c) states: "Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. … The Commission will consider approval of contingency plans only after the utility receives bids, as described in subparagraph 3618(b)(II). …"

accept a single, non-negotiable PPA will discourage some IPPs from responding to the RFPs. Public Service also recommends denying Staff's proposed 90-day negotiation limit.

b. Commission Findings and Conclusions

76. Due to the complexities involved in the negotiation process, we agree with Public Service that a non-negotiable model PPA contract in these circumstances would be unnecessarily restrictive. We further find that a 90-day time limit for contract negotiations may not be appropriate and potentially could alter negotiating positions. We therefore deny Staff's recommendations.

10. Capital Lease Accounting and Portfolio Financing

a. Background Summary

77. In its initial filings in this proceeding, Public Service raised concerns about certain accounting issues that may arise with respect to the contracts the Company expects to sign with winning bidders. For instance, the Company explained that Variable Interest Entity accounting, lease accounting, and derivative accounting could ultimately have a negative impact on its credit ratings.[36] Public Service stated that it was specifically concerned that a revised lease accounting standard could require certain types of PPAs to be classified like "capital leases" rather than "operating leases." Public Service thus proposed that during PPA negotiations, the Company would assess the contract using any new lease standards in order to identify potential accounting implications.[37]

78. Both Staff and CCT recommended that the Commission authorize no adjustments to bid prices for potential capital lease accounting issues. CCT and Staff also recommended that

[36] Volume 2 of Public Service's Application, at 2-36 to 2-41 (Hearing Exhibit 1(B)).

[37] Supplemental Direct Testimony of Public Service witness Haworth, at 4 (Hearing Exhibit 33).

the Commission find that signed PPAs and PPAs under negotiation as a result of this ERP will not be affected by any new accounting standards. CCT and Staff further suggested that the Commission require the Company to make a filing after an established accounting standard is adopted that specifies how the Company intends to apply that standard going forward, so that the Commission could act on this information accordingly.

79. In its Statement of Position, CCT states that the Commission should affirm, and hold Public Service to, its commitment at the hearing that, regardless of when any new draft rule is ultimately proposed regarding capital lease accounting, the draft rule would not be used in comparing, evaluating, or selecting bids in Phase II. CCT also states that Public Service does not disagree with the position that the model PPAs used in Phase II should not include any terms that would subject the IPP to continued liability for FIN 46 or capital lease issues after the contract is executed.[38]

80. In addition, the model PPA filed with the ERP included the following definition for "portfolio financing":

> … a financing of the Facility in conjunction with other electric generating asset(s) owned by Seller or its Affiliates, where the Facility serves, in part, as collateral for the debt borrowed to finance such other generating asset(s), and such other generating asset(s) serve, in part, as collateral for the Facility, provided, however, that (i) the purchaser(s) of the output of such other generating asset(s) is not Company or an Affiliate of Company, (ii) the purchaser(s) of the output of such other generating asset(s) has unsecured bond ratings of Investment Grade or substantially equivalent financial wherewithal; and (iii) all other generating asset(s) are located in the United States and generate energy as their primary business.

[38] CCT's Statement of Position filed November 26, 2012, at 14-15.

81. CCT asserted in answer testimony that those terms in the model PPA will unnecessarily restrict the IPP's ability to finance their facilities. In response, Public Service agreed to remove the definition of portfolio financing from the model PPAs.

b. Commission Findings and Conclusions

82. We agree with CCT and Public Service that the removal of the definition of "portfolio financing" from the model PPA is appropriate.

83. We instruct Public Service not to adjust bids for potential changes in PPA accounting as part of its bid evaluation in Phase II. Further, Public Service is required to eliminate from its model PPA provisions that subject the IPP to continued liability for FIN 46 or capital lease issues after the contract is executed.

84. In order to address the treatment of PPAs in future dockets, we will require Public Service to make a filing in a new proceeding seeking approval of a specific approach for addressing the new standards going forward. This filing shall be made only after the conclusion of Phase II of this ERP and only when it is reasonably certain that the new accounting standards will be implemented.

D. Section 123 Resources

85. Section 40-2-123(1)(a), C.R.S., states:

> The commission shall give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

86. In accordance with that directive, we set forth below findings and clarifications regarding our consideration of the acquisition of "Section 123 resources" in this ERP.

New and clean energy technologies are novel and, therefore, are not likely to be least cost. Nevertheless, the acquisition of Section 123 resources can be shown to benefit Colorado, provided that their implementation can be achieved at a reasonable cost and ratepayer impact.

1. Definition of Section 123 Resources

a. Background Summary

87. In the 2007 ERP, by Decision No. C08-0929, Docket No. 07A-447E, the Commission determined that a Section 123 resource means:

> A new clean energy, or energy efficient technology, or a demonstration project [that] is clean and incorporates one or more technologies, representing a substantial portion of its overall installed cost, that have not been regularly commercially demonstrated, up to the point in time that the resource is formally bid, or if not bid, acquired.

88. The Commission also determined that qualifying technologies would include concentrating solar power with storage, wind with compressed air storage, and developmental demand-side management (DSM) programs that have not yet been proven as cost effective, on a case-by-case basis.

89. Public Service supports this same definition of a Section 123 resource for application in this ERP. The Company concludes that this definition is appropriately broad and provides reasonable guidance as to whether a demonstration project would qualify as a Section 123 resource. Public Service further recognizes that the definition the Commission applies to a Section 123 resource should emphasize that the costs of this resource are excluded from the determination of the 2 percent cap on the retail rate impact.[39]

90. With respect to implementing this definition, Public Service proposes that the Commission adopt a process in Phase II where: (1) bidders first explain in their bids whether

[39] Public Service Brief Concerning Section 123 Resources filed September 21, 2012.

their resources qualify for Section 123 treatment; and (2) the Company and IE would jointly determine whether those bids should be granted Section 123 status. If Public Service and the IE disagree, the issue would be brought to the Commission for resolution. This process is similar to what was used in the Company's 2009 all-source solicitation pursuant to its 2007 ERP.[40]

b. Commission Findings and Conclusions

91. By this Decision we affirm the definitions set forth in Commission rules, including paragraphs 3602(q) and 3659(m) related to the Commission's implementation of legislative directives set forth in Section 123. We further clarify these rules and provide instruction to Public Service for inclusion of Section 123 resources in its RFP.

92. For the purpose of bid evaluation at the start of Phase II of this ERP, we further clarify that, per the statutory language, a Section 123 resource must be both *new* and *clean*. A new project shall either: (1) incorporate one or more technologies, representing a substantial portion of its overall installed cost, that have not been regularly commercially demonstrated,[41] up to the point in time that the resource is formally bid, or if not bid, acquired; or (2) be a project used to demonstrate the feasibility of a technology not before implemented in its proposed configuration. A clean project must demonstrate that it would likely cause a decrease in greenhouse gas emissions (*e.g.*, carbon dioxide) or significantly reduce other pollutants. A clean project may also result in reduced water usage.

93. For the purpose of resource selection at the end of Phase II of this ERP, the Commission will determine whether the Section 123 resource is *cost effective* in that it can be acquired at a reasonable cost and rate impact, bearing in mind the project's beneficial

[40] Rebuttal Testimony of Haeger, at 45-46 (Hearing Exhibit 5).

[41] This review will consider regular commercial demonstration both within the State of Colorado and elsewhere.

contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

94. In setting forth these clarifications, the Commission is mindful of costs and rate impacts with respect to resource selection, including ratepayer impact based on the scale and scope of the proposed project, and our statutory obligation to give fullest possible consideration to the potential acquisition of Section 123 resources bidding into the competitive bidding solicitation. We recognize that these technologies are intended to benefit Colorado in the future, including by diversifying its energy resources.

2. Competitive Bidding and Set Asides for Section 123 Resources

a. Background Summary

95. Public Service states that, although the Company prefers short-term, low cost resources, Section 123 resources may be to bid into its proposed competitive solicitation.[42] The Company will then evaluate the qualifying bids and prepare an analysis of portfolios that include these resources in its 120-day report in Phase II.[43] Public Service argues that this approach will provide the Commission the information necessary to determine the costs and benefits of the Section 123 resources bid into the solicitation, including "a more consistent review of the economic viability and potential customer impacts of these resources relative to more traditional resources."[44] Public Service opposes the establishment of a set aside for

[42] Public Service clarifies that the resource must be 10 MW or greater. Public Service Brief Concerning Section 123 Resources filed September 21, 2012.
[43] Rebuttal Testimony of Public Service witness Haeger, at 47 (Hearing Exhibit 5).
[44] *Id.*, at 48.

Section 123 resources, explaining that it is ahead of compliance with the RES and that the Renewable Energy Standard Adjustment currently has a negative deferred balance.[45]

96. Contrary to Public Service's position, a number of parties have suggested that the Commission establish a set aside, which designates that a certain amount of the resource need would include Section 123 resources. For instance, WRA suggests that the Commission establish a "soft-target set-aside" of at least 100 MW for Section 123 resources to signal that the Commission wants to see these types of resources added to the Company's system. WRA argues that foregoing a set-aside will likely limit the number and quality of Section 123 bids, because Section 123 resource bids will not compare favorably against other bids on a least-cost basis. WRA concludes that Section 123 resource developers are unlikely to dedicate the time, cost, and effort to submit bids under the no-set-aside approach proposed by Public Service. [46]

97. SolarReserve also advocates for a Section 123 set-aside. According to SolarReserve, only a set-aside will allow the Commission to meet its obligations under § 40-2-123(1), C.R.S., because innovative clean energy technologies will not be able to compete against fossil fuel technologies based on cost.[47] SolarReserve further suggests that, in its experience, policymakers use set-asides to ensure beneficial contributions of resources, such as those identified in the statute, are considered properly.

[45] Public Service Brief Concerning Section 123 Resources filed September 21, 2012. Public Service clarifies that the Company does not propose to acquire a Section 123 resource unless it is also an "eligible energy resource," or, in other words, a resource that can be used to demonstrate compliance with the RES.

[46] Corrected Answer Testimony of WRA witness Farnsworth, at 18-19 (Hearing Exhibit 97).

[47] Solar Reserve's Brief in Response to Decision No. C12-1001-I filed September 21, 2012.

98. Like Public Service, OCC, C12, and SW Generation oppose a set-aside. SW Generation argues that a set aside risks displacing other generation that could provide greater benefits to consumers.[48] C12 concludes that it would be unreasonable to expect that the Commission could "guess at an appropriate set-aside" in Phase I in advance of receiving bids.[49]

b. Commission Findings and Conclusions

99. There is insufficient basis in this particular ERP for the establishment of a set aside of any amount, "hard" or "soft" and therefore, we decline to establish a set aside for Section 123 resources. We are committed, however, to the consideration of the acquisition of Section 123 resources in this ERP and encourage developers of potential Section 123 resources to propose cost-effective projects as part of the competitive RFP process. Furthermore, in support of our consideration of Section 123 resources in Phase II, we address in detail below how Section 123 resource bids shall be evaluated by Public Service and how the results of its evaluation shall be presented in the Company's 120-day report.

100. We further note the Commission will review, on an ongoing basis, the process of continuing to enable the fullest possible consideration of Section 123 resources in the context of competitive bidding, including potential consideration in future rulemakings.

3. Proposed Designation of Section 123 Status

a. Background Summary

101. Two parties have presented specific projects that seek to qualify for Commission consideration as Section 123 resources: SolarReserve and C12.

[48] SW Generation's Comments Regarding Section 123 Resources in Response to Commission Decision No. C12-1001-I, filed September 21, 2012.
[49] Initial Brief in Response to Commission Request for Comments on Section 123 Issues of C12 filed September 21, 2012.

102. SolarReserve describes a concentrating solar power (CSP) with thermal storage project. Public Service requests that the Commission determine in Phase I whether or not CSP with thermal storage is a Section 123 resource for purposes of evaluating any bids from this technology in the all-source solicitation.[50] Public Service states that it still considers CSP with thermal storage to qualify as a Section 123 resource.

103. C12 describes a 250 MW natural gas-fired generating facility with integrated carbon capture and storage technology to be constructed in Moffat County.[51] Public Service states that a project that includes carbon capture and sequestration technology "would appear to meet the definition of a Section 123 resource" for the purpose of evaluating any bids from this technology in the Company's proposed all-source solicitation. Public Service also raises concerns about the potential cost effectiveness of the project envisioned by C12.[52]

b. Commission Findings and Conclusions

104. Rather than determine the Section 123 classification of these two projects in this Phase I decision, we note that they may be bid into Public Service's all-source solicitation for our later consideration in Phase II, when we determine whether these and other resources can be implemented cost effectively.

E. Demand Side Resources and Combined Heat and Power

1. Demand Side Resources in Determination of Resource Need

105. Public Service explains that future customer demands are a function of both electric end uses at the customers' premises and any anticipated savings achieved through

[50] Rebuttal Testimony of Public Service witness Haeger, at 44 (Hearing Exhibit 5).
[51] Answer Testimony of C12 witness Dawe, at 2 (Hearing Exhibit 53).
[52] Rebuttal Testimony of Public Service witness Haeger, at 45 (Hearing Exhibit 5).

conservation or efficiency improvements. Some efficiency improvements relate directly to the Company's DSM programs.

106. Public Service states in the ERP that, when determining its resource needs, the Company included the energy savings goals established by the Commission in Docket No. 10A-554EG from 2011 through 2015. For each year 2016 through 2020, however, the Company used a constant annual level, namely 411 GWh, which is the same level of expected DSM efficiency savings in 2015. In its ERP, Public Service takes the position that 411 GWh is a reasonable estimate of the maximum achievable savings from electric DSM in Colorado.

107. Staff faults Public Service for using the 411 GWh figure in years 2016 through 2020 and not the higher energy savings goals established by the Commission in Docket No. 10A-554EG. Staff argues that by using the higher Commission-approved energy savings goals, the Company would experience larger demand savings (in MW) than reflected in its resource need calculations. Staff therefore suggests that Public Service be directed to apply the demand reductions associated with the energy savings goals approved by the Commission in Docket No. 10A-554EG in recalculating the resource need. Staff further suggests that the Commission direct Public Service to use the same method for adjusting its reserve margin as was adopted in Docket No. 07A-447E to address the possibility of any increased risk surrounding the Company's abilities to achieve the higher savings goals established for years 2016 through 2020.

108. We conclude that it is not appropriate to disregard or to modify the energy savings goals we established in Docket No. 10A-554EG for this ERP. The Commission adopted energy savings goals for Public Service in Docket No. 10A-554EG consistent with § 40-3.2-104, C.R.S.

The established goals span the seven-year RAP proposed by the Company.[53] The Commission also has agreed with Public Service on a number of occasions that it is preferable to address the acquisition of demand side resources in proceedings separate from an ERP for both practical and policy reasons. In this proceeding, however, Public Service has argued against using previously established energy savings goals, reiterating many of the same objections it raised regarding the Commission-approved goals from Docket No. 10A-554EG.

109. Public Service is therefore directed to adjust its resource need calculations for Phase II consistent with those previously established energy savings goals. We also note that Public Service is scheduled to make an application filing in 2013 that will be devoted entirely to the acquisition of demand side resources. That future proceeding will provide the proper opportunity for the Company to address whether it is necessary to modify its energy savings goals and to establish new demand reduction goals.

110. Regarding Staff's suggestion to require Public Service to apply related adjustments to its reserve margin consistent with the approach approved in the 2007 ERP by Decision No. C08-0929, we are not convinced that adjustments to the planning reserve margin are necessary in order to account for the alleged incremental risk associated with higher DSM levels. Public Service has both the time and the variety of means to address unexpected resource needs of the potential magnitude that could arise due to shortfalls relative to savings and demand reduction goals.

[53] Notably, 2018 is the year identified in the statute by which Public Service is required to meet minimum energy savings and demand reduction levels. *See*, § 40-3.2-104(2), C.R.S.

2. Market Potential

111. Public Service acknowledges that the Commission previously directed the Company to file an application proposing demand reduction goals for 2014 through 2020.[54] Although that filing has not yet been made, Public Service asserts in this proceeding that its traditional demand response programs—the Interruptible Service Option Credit for large customers and the Saver's Switch direct load control program for residential central air conditioning—have already achieved most of the demand reduction the Company thinks is possible at this time.[55]

112. Staff argues that, because there are several years before Public Service needs to acquire any additional capacity (*i.e.*, 2017), the Company has sufficient time to complete a market potential study for demand response resources and combined heat and power (CHP).[56] Staff also argues that there is sufficient time for the Commission to "work through any technical or policy issues related to an increase in these resources."[57] Staff further argues that the demand response study provided by the Company in response to discovery in this proceeding is inadequate for setting demand response goals.[58] Staff therefore suggests that the Commission direct Public Service to complete a "quantified study" assessing the potential of different

[54] Volume 1 of Public Service's ERP, at 1-48 (Hearing Exhibit 1(A)). By Decision No. C12-0442, issued in Docket No. 10A-554EG, on April 30, 2012, the Commission granted Public Service's request to file an application concerning the market potential for demand reductions from load management, demand response, and interruptible services no later than June 15, 2013, consistent with the timing of the Company's next energy efficiency application also due at that time. The Commission recognized, however, that parties in this Docket would receive, in response to discovery and no later than May 11, 2012, a demand response study the Company had recently commissioned. The Commission also recognized that demand reduction in the years after 2013 may be addressed in this Docket.

[55] Rebuttal Testimony of Public Service witness Sundin, at 14 (Hearing Exhibit 50).

[56] According to Staff, the U.S. Department of Energy defines CHP as: "an integrated set of technologies for the simultaneous, on-site production of electricity and heat."

[57] Answer Testimony of Staff witness Hay, at 25-26 (Hearing Exhibit 69).

[58] *See id.*, at 26. The study, titled Benchmarking of Demand Response Potentials – Final Report: Adaptation of FERC's NADR Model to Xcel Energy's Public Service Company of Colorado Territory, is attached to the Answer Testimony of Staff witness Keith Hay as Exhibit No. KMH-1.

demand response programs in the Company service territory.[59] Staff suggests that this new study examine demand response resources in a manner similar to the way the Company's earlier studies examined the market potential for energy efficiency resources.[60]

113. In response, Public Service states that it is not convinced that more time and money should be spent on further study of market potential.[61] The Company states that determining the market potential for demand response is more complex than determining market potential for energy efficiency. It also states that the demand response study provided in this docket served as a benchmark of its current program against national demand response programs and confirmed that the growth potential for demand response depends on price signals and enabling technologies such as automated meter infrastructure.[62] The Company therefore suggests that the Commission wait until the Company completes its assessment of its SmartGridCity Pricing Pilot and has sufficient time to compare those results to other pricing pilots being conducted across the nation.[63]

114. The Commission was unable to establish demand reduction goals for Public Service in Docket No. 10A-554EG due to the absence of information concerning the market potential for demand reductions from efforts other than energy efficiency. The Commission therefore instructed Public Service to address the market potential for demand reductions from load management, demand response initiatives, and interruptible services in order for the Commission to establish, in a future proceeding, appropriate demand reduction goals for Public Service through 2020.

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[59] *Id.*, at 29.
[60] *Id.*, at 4.
[61] Public Service estimates that a new demand response study could cost upwards of $156,000. Rebuttal Testimony of Public Service witness Sundin, at 13 (Hearing Exhibit 50).
[62] *Id.*, 9-11.
[63] *Id.*, 13.

115. Consistent with those instructions, we again direct Public Service to determine what information is necessary to support the development of demand reduction goals and to provide such information to the Commission in order to avoid deferring this issue to yet another future proceeding for lack of information. In addition, in order to inform its 2015 ERP, we expect Public Service to have properly examined the market potential for CHP resources in its service territory.

3. Competitive Bidding for Demand Side Resources

116. The Commission considered whether demand side resources, including energy efficiency and demand response, should be acquired through the competitive bidding process in Docket No. 10R-214E. In Decision No. C10-0958, issued August 31, 2010, the Commission concluded that there may be solutions to the potentially negative impacts of competitive bidding on the Company's ability to meet its energy savings and demand reduction goals and on its existing DSM programs. The Commission also stated that it expected to re-examine such issues in a future DSM or ERP proceeding.

117. Public Service opposes allowing demand side resources to bid into its all-source solicitation in this ERP. In response to calls for competitive bidding from OCC and other parties, the Company raises many of the same objections as it did in the aforementioned rulemaking proceeding. Staff specifically suggests that the Commission allow CHP and demand response to bid into the all-source solicitation proposed by Public Service.[64] More generally, RUC suggests that the costs of DSM programs are far less than the costs of additional power supplies. RUC therefore recommends that additional supply sources should be considered only as a last resort and then only to the extent that DSM and other strategies are not feasible.

[64] Staff's Statement of Position filed November 26, 2012, at 19.

118. With respect to this ERP, we do not approve a prohibition on bids for demand side resources as requested by Public Service. We instead encourage the Company to solicit bids through an RFP for demand side resources to be issued as part of the all-source solicitation. We are interested in whether bids for demand-side resources can now be supported by third-party providers and in testing whether their bids would cause the same practical and logistical problems that the Company experienced in past solicitations. We will reserve to Phase II the determination of whether the acquisition of additional demand-side resources is in the public interest based on the specific bids received and the Company's analysis of those bids in its 120-day report.

119. Consistent with these findings, we approve Public Service's proposal to consider bids, including bids associated with CHP, that provide no less than 10 MW of peak firm load obligation reduction. We also approve the Company's proposal to adjust its resource need calculation in Phase II with the removal of the 46 MW of demand response for the years following the term of the current contract with a third-party demand response supplier.

F. Independent Evaluator and Phase II Process

120. By Decision No. C12-0882-I, issued August 1, 2012, the Commission noted that no IE had been proposed to the Commission pursuant to the ERP Rules. The Commission therefore directed Staff, OCC, and Public Service to file a joint status report concerning selection of an IE with a proposed timeline to secure its services, when appropriate.

121. By Decision No. C12-0975-I, issued August 17, 2012, the Commission further directed Public Service, Staff, OCC, and other parties to file comments addressing whether an IE should be hired, the IE's scope of work, and payment for the IE's services.

122. In its comments, Staff suggests that an IE is needed in Phase II because no party is able to monitor the bid evaluation effectively, to investigate options not considered by Public Service in its computer-based portfolio modeling, and to review the reasonableness of the modeling results. Staff notes that, despite recent changes in rules and procedures that provide more information to the parties regarding the inputs to the computer modeling, such access would primarily assist in the identification of potential errors specific to individual bids.

123. Staff also suggests that the Commission retain Accion Group, Inc. (Accion) as the IE. By way of Accion's scope of work, Staff recommends that the IE: (1) fulfill the tasks set forth in the Commission's ERP Rules; (2) provide a web platform for the receipt of bids and for communications with bidders; and (3) monitor contract negotiations subsequent to Phase II.

124. OCC suggests that rather than hiring an IE for Phase II, the Commission should conduct a fully-litigated proceeding. While OCC agrees that Public Service's bid evaluations and modeling should be reviewed to assure fairness in the bidding process, OCC takes the position that parties now have sufficient access to relevant information such that an IE is no longer necessary to ensure fair and accurate bid evaluation. OCC also suggests that the Commission require Public Service to perform limited bid evaluation modeling on behalf of intervenors or the Commission.

125. OCC further states that any evidence relied upon by the Commission to make its Phase II decision must be subject to discovery and cross-examination. Accordingly, OCC recommends that, if an IE is engaged, the IE be used as an expert witness whose report would be construed as testimony and who would be subject to discovery and cross-examination. OCC also takes the position that the IE would be hired as an agent of the Commission and therefore the Commission should pay for the IE from its own budget.

126. In response to OCC's position, Staff replies that the IE's function benefits Public Service's ratepayers as well as the parties and the utility.[65] Further, Staff notes that payment of the IE by the Commission through the fixed utility fund would require that all fixed utility companies, and ultimately their customers, would fund the IE in this ERP proceeding. Staff further rejects OCC's argument that there would be an appearance of impropriety if Public Service were to pay for the IE. Public Service likewise opposes OCC's contention that the IE's independence will be undermined through the processes proposed in the ERP Rules.[66]

127. Public Service also argues in its comments that, because the Commission has taken steps to permit parties in this proceeding to view certain information related to bid evaluation modeling that was previously withheld from them, the need for an IE is diminished. Nonetheless, Public Service agrees that there is value in the IE as a "watchdog." Public Service further states that the IE should not offer new evidence, but rather, as contemplated by the ERP Rules, evaluate the fairness of the bid procedure and bid evaluation.[67]

128. Public Service opposes requests by parties to depart from the processes set forth in the ERP Rules for the IE in Phase II. Public Service reminds the Commission that the chief problem with a fully-litigated Phase II proceeding is that bidders cannot hold their fixed price bids through the time it takes to complete them. According to Public Service, the IE is therefore charged with checking the portfolio modeling of the bids to ensure a fair evaluation done in accordance with the Commission's Phase I decision. Public Service further states that the Company has neither the time nor the resources to work with the parties in Phase II to design multiple scenarios and perform modeling runs. Moreover, according to Public Service,

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[65] Staff's Reply Comments Regarding the Independent Evaluator filed September 7, 2012, at 6.
[66] Public Service's Reply Comments Concerning the Independent Evaluator filed September 7, 2012, at 12.
[67] *Id.*, at 6.

Phase II could result in the re-litigation of issues decided in Phase I if a hearing process is used. Public Service also contests the suggestion that the IE should monitor contract negotiations with bidders. Public Service states it would be a waste of money, because negotiations are conducted among sophisticated business people, and each side has sufficient bargaining power.

1. Scope of Work for Independent Evaluator

129. We agree with the parties that several anticipated proposals in Phase II warrant the engagement of an IE: Public Service plans to put forward “low-cost, brown-field expansions of existing Company-owned generating facilities” that would be sufficient to meet the entire resource need; Public Service intends to present in its 120-day report at least one portfolio that meets the need entirely with Company-owned facilities; Public Service proposes to “backfill” PPAs with Company self-build options; Public Service solicits offers in Phase II to buy IPP assets as an explicit option in its draft RFP; and, Public Service intends to rely heavily on computer-based portfolio modeling in its bid evaluation and for its preparation of the 120-day report.

130. We also agree with Public Service that the new bid transparency provisions of the ERP Rules will help the IPPs understand how their bids are being considered in the evaluation process. The updated ERP Rules significantly increase the availability of information and processes to the parties as compared to the 2007 ERP. However, we agree with Staff that the IPPs will be examining only how their own submissions fare in the bid evaluation and will obviously not have access to other IPPs’ bids or the Company’s own proposals.

131. We therefore find that an IE is appropriate in the Phase II proceeding of this ERP for the limited purposes of fulfilling certain roles contemplated under Rule 3613. Under this limited scope 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. Per Staff's recommendation, 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.[68]
- The IE shall also provide a log of contacts with the utility and other parties pursuant to paragraph 3612(d) of the ERP Rules.

132. In its Phase II report, 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; those duties rest solely with the Commission. In this limited role, the IE merely provides a resource to make more transparent the bid evaluation process in order for parties and the Commission to more fully analyze, comment, and review.

133. Ideally, the IE will be engaged before the release of the RFPs for the all-source solicitation. The IE must start its work before the receipt of bids to the all-source solicitation. During Phase II, 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.

[68] 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.

2. Process to Approve Independent Evaluator

134. As the selection of an IE is not yet complete, we will adopt further procedures to secure an acceptable candidate. We note that Staff and Public Service appear to be well informed about the credentials of Accion. While OCC opposes using an IE generally, it does not appear to oppose Accion.

135. Public Service shall make a filing no later than ten business days following the mailed date of this Phase I decision that indicates whether there is agreement that Accion is recommended as the IE for Phase II. If either Public Service or Staff objects to Accion, the filing should propose an alternative IE including its credentials.[69] If there is disagreement on who should serve as the IE, the filings should propose a process by which the Commission will select an IE for Phase II.

136. If the filing indicates that there is agreement on Accion as the IE, Public Service shall instruct Accion to prepare a contract for its services. Public Service shall consult with Staff regarding the final terms of the contract, and the contract shall then be filed in accordance with paragraph 3612(b) of the ERP Rules for approval by the Commission as soon as practicable, but in any event prior to Public Service commencing bid evaluation.

3. Phase II Process

137. Consistent with the Commissioner's careful consideration of the options concerning a fully litigated Phase II hearing in Decision No. C10-0958, and recognizing the new provisions that provide more access to information in Phase II, we anticipate for this ERP that parties will be more knowledgeable in their preparation of comments submitted under

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[69] While we are interested in and would prefer agreement generally between OCC, Public Service, and Staff as to the selection of the IE, if Accion is found acceptable, we only require consensus between Public Service and Staff prior to engaging Accion as the IE engaged in Phase II of this ERP.

paragraph 3613(e). The Commission therefore confirms that a fully litigated proceeding is not required[70] or appropriate.[71] However, parties filing comments on either the Company's 120-day report or the IE's report may suggest to the Commission that certain issues or topics be further examined before the Commission issues its Phase II decision. The Commission can then determine whether an additional process is needed in Phase II for good cause shown.

138. By Decision No. C10-0958, the Commission recognized that, when intervenors other than Staff and OCC are able to more fully participate in Phase II "since their attorney(s) and expert(s) will be able to review the highly confidential information pursuant to the approach [adopted in the rules]," their Phase II comments should be more meaningful, therefore reducing the need for a hearing. Further, the Commission agreed that all parties should have the opportunity to comment on the IE report in Phase II and modified timelines set forth in Rule 3613 accordingly.

139. We also agree with the parties that the IE is engaged to benefit the docket, including the parties, Public Service, and ultimately Public Service's ratepayers. Under the circumstances of this ERP and the scope of the IE's engagement as set forth in this Decision, we find that the IE is not acting generally as an advisor to the Commission. Therefore, we find paragraph 3612(f) concerning the IE's role as an advisor to the Commission inapplicable to this ERP and waive that paragraph of the ERP Rules.

[70] *Sigma Chi Fraternity v. Regents of the University of Colo.*, 258 F.Supp. 515, 528 (D. Colo. 1996).
[71] *See, e.g., Public Service Co. of Colo. v. Public Utils. Comm'n*, 653 P.2d 1117 (Colo. 1982).

4. Payment of Independent Evaluator Services

140. We find good cause to affirm paragraph 3612(b) of the ERP Rules, which sets forth that the utility shall pay for the IE's services pursuant to a contract approved by the Commission.

141. OCC argues that Rule 3612 places an IE into the role of an advisor to the Commission, therefore subject to payment from Commission funds. OCC cites § 40-2-104(1), C.R.S., as granting the Commission authority to employ individuals to perform Commission duties, and adds that § 40-2-107(3), C.R.S., prohibits the Commission from incurring expenses not paid by the controller from the funds appropriated for the Commission's use. OCC also argues that, if the IE serves as an advisor to assist the Commission in evaluating the Company's ERP, then requiring Public Service to pay for the IE creates an appearance of impropriety and a conflict of interest.

142. Contrary to OCC's interpretation, § 40-2-107, C.R.S., does not prohibit Public Service's payment for the IE in this case. Even if the test under this provision were as OCC asserts – that any individual performing duties of the Commission must be paid though the state controller – the factual predicate does not exist. The IE does not serve as an advisor to the Commission and will not recommend findings of fact or conclusions of law.[72] In contrast, the IE will work with the parties to, among other things, evaluate the bid process and assess the inputs and results of Public Service's modeling. The IE will be a resource for the parties to understand the intricacies of Public Service's modeling and bid evaluation, but the IE will not perform any

[72] In this proceeding we explicitly waive paragraph 3612(f) due to the limited scope of the IE's contributions; however, we note that even in the 2007 ERP, the IE's role was to benefit the docket, including the parties, Public Service, and ultimately Public Service's ratepayers. Even under those circumstances, payment of the IE's services by Public Service was proper. Here, the scope of engagement of the IE is even further limited such that the report itself is the only major contribution by the IE.

duties under the authority of the Commission. Thus, the IE's services do not constitute a Commission expense that otherwise should be paid through the fixed utilities fund.

143. Further, OCC's interpretation of § 40-2-107, C.R.S., is at odds with the application of similar statutes and rules that authorize the courts to order parties to the case to pay for the use of an independent consultant or master. Similar to § 40-2-107, C.R.S., as it relates to the Commission, § 13-3-104, C.R.S., requires that salaries and other expenses of all state courts shall be funded though annual appropriations from the state. This statute does not prohibit a court from implementing Rule of Civil Procedure 53 regarding the appointment of a master. A master may have far more expansive powers than the IE will exercise in Phase II, as a master may submit a report making findings of fact and conclusions of law. Colorado Rule of Civil Procedure (C.R.C.P.) 53(e)(1). However, despite these powers, and in the face of § 13-3-104, C.R.S., the parties to the case shall pay for the master's services, not the court out of state funds. C.R.C.P. 53(a). [73]

144. We also agree with Staff and Public Service that there is no appearance of impropriety if Public Service pays for the IE's services. The Phase II process is structured to ensure transparency, and consistent with that structure the IE's analysis and report will enhance further the openness of Phase II. Parties will have access to confidential data relating to Public Service's model and its bid evaluations. Parties also will have access to the IE report and may use it as a resource for advocating their respective positions.

[73] Furthermore, OCC's own analogy to a court appointed expert would likewise lead to the conclusion that Public Service's payment of services is appropriate. OCC also cites Colorado Rule of Evidence 706 with approval in support of its position that the role of an IE is similar to a court appointed expert and thus should be subject to discovery and cross-examination. However, under Rule 706(b), the parties, not the court, in civil actions shall pay for the expert as determined by the court.

5. Bidders and Bid Information

145. Although CCT supports the use of an IE in Phase II, it nevertheless raises concerns regarding transparency and accuracy in bid evaluation. For instance, CCT advocates that bidders should be given an opportunity to correct potential errors in assumptions proposed to be used by Public Service in bid evaluations prior to a final decision on whether the bid should pass the initial screening.[74]

146. Public Service responds that these proposed steps introduce unnecessary delay, arguing that the Company's screening procedures adequately meet the new disclosure requirements in the ERP Rules. Further, the Company explains that it set up its bidding process with automatic procedures to provide information to bidders regarding how their bid information will be used by the Company, such as the calculation of the Levelized Energy Cost (LEC) for the initial bid screening, in an effort to increase transparency in the bid evaluation process.[75]

147. We are satisfied that the implementation of the procedures set forth in the ERP Rules adopted in accordance with § 40-6-107, C.R.S., in combination with an IE, will be sufficient to ensure transparency in the bid evaluation process. We therefore direct Public Service to notify the owner or developer if a bid is not advanced to computer-based modeling and to explain the reasons that the bid was not advanced, including all of the information used in its initial assessment of the bid. This process as set forth in paragraph 3613(a), including the associated timelines, provides transparency and the appropriate

[74] Corrected Answer Testimony of CCT witness Monsen, at 57 (Hearing Exhibit 57).

[75] Rebuttal Testimony of Public Service witness Haeger, at 46 (Hearing Exhibit 5). Note also that Public Service's dispatchable and renewable 2011 Draft RFPs include a tab for specific application to the LEC.

opportunity for notification to the owner or developer of potential inadequacies of the bids being considered.

6. Bidder Nondisclosure Agreement

148. Paragraph 3613(b) of the ERP Rules requires that, for bids advanced to computer-based modeling:

> [T]he utility shall, contemporaneously with the notification in paragraph 3613(a), also provide to the owner or developer the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the utility. The utility shall provide such information so that modeling errors or omissions may be corrected before the competitive acquisition process is completed. Such information shall explain to the owner or developer how its facility will be represented in the computer-based modeling and what costs, in addition to the bid information, will be assumed with respect to the potential resource. …

149. In the event that this information contains confidential or highly confidential information, the owner or developer shall execute an appropriate nondisclosure agreement prior to receiving this information.

150. Public Service shall provide a nondisclosure agreement for the purposes of complying with the requirements set forth in paragraph 3613(b) no later than ten business days following the mailed date of this Phase I Decision.

G. Phase II Bid Evaluation and Modeling

1. Resource Portfolios and Sensitivities

151. In Volume 1 of its ERP and through the testimony of its witnesses, Public Service describes how it proposes to model potential resource portfolios in the development of its 120-day report in Phase II, based on the bids and utility proposals received to its all-source

solicitation.[76] At hearing, Public Service also offered Hearing Exhibit 144 that outlines the Company's proposed bid evaluation modeling runs, its proposal to present various resource portfolios, and suggested calculations intended to demonstrate the sensitivity of modeled results when changes are made to key inputs and assumptions (*i.e.*, sensitivities).

152. According to Hearing Exhibit 144, Public Service generally proposes one modeling run in which it will use Strategist®[77] to develop a large number of portfolios of the various resource combinations that will meet the resource need during the RAP. Strategist will calculate the Net Present Value Revenue Requirements (NPVRR) for each portfolio, and rank the portfolios in order of NPVRR, beginning with the least-cost resource mix. Based on Hearing Exhibit 144, Public Service proposes to establish four groups of portfolios in its 120-day report: (1) least cost resources; (2) renewable resources; (3) Section 123 resources; and (4) renewables and Section 123 resources.

153. To provide the Commission with a description of feasible portfolios for consideration in Phase II, Public Service proposes to provide in its 120-day report six different portfolios of resources, in the order of NPVRR, within each of the four groups listed above. Public Service proposes to then select the six portfolios such that they demonstrate "meaningful differences" in the mix of resources. For example, if two portfolios differ only by a slight variation in the implementation date for one resource, only the more economical of these two portfolios will be presented.

[76] *See* Volume 1 of Public Service's Application, at 50-55 (Hearing Exhibit 1(A)); Direct Testimony of Public Service witness Hill, at 13-16 (Hearing Exhibit 9).

[77] Strategist is a computer-based model designed to represent the characteristics of the Company's system for the simulation of the economic dispatch of generating resources in a least-cost manner.

154. Public Service then proposes to present the following sensitivities based on changes to the following model inputs or assumptions: (1) natural gas prices; (2) carbon prices;[78] (3) wind production tax credits; solar investment tax credit; (4) construction cost escalation rates; and, (5) alternative approaches to modeling PPAs after contract terms (as discussed below). Public Service proposes that the six portfolios in each of the four groups will be re-ranked by the new NPVRR, calculated based on that sensitivity re-pricing.

155. We generally approve Public Service's modeling proposal consistent with the modifications set forth in this Decision, such as the changes discussed below concerning the presentation of Section 123 resources, the treatment of Arapahoe 4 and Cherokee 4, and carbon costs.

156. In addition, Public Service proposes to use a modeling convention that "locks down" a common generic expansion plan for additional resources acquired after the RAP.[79] We find good cause to approve this approach, since it will help identify the cost differences between portfolios when alternative resources are acquired during RAP. This approach was also used for the 2007 ERP.

2. Modeling of Section 123 Resources

157. Public Service agrees that the Commission ultimately decides whether a resource is a Section 123 resource. Public Service states that, to the extent the Commission wants to

[78] As discussed below, Public Service is directed to present two distinct cases with respect to carbon costs: one case with a $0/ton cost and another with a $20/ton cost starting in 2017 escalated annually by inflation. The Company may also present additional carbon cost sensitivities at its discretion. However, for the purpose of the other required sensitivities (*e.g.*, natural gas costs), we direct Public Service to present the $0/ton case as the baseline for these analyses.

[79] *See* Volume 2 of Public Service's Application at 2-239 (Hearing Exhibit 1(B)).

determine which bids should be considered Section 123 resources for the purpose of bid evaluation and modeling in Phase II, the Commission will need to make that determination no later than 30 days after the bids are received.

158. Several parties suggest that the Commission develop assumptions, criteria, and models to evaluate Section 123 resource bids quantitatively in Phase II. WRA, for instance, insists that it is the Commission's fundamental responsibility to credit Section 123 bids with the public interest benefits required by statute. C12 suggests that the Commission direct Public Service to score Section 123 resources in a quantitative rather than qualitative manner. OCC also insists that the selection of a Section 123 resource is contingent on the demonstration of quantifiable benefits. According to OCC, the intervenors also should have the opportunity to examine the evidence, and provide testimony in response to Public Service in order to provide the Commission a record upon which it could base its decision to order Public Service either to acquire or to defer the acquisition of Section 123 resources.

159. In response to requests for a more quantitative analysis of Section 123 benefits, Public Service explains that certain benefits, such as emission reductions and lower sensitivities to high fossil fuel prices, can be measured and evaluated. However, the Company notes that certain other benefits, such as increased energy security or economic prosperity, must be evaluated on a qualitative basis outside of Strategist.

160. To fulfill the statutory directive to give Section 123 resources fullest possible consideration, and based on the circumstances of this ERP proceeding, we find that the following three-step process shall be implemented.

161. First, Public Service shall identify the bids that claim to be Section 123 resources in its 30-day report required under paragraph 3618(b) of the ERP Rules. Public Service shall

also identify its opposition, if any, to the Section 123 status of each disputed bid and provide to the Commission, under seal, a copy of the disputed bids. The Commission will then determine whether the bid qualifies for further evaluation as a Section 123 resource.

162. Second, we direct Public Service to present a group of resource portfolios in its 120-day report where each portfolio is differentiated from the least-cost resource mix by the inclusion of a single proposed Section 123 resource. The presentation of this information will assist the Commission in assessing the costs and rate impacts of each proposed Section 123 resource. We recognize that this approach represents a deviation from the presentation of Section 123 resources contemplated in paragraphs 3604(k) and 3613(d) of the ERP Rules and therefore waive those provisions to the extent they conflict with this Order.

163. Third, with respect to the assessment of the benefits of the bid Section 123 resource, we agree with Public Service that Strategist analysis will best accommodate a quantitative analysis of emission reductions and reduced sensitivities to high fossil fuel prices. However, we conclude that there is an insufficient record to prescribe a quantitative approach to all beneficial contributions from Section 123 resources. By way of example, for some factors set forth in § 40-2-123(1)(a), C.R.S., such as "energy security," a quantified approach may be impossible. Therefore, we direct Public Service to set forth in the 120-day report a summary of the information the bidders provide concerning the expected benefits from the implementation of their proposed resources.

164. In the event Public Service concludes that additional time is require to prepare the 120-day report to include full evaluation of each bid claiming Section 123 resource status, Public Service may seek additional time. As previously discussed, we reject OCC's request for a fully litigated Phase II process.

3. Modeling Potential Plant Retirements

165. As part of its all-source solicitation, Public Service proposes to review bids for the potential replacement power for the Cherokee 4 and Arapahoe 4 units. This proposal, according to the Company, is consistent with Commission requirements specified in Decision No. C10-1328, Docket No. 10M-245E, issued December 15, 2010, regarding Public Service's emission reduction plan filed pursuant to §§ 40-3.2-201 through 40-3.2-210, C.R.S., the Clean Air Clean Jobs Act (CACJA).[80]

166. Cherokee 4 and Arapahoe 4 are coal-fired base load units that were to be repowered to natural gas as "must-run" facilities pursuant to Public Service's CACJA emission reduction plan. Subsequent analysis has determined that the units will not be required to operate as "must-run" facilities for system stability purposes. Instead, based on recently completed transmission studies, the two units will operate as fully dispatchable peaking units.

167. Public Service proposes a separate Strategist modeling analysis as the first stage of its bid evaluation in Phase II, where the entire bid pool would "compete" against the operation of Arapahoe 4 and Cherokee 4 as gas-fired peaking units.[81] Public Service would prepare three separate cases: (1) Arapahoe 4 (*i.e.*, 109 MW) retired year end 2013; (2) Cherokee 4 (*i.e.*, 352 MW) retired year end 2017; and, (3) Arapahoe 4 and Cherokee 4 retired at year end 2013 and 2017, respectively. Portfolios would be developed to fill the resulting capacity shortfalls, and

[80] Paragraph no. 116 of Decision No. C10-1328 requires Public Service to "present alternatives to running Arapahoe 4 on natural gas in [this ERP filing] due October 31, 2011, so long as these potential alternatives meet or exceed the emission reductions achieved by the fuel conversion we adopt here." Paragraph no. 135 of the same decision addresses Cherokee 4 stating that, "[a]s with Arapahoe 4, circumstances may change such that it becomes less expensive and more effective from an emission reduction perspective to no longer burn natural gas at Cherokee 4. … We therefore require Public Service to present alternatives to running Cherokee 4 on natural gas in its ERP filing due October 31, 2011, so long as these potential alternatives meet or exceed the emission reductions achieved by the fuel conversion we adopt here. Along those lines, we encourage Public Service to continue to explore the early retirement of Cherokee 4 such that the unit no longer operates after 2022."

[81] Second Corrected Supplemental Rebuttal Testimony of Public Service witness Hill, at 19-20 (Hearing Exhibit 15).

Strategist would be configured to consider replacements that provide capacity within +/-20 MW of these MW ratings. Public Service would also verify that the replacement generation meets or exceeds the emissions reductions achieved through the operation of Arapahoe 4 and Cherokee 4 on natural gas.

168. Public Service further proposes that if either Arapahoe 4 or Cherokee 4 is displaced by a cheaper replacement resource in this first stage analysis, the unit will not necessarily be retired but will instead "compete" in the second stage of the bid evaluation, *i.e.,* the traditional all-source Strategist analysis described above. Although Public Service intends to use Arapahoe 4 and Cherokee 4 as competitors, the Company takes that position that the ERP Rules do not require the utility to "bid" an existing resource.

169. Staff and CCT recommend requiring Arapahoe 4 and Cherokee 4 alternatives to be evaluated as a part of the all-source bid evaluation process and not evaluated pursuant to a separate, first stage analysis where Public Service would give preference to short-term PPA bids.[82] Staff proposes instead that Cherokee 4 and Arapahoe 4 replacement should be analyzed by allowing Strategist to select the most economic resource options.

170. We did not state in Decision No. C10-1328 how alternatives to Arapahoe 4 and Cherokee 4 would be evaluated in an ERP context. We clarify here that Public Service shall provide in its 120-day report in Phase II of this ERP a modeling evaluation of the potential substitution of these resources with resources bid into the RFP.

171. First, we agree with Public Service that a utility is not required to "bid" existing resources into a competitive solicitation process.[83] However, this ERP presents a unique

[82] Corrected Supplemental Answer Testimony of CCT witness Monsen, at 25 (Hearing Exhibit 58).

[83] For instance, we do not require Arapahoe 4 and Cherokee 4 to be represented according to the "point cost" criteria that apply to proposals for additional utility-owned resources.

opportunity to evaluate whether potential, cost-effective alternatives to using Arapahoe 4 and Cherokee 4 as "peakers" are currently available.

172. Second, we find the +/- 20 MW capacity requirement proposed by Public Service to be unnecessarily restrictive, as it may prevent valid replacements for Arapahoe 4 and Cherokee 4 from being considered. Therefore, we deny Public Service's two-stage evaluation proposal.

173. Third, Arapahoe 4 and Cherokee 4 shall be modeled as a part of the all-source Strategist bid evaluation in a way that allows for it to include these units (individually and together) in conjunction with, or in place of, other bid resources in order to meet the forecast needs in the most economic manner.

174. Finally, we clarify that this modeling requirement for Arapahoe 4 and Cherokee 4 applies only to the specific case currently before the Commission of analyzing alternatives as ordered in Decision No. C10-1328 and does not create a precedent with respect to modeling requirements for other existing utility resources in future ERPs. Further, we adopt Public Service's position that the Company is not required to "offer up" early retirement of Arapahoe 4 or Cherokee 4 as part of this ERP.[84] We agree with the Company that it may be difficult to find competitive replacement for this generation, and, as a consequence, Phase II of this ERP may demonstrate that it is in the public interest to operate the two facilities as natural gas-fired peaking units until they reach the end of their useful lives, consistent with the Company's CACJA emission reduction plan.

[84] Volume 1 of Public Service's Application, at 1-47.

4. Carbon Costs

175. Section 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.

176. In the 2007 ERP, the Commission approved the application of a price on future carbon emissions for bid evaluation consistent with this statutory allowance.

177. Because Strategist simulates the economic dispatch of Public Service's generating resources in a least-cost manner, the imposition of a carbon price changes the calculation of the NPVRR of each portfolio. In general, the portfolios that have more fossil-fueled generation have higher NPVRR values due to carbon pricing.

178. Public Service argues that, because carbon dioxide regulation remains in flux, the use of a "zero carbon price" in this ERP is appropriate for its base case modeling.[85] However, the Company also proposes to run sensitivities using carbon costs based on information from different consulting firms.

179. WRA contends that it is highly likely that future carbon regulation will attach a price to carbon emissions during the 40-year planning period proposed by Public Service. WRA specifically recommends that the Commission order Public Service to use in its modeled

[85] Direct Testimony of Public Service witness Ihle, at 10 (Hearing Exhibit 23). Gas Producers support this approach. *See* Gas Producer Statement of Position filed November 26, 2012, at 2.

baseline case a proxy cost of carbon emissions starting at $20 per ton in 2017, escalating at 7 percent annually.[86]

180. Boulder, Interwest, C12, and RUC also argue that a $0 per ton cost of carbon for the indefinite future is not a realistic scenario.[87] In contrast, IREA suggests that the Commission should not impute carbon costs or other "externality taxes" when evaluating additional utility resources. IREA argues that there is not adequate evidence in this proceeding to justify the imputation of such costs. IREA further suggests that, given the few resources needed during the resource acquisition period, a carbon proxy cost will have no effect.[88]

181. In its rebuttal case, Public Service takes the position that, at some point in the future, there may be regulatory efforts to reduce carbon emissions; however, some of these efforts may not involve placing a direct price on carbon emissions.[89] Public Service also argues that using a $0/ton carbon proxy price is consistent with the Environmental Protection Agency's (EPA) current greenhouse gas regulatory program that discourages new coal plants independent of any contemplated price for carbon.[90] Public Service also argues that bid analyses based on a $0/ton cost for carbon emissions are essential because they will provide the benchmark against which the tradeoff between the costs and benefits of lower emitting resources can be measured

[86] Corrected Answer Testimony of WRA witness Farnsworth, at 23 (Hearing Exhibit 97). In addition, WRA recommends that the Commission direct the Company to test three carbon price sensitivities: the "3-Source Blend" combining the forecasts of the three consulting firms; a $20/ton in 2017 forecast—WRA's suggested baseline value; and a "True Cost" forecast starting at $40/ton in 2017 with a 7 percent annual escalation rate, which is the same "high sensitivity case" used in the Company's CACJA emissions reduction plan considered in Docket No. 10M-245E. *Id.*, at 28-29.

[87] According to C12, all of the factors which led to the initial regulatory limits imposed by the Environmental Protection Agency are strengthening and future additional regulations are likely. Answer Testimony of C12 witness Dawe, at 32 (Hearing Exhibit 53). RUC suggests that the Commission direct Public Service to apply an "external cost adder" in the range from $20 to $40 per ton of carbon emissions escalating at a rate of 2 percent to 4 percent per year to cover all externalities more generally. Answer Testimony of RUC witness Neumann-Lee, at 13 (Hearing Exhibit 90).

[88] Cross-Answer Testimony of IREA witness Jones, at 6-7 (Hearing Exhibit 100).

[89] Rebuttal Testimony of Public Service witness Ihle, at 3-5 (Hearing Exhibit 24).

[90] *Id.*, at 12.

and because they will demonstrate the magnitude of carbon price assumptions on overall estimated portfolio costs.[91] The Company also argues, however, that a carbon price as high as $40 per ton as soon as 2017 is not plausible, given natural gas prices, technology changes, economic factors, and other prevailing influences.[92]

182. We agree with Public Service that the EPA is continuing to regulate carbon emissions from new power plants through its New Source Review program and may further regulates existing power plants through its New Source Performance Standard program. EPA has not proposed any carbon pricing mechanism. Further, 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.

183. Nonetheless, we agree with WRA and other parties that it is useful to examine a scenario where a price is attached to carbon emissions, since fossil-fueled generation plants have long useful lives and may continue to operate in the future after the adoption of some level of carbon pricing. When prices attach to carbon emission, clean technologies such as renewable resources and Section 123 resources provide benefits to ratepayers when they displace fossil-fueled generation and reduce emissions.

184. In contrast to its last ERP, Public Service is not expecting to acquire wind or solar resources as part of its proposed all-source solicitation. Although these technologies are not precluded from responding to the RFPs, Public Service does not need to acquire these resources for compliance with the RES. The Company is also not anticipating the receipt of bids for

[91] Rebuttal Testimony of Public Service witness Hill, at 53-54 (Hearing Exhibit 14).
[92] Rebuttal Testimony of Public Service witness Ihle, at 15 (Hearing Exhibit 24).

additional coal-fired generation. Therefore, the need for carbon prices to distinguish benefits across portfolios in Phase II is diminished in this ERP.

185. With respect to Section 123 resources, carbon pricing may have an impact on their cost-effective implementation in the future. However, when we consider near term costs and rate impacts from the implementation of such resources, we must also recognize that there is presently no price attached to carbon emissions that ratepayers would actually be required to pay.

186. We conclude that the best approach for considering carbon costs is to require Public Service to present in its 120-day report two distinct cases for the bid evaluation modeling results. One case would conform to Public Service's proposed base case with a $0/ton cost for carbon.

187. The second case would attach a positive cost to carbon emissions to assist us in assessing the carbon reduction benefits and long-term cost-effectiveness of potentially acquiring certain Section 123 resources. We agree that $20/ton beginning in 2017 is a reasonable starting value. However, we do not agree that a 7 percent escalation rate is appropriate in this instance. We instead direct the carbon prices in this second case to escalate annually at the general rate of inflation.

188. Although we do not require it, Public Service may run additional carbon price sensitivities for presentation in its 120-day report. We also encourage Public Service to present a sensitivity case that demonstrates a significant difference in carbon emissions based on the economic dispatch of resources as influenced by carbon pricing.

189. Finally, we direct Public Service to present information in the 120-day report on the carbon emission profiles of each resource portfolio in terms of tons of carbon emitted.

We anticipate that this data will further inform our consideration of the potential acquisition of clean technologies even in the absence of discrete carbon pricing.

5. Gas Costs

190. As discussed in detail in ERP, Volume 2 pages 2-263, Public Service proposes to use a “four source blend” of the New York Mercantile Exchange futures prices and long-term forecasts from Wood Mackenzie, Cambridge Energy Research Associates, and Petroleum Industry Research Associates, in a manner similar to the method that was used in the 2007 ERP. This forecast is a primary component of the modeling of the various resource proposals over the 40-year NPVRR evaluation. The Company also proposes gas price sensitivities based on the standard deviation of historical data. Finally, the Company will update its forecasts and sensitivities, using the methodology approved by the Commission in the Phase I decision.

191. Gas Producers recommend two alternative methods for sensitivities. The first method is intended to be market based and requires Public Service to set a seasonable short-term price ceiling and request a price quote for a “costless collar” that would set the floor price. The ceiling and floor prices would be escalated through the end of the forecast period. The second method involves the solicitation of high and low price forecasts from the third-party forecasters.

192. Public Service states that Gas Producers’ proposed alternative approaches for setting sensitivity ranges would be difficult to implement in practice. An objective price for a “reasonable” ceiling would be difficult to determine with the varying interests of stakeholders in the ERP process, and any selection by the Company would be very contentious. Public Service recommends using its proposed sensitivities based on historical standard deviation.

193. We find Public Service's proposed methodology, including the "four-source blend" and proposed standard deviation-based gas price sensitivities appropriate. Further, we agree with Public Service that Gas Producers' methodology is not practical. We therefore approve Public Service's proposed methodology.

6. Modeling PPAs After Contract Terms

194. In this ERP, a PPA contract can extend up to 25 years but may be much shorter, such as the 10-year PPA with SW Generation that is part of the Arapahoe transaction discussed above. All PPA terms are shorter than the useful life of any additional utility-owned resource that may be expected to operate for 40 to 60 years. When PPAs' bids are compared to utility self-build options in Phase II, it is necessary to approximate an extension or replacement for the PPAs after contract expiration to address the problem of unequal lives in order to calculate the NPVRR for each portfolio.

195. Public Service proposes to use its utility self-build estimates to "backfill" the remaining years of modeling where PPA bids expire before the end of the 40-year resource planning period. However, Staff and CCT object to Public Service's proposal to use self-build estimates to backfill the remaining years of IPP bids, and they discuss other options in testimony.

196. In hearings, a different approach was discussed where Public Service would provide "bookends" for the representation of expired PPA bids or, in other words, an upper and lower range of backfilling assumptions. To represent the lower cost boundary, Staff and CCT recommend implementing the annuity method used in Docket No 07A-447E, which estimates the continuation of the actual bid price to backfill the remaining years of IPP bids. Staff and CCT also recommend requiring a full Strategist modeling run to derive the upper and lower

boundaries, rather than simply recalculating portfolio costs by replacing the Company's backfilling costs with annuity backfilling costs through a sensitivity analysis.

197. We agree with Staff and CCT that the Company's proposal to use utility self-build estimates could result in IPP project costs being unfairly inflated in comparison to utility proposals under certain circumstances. Consistent with our discussion on this issue in Decision No. C08-1153 in the 2007 ERP,[93] we find that IPPs could re-bid existing capacity at new costs, or if the market is oversupplied the bid prices might be significantly discounted from the cost of new capacity. Therefore, we require Public Service to present in its 120-day report the "bookends" with a range of costs to represent the boundaries of potential future prices for the replacement of expiring bids. We approve Public Service's proposed utility self-build approach as one boundary and set the annuity method used in the 2007 ERP for the other boundary.

198. We agree with Public Service that using the portfolios generated by the model run based on one backfilling approach but re-priced according to the alternative approach would be far less labor intensive than requiring new model runs. We also anticipate that this sensitivity re-pricing will provide useful NPVRR calculations at a reasonable level of accuracy.[94] Since Public Service must implement the Strategist modeling, we defer to the Company's judgment as to the most efficient method. Therefore, Public Service may run the Strategist model using the utility self-build backfilling method as it has proposed and then re-price the model-generated portfolios based on the annuity backfilling method.

[93] *See* Decision No. C08-1153, Docket No. 07A-447E issued November 7, 2008, ¶¶ 105-108.

[94] According to Public Service, Strategist develops approximately 2,500 different portfolios in each model run. Sensitivity re-pricing portfolios based on different input assumptions is therefore expected to entail the same "universe of portfolios" as would be generated by a new model run. *See* Hill statements in Transcript Volume 2, pages 95 through 98. Nevertheless, we instruct Public Service to confirm that the re-pricing of the base case portfolios presented in the 120-day report using on the annuity approach includes the most cost-effective IPP proposals from that "universe of portfolios."

7. Beneficial Contributions of Proposed Resources

199. Public Service proposes to require all bidders, and not just bidders of Section 123 resources, to provide information concerning "the beneficial contributions" of their proposed technologies, including benefits associated with energy security, economic prosperity, environmental protection, and insulation from fuel price increases. The Company argues that this information will allow the Company to present the expected benefits from acquiring the least-cost bids to the competitive solicitation in its 120-day report.

200. We find that the information on the beneficial contributions from the implementation of the least-cost resources will help the Commission consider whether certain benefits are common across proposals and whether certain benefits tie specifically to the implementation of a particular new and clean energy technology. We therefore disagree with parties who argue that fullest possible consideration of Section 123 resources precludes the Commission from considering the benefits of non-Section 123 resources and grant Public Service's proposal that all bidders be required to provide information concerning the beneficial contributions of their technologies in their bids.

8. Sales Forecast, Demand Forecast, and Reserve Margin

201. In its ERP, Public Service submitted forecasts for energy sales, numbers of customers, and peak system demands. The forecasts were generated by a series of dynamic and time series regression models and are similar to the forecasts used by the Company in previous ERPs. The forecasts filed in October 2011 were later updated and filed in the docket on July 5, 2012.

202. Staff recommends that the Commission consider the Company's forecasts only to be rough estimates not to be taken as firm or reliable measures of future load requirements.

Public Service responds that the Company's forecasting methodology and underlying regression models are statistically valid and produce reasonable results. Public Service further recommends that the Commission allow the Company to update its energy sales and demand forecasts prior to the Phase II bid evaluation in order to incorporate the most current information available at that time.

203. As in past ERPs, we approve the forecasting methodology employed by Public Service. We also find good cause to direct the Company to update its forecast based on current information for the calculation of the resource need for Phase II. Parties will have the opportunity to comment on risks and potential biases of the revised forecast in Phase II comments.

204. In addition, we approve the proposed reserve margin of 16.3 percent. This value was used in the 2007 ERP and appears to be uncontested for application in this ERP.

H. Additional Modeling Assumptions

1. Gas Price Volatility Mitigation Adder

205. Consistent with past resource evaluation practices, Public Service proposes a Gas Price Volatility Mitigation (GPVM) adder to forecast gas prices in order to represent the additional costs of the Company's efforts to manage potential variability in future natural gas prices. Public Service states that the GPVM adder is necessary to reflect fuel price risks when comparing gas-fueled resources to other types such as wind and solar. Further, the Company incurs real costs to mitigate gas price volatility through its risk management program. The Company also clarifies that the GPVM adder is not applied to gas contracts with fixed pricing.

206. Gas Producers contest the use of a GPVM adder, asserting that gas prices are now lower and more stable than they were in the past.

207. Because Public Service has a long-standing GPVM program, which incurs actual costs to mitigate volatility, it is appropriate for the Phase II modeling to represent such costs. We therefore approve Public Service's GPVM adder for use of this ERP.

2. Coal Costs

208. Public Service's proposed coal price forecasting methodology is described in ERP Volume 2, page 2-265, based on existing coal contracts and professional forecasts.

209. Ms. Glustrom and her witnesses contest Public Service's proposals regarding coal costs, generally arguing that coal supply limitations will result in costs that are higher than forecasted. Ms. Glustrom recommends implementing additional coal price sensitivities.

210. In rebuttal, Public Service opposes these claims and recommends using its proposed methodology.

211. Based on the evidence in this docket, we approve the use of Public Service's coal forecasting methodology and deny Ms. Glustrom's request for coal price sensitivities. While these sensitivities may be appropriate in different circumstances, they are not warranted at this time, particularly because the acquisition of additional coal-fired generation is not likely to be proposed in the all-source solicitation.

3. Surplus Capacity Credit

212. In its initial ERP filing, Public Service proposed to apply a credit to portfolios with firm generation capacity in excess of the planning reserve margin requirements, starting at \$2.79/kW-month in 2011 and escalating at the rate of inflation. According to the Company, the \$2.79/kW-month is based on bids for seasonal capacity for 2011. The credit would be applied

through 2018, the end of the RAP, but only during the four summer months June through September. After 2018, Public Service proposes to apply a different credit. The credit would apply in all months and its value would be based on the avoided capacity of a generic combustion turbine. The Company plans to update the value of the surplus capacity credit to be applied after 2018 in Phase II.

213. Staff opposes the application of a surplus capacity credit as proposed by the Company, arguing that no credit should apply to resources or portfolios, since no additional capacity is required until 2017.

214. At hearing, Staff and Public Service attempted to reach agreement on a surplus capacity credit but ultimately proposed separate new alternatives. CCT asserts that the Commission should adopt Public Service's original surplus capacity proposal but also suggests a third new proposal in its Statement of Position. SW Generation recommends using Public Service's original proposal.

215. We agree with CCT and SW Generation that the credit levels as originally proposed by Public Service should be applied for bid evaluation in this ERP. We find it reasonable to account for some value for the anticipated surplus capacity and thus disagree with Staff. We are also concerned with the alternate proposals made at hearing, as these late submissions did not allow for a full examination by the parties of the subsequent recommendations.

4. Gas Transportation Adder

216. Public Service explains that virtually all gas-fired PPA bids entail tolling agreements, where the Company is responsible for supplying natural gas to the IPP's generation facility. In addition, the Company states that it generally cannot rely on interruptible gas pipeline

transportation for such tolling arrangements and, in certain locations, it also cannot obtain a discounted firm gas transportation arrangement. Therefore, for proposed PPAs with facilities located outside of the Company "Core Area," Public Service recommends that it should assign to the bid the costs for firm transportation services charged at the pipeline's full firm rates.[95]

217. We find that Public Service's proposal is reasonable and approve its plan to apply these gas transportation adders in Phase II bid evaluation. We agree that it may not be feasible for the Company to secure discounts outside of its "Core Area" and that firm transportation may be the appropriate level of service required to operate the IPP plant.[96]

5. Discount Rate

218. Public Service explains that the purpose of a discount rate in the ERP context is to allow for different resource options to be compared despite the existence of different cost profiles over their relatively long useful lives. In other words, a discount rate allows the Commission to determine if one resource is more or less expensive than another resource on a net present value basis.[97]

219. Public Service explains that, for this ERP, it will use the same discount rate it used in Docket Nos. 10A-327E (concerning the acquisition of the Rocky Mountain Energy and the Blue Spruce Energy Center) and 10M-245E (concerning the Company's emission reduction plan pursuant to the CACJA).[98] Specifically, the Company states that it will use its after tax weighted

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[95] *See* Rebuttal Testimony of Public Service witness Dallinger, at 6-8 (Hearing Exhibit 26).

[96] We understand that Public Service no longer intends to assign costs to portfolios in Phase II in conjunction with its Winter Generation Adequacy Study as initially proposed. Staff raised concerns about that study, arguing, for example, that it failed to assess certain alternatives for addressing potential shortfalls in winter generation capacity.

[97] Net present value calculations adjust costs associated to account for the "time value of money," where rate reflects the level of discounting over time by which one is indifferent between paying "a dollar in an earlier period or a dollar escalated by the discount rate in a later period." Rebuttal Testimony of Public Service witness Sheesley, at 5 (Hearing Exhibit 49).

[98] Volume 2 of Public Service's Application, at 2-263 (Hearing Exhibit 1(B)).

average cost of capital (WACC) for determining the NPVRR values for the various resource portfolios.[99]

220. In response to Interwest and RUC arguments that other discount rates may be more appropriate,[100] Public Service argues that the after tax WACC should be used because it is "the only discount rate that makes the Company indifferent between making expenditures today and making different expenditures at any given time in the future."[101]

221. We agree with Public Service that the after tax WACC is the appropriate discount rate for calculating the NPVRR values in the Phase II bid evaluation.

6. Renewable Resource Integration Costs

222. Public Service explains that the variability of renewable generation can result in costs to its system that are not captured or reflected in traditional resource planning models such as Strategist. To ensure all generation resources are compared on an equivalent basis, the Company develops estimates of the additional costs incurred to integrating intermittent resources for evaluating new power supply options.[102]

223. For this ERP, the Company performed a 2 MW and a 3 GW wind integration cost study. Public Service proposes to apply the results of that recent study when evaluating bids for additional wind resources. However, the costs would be recalibrated for Phase II based on the

[99] The WACC at present is 7.609 percent. The Company suggests that this value may be updated for Phase II bid evaluation based on changes to the Company's capital structure.

[100] *See* Answer Testimony of Interwest witness Cox, at 23 (Hearing Exhibit 81); Answer Testimony of RUC witness Bardwell, at 7 (Hearing Exhibit 88).

[101] Rebuttal Testimony of Public Service witness Sheesley, at 6 (Hearing Exhibit 49).

[102] *See* Answer Testimony of Public Service witness Xavier (Hearing Exhibit 75).

updated natural gas price forecast and the expected amount of wind and energy storage on the system. For additional solar resources, the Company proposes to apply costs developed in a 2009 solar integration study, updated to the latest gas price forecast.

224. We agree with Public Service that integration costs should be included in the evaluation of intermittent resources bid into the competitive solicitation. We also agree that these integration costs should be revised prior to Phase II bid evaluation based on the updated forecast of gas costs and other inputs (such as the amount of wind and energy storage on the system). Therefore, we approve the Company's methodologies for calculating integration costs based on the studies filed with the ERP and approve the updating of the integration costs, as proposed, for application in Phase II.

7. Coal Cycling Costs

225. In its study "Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment," Public Service examines the protocols for system operations during periods of high wind generation relative to customer load when base load coal units must ramp up and down. The analysis was completed, in part, to estimate the additional costs to the system, including increased wear and tear to the coal units, increased O&M costs, and the costs associated with curtailing wind generation procured under must take contracts.

226. Interwest asserts that there are fundamental modeling errors in the Company's study that invalidate the results. In rebuttal, Public Service defends the study but also offers to review and to update the inputs and assumptions to the cost calculations in response to certain criticisms. Public Service also proposes to apply the coal cycling costs to any new generation resource that is expected to impact the cycling of Public Service's existing coal fleet, whether the new resource is a new base load supply, a new renewable resource such as wind, or any other

must-take resource. In addition, the Company proposes to apply a coal cycling credit to any new electricity storage resources.

227. As a general matter, we expect coal cycling to evolve into a normal cost of doing business as reflected in the economic dispatch of system resources. Greater system flexibility will serve to reduce such costs, as will the recalibration of optimal base load generation levels when significant amounts of intermittent resources are added. Accordingly, we find that new protocols for system operations represent a worthwhile topic for further study for future ERPs. Changes in system operations could ultimately eliminate the need to apply coal cycling costs in bid evaluation.

228. For this ERP, however, coal cycling will be an issue because existing base load generation will represent a significant part of the Company's generation fleet during much of the resource planning period. We therefore agree with Interwest and Public Service that it is appropriate to apply coal cycling costs to any additional resource bid into the competitive solicitation that will cause coal cycling. We also agree with Public Service that it is necessary to complete a review of the inputs and assumptions to the coal cycling study in order to derive the appropriate costs to be applied in Phase II bid evaluation. However, we do not find that a tariff is the appropriate way to apply coal cycling costs in an ERP context; therefore, we do not direct the Company to make a tariff filing as suggested by Interwest.

8. Flexible Generation

229. SW Generation and WRA raise concerns that additional generation flexibility is needed in Public Service's system, yet the Company's ERP does not adequately value flexible attributes of various resources.[103]

[103] Corrected Answer Testimony of WRA witness Farnsworth, at 15 (Hearing Exhibit 97).

230. In response, Public Service states that the bid screening process and Strategist modeling include variables to capture the value of generation flexibility. Public Service recommends not adopting an adjustment in bid prices or other methods that artificially favors flexible resources.[104]

231. In hearing, however, Public Service proposed that any bid generation unit that has 30-minute response capability could receive a credit of $0.20 per kW month. To the extent the unit also has quick start better than 30 minutes; it could receive an additional $0.02 per kW month.[105]

232. SW Generation recommends requiring Public Service to perform an additional analysis of flexible resource values prior to Phase II and to incorporate the results into the bid evaluation process with an opportunity for comments from the parties. At a minimum, according to SW Generation, the Commission should order Public Service to add $0.22 per kW-month for resources that can respond more quickly than 15 minutes.

233. We deny SW Generation's request to require Public Service to perform an additional analysis of flexible resource values prior to Phase II. However, we find it reasonable to apply the following credits: $0.20 per kW month for any unit that has a 30-minute response capability and $0.22 per kW month for any unit that has a 15-minute response capability.

9. Transmission

234. Per paragraph 3604(d) of the ERP Rules, Public Service describes the transmission system it owns, operates, and maintains including the substations, service territory, and connections with neighboring transmission systems.[106]

[104] Rebuttal Testimony of Public Service witness Haeger, at 38 (Hearing Exhibit 5).
[105] *See* Transcript, Vol. 3, from November 1, 2012 Evidentiary Hearing at 18, ln 8 – 19, ln 17.
[106] Volume 2 of Public Service's Application, at 2-81 (Hearing Exhibit 1(B)).

235. For purpose of bid evaluation in Phase II, Public Service proposes not to assign transmission delivery costs to projects that will use existing transmission capacity or that will utilize transmission projects for which Public Service has already been granted a certificate of public convenience and necessity, provided that sufficient transfer capability is available on the relevant lines. The Company does propose, however, to assign incremental transmission interconnection costs and network upgrade costs to each bid or proposal, as appropriate, if additional transmission investment will be required.

236. Tradewind has limited its advocacy in this docket to the area of transmission as it relates to the bid evaluation process in Phase II. Specifically, Tradewind requests that the Commission enter a Phase I decision as follows: Where the preponderance of evidence in an ERP suggests that a specific planned transmission project could reasonably be placed in service in whole or part during the RAP, bidders may submit project proposals with corresponding in-service dates to interconnect to that transmission project without pre-modeling cost imputations applied to their bids.

237. We are not convinced that it is appropriate to adopt Tradewind's proposal at this time for purposes of bid evaluation in this ERP. We find that Public Service's proposal is an equitable approach to resource acquisition and bid comparison. We therefore approve Public Service's proposal to assign to bids the costs of any radial transmission project necessary to connect a project to the Company's existing network. This approach represents an equitable approach to resource acquisition and bid comparison.

10. Additional Modeling Assumptions

238. Public Service lists specific assumptions that it proposes to use as the basis for its resource modeling in Phase II. These assumptions are listed in ERP Volume 2 Attachment 2.8-1 Table 2 (pages 2-274 through 2-276). This list also identifies whether each assumption will be updated prior to bid evaluation in Phase II. Public Service requests the Commission approve this proposed list of assumptions and updated status.

239. To the extent that a modeling input or assumption is not addressed elsewhere in this Decision, we approve Public Service's proposed assumptions and updating methodologies as established in Attachment 2.8-1.

240. To ensure disclosure of the updated information listed in Attachment 2.8-1 to parties and bidders, we require Public Service to file with the Commission all updated modeling inputs and assumptions prior to the RFP deadline for bids.

I. Historic and Expected Use of Existing Resources

241. The Commission's ERP Rules are prescriptive concerning the determination of a resource need during an RAP. Rule 3606 sets forth the requirements for electric energy and demand forecasts, Rule 3607 sets forth the requirements for an evaluation of existing resources, and Rule 3609 addresses the planning reserve margin. These are three main inputs to the calculation of the need for additional resources under Rule 3610.

242. With respect to its existing system resources, Public Service presents an evaluation of Company-owned base load coal-fired generation facilities, Company-owned natural-gas fired facilities, and IPP generation facilities that provide firm capacity and energy to the Company through PPAs. For example, Attachment 2.4-5 on page 2-74 of Volume 2 of the ERP presents the capacity factor estimates for the Company's owned facilities for each year

during the resource acquisition period. Notably, the capacity factor for the Comanche 3 base load coal plant is expected to be around 85 percent for most years between 2012 and 2018. The expected capacity factor for the Blue Spruce Energy Center is expected to be well below 2 percent during the RAP with the exception of 2018 when it is expected to increase above 2 percent. The operating profile for the Blue Spruce facility appears in all years to be that of a peaking facility.

243. Based on information produced during the hearings, however, we are concerned that the actual operation of certain plants has deviated far from the expectations set forth in Public Service's ERP. For instance, Hearing Exhibit 107 shows that the capacity factor for the Comanche 3 facility was only 52.7 percent in 2011, and Hearing Exhibit 172 shows that the Blue Spruce plants produced more than three times the energy than was expected in 2011. We are concerned that such deviations from expected operations can have an impact on ratepayers in terms of higher fuel and purchased energy costs.

244. Given these concerns, we direct the Energy Section of the Commission Staff to present to us at a public meeting a proposal to open an investigation concerning the operation of the Company's existing generation resources. We specifically want to learn why the plants operated the way they did in 2011 and 2012 and whether the plants are presently operating closer to their expected profiles as represented in the ERP filing. We find that initiating a separate investigatory docket is the most appropriate way forward, and we direct Public Service to cooperate with Staff as it prepares the framework for its investigation.

J. Requests Not Explicitly Addressed

245. Various studies were proposed by parties, including those considering alternative coal plant operations, expanded winter generation adequacy, wind generation impacts on

system operations, and energy imbalance markets. For the purposes of this ERP, we find that these studies are not required to move forward with Phase II and therefore decline to order Public Service to complete them at this time. To the extent that such studies are appropriate in future dockets, we encourage Staff and other parties to raise the need to pursue the additional analysis at that time for further consideration.

246. Finally, to the extent other specific requests made by Public Service or an intervening party are not addressed in this Order they are denied.

II. ORDER

A. The Commission Orders That:

1. The Application for Approval of 2011 Electric Resource Plan filed by Public Service Company of Colorado (Public Service) on October 31, 2011 in Docket No. 11A-869E, as consolidated by Decision No. C12-0882-I with Docket Nos. 12A-782E and 12A-785E, is approved with modifications, consistent with the discussion above.

2. The Application for Acquisition of the Brush Generating Facilities filed by Public Service on July 5, 2012 in Docket No. 12A-782E, is denied, consistent with the discussion above.

3. The Application to Retire Arapahoe Unit No. 4 and Enter into a Transaction with Southwest Generation Operating Company, LLC filed by Public Service on July 5, 2012 in Docket No. 12A-785E, is granted, in part, and denied, in part, consistent with the discussion above.

4. No later than ten business days after the effective date of this Order, Public Service and Trial Staff of the Colorado Public Utilities Commission shall file information regarding the selection of an Independent Evaluator, consistent with the discussion above.

5. Public Service shall file all updated modeling inputs and assumptions prior to the bid deadline for its competitive resource solicitation, consistent with the discussion above.

6. To the extent requests are not addressed in this Order they are denied.

7. 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 Order.

8. This Order is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 18, 2012.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JOSHUA B. EPEL

JAMES K. TARPEY

PAMELA J. PATTON

Commissioners