Decision No. C21-0246

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19R-0096E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO ELECTRIC RESOURCE PLANNING, THE RENEWABLE ENERGY STANDARD, NET METERING, COMMUNITY SOLAR GARDENS, QUALIFYING FACILITIES, AND INTERCONNECTION PROCEDURES AND STANDARDS.

DECISION CLOSING RULEMAKING PROCEEDING

Mailed Date: April 23, 2021
Adopted Date: March 24, 2021

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I. BY THE COMMISSION

A. Statement

1. On February 27, 2019, the Colorado Public Utilities Commission (Commission) issued a Notice of Proposed Rulemaking (NOPR) to amend the Commission's Rules Regulating

Electric Utilities, 4 *Code of Colorado Regulations* (CCR) 723-3 (Electric Rules).[1] The proposed amendments revise the Electric Rules in six areas: (1) the rules governing Electric Resource Planning (ERP Rules) at 4 CCR 723-3-3600, *et seq.*; (2) the Renewable Energy Standard Rules (RES Rules) at 4 CCR 723-3-3650, *et seq.*; (3) the Net Metering Rules presently in 4 CCR 723-3-3664; (4) the rules governing Community Solar Gardens (CSG Rules) presently in 4 CCR 723-3-3665; (5) the provisions for utility purchases from Qualifying Facilities (QF Rules) presently at 4 CCR 723-3-3900, *et seq.*; and (6) the Interconnection Standards and Procedures presently in 4 CCR 723-3-3667. The NOPR scheduled an initial five-day public comment hearing.

2. The provisions in the Electric Rules initially addressed in the NOPR were subsequently reduced through decisions issued in this proceeding and through separate NOPRs issued to initiate new and separate rulemaking proceedings. As explained below, the Commission severed from this Proceeding the CSG Rules and the Interconnection Standards and Procedures by Decision No. C19-0822-I issued October 7, 2019 (October 2019 Decision), and subsequently opened separate rulemakings in Proceeding No. 19R-0608E for the CSG Rules[2] and Proceeding No. 19R-0654E for the Interconnection Standards and Procedures.[3] By Decision No. C20-0661-I issued September 15, 2020 (September 2020 Decision), the Commission likewise severed the RES Rules and Net Metering Rules from this Proceeding.[4]

3. Although this rulemaking significantly narrowed due to the severing to separate rulemaking proceedings four of the six areas addressed by the NOPR, leaving the ERP Rules and

[1] *See* Decision No. C19-0197.

[2] Decision No. C19-0900, issued November 5, 2019, Proceeding No. 19R-0608E.

[3] Decision No. C19-0951, issued November 25, 2019, Proceeding No. 19R-06545E.

[4] A new and separate NOPR for the RES Rules and Net Metering Rules has not issued to open that pending rulemaking proceeding.

the QF Rules at the core of this rulemaking, the Commission examined within the scope of this proceeding the potential need for revisions to the Electric Rules caused by changes in Colorado statutes.

4. Pursuant to House Bill (HB) 19-1261, as codified at §§ 25-7-102, 25-7-103, and 25-7-105, C.R.S., the Colorado Air Quality Control Commission (AQCC) within the Colorado Department of Public Health and Environment (CDPHE) must promulgate rules and regulations necessary to ensure progress toward a 26 percent reduction in statewide greenhouse gas (GHG) pollution by 2025, a 50 percent reduction by 2030, and a 90 percent reduction by 2050, relative to 2005 statewide levels. Complementary provisions in Senate Bill (SB) 19-236, codified at § 40-2-125.5, C.R.S, address Clean Energy Plans (CEP) that require emissions caused by Colorado retail electricity sales to decrease 80 percent by 2030 relative to 2005 levels. Notably, § 25-7-105(1)(e)(VIII)(C), C.R.S., prohibits the AQCC from mandating GHG emission reductions by 2030 which is more than is required under a Commission-approved CEP.

5. Through the October 2019 Decision, the Commission proposed further rule revisions in response to legislative changes enacted by the 2019 General Assembly.[5] The Commission also scheduled an additional public comment hearing for October 29, 2019.

[5] This rulemaking also was intended to satisfy the requirements of SB 18-009, codified at § 40-2-130, C.R.S., that requires the Commission to adopt rules allowing the installation, interconnection, and use of energy storage systems. Specifically, SB 18-009 requires the Commission to incorporate the following principles into its Electric Rules: (1) customers have the right to install and interconnect energy storage systems without unnecessary restrictions or rules and without discriminatory rates or fees; (2) utility approvals and interconnection reviews shall be simple, streamlined, and affordable for customers; (3) utilities shall not require a meter in addition to a single net energy meter for the purpose of monitoring the energy storage system; and (4) net metering, as described in § 40-2-124, C.R.S., is neither altered or superseded. Some of these requirements were later addressed in the standalone rulemaking modifying the Commission's Interconnection Standards and Procedures (Proceeding No. 19R-0654E). Given that the Commission also severed the RES Rules and Net Metering Rules from this proceeding, several provisions from SB 18-009 may be addressed in a forthcoming rulemaking.

6. Through Decision No. C20-0207-I, issued April 2, 2020 (April 2020 Decision), the Commission proposed further revisions to the ERP Rules and QF Rules, including new rules that also would implement certain provisions in SB 19-236. The April 2020 Decision also scheduled an additional public comment hearing for April 23, 2020.

7. Through the September 2020 Decision, the Commission proposed additional revisions to the ERP Rules regarding the consideration and treatment of new transmission resources used to interconnect new generation resources acquired through the ERP process established by the ERP Rules in recognition, in part, of the requirement in SB 19-236 that the next ERP filed by Public Service Company of Colorado (Public Service) must include a CEP. The September 2020 Decision scheduled the final public comment hearing in this rulemaking proceeding.

8. Comments throughout this proceeding have been numerous and from many interested participants. In addition to Public Service and Black Hills Colorado Electric, LLC (Black Hills), the two investor-owned electric utilities in Colorado, and the aforementioned CDPHE, participants in this rulemaking proceeding included: Tri-State Generation and Transmission Association, Inc. (Tri-State); the Colorado Rural Electric Association; Holy Cross Electric Association, Inc.; Colorado Energy Consumers (CEC); the Colorado Office of Consumer Counsel (OCC); Energy Outreach Colorado; the Colorado Energy Office (CEO); the Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Western Resource Advocates (WRA); Sierra Club; the Southwest Energy Efficiency Project; Vote Solar; Colorado Solar and Storage Association and the Solar Energy Industries Association (COSSA/SEIA); GRID Alternatives Colorado, Inc.; Southwest Generation Operating Company, LLC; Sustainable Power Group, LLC (sPower); SunShare LLC; Colorado Renewable Energy

Society; the City of Boulder; the City of Golden; San Juan County; The Western Way; the Institute for Policy Integrity at New York University School of Law; Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (RMELC/CBCTC); and various individuals.

9. In consideration of those comments and consistent with the discussion below, we close this rulemaking proceeding without further amending the Electric Rules. We conclude that the statutory changes from the 2019 General Assembly do not require new ERP Rules or new QF Rules for the consideration of CEPs filed as ERPs. Notwithstanding our determination not to promulgate rule modifications in this proceeding, we address how the Commission may accomplish various goals and objectives raised by the participants in this rulemaking when considering a CEP filed for approval as an ERP.

10. We further conclude that Colorado can continue to comply with the Public Utility Regulatory Policies Act of 1978 (PURPA) and the rules of the Federal Energy Regulatory Commission (FERC) that implement PURPA in the forthcoming CEP proceedings in accordance with unmodified Electric Rules. As discussed below, competitive bidding remains the cornerstone of Colorado's resource acquisitions developed through the ERP process, and FERC Order No. 872[6] supports the use of competitive solicitations as a means to foster competition in the procurement of generation and to encourage the development of QFs.

[6] *Qualifying Facility Rates and Requirements*, Order No. 872, 172 FERC ¶ 61,041 (July 16, 2020) (Order No. 872).

B. Background and Developments

1. Procedural Background

11. The Commission explained in the NOPR that it had opened an administrative proceeding in October 2017 to receive information on potential changes to the Electric Rules and directed the Staff of the Colorado Public Utilities Commission (Staff) to work with stakeholders and other interested participants to develop draft rule changes that may be presented in a future NOPR (Stakeholder Outreach Proceeding, Proceeding No. 17M-0694E). The Commission focused Staff's efforts primarily on the ERP Rules, the RES Rules, and the QF Rules, however, the Commission also sought input on potential new rules for Distribution Resource Planning.[7]

12. The Commission summarized its recent decisions in which it expressed an interest in examining potential revisions to the Electric Rules. For example, when it opened the Stakeholder Outreach Proceeding, the Commission noted that, in Proceeding No. 16A-0396E, Public Service's most recent ERP proceeding, the Commission stated its intent to conduct a comprehensive rulemaking to review its ERP Rules and its RES Rules. Through filings in Public Service's previous ERP proceeding, Public Service represented that it and other parties supported a comprehensive rulemaking to address inconsistencies between the two sets of rules and suggested that some streamlining of the rules could be achieved prior to commencement of its next ERP cycle. Rulemaking participants, including WRA, agreed with Public Service about addressing inconsistencies and offered that a rulemaking could also provide better clarity

[7] Through its NOPR, the Commission determined it would not include distribution system planning (DSP) rules in the proposed rules. However, after the issuance of the NOPR, SB 19-236 was enacted and requires the Commission to promulgate DSP rules. The Commission conducted stakeholder outreach regarding potential DSP rules in Proceeding No. 19M-0670E, and subsequently issued a separate NOPR opening a rulemaking for the adoption of DSP rules in Proceeding No. 20R-0516E. *See* Decision No. C20-0837 issued December 3, 2020 in Proceeding No. 20R-0516E. The DSP rulemaking is ongoing.

between the ERP Rules and RES Rules by removing confusion among the electric utilities and other stakeholders.

13. The Stakeholder Outreach Proceeding also encompassed discussion on the QF Rules, which are necessarily intertwined with the ERP Rules and RES Rules. In the previous Public Service ERP proceeding, sPower requested the Commission waive Rule 3902(c) of the QF Rules indefinitely, arguing that the rule does not comply with PURPA requirements and FERC's PURPA Rules. The QF developer further requested the Commission require Public Service to use a particular calculation of its avoided cost for the purpose of purchasing output from QFs. By Decision No. C16-1156-I, issued on December 19, 2016 in Proceeding No. 16A-0396E, consistent with all party responses to the QF developer's requests, the Commission concluded that waiving rules for an indefinite period and setting a QF methodology for determining avoided costs amounts to rules of general applicability, which must be decided through an appropriate rulemaking procedure. The Commission therefore found that sPower's request was inappropriate in the Public Service ERP proceeding, but stated that such a request may be considered in an appropriate proceeding, including a separate application or rulemaking proceeding, which could be requested by an interested stakeholder at any time through an appropriate filing.[8] No rulemaking requests were received. Nevertheless, in the NOPR initiating this proceeding, the Commission determined that QF rules should be comprehensively considered within its review of the ERP Rules. The Commission recognized recent filings that, although improper, raised questions about the Commission's QF Rules that are best considered in

[8] Prior to issuing the NOPR opening this rulemaking proceeding, the Commission conducted a separate, targeted rulemaking in Proceeding No. 18R-0492E to address a specific provision in the QF Rules that was subject to sPower's challenge of the Commission's Electric Rules in Federal court.

the context of rulemaking, and noted that Colorado has used its competitive bidding process for nearly three decades as the fundamental means to determine avoided costs.

14. The NOPR further explained that the Stakeholder Outreach Proceeding and the timing of the adoption of the NOPR reflected an initial intention to promulgate modified Electric Rules prior to the next ERP filings from Public Service and Black Hills.[9] Despite the impending ERP filings, the need for modified ERP Rules was questioned by Public Service from the onset of this rulemaking effort. Public Service stated that the Commission's structure and rules for resource planning, renewable energy planning, and other planning processes are working for Colorado's energy customers. Public Service further stated that it had achieved successes in partnership with the Commission and a broad set of stakeholders within the context of the existing Electric Rules. Public Service concluded there was no need for a significant re-write or over-haul of the Electric Rules; however, it recognized certain opportunities for better integration of efforts and for clarification of some elements within the existing framework. With respect to the ERP Rules, Public Service expressed support for the two-phase ERP process as currently set forth in the ERP Rules and did not seek significant changes to this existing approach. Moreover, as a general principle, Public Service argued that the ERP Rules must provide a solid framework to guide the complex resource planning process yet also provide enough flexibility to support an evolving utility industry.

15. Although Public Service did not advocate for substantial changes to the ERP Rules, it aggressively opposed several of the suggestions raised by other stakeholders. For

[9] Under the existing ERP Rules, Public Service and Black Hills were required to file their next ERPs in October 2019. This filing requirement was waived for both utilities, and the Commission determined that filing deadlines for the next ERPs were being considered through the promulgation of new ERP Rules in this proceeding. In March 2021, the Commission affirmed that Public Service could file its next ERP as early as March 31, 2021 in Proceeding No. 21M-0061E.

example, Public Service opposed the suggestion that the Commission establish new rules and procedures for examining the cost-effectiveness of the utility's existing generators within the context of an ERP proceeding. Public Service contended that "a retroactive review" of existing resources would equate to improper second guessing of prior Commission prudency decisions. Public Service also took the position that, from a policy perspective, any requirement that all utility-scale resources be acquired exclusively through the ERP process would deprive utilities of the flexibility to act quickly if an opportunity for a strategic resource acquisition arises.

16. The NOPR scheduled a five-day rulemaking hearing beginning on April 29, 2019 and concluding on May 3, 2019. The final days of the hearing coincided with the finalization of SB 19-236 by the General Assembly. Aware of the situation, the Commission solicited post-hearing comments addressing the new legislation from the 2019 General Assembly.

2. Proposed Changes to the ERP Rules

17. In the NOPR and the proposed rules attached to the decision, the Commission proposed to reorganize the ERP Rules around the Phase I and Phase II requirements and procedures to clarify both the objectives of each phase of the ERP and the resulting Phase I and Phase II Decisions.

18. The Commission proposed to modify two defined terms that are central to the ERP process: the "resource acquisition period" and "resource planning period." The NOPR explained that these changes would address: (1) the shorter acquisition periods required for clean energy resources as compared to coal plants; and (2) a shorter period for calculating revenue requirements and rate impacts than the planning periods used by the utilities in their past

ERP filings with the aim address recurring concerns about “tail effects” in the Phase II bid evaluation and modeling.[10]

19. The Commission introduced new requirements for the utility’s initial ERP application filing to require certain information intended to support examination in an ERP proceeding of the potential early retirement of utility-owned resources during the planning period. The Commission sought to examine potential changes to the provisions for evaluating existing resources with respect to plant retirements and replacement capacity based on the experience gained in recent ERPs and other resource procurement proceedings.

20. The NOPR also introduced a new requirement for the utilities to submit a benchmarking analysis of each of their existing generation resources to address operating characteristics and costs for multiple purposes, including, for example, to identify the existing resources whose cost or performance deviates from expectations, which can impact ratepayers in the future with higher fuel and purchased energy costs or to inform the analysis for potential early plant retirements.

21. The Commission proposed to modify the ERP Rules to make “potential emission reductions” as a discrete potential driver of a utility’s resource need.[11]

22. The Commission enhanced the provisions relating to best value employment metrics (BVEM) both for utility-owned resources and bids into the Phase II ERP competitive solicitations based on discussions held between Public Service and RMELC/CBCTC.

[10] In accordance with SB 19-236, a CEP may have a resource acquisition period extending through 2030, which is much further out than the modified resource acquisition period initially contemplated in the rulemaking.

[11] This concept is the underpinning of § 40-2-125.5, C.R.S., governing CEPs pursuant to SB 19-236.

23. Finally, the Commission proposed to modify the provisions governing the selection of an Independent Evaluator (IE), the potential scope of work of the IE in Phase II of the ERP, and communications between Staff and the IE in Phase II bid evaluation and selection.[12]

3. Proposed Changes to the QF Rules

24. In the NOPR, the Commission stated that one of the principal objectives of this rulemaking is to clarify the role of the ERP competitive bidding process with respect to potential purchases of energy and capacity from QFs, while ensuring ongoing compliance with PURPA. The Commission observed that the rules addressing Small Power Producers and Cogenerators set forth at 4 CCR 723-3-3900 *et seq*., have not been substantially modified for decades. The Commission noted that several non-utility stakeholders have claimed that certain provisions in the Commission's existing rules governing utility purchases from QFs are contrary to the. requirements of PURPA. In contrast, the utilities and others argue that the existing QF rules, combined with other provisions in the Electric Rules, are fully compliant with PURPA.

25. The modifications to the QF Rules proposed in the NOPR preserve the ERP competitive bidding process as the primary means for a QF to secure a contract for the purchase of energy or capacity from the electric utilities. The Commission clarified that it will determine in the Phase I ERP process whether the utility's Phase II competitive solicitation will be reasonably open to QF bids. If QFs have a reasonable opportunity to secure a purchase contract with the utility by means of the ERP competitive bidding, the Commission explained that it will rely on ERP competitive bidding as the means to a legally enforceable obligation for

[12] The Commission has waived rules related to the IE in every resource procurement proceeding in which an IE was retained since the ERP Rules were initially promulgated. Nothing prevents the Commission for addressing the selection of the IE and the IE's scope of work as may be necessary for consistency with FERC Order No. 872.

QFs. The proposed QF Rules also provided for a new tariff-based QF program that would arise when ERP competitive bidding becomes irregular, infrequent, or too expensive for owners and developers of small QFs. The NOPR further sought to bring the QF interconnection and operation provisions up to date with current practices that rely on the requests for proposals (RFPs) and model contracts reviewed during the course of a utility's ERP proceeding.[13]

4. Examination into the Implementation of the 2019 Legislation

26. Considering comments following the enactment of SB 19-236 just after the conclusion of the hearings scheduled by the NOPR, the Commission proposed additional rule changes in the October 2019 Decision and again sought to collect additional information and to receive comments on further revisions to the Electric Rules regarding the implementation of certain legislation enacted from the 2019 General Assembly. For example, the Commission observed that ERP application proceedings had historically served as the primary vehicles for examining cost-effective emission reduction strategies and that the enacted legislation from the 2019 General Assembly will cause carbon emission reductions to dominate the utilities' future ERP application proceedings, eclipsing both the RES and avoided fuel costs as the drivers of resource needs and resource selection. The Commission also stated that information from the AQCC about its anticipated timelines for the implementation of HB 19-1261 was critical for the Commission to determine when Public Service and Black Hills will be in a position to file ERPs that are responsive to the carbon reduction goals established pursuant to HB 19-1261 or that are otherwise consistent with the requirements of a CEP.

[13] As discussed herein, while the initial NOPR included broader considerations of the Electric Rules, rule topics with the exception of the ERP Rules and QF Rules have been split off from this proceeding and are therefore not discussed in detail through this final decision.

27. addition, the October 2019 Decision set forth proposed rules in a new section of the Electric Rules to implement new statutory provisions in § 40-3.2-106, C.R.S., that require the utilities to consider the cost of carbon dioxide emissions based on the federal government's latest calculation of the social cost of carbon (SCC) when determining the cost, benefit, or net present value of any plan or proposal submitted in certain proceedings before the Commission. The Commission also proposed another new section of the Electric Rules to implement the statutory provisions set forth in § 40-2-133, C.R.S., related to workforce transition plans required when a utility files for approval of either an ERP or a proposed early retirement of an electric generating facility.

28. The Commission further solicited comments on the policy goals of Governor Jared Polis set forth in the "Polis Administration's Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" (Roadmap) as they relate to the Commission's Electric Rules. The Commission noted that the Roadmap addresses at least four types of assumptions that could have an impact on an electric utility's electric energy and demand forecasts as examined in an ERP proceeding: (1) a customer's entitlement to install retail distributed energy resources (DERs) at their homes and businesses, with all customers having the ability to adopt 100 percent renewable energy before 2040 and to "export unused electricity to the utility system"; (2) achievement of 2 percent demand side management (DSM) goals; (3) widespread consumer adoption of electric vehicles and a Zero Emission Vehicles standard; and (4) a blueprint for building electrification, with "clean electricity" as an alternative to burning fossil fuels in buildings as a means to reduce emissions. The Commission encouraged CEO to take the lead on developing and presenting a consensus view on alternative rule changes that address the

Roadmap generally and the four types of assumptions that could have an impact on electric utilities' electric energy and demand forecasts.

29. In its April 2020 Decision, the Commission crafted a full set of modified ERP Rules and QF Rules for comment and hearing in response to stakeholder comments filed through February 2020 and to the statutory changes from the 2019 General Assembly. The Commission also reworked proposed rules governing the application of the SCC and workforce transition plans.

30. Concerning the ERP Rules, the Commission stated in the April 2020 Decision that "the overall ERP practices were not significantly altered by statute. However, considering the changed statutes and subsequent stakeholder comments, we offer further rule revisions for participant comment within this rulemaking as discussed below and included in the attachments to this Decision."[14] The Commission observed that the proposed benchmarking of existing generation to generic resources in an ERP context, intended to identify existing resources whose cost or performance deviates from expectations and to inform the analysis for potential early plant retirements, was proposed prior to legislative changes regarding carbon emission reduction requirements. The Commission concluded that:

> Benchmarking is a new proposal, which was introduced into the proposed rules prior to statutory changes regarding Clean Energy Plans. Conducting a comprehensive assessment of existing generation resources in an ERP is required to develop and support a Clean Energy Plan. We invite further participant comment given these observations and concerns, but remind stakeholders not to complicate the practical purpose of benchmarking in adjudication through overly prescriptive rules.[15]

[14] April 2020 Decision at ¶ 46.

[15] *Id.* at ¶ 68.

31. The Commission also observed in the April 2020 Decision, that the role of the new rule set forth in the NOPR requiring the utility's initial ERP filing to include an assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period was "greatly altered" by SB 19-236 and HB 19-1261. The Commission stated: "HB 19-1261 and SB 19-236 require a refocusing of an ERP proceeding, beyond only addressing new resources and toward review of all resources, in order to achieve decarbonization requirements."[16] The Commission explicitly sought more information from stakeholders for additional information and comment on the following before adopting final provisions in any new ERP Rules:

(1) whether an additional assessment regarding resource retirements should be required in Rule 3604 if a Clean Energy Plan is also required to be filed in the utility's next ERP either by statute or by another Commission rule;

(2) whether this separate and additional assessment of resource retirements should include both utility-owned generation and contracted resources; and

(3) whether additional rule provisions or Commission determinations are necessary to address stakeholder concerns about stranded utility costs and breached contracts.[17]

32. The Commission also observed in the April 2020 Decision that the filing made by CEO in December 2019 jointly with most of the active participants in this rulemaking confirmed agreement among the stakeholders that the statutory GHG reduction goals set forth in § 25-7-102(2), C.R.S., per HB 19-1261 or required in a CEP pursuant to § 40-2-125.5, C.R.S., per SB 19-236 will necessarily require an assessment of potential cost-effective early retirements of utility-owned resources. The Commission also rejected Sierra Club's proposal that the Commission adopt a rule requiring an initial presentation of a scenario that represents either a

[16] *Id.* at ¶ 79.
[17] *Id.* at ¶ 80.

90 percent or 95 percent reduction in carbon emissions by 2030 relative to 2005 levels. The Commission aimed "to avoid overly prescriptive requirements that risk overburdening the Phase I ERP proceeding that must meet the state's carbon and other greenhouse gas reduction goals."[18]

33. In its September 2020 Decision, the Commission scheduled a final hearing in this rulemaking proceeding. The Commission focused the additional hearing exclusively on the consideration and treatment of new transmission resources used to interconnect new generation resources acquired through the ERP process established by the ERP Rules. The Commission observed that Public Service had stated in the then ongoing transmission planning proceeding in Proceeding No. 20M-0008E that its forthcoming CEP "will present significant drivers for transmission planning" such as "new interconnection facilities for clean energy resources" and "Decommissioning, or redevelopment, of existing transmission facilities associated with the potential for accelerated fossil-fuel retirements."[19] The Commission concluded that:

> …additional comments are necessary regarding the consideration of new transmission investment in the ERP process before we adopt any revisions to the transmission-related provisions in the ERP Rules. We are concerned by CIEA's observation that the Commission's transmission planning process may be irrelevant from the perspective of a bidder in an ERP competitive solicitation, particularly when Public Service must file a Clean Energy Plan as part of its next ERP. We are further concerned about the possibility that, without modifications to the ERP Rules addressing new transmission investment, the most cost-effective development of new generation resources may be precluded due to the lack of a full presentation of transmission investments that could be operational in time to fulfill resource needs as late as 2030, the end of the resource acquisition period for a Clean Energy Plan.
>
> We seek to ensure to the extent it is possible, that new utility transmission investments associated with a Clean Energy Plan filed pursuant to § 40-2-125.5(4), C.R.S., will be sufficiently addressed in Phase I prior to the issuance of the RFPs in Phase II. We are also interested in examining whether

[18] *Id.* at ¶ 116.

[19] September 2020 Decision at ¶ 9.

> certain backstop provisions should be introduced to the ERP Rules governing the Phase II process to achieve the same end: the identification of new transmission investments that could be operational in time to fulfill resource needs as late as 2030. With respect to Phase II processes, we seek comments regarding opportunities for bidders to refresh their bids or to renegotiate contracts if the viability of new transmission resources emerges with increased certainty during bid evaluation in Phase II. We specifically seek more information about the possibility of an extended bid evaluation process justified by closer examination of RFP bids and the utility's transmission system for better integration of the new resources and the avoidance of wasteful or poorly utilized radial lines.[20]

5. Closing Rulemaking without Adopting Revised Electric Rules

34. Considering the record in this proceeding, including all participant comments, we conclude that the statutory changes from the 2019 General Assembly do not require new ERP Rules or new QF Rules for the consideration of CEPs filed as ERPs. Changes made in SB 19-236 and HB 19-1261 have focused or made obsolete many of the ERP Rules initially proposed in the NOPR, rendering the proposed revisions unnecessary. In addition, the statutory objectives identified by the 2019 General Assembly may be met under current rules without revision through individual adjudications. To move forward also avoids delay in implementation of the laudable goals set forth in statute, including ensuring significant carbon emission reductions in coming years, where rules are unnecessary to commence or continue necessary adjudications.

35. While the NOPR introduced new provisions and concepts into the ERP process, primarily to prompt examination of potential early retirements of utility-owned resources as part of an expanded evaluation of the continued use of all existing utility resources, we hold to our determinations in previous orders in this proceeding that SB 19-236 and HB 19-1261 have altered the need to adopt modified ERP Rules and that carbon emission reductions required by the enacted legislation from the 2019 General Assembly will dominate the utilities' future

[20] *Id.* at ¶¶ 18-19.

ERP application proceedings as the drivers of resource needs and resource selection. We are further mindful that, based on CEP-related announcements by the Polis administration and the Colorado electric utilities indicate, all coal plants operating in Colorado will be addressed by CEPs or ERPs presently before the Commission.

36. We further agree with the majority of the stakeholders that the reorganization of the ERP Rules is convenient but not essential. Stakeholders are well aware of the Phase I and Phase II processes without explicit separation or reorganization in the rules.

37. We also conclude that Colorado can continue to comply with PURPA by implementing its ERP processes in accordance with unmodified ERP Rules and QF Rules.

38. Despite our decision not to adopt rule revisions in this proceeding, we discuss below several specific issues raised by the participants in this rulemaking effort and describe that these concerns are best met through adjudication processes and Commission decisions in forthcoming ERP proceedings that include a CEP and, in any event, are not necessary to codify or address through revised rules at this time.

6. Statutory Changes from the 2019 General Assembly

39. The statutory changes from the 2019 General Assembly have altered or eliminated underlying rationale for an ERP-focused rulemaking. Significantly, ERP filings became dictated by statute to the extent they required or include CEP considerations. Because the statutes necessarily must be followed, updates to ERP Rules became less necessary to instigate potential coal plant retirements and other policy objectives that, after 2019, were directed in statute regardless.

40. Most notably, the new statutory mandate on Public Service to file a CEP as its next ERP pursuant to § 40-2-125.5, C.R.S., fundamentally diminishes the need for the

Commission to pursue assertive rulemaking to cause an ERP proceeding to encompass: (1) the examination of potential early retirements of coal plants; and (2) the investigation of modified operations of fossil-fueled generation resources into the future, both as cost-effective means to achieve significant reductions in GHG emissions.

41. As this rulemaking progressed, the Commission examined the question of whether it was still necessary to pursue potential rule changes associated with plant retirements and replacement capacity. The October 2019 Decision and the April 2020 Decision also tested the more general proposition of whether changes to the ERP Rules were necessary to implement 2019 legislation, including SB 19-236 and HB 19-1261.

42. We conclude that no compelling justification has been given by any of the participants in this proceeding that new ERP Rules are needed for the Commission to consider CEP filings or to implement other statutory changes from the 2019 General Assembly. We further agree with the rulemaking participants, including utilities and non-utilities, who state that "no more process" is needed in this rulemaking on a number of issues. Rulemaking participants also provided no submissions of proposed redline rule changes necessary to implement the new statutory provisions.

43. We therefore close this proceeding without adopting rule revisions for the aforementioned reasons and based on the following determinations.

7. Clean Energy Plan Filing Announcements and Related Actions

44. The April 2020 Decision contemplated a situation where the AQCC had not yet promulgated its rules to implement HB 19-1261 such that new ERP Rules would instead be

required to "foster consideration of Clean Energy Plan filings."[21] However, at the interagency workshop held on February 23, 2021 in Proceeding No. 21M-0061E, CEO and CDPHE described the Colorado utility announcements regarding their intentions to make CEP filings with the Commission or otherwise pursue ERPs that achieve commensurate GHG emission reductions. With respect to the investor-owned electric utilities subject to the ERP Rules, CEO and the CDHPE reported that both Public Service and Black Hills[22] are committed to filing CEPs that will reduce GHG emissions by at least 80 percent by 2030. These announcements have thus also altered the need to promulgate new ERP Rules at this time.

45. The Commission also has taken steps specifically to receive Public Service's CEP filing as its next ERP before new ERP Rules can be put in place.

46. On February 2, 2021, in Decision No. C21-0057 issued in Proceeding No. 21M-0061E, the Commission clarified that the rulemaking in this proceeding is ongoing and will not result in revised ERP Rules for effect prior to March 31, 2021. The Commission stated instead that: "The Commission will establish specific procedures for the review of the CEPs in the proceedings in which they are filed pursuant to SB 19-236 and the Commission's Electric Rules in effect at the time of the filing."[23] The Commission also stated that: "The Commission will address any potential changes to the Electric Rules in Proceeding No. 19R-0096E by separate decisions in that rulemaking proceeding."[24] In opening the proceeding, the Commission stated that CEP filings shall be permitted upon conclusion of the interagency workshop proceeding, but not earlier than March 31, 2021.

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[21] April 2020 Decision, ¶ 50, p. 19.

[22] Black Hills no longer has coal generation units in Colorado.

[23] Decision No. C21-0057 at ¶ 18.

[24] *Id.* at ¶ 19.

47. Public Service confirmed on February 24, 2021, the day after the interagency workshop in Proceeding No. 21M-0061E, its intent to file its CEP as its next ERP on March 31, 2021, and that the filing will address the retirement of all of Public Service's remaining coal operations in Colorado. Through its announcement, Public Service states its intent to propose the conversion from coal to natural gas of the Pawnee Generating Station in 2028 and an early retirement of the Comanche 3 Generating Unit in 2040.[25]

48. At the March 10, 2021 CWM, the Commission closed Proceeding No. 21M-0061E, and affirmed its direction for Public Service to file its CEP as early as March 31, 2021 to be reviewed as the utility's next ERP under unmodified ERP Rules.[26]

8. Reprioritization of Commission Policy Making Efforts

49. Although the Commission stated in the NOPR that it intended to comprehensively review its ERP Rules in conjunction with its rules implementing the RES Rules and other provisions in the Electric Rule, the Commission later narrowed the scope of this proceeding, as explained below. This refocusing of the Commission's examination of potential changes to the ERP Rules and the companion QF Rules was necessary, in part, due to the new statutory provisions governing the development and filing of CEPs as ERPs pursuant to SB 19-236 and due to the numerous related obligations on the Commission caused by the enactment of SB 19-236 and other statutes.

50. In the October 2019 Decision, the Commission determined that the promulgation of new CSG Rules, previously contained within the RES Rules, was severable from this

[25] *See* https://investors.xcelenergy.com/news-market-information/press-releases/press-release/2021/Xcel-Energy-Announces-2030-Clean-Energy-Plan-to-Reduce-Carbon-Emissions-85/default. Public Service filed its CEP as its next ERP on March 21, 2021 in Proceeding No. 21A-0141E.

[26] Decision No. C21-0154, Proceeding No. 21M-0061E, issued March 15, 2021.

proceeding and that new CSG Rules allowing for the new statutory provisions from the 2019 General Assembly would take effect sooner than if they remained in this proceeding. Likewise, the Commission concluded that the Interconnection Procedures and Standards, also once contained within the RES Rules, were also severable from this rulemaking proceeding and that a separate rulemaking would be more efficient.

51. Following the review of comments submitted in response to the October 2019 Decision and the April 2020 Decision, the Commission also determined that the balance of the RES Rules, including the Net Metering Rules, were also severable from this rulemaking.

52. With respect to the specific statutory obligations requiring the refocusing of the Commission's rulemaking efforts, SB 19-236 required the promulgation of entirely new ERP Rules for Tri-State pursuant to § 40-2-134, C.R.S. The Commission leveraged the work done in this ongoing proceeding for the ERPs filed by Colorado's investor-owned electric utilities in crafting the new rules for the state's wholesale generation and transmission electric cooperative, as described in detail in Decision No. C19-0651, the NOPR opening the rulemaking in Proceeding No. 19R-0408E on July 31, 2019. The Commission adopted final rules governing ERPs filed by Tri-State by Decision Nos. C20-0155 and C20-0304, issued on March 10 and April 28, 2020, respectively. In accordance with these new ERP provisions, Tri-State filed an initial assessment of its existing resources on June 1, 2020 in Proceeding No. 20M-0218E and filed a complete ERP application on December 1, 2020 in Proceeding No. 20A-0528E.

53. In addition, laws enacted by the 2019 General Assembly required:

- New transportation electrification plans (TEPs) to be submitted by the | nvestor-owned electric utilities pursuant to SB 19-077 (§§ 40-1-103.3(2) and (6), 40-3-116, and 40-5-107, C.R.S.). On October 23, 2019, the Commission opened a miscellaneous proceeding to solicit comment and information from utilities and interested stakeholders. Staff presented a summary of the comments and information received at the Commissioners' weekly meeting of February 19, 2020 and closed the proceeding in anticipation of the filing of the first TEPs on May 15, 2020.

- The promulgation of rules for the filing of distribution system plans and the evaluation of non-wire alternatives (§ 40-2-132, C.R.S.). The Commission was specifically mandated to promulgate rules to address a method for evaluating the costs and net benefits of using distributed energy resources (DERs) as non-wire alternatives and to forecast the growth of DERs within the systems of the investor-owned electric utilities.
- Revisions to the Commission's CSG Rules (modifications to § 40-2-127, C.R.S.). The Commission again leveraged the work done in this proceeding by issuing a NOPR in Proceeding No. 19R-0654E on November 25, 2019 and adopted final rules at the Commissioners' weekly meeting of February 24, 2021.
- An investigation into financial performance-based incentives and performance-based metric tracking to identify mechanisms for aligning utility operations, expenditures, and investments with various public benefit goals, including safety, reliability, cost efficiency, emissions reductions, and the expansion of DER (§ 40-3-117, C.R.S.). The Commission opened an investigation into "PBR" on December 5, 2019 and submitted its findings in a report to the General Assembly on November 30, 2020.
- An investigation of the costs and benefits to electric utilities, other generators, and Colorado electric utility customers resulting from electric utility participation in energy imbalance markets (EIMs), regional transmission organizations (RTOs), power pools, or joint tariffs (§§ 40-2.3-101and 102, C.R.S.). The Commission opened Proceeding No. 19M-0495E on September 17, 2019[27] for the purposes of collecting comments and other information helpful in analyzing the potential advantages and disadvantages in joining one of the types of energy markets identified in the statute and of aiding the Commission in its determination of whether such participation is in the public interest. On March 23, 2020, the Commission issued an RFP for quantitative modeling and analysis in support of its investigation. Final modeling results are expected to be available in April 2021.

9. FERC Affirmation of Competitive Bidding for PURPA Compliance

54. Recent actions by FERC show that it agrees that the competitive bidding process at the core of Colorado's ERP process remains a viable, if not preferred, path for continued compliance with PURPA.

[27] *See* Decision No. C19-0756.

55. Through the September 2020 Decision, the Commission took administrative notice of FERC Order No. 872, issued July 16, 2020, and solicited comment on whether this FERC decision or any other direction should be codified in Colorado rules at this time, pending finalization of FERC's rules regarding QFs. The Commission noted that, within its findings in Order No. 872, FERC states that it "support[s] the use of competitive solicitations as a means to foster competition in the procurement of generation and to encourage the development of QFs in a way that most accurately reflects a purchasing utility's avoided costs." The Commission further stated that Order No. 872 includes that states are afforded flexibility to use a "properly structured" competitive solicitation to determine avoided cost rates for QFs. The Commission therefore concluded that:

> Although FERC's rulemaking is not yet complete, this Commission is mindful of FERC's actions, and agrees with the goals of best ensuring an open and transparent competitive solicitation. We therefore find it appropriate to allow participants in this Proceeding the opportunity to address Order No. 872, including specifically whether the Colorado Commission's QF Rules should be further revised in this rulemaking.[28]

56. Although participants remained sharply divided throughout this proceeding on whether the Colorado's ERP processes that relied on competitive bidding could be the primary means for PURPA compliance, participant comments following FERC Order No. 872 were limited. While PURPA compliance and related challenges were once a primary reason to consider revisions to the ERP and QF rules, FERC Order No. 872 significantly reduces the need for revised rules for this reason. Remaining concerns from participants, including certification by and clarification of the scope of work conducted by an IE in a particular proceeding, are most efficiently addressed through specific adjudication determinations, rather than rule revisions.

[28] September 2020 Decision at ¶ 34.

10. Need for New Rulemaking for Post-CEP Electric Resource Planning

> Many of the comments provided by rulemaking participants since the close of the 2019 General Assembly make clear that the Commission will need to develop resource planning policies and procedures for implementation after the investor-owned utilities submit their next ERPs as CEPs. Although some of the issues that may surface in those future ERPs have been identified in this proceeding, we conclude that there is insufficient basis for adopting appropriate rule revisions at this time. A better course of action than adopting the rule changes as examined here is returning to the question of how the Electric Rules should be revised after the Commission has undertaken the detailed review and approval of the forthcoming CEPs pursuant to the statutory provisions in SB 19-236.

57. In comments filed on May 7, 2020, for instance, CDPHE foreshadowed the need for the Commission to develop policies for a post-CEP environment in which the Commission would need to require Colorado utilities to spur beneficial electrification:

> As the Department's October 2019 comments in this proceeding addressed, it is likely that widespread electrification of transportation, buildings, and industry will be necessary in order to meet the goals of HB 1261. Accordingly, the Department encourages the [Commission] to require utilities to incorporate policies and investments that spur electrification. If the State and utilities are successful in achieving widespread electrification, this will lead to increased demand for, and thus additional generation from, the electric utilities, while significantly decreasing net GHG emissions across the economy as a whole… To maximize the effectiveness of CEPs in supporting the GHG reduction goals of Colorado, PUC rules should encourage rapid decarbonization of the grid. [Commission] rules should also recognize and prioritize the importance of supporting and expanding electrification of the transportation, building, and industrial sectors as critical elements for meeting the overall GHG emission reduction goals of Colorado.[29]

58. Despite CDPHE's observations and suggestions, we lack a basis in this rulemaking for modifying the ERP Rules or other sections of the Electric Rules to advance further decarbonization of the Colorado electric utilities beyond the critical steps embodied in the

[29] CDPHE Comments at pp. 3 and 5.

CEPs. A reasonable alternative to promulgating new rules in this proceeding is to pursue rulemaking efforts in the future, building on the CEPs adjudicated pursuant to the 2019 statutes to craft modified Electric Rules that govern future clean energy actions and investments related to further emission reductions pursuant to HB 19-1261. To do so in this proceeding would be premature.

C. Electric Resource Planning Rules

59. We appreciate that many of the participants in this rulemaking have put in considerable work developing and filing comments regarding the potential rule changes examined over the past years. Had SB 19-236 and HB 19-1261 lacked the provisions requiring Public Service to file a CEP as its next ERP, this rulemaking likely would have culminated in several rule changes, particularly in the ERP Rules related to the examination of existing utility resources from both economic and environmental perspectives, including potential early retirements of coal plants. The statutory changes affirm the policy objectives these rules were intending to address, and at the same time, provide the necessary policy and direction to render the revised rules unneeded.

60. Although we decline to modify the ERP Rules for the various reasons discussed above, we find it necessary and appropriate to address in this Decision, specific topics discussed by the rulemaking participants as they relate to the next cycle of ERP application proceedings that will include CEPs.

1. Resource Planning to Accomplish GHG Emission Reductions

61. In the April 2020 Decision, the Commission updated Proposed Rule 3601(c)[30] to state that carbon emission reductions are among the primary goals of ERP. That rule revision reflects, with minor revisions, proposals made by CEO.

62. We conclude that SB 19-236 and HB 19-1261 support the conclusion that carbon emission reductions are among the primary goals of ERP. Given the prescriptive and direct statutory changes, rule revisions are not required at this time, but the updated 2019 statutes affirm and direct the Commission on this very point.

2. Cost-Effective Resource Plan

63. In the NOPR, the Commission proposed to add the phrase "and operated" to the definition of a "cost-effective resource plan," explaining that these costs have long been embedded in the calculation of net present value revenue requirements.[31]

64. Sierra Club recommends that the Commission further alter the definition of "cost-effective resource plan" in Rule 3602(c) such that existing resources are considered to be part of the resource plan. Sierra Club claims that it is critical that the ERP Rules require an existing resource assessment separate from that required in support of a CEP for two reasons: (1) a utility cannot develop a cost-effective resource plan without an examination of the economics of its existing resources due to rapid changes in the cost of wind and solar resources;

[30] *See* Proposed/Existing Rule 3601. Overview and Purpose. Consistent with the NOPR and the subsequent decisions presenting potential changes to the ERP Rules, the "Proposed Rules" reflect the numbering in the modified rules (*e.g.,* Attachment C to the NOPR for the reorganized ERP Rules), whereas "Existing Rules" reflect the numbering in the Electric Rules currently in effect.

[31] Proposed/Existing Rule 3602. Definitions.

and (2) there may be cost savings from retiring resources, or changing the operation of resources, beyond what is needed to meet the statutory requirements of a CEP.

65. We agree with Sierra Club that the Commission's ERP process includes an examination of the economics and environmental profiles of existing resources. Assessments of existing resources in an ERP context can lead to the determination of a resource need pursuant to Rule 3610.[32] If a plant is uneconomic or operationally deficient due to emissions, it may be retired early or otherwise addressed in a manner that causes a change in the utility's resource need. The ERP fundamentally addresses how the utility should meet a defined resource need through both the acquisition of new resources and the continuing operation of existing resources, perhaps modified as compared to expected performance at the time the resource was acquired.

3. Early Plant Retirements

66. In the NOPR, the Commission proposed new provisions to address the potential early retirement of utility-owned resources during the planning period. The proposal reflected the Commission's intentions to examine potential changes to the provisions for evaluating existing resources with respect to plant retirements and replacement capacity based on the experience gained in recent ERPs and other resource acquisition proceedings. The proposed rule language was intended to ensure that the utilities provide sufficient information on potential plant retirements in their initial ERP filings.

67. The October 2020 Decision did not address the early retirement rule provisions set forth in the NOPR. However, the decision addressed extensively SB 19-236 that will require Public Service to file a CEP as its next ERP.

[32] Proposed Rule 3610. Assessment of Need for Resources.

68. The series of paragraphs in Rule 3604[33] set forth in the proposed rules attached to the April 2020 Decision included two provisions related to early plant retirements. Proposed Rule 3604(l) was a version of the early plant retirement assessment addressed in the NOPR, while Proposed Rule 3604(m) was a new assessment of the costs and benefits of early retirements and the acquisition of new utility resources required to reduce carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030, consistent with the requirements for a CEP. The April 2020 Decision also queried: (1) whether an additional assessment regarding resource retirements should be required in Rule 3604 if a CEP is also required to be filed in the utility's next ERP either by statute or by another Commission rule; (2) whether this separate and additional assessment of resource retirements should include both utility-owned generation and contracted resources; and (3) whether additional rule provisions or Commission determinations are necessary to address stakeholder concerns about stranded utility costs and breached contracts.

69. CEO states that the ERP will be the primary venue to address early retirements in the future, while the CEP will be a one-time filing made possibly by only one utility. Further, CEO observes that in order to achieve the state's goal of 90 percent economy-wide reduction in GHG emissions by 2050,[34] it may be necessary to eliminate all such emissions from electric generation. Therefore, future ERP proceedings will need to include an assessment of any remaining fossil resources. CEO further observes that any rules adopted will likely remain in effect for some time, and so should ensure that early retirement of GHG emitting resources are assessed on an ongoing basis. CEO also argues that stakeholders should be able to recommend

[33] Proposed/Existing Rule 3604. Contents of the Electric Resource Plan.

[34] *See*, § 25-7-102(2)(g), C.R.S.

plants for assessment and the Commission should be able to direct utilities to model plant retirements.

70. WRA states that a CEP filed in accordance with § 40-2-125.5(4)(a)(III), C.R.S., would satisfy the requirement to evaluate the early retirement of existing resources within the planning period required by Proposed Rule 3604(m) but may not satisfy the requirements of Proposed Rule 3604(l). WRA explains that Proposed Rule 3604(l) requires evaluation of potential early retirement of all resources with planned retirement dates during the planning period, which may extend beyond 2030. WRA does not see the Rule 3604(l) requirements as unnecessarily duplicative with either the CEP requirements or the requirements of proposed Rule 3604(m). WRA argues that it is important to retain proposed Rule 3604(l) in order to ensure that resource retirements are considered in other ERP proceedings that do not include a CEP. It is equally important to retain Proposed Rule 3604(l) to ensure proper evaluation of early retirement for those resources with a retirement date beyond 2030, but within the planning period defined by rule.

71. Like CEO and WRA, CIEA notes that Public Service is only required to file one CEP and argues that Proposed Rule 3604(l) should be retained to apply both to future, non-CEP filings by Public Service and to apply to Black Hills, which is not statutorily required to file a CEP. To clarify that a utility would not be required to conduct two separate early retirement assessments for a given unit, CIEA suggests that Proposed Rule 3604(l) be amended to begin "If not presented under section (m), below…"

72. In contrast, Public Service argues that additional assessments of early retirements as contemplated under proposed Rules 3604(l) and (m) are not necessary if, like Public Service, the utility is also required to file a CEP. Public Service further argues that such an assessment

also should not be required in future ERPs that will be subject to "an ongoing and statutory clean energy target overlay." More specifically, Public Service explains that while the detailed statutory process and CEP framework outlined in SB 19-236 governs only the next ERP filing with a resource acquisition period that extends through 2030, SB 19-236 also directs Public Service to continue its clean energy transition by seeking to provide its customers with energy generated from 100 percent clean energy resources by 2050. Public Service thus states that the post-2030 emissions trajectory will require it to continue to analyze its existing fleet and implies further potential actions with respect to existing resources. Accordingly, ERPs beyond Public Service's next ERP will consider those actions and continue to have the same carbon dioxide emission reduction overlay that this next ERP cycle will have. Public Service states that to achieve this long-term goal, its resource planning efforts over the next several decades will require the flexibility to evaluate a variety of approaches beyond just the early retirement of utility-owned resources.

73. Sierra Club takes issue with the Public Service contentions, stating that the utility's position is based on the mistaken assumption that requiring utilities to analyze early retirements is designed only to reduce GHG emissions. Sierra Club argues that the primary reason for examining early retirements is to ensure the cost-effectiveness of utility portfolios. Sierra Club suggests that it may be cost-effective to retire units even if those units do not need to be retired to meet the carbon reduction targets in SB 19-236, and observes that there is a 20-year period, from 2030 to 2050, during which SB 19-236 contains no interim carbon reduction targets, and for the ERPs covering that period, Public Service might not assess the cost-effectiveness of early retirements without a rule such as Proposed Rule 3604(l).

74. We agree with WRA, Sierra Club, and CEO that the evaluation of potential early plant retirements for both economic and emission reduction purposes should be an ongoing exercise for future ERP applications. However, as discussed above, we conclude that any modified ERP Rules coming from this proceeding are unlikely to be fully adequate to address electric utility resource needs beyond 2030 or otherwise for ERPs filed after approval of a CEP. Consistent with the statements from CEO, any revised ERP Rules would be in effect for a long period; we do not aim to adopt rules that are outdated or insufficient upon adoption. The Commission's ERP Rules will require further refinement in the future as a result of progress in AQCC's efforts to promulgate and implement rules pursuant to HB 19-1261. At the same time, the current rules are flexible enough to address and avoid delay in instant ERP filings that contain a CEP.

4. Utility Ownership of Renewable Energy Resources

75. In the NOPR, the Commission reorganized the existing provisions in the ERP Rules addressing alternative plans put forward by the utility in Phase I of the ERP proceeding (*i.e.*, plans other than using competitive all-source bidding). The Commission also moved the rules implementing § 40-2-124(1)(f)(I), C.R.S., from the RES Rules to the ERP Rules (*i.e.*, Existing Rule 3660(h)).

76. SB 19-236 eliminates § 40-2-124(1)(f)(I), C.R.S., that had allowed a utility to develop and own as rate-based property, certain amounts of renewable energy resources without being subject to the competitive bidding requirements of the Commission's ERP and RES Rules.

77. The Commission later presented modifications to Rule 3614(c) in the April 2020 Decision due to the repeal of § 40-2-124(1)(f)(I), C.R.S.

78. We conclude that the repeal § 40-2-124(1)(f)(I), C.R.S., can be adequately addressed in any ERP proceeding prior to the revision of the Commission's RES Rules. In addition, because § 40-2-124(1)(f)(I), C.R.S., is presently addressed exclusively with the Commission's RES Rules, the repeal of those provisions also can be addressed in any subsequent rulemaking to modify the RES Rules.

5. Phase II 120-Day Report

79. In the April 2020 Decision, the Commission added requirements that the Commission address in the Phase I decision the contents of the 120-Day Report to be filed by the utilities in Phase II.[35] The Commission also presented new provisions in Proposed Rule 3614(f)(III) regarding the contents of a Phase I decision to require the Commission to: (1) set forth the specific carbon costs to be used in the 120-day report; (2) define the "base case portfolio" the utility must present in its 120-day report as required for the use of the social cost of carbon; (3) address additional alternative portfolios, as the Commission may want, to address the social cost of carbon and other values of carbon dioxide costs; and (4) to set forth the other factors the Commission intends to consider in approving a resource plan in addition to considering the cost of carbon dioxide.[36]

80. CEC requests the Commission add a new paragraph to Proposed Rule 3604 that requires the utility to "provide as a baseline case the least cost portfolio to allow the Commission and interested parties to meaningfully evaluate competing alternatives."[37] CEC explains that this least cost portfolio would honor and comply with statutory standards, yet would allow the

[35] Proposed Rule 3615. Phase II
[36] Proposed Rule 3614. Phase I
[37] Proposed/Existing Rule 3604. Contents of the Electric Resource Plan.

Commission and the parties to an ERP proceeding to meaningfully understand which costs towards compliance are necessary, and which costs are "extra."

81. In response to CEC, WRA states that it does not oppose a least cost portfolio, so long as that portfolio is compliant with carbon emission reduction requirements. However, WRA argues that establishing a requirement that utilities present a "baseline," "planned," or "business as usual" portfolio is problematic, particularly if that portfolio is inconsistent with the minimum GHG reduction requirements of HB 19-1261 and SB 19-236. WRA states that the Commission should be cautious about requiring utilities to present portfolios to the Commission as "business as usual," "baseline" or "planned" if those portfolios can never be a regulatory reality. WRA concludes that presentation of any "least-cost" benchmark portfolio must reflect the reality of the carbon emissions reductions required by Colorado law.

82. While acknowledging the concerns of parties such as those expressed by WRA above, the OCC supports CEC's call for the presentation of a baseline portfolio. The OCC argues that a baseline portfolio would not consider un-planned retirements or other alternatives to meet low-carbon goals. The OCC states that this baseline portfolio would provide a constant point to compare other portfolios to and that without a defined baseline portfolio, there is no way for the Commission to be able to justify and balance the objectives of the Colorado Legislature (Legislature) as stated in SB 19-236. The OCC further argues that the costs of all alternative portfolios should provide as complete and transparent a view as possible, quantifying, at a minimum, stranded costs, employee transition costs, unit retirement costs, transmission interconnection and other system impact costs, and contract termination costs. These costs should be provided as accurately and as reasonably possible with the knowledge that these costs

impact the total cost of the portfolio over time and, in turn, impact the Commission's evaluation and selection process.

83. In this rulemaking, the Commission examined several potential rule changes intended to ensure the utility's Phase II 120-Day Report contained information necessary for the Commission to establish a final cost-effective resource plan. However, these same intentions can be achieved by the Commission in its Phase I decision rendered without any changes to the ERP Rules. We therefore clarify that under current rules the Commission necessarily determines what resource combinations must be presented by the utility in its 120-Day Report and, as necessary, define a "least cost portfolio" for presentation in Phase II, particularly if the least-cost plan differs from the "base case portfolio" used specifically to apply the statutorily required SCC for carbon dioxide emissions.

6. Governor Polis' Roadmap

84. In the October 2019 Decision, the Commission observed that the Polis Administration's "Roadmap to 100 percent Renewable Energy by 2040 and Bold Climate Action" speaks to at least four policy objectives that could have an impact on an electric utility's electric energy and demand forecasts. The Commission stated that: "The Roadmap and the participant comments regarding energy efficiency, demand response, retail renewable distributed generation, and other factors that have impacts on energy sales and demand forecasts suggest further examination of potential changes to Rule 3606 may be in order."[38] The Commission therefore encouraged CEO to take the lead on developing and presenting a consensus view or rule changes regarding Rule 3606.[39]

[38] Decision No. C19-0822-I at ¶ 43.

[39] Proposed/Existing Rule 3606. Electric Energy and Demand Forecasts.

85. In a joint filing that CEO submitted on December 20, 2019, the parties participating in CEO's efforts proposed two additions to Proposed Rule 3606(b), specifying that: (1) a utility's base forecast would incorporate savings from approved DSM programs, expected levels of distributed energy resources, and levels of transportation electrification consistent with the base assumption used in the utility's most recent transportation electrification plan; and (2) the utility would provide a separate forecast of load growth due to non-transportation-related beneficial electrification. The Commission included both provisions in the revised Proposed Rule published along with the April 2020 Decision.

86. Because CEO and the participating parties crafted a reasonable approach to address the implementation of the Polis Administration's Roadmap as it would likely be reflected in the utility's electric energy and demand forecasts, the utilities should anticipate providing the agreed upon forecasts to underpin their ERP filed as CEPs as well as a diverse range of additional alternative demand scenarios associated with various potential approaches for implementing the Roadmap.

7. Joint Proposal Addressing Transmission

a. Rulemaking Developments

87. In the April 2020 Decision, the Commission chose not to accept a proposal by CIEA that transmission network upgrades be evaluated separately from the bid evaluation and selection process, finding that the proposal was:

> …unnecessary, duplicative and could unfairly disadvantage or prejudice certain bidders over others. The biennial transmission plan filings pursuant to the Commission's Transmission Planning Rules as referenced in Proposed Rule 3608(b) are intended to address such opportunities for transmission project development before a Phase II ERP process. CIEA's proposal risks upsetting this process, and potentially causing certain bidders and projects to gain advantage

> because of the utility's previously undisclosed intentions to develop network upgrades.[40]

88. In subsequent comments, CIEA contended that the Commission should allow itself a proactive role in transmission in Phase I of an ERP and a means to address what is an "obstacle in plain sight" to Colorado's clean energy goals—that any policy addressing expected transmission constraints must be available to bidders prior to upcoming RFPs for Tri-State, Public Service, and Black Hills (2021, 2022, and 2023 respectively). CIEA noted that bidders cannot change their interconnection points after their bids are submitted, and argues that transmission solutions adopted after those RFPs will not affect resources to be added before 2030, because the respective resource acquisition periods will extend to 2030. CIEA again proposed a modification to Rule 3608(d) that would require utilities to analyze the costs and benefits of planned transmission assets separately from its evaluation of responses to its RFP. This would replace existing language requiring utilities to utilize transmission-related costs and benefits as criteria in bid evaluation.

89. Further, CIEA recommended allowing bidders to identify interconnection points on planned transmission lines that are presented in a Rule 3627 report. CIEA claimed that doing so would provide a transparent method to integrate Rule 3608(d) into the ERP and allow the Commission to evaluate transmission benefits as well as costs in Phase II. CIEA referenced the "chicken-and-egg" transmission problem, where the costs for new bulk system transmission lines that provide system benefits are assigned to bid portfolios, thereby rendering them non-competitive and eliminating such portfolios from inclusion in the 120-Day Report. CIEA stated that in order to avoid exclusion, bidders opt to specify gen-ties, and that gen-ties now connect the bulk of Colorado's renewable generation in a "hub-and-spoke" configuration. CIEA

[40] Decision C20-0207-I at ¶164.

complained that the Commission's practice of requiring interconnection only to existing transmission resources or those that have a Certificate of Public Convenience and Necessity (CPCN) limits bidders to the few remaining interconnection areas in Colorado, requiring long tie-lines, which CIEA claims is an expensive and inefficient way to integrate renewable energy.

90. CIEA pointed to Public Service's construction of the Rush Creek transmission line as an example of a better way to interconnect renewable resources. That line interconnects 1,600 MW of low-cost wind power, including 800 MW of projects approved as part of the CEP Portfolio that according to CIEA would not have been selected but for the existence of the Rush Creek line. CIEA argued that the benefits of enabling multiple projects in an efficient manner are not calculated or considered in the ERP Rules, and that new bulk transmission lines benefit the future of the system beyond a given RFP by enabling future low-cost renewable generation.

91. Finally, CIEA countered the Commission's finding in the April 2020 Decision that the Commission's transmission planning process provides "opportunities for transmission project development before a Phase II ERP process,"[41] stating that projects identified through that process are unavailable in the ERP process, both in the current and proposed rules. As a result, CIEA argued, the Commission's transmission planning process is currently irrelevant from the perspective of a bidder in an RFP. Allowing bidders to specify interconnection to projects identified in the Rule 3627 Report[42] process would address this problem without raising the disclosure concerns the Commission expressed in the April 2020 Decision. CIEA therefore proposes a modification to Rule 3614(f)(II) that would explicitly give the Commission authority

[41] *Id.*

[42] Rule 3627 requires the Colorado electric utilities to file a ten-year transmission plan every two years. The most recent plan is referred to as the Rule 3627 Report.

to modify a utility's RFP to enable bidders to specify interconnection to planned transmission resources.

92. In response to CIEA, Public Service argued that CIEA's proposals would fundamentally change the ERP process in a manner that should not be considered so late in this NOPR process. According to Public Service, analyzing transmission costs separately from portfolios isolates costs and prevents a holistic evaluation of all costs associated with a portfolio. Public Service further argued that allowing bidders to propose interconnection to transmission projects only in the planning stage will introduce significant uncertainty in the future delivery of these projects. Public Service nevertheless acknowledged the importance of transmission infrastructure development in facilitating decarbonization. Public Service stated that the Commission's rules establish a process to coordinate transmission planning and that SB 07-100 created a path to facilitate transmission buildout to unlock cost-effective clean energy resources. Public Service argued that given these regulatory and statutory paths, rule changes to modify the cost evaluation process or allow bidders to specify connection to speculative transmission lines are not appropriate.

93. CEO, in contrast, stated its support for the rule modifications proposed by CIEA, urging the Commission to act in a timely manner, noting that policies to fix the issues raised by CIEA must be in place in time to be relevant for the upcoming competitive bidding processes for Tri-State, Public Service, and Black Hills.

b. Transmission Needed for Pending Clean Energy Plans

94. On February 3, 2020, Public Service, Black Hills, and Tri-State filed a ten-year transmission plan in Proceeding No. 20M-0008E pursuant to the Electric Rules. In the plan filing, Public Service states that a CEP "will present significant drivers for transmission

planning" such as "[n]ew interconnection facilities for clean energy resources" and "[d]ecommissioning, or redevelopment, of existing transmission facilities associated with the potential for accelerated fossil-fuel retirements."[43]

95. Through Decision No. C20-0213-I, issued on April 7, 2020, the Commission issued notice of the filing of the electric utilities' biennial transmission plan filings submitted in Proceeding No. 20M-0008E. The Commission concluded that additional information from the utilities was necessary in light of §§ 25-7-105(1)(e)(VIII)(B) and 40-2-125.5, C.R.S., that require or allow certain electric utilities to file a CEP. The Commission thus directed the utilities to supplement their joint transmission filings initially submitted in Proceeding No. 20M-0008E.

96. In the supplemental filing submitted on June 8, 2020 in response to Decision No. C20-0213-I, Public Service offered the following:

> Public Service recognizes that better and earlier integration of transmission planning into the resource planning process will be critical going forward as it looks to achieve 80 percent carbon reduction by 2030 as part of its next ERP. Since the 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. This includes earlier identification to Public Service's transmission planners of the size and location of potential resources needed to meet public policy initiatives, so that Public Service can better plan the transmission necessary to accommodate these new resources and reconsideration of what Senate Bill 07-100 provided for transmission to be built in advance of identified generation resources in the identified Renewable Energy Zones.
>
> Public Service's Transmission Planning and Resource Planning departments are coordinating efforts to generally identify the actions that will be necessary to meet Public Service's carbon reduction goals under § 40-2-125.5(3)(I), C.R.S. As part of that process, Transmission Planning has conducted analyses of the potential standalone generation injection capabilities of various locations on Public Service's transmission system. Identifying stand-alone generation injection capability is the first step to understand how the existing transmission system might accommodate development of new clean energy resources such as wind

[43] 10-Year Transmission Plan for the State of Colorado to Comply with Rule 3627 of the Colorado Public Utilities Commission Rules Regulating Electric Utilities, filed on February 3, 2020 by Public Service, Black Hills, and Tri-State in Proceeding No. 20M-0008E as updated on June 8, 2020, pp. 17-18.

> and solar. Identifying and maximizing opportunities to utilize the existing transmission system can potentially reduce future transmission costs.
>
> Looking beyond the existing transmission system, in the Joint 10-Year Transmission Plan, Public Service identified and described conceptual new transmission plans that have been developed through the coordinated planning process and that could lay the framework for new transmission infrastructure to support Clean Energy Plan goals. These conceptual plans include the Weld-Rosedale-Box Elder - Ennis 230 & 115 kV Transmission Lines and the Weld County Transmission Expansion, the Lamar Front Range Transmission Project, and the San Luis Valley Project. Using the stand-alone injection capabilities described above along with these conceptual new transmission plans, Public Service is assessing different pathways for how it could achieve the carbon reduction targets of § 40-2-125.5(3)(I), C.R.S through combinations of actions including early coal retirements, reduced coal operations, additional renewable resources (utility scale and distributed) additional storage technologies, and continued expansion of energy efficiency programs, while also maintaining a high level of system reliability.
>
> Through a coordinated effort, Transmission Planning and Resource Planning are utilizing the stand-alone generation injection locations and the conceptual new transmission plans to develop portfolios for analysis that meet the Company's clean energy goals. Preliminary analyses are being conducted using generic cost and performance information for renewable, storage, and other generation technologies, which, in combination with coal-related actions, could be part of a Public Service Clean Energy Plan that will be brought forward to the Commission for approval in the future. Ultimately, the specifics of Public Service's preferred Clean Energy Plan will not be known until Public Service completes its Phase II competitive solicitation evaluation process as part of its next ERP and reports the results of that process to the Commission. This is anticipated to occur in 2022.[44]

97. In the September 2020 Decision issued in this proceeding, the Commission concluded that additional comments were necessary from the rulemaking participants regarding the consideration of new transmission investment in the ERP process before any revisions to the transmission-related provisions in the ERP Rules were adopted. The Commission expressed concern about CIEA's observation that the Commission's transmission planning process may be irrelevant from the perspective of a bidder in an ERP competitive solicitation, particularly when

[44] *Supplemental Joint Report for the State of Colorado to Comply with Rule 3627 of the Colorado Public Utilities Commission Rules Regulating Electric Utilities* (Supplemental Joint Report) filed by Public Service, Black Hills, and Tri-State on June 8, 2020 in Proceeding No. 20M-0008E, pp. 11-12.

Public Service must file a CEP as part of its next ERP. The Commission also stated concerns about the possibility that, without modifications to the ERP Rules addressing new transmission investment, the most cost-effective development of new generation resources may be precluded due to the lack of a full presentation of transmission investments that could be operational in time to fulfill resource needs as late as 2030, the end of the resource acquisition period for a CEP.

98. In response, the Commission stated in the September 2020 Decision that it sought to ensure to the extent it is possible, that new utility transmission investments associated with a CEP filed pursuant to SB 19-236 will be sufficiently addressed in Phase I prior to the issuance of the RFPs in Phase II. The Commission further expressed interest in examining whether certain backstop provisions should be introduced to the ERP Rules governing the Phase II process to achieve the same end: the identification of new transmission investments that could be operational in time to fulfill resource needs as late as 2030. With respect to Phase II processes, the Commission sought comments regarding opportunities for bidders to refresh their bids or to renegotiate contracts if the viability of new transmission resources emerges with increased certainty during bid evaluation in Phase II. The Commission specifically sought more information about the possibility of an extended bid evaluation process justified by closer examination of RFP bids and the utility's transmission system for better integration of the new resources and the avoidance of wasteful or poorly utilized radial lines.

99. For the purpose of soliciting the additional comments, the Commission took administrative notice of the filings made by Public Service, Black Hills, and Tri-State in Proceeding No. 20M-0008E and proposed potential revisions to the transmission-related provisions in the ERP Rules through the September 2020 Decision. The Commission also sought additional information and comment on: (1) whether applications for approval

of a CPCN for new transmission facilities should be filed concurrently with the initial ERP filing that launches Phase I of an ERP proceeding, particularly when the new transmission facility is necessary for the utility to achieve either the emission reductions required for a CEP pursuant to § 40-2-125.5(3)(a)(I), C.R.S., or the emission reductions required pursuant to Proposed Rule 3604(m) as set forth in the April 2020 Decision;[45] (2) whether any of the transmission-related information addressed in the rules proposed in the September 2020 Decision require extraordinary protection as highly confidential information, and whether such extraordinary protection requires different non-disclosure and access provisions as compared to other information claimed to be highly confidential in an ERP proceeding; and (3) whether Proposed Rule 3615(e)(V) provides sufficient rights and protections to bidders that they will be both encouraged to submit bids and able to refresh bids if transmission resources are modified during the course of Phase II.[46]

c. Joint Transmission Proposal

100. Prior to the October 13, 2020 hearing scheduled by the September 2020 Decision, Public Service filed a "Joint Transmission Proposal" on behalf of itself, Black Hills, CEO, CIEA, Interwest, and WRA, proposing an alternative approach to integrating transmission planning considerations into the ERP process. In subsequent joint comments filed on October 30, 2020, both CEC and COSSA/SEIA signed on to a revised Joint Transmission Proposal, subject to certain modifications. The Joint Parties state that their proposal "…seeks to strike the careful balance of better aligning transmission planning with the ERP process, maintaining

[45] Proposed/Existing Rule 3604. Contents of the Electric Resource Plan.
[46] Proposed Rule 3615. Phase II

the successful architecture of the ERP process, and advancing the State of Colorado's decarbonization goals, while providing for consumer protections."[47]

101. With respect to Phase I of an ERP, the Joint Parties propose that the most recently accepted or approved ten-year transmission plan submitted by the utility pursuant to the Commission's Electric Rules serve as the anchor for the Phase I process and ultimate Phase I decision regarding bid-eligible planned transmission projects. The transmission plan would be the starting point for assessment of transmission projects to which a developer could propose interconnection without the bid being burdened with costs from the transmission project. As part of its Phase I submission, a utility would provide a proposed list of "bid-eligible" transmission projects with appropriate support for the designations and including projected in-service dates for those projects. This list would include projects already granted a CPCN, projects for which a CPCN is pending, and "planned" transmission projects that have been studied and are feasible from the utility's perspective. Intervenors would have the right to propose alterations to the utility's proposed list, subject to the requirement that any additions to that list would have to have been formally studied in a FERC-approved planning process (*e.g.,* the Colorado Coordinated Planning Group) and eligible for ownership by the filing utility, regardless of whether such projects had been included in a ten-year transmission plan.

102. Based on a review of the record developed by the utility's filing, intervenor responses, utility rebuttal and any intervenor cross-answer testimony, and the evidentiary hearing, the Commission would make findings in the Phase I decision regarding the set of transmission projects to which bidders may propose interconnection. Developers that propose interconnection to such projects would not bear any cost burden for the transmission project on

[47] Updated Joint Transmission Proposal and Joint Final Comments to Decision No. C20-0661-I, p. 4.

their bid. Also, developers proposing interconnection to Commission-approved *planned* transmission lines—those for which there is neither a granted nor pending CPCN—have the option of specifying an alternative point of interconnection (POI) on the existing transmission grid under the same bid fee (*i.e.,* without additional charge). The Joint Parties submit that this approach provides certainty regarding bid-eligible transmission projects at the end of Phase I, which puts the bidders and the utility in the best position to submit and evaluate, respectively, project bids in the Phase II competitive solicitation.

103. In addition, utilities would include as part of their Phase I filing, a proposed approach for considering the potential quantifiable and non-quantifiable benefits of any planned transmission lines necessary to support bid portfolios in the Phase II process. Parties to the proceeding would have the opportunity to review the utility's proposed approach to evaluate such benefits through the normal Phase I litigation process and propose recommendations for the Phase I decision. The Commission would issue a finding regarding the approach for considering these transmission benefits in the evaluation of the bid portfolios presented in the 120-Day Report. These transmission benefits would not serve to decrease the actual costs of a portfolio from a net present value of revenue requirements (NPVRR) evaluation perspective; nevertheless, any projected benefits would provide a helpful analytic guidepost for the Commission to consider if evaluating: (1) a portfolio with lower NPVRR and lower future transmission capacity headroom benefits versus; and (2) a portfolio with a higher NPVRR but higher future transmission capacity headroom benefits.

104. With respect to Phase II of an ERP, the Joint Parties propose that if the Commission approves a resource plan in Phase II that entails construction of any planned transmission requiring a CPCN, the utility would be granted a "presumption of need" as part of

the Phase II decision.[48] CPCN applications for transmission investment filed pursuant to the approved resource plan would require utilities to provide "CPCN-quality" cost estimates with robust testimony and supporting evidence, which intervenors may challenge. A Commission decision approving the CPCN would provide the utility with a presumption of prudence with respect to these costs, the recovery of which would be subject to a subsequent rate proceeding. The Joint Parties recognize that, from a forward-looking perspective, undertaking increased transmission investment now to position utilities for the next act in decarbonizing the power sector—advancing toward the 2050 clean energy target of a 100 percent emissions reduction from 2005 levels—may justify portfolios with increased transmission investment in the instant ERP cycle as opposed to waiting for future ERP cycles to make the transmission investment in significant projects.

105. The OCC cautions that the Joint Transmission Proposal could result in overbuilding the transmission system in a manner that would be unduly burdensome to ratepayers. The OCC recommends that in order to avoid this, any transmission approved through the ERP process should be pared down to include only the needs of the ERP. The OCC further argues that the final transmission plan might receive a presumption of need, but should not be granted cost prudency in advance. Notwithstanding that caution, the OCC expresses general support for establishing a process to encourage appropriate levels of transmission as the "anchor" for an ERP.[49]

[48] The original proposal filed prior to the October 13, 2020 hearing had specified that a "presumption of prudence" for new transmission projects would attach following Commission approval of the resource plan, but this was modified to "the presumption of need" in the revised Joint Transmission Proposal filed on October 30, 2021.

[49] Note that the revised Joint Proposal substitutes a presumption of need for the presumption of prudence contained in the original Joint Proposal. The Joint Proposal no longer calls for a presumption of prudence for transmission projects.

106. The Joint Parties appear to have recognized the validity of the OCC argument on this topic, as the revised Joint Proposal submitted after the October 2020 hearing substituted a finding of the presumption of *need* would attach to any new transmission approved in a Phase II decision, rather than a presumption of prudence.

d. Findings and Conclusions

107. New transmission capacity will be essential in achieving the carbon dioxide emission reductions required by the 2019 General Assembly. The Joint Transmission Proposal maps out a reasonable process for addressing the "chicken-and-egg" problem that has previously inhibited the transmission development necessary to access the magnitude of low-cost renewable resources at the scale required to achieve the carbon emission reduction goals pursuant to SB 19-236. We will consider putting in place the necessary conclusions and findings in the Phase I decision to implement the terms of the Joint Transmission Proposal based upon the specific record of the ERP applications soon to be brought forward with CEPs and taking into account proposals moving forward in other proceedings such as, for example, the application of Public Service for a Colorado Power Pathway in Proceeding No. 21A-0096E.[50] In other words, we anticipate the investor-owned electric utilities filing a CEP to apply the agreed upon approach for addressing transmission-related issues, to the extent those same procedures are necessary.

[50] We recognize that Public Service has indicated that it does not intend to make use of the process envisioned by the Joint Transmission Proposal in its forthcoming CEP filing. In its March 2, 2021 application for a CPCN for its "Colorado Power Pathway" in Proceeding No. 21A-0096E, Public Service explains that it is hoping to move this set of proposed transmission projects forward on a separate and faster track than the ERP proceeding including its forthcoming CEP, so that it can place at least a portion of the proposed transmission project into service in 2025, which is the last year in which the federal production tax credit and investment tax credit will be available for wind and solar projects (unless those credits are extended). Public Service explains that under the Joint Transmission Proposal, the decision on whether or not to move forward with CPCNs for new transmission capacity that was "bid-eligible" in the RFP would not come until the Commission issues its Phase II decision, essentially preventing wind and solar developers to qualify for the tax credits.

108. With respect to the OCC's arguments, we appreciate the modification of the Joint Transmission Proposal to provide a presumption of need related to transmission projects, rather than prudence, following the Phase II decision. Granting a presumption of need should provide a utility with sufficient assurance that a proposed transmission line would gain approval in a subsequent CPCN proceeding to move forward in executing contracts with developers proposing POIs on that line. We note, however, that § 40-2-125.5(5)(V)(c), C.R.S., states: "Any actions, including transmission development, taken by the [utility] shall be presumed prudent to the extent those actions are a part of an approved [CEP]."

8. Best Value Employment Metrics

109. In the NOPR, the Commission consolidated the provisions in the ERP Rules defining the BVEM into Proposed Rule 3613.[51] The Commission further enhanced the BVEM–related provisions in the ERP Rules based on comments from Public Service developed in consultation with the RMELC/CBCTC.

110. In comments filed following the April 2020 Decision and in light of the passage of SB 19-236, RMELC/CBCTC contends that in order to satisfy the new statutory mandates of § 40-2-129(1)(a), C.R.S., the Commission must adopt BVEM-related rules for an ERP that: (1) ensure that all electric resource acquisitions are subject to mandatory BVEM requirements as part of the ERP process; (2) ensure that utilities obtain comprehensive and detailed BVEM documentation during the RFP process; (3) provide clear direction to bidders regarding BVEM documentation standards that bids must meet; and (4) ensure that the Commission considers comprehensive and detailed BVEM documentation prior to ERP approval, receives certification with objective BVEM performance standards, or waives BVEM documentation requirements

[51] Proposed Rule 3613. Best Value Employment Metrics.

when a utility agrees to use a project labor agreement for construction or expansion of a generating facility. RMELC/CBCTC argues that in the past, the absence of clear and enforceable BVEM documentation standards has resulted in the failure of utilities and non-utility bidders to submit adequate BVEM documentation, thereby making it impossible for the Commission to base its decision on the review of BVEM in accordance with § 40-2-129(1)(b), C.R.S.

111. Notwithstanding the Commission's proposal to adopt the new rule language RMELC/CBCTC developed with Public Service, RMELC/CBCTC argues that the Commission's proposed ERP Rules fall short of the new statutory requirements contained in SB 19-236 in that the repeated inclusion of the phrase "for example and as applicable" regarding the types of documentation to satisfy each element of the BVEM criteria to be submitted by bidders will allow them to withhold BVEM documentation from the Commission without consequence. RMELC/CBCTC contends that the proposed modifications rules thus will fail to ensure that the Commission's decision will "be based in part on review of the best value employment metrics criteria set forth in any solicitation document"[52] in contravention of statute and the Legislature's intent. RMELC/CBCTC proposes revised language for Proposed Rules 3613(a) through (d) to address this alleged shortcoming.

112. CIEA opposes the recommendations of RMELC/CBCTC. CIEA notes that the Commission did not adopt changes that RMELC/CBCTC had advocated in the April 2020 Decision because of the practical and legal issues it raised for bidders and the bid process. CIEA argues that the Commission should reject "this renewed attempt to bring bidders into the utility regulatory process, which raises threshold jurisdictional issues."[53] CIEA further argues that the

[52] RMELC/CBCTC Final Comments at p. 4.

[53] CIEA Response Comments p. 18.

Commission should find that its rules strike the right balance between having strong and detailed requirements for information and the practical considerations of wholesale electric market participants to so provide.

113. The April 2020 Decision analyzed the extensive comments from rulemaking participants regarding the BVEM provisions in the ERP Rules. That decision also explains that SB 19-236 prohibits Commission orders approving an ERP that fail to either provide the BVEM required by an RFP or certify compliance with objective BVEM standards; the Commission may, however, approve an ERP if the utility agrees to use a project labor agreement for construction of expansion of a generating facility.

114. Based on its analysis in the April 2020 Order, the Commission proposed to require the 120-Day Report to provide the Commission with the BVEM information provided by bidders. The Commission also modified the proposed rule changes to better allow the Commission proceeding flexibility with respect to the bid-related provisions in § 40-2-129, C.R.S. However, the Commission emphasized that ERP proceedings do not typically include Commission approval of specific contracts with bidders. While ERP proceedings can culminate in approvals of resource portfolios that include bids from specific bidders, the projects are assessed as bids as opposed to final contracts. Because detailed project development parameters including such things as labor agreements are not available at the time a bid is prepared, the Commission determined that it is unlikely a bidder would be in a position to offer certification or a project labor agreement during an ERP proceeding. Furthermore, the Commission rejected suggestions that the IE assess the BVEM information as part of its scope of work. The Commission stated that it can satisfy its statutory obligations regarding BVEM in Phase II without assistance from the IE.

115. In comments submitted following the April 2020 Decision, Public Service states that it is fully aligned with RMELC/CBCTC on the need to obtain better, more thorough BVEM data from bidders through the RFP process. Public Service notes that BVEM information supplied by bidders in the past has been scant, thereby limiting the Commission's ability to consider it in any meaningful way. Public Service states that Proposed Rule 3613 goes a long way to address this problem, as do the relevant provisions of SB 19-236, which amended § 40-2-129, C.R.S., by requiring that utilities obtain BVEM documentation from bidders and provide it to the Commission.

116. Public Service further states that this statutory framework was designed to remedy the challenges bidders have expressed with providing robust and detailed BVEM at the time of bid preparation, and puts non-utility bidders and utilities on similar footing in complying with the provision of BVEM information. Public Service recommends adding language to Proposed Rule 3614(d)(III) that would clarify that bidders have the option of either providing BVEM information or certifying compliance with BVEM performance standards included in the RFP.

117. We appreciate that Public Service is fully aligned with RMELC/CBCTC on the need to obtain better, more thorough BVEM data from bidders through the RFP process. We are also confident that Public Service understands that the implementation of the changes to § 40-2-129, C.R.S., pursuant to SB 19-236 will require utilities to provide that BVEM information to the Commission and to allow for certification of compliance with performance standards as set forth in the utility's RFP or otherwise use a project labor agreement. In accordance with § 40-2-129, C.R.S., Public Service should require BVEM documentation from bidders and provide it to the Commission. As guidance, Public Service should use the consensus language adopted for Proposed Rule 3613 in its RFP filed with its ERP containing a CEP.

118. We likewise will ensure compliance with § 40-2-129, C.R.S., when reviewing the CEPs for approval and will render the necessary findings and conclusions in the Phase I and Phase II decisions. We agree with Public Service that the statutory provisions in SB 19-236 sufficiently address the challenges non-utility bidders have expressed with providing robust and detailed BVEM at the time of bid preparation. Consistent with the April 2020 Decision, we further acknowledge the practical issues faced by bidders in that they will not have comprehensive and detailed BVEM at the time their bids are submitted in response to an RFP and then evaluated for bid selection. Accordingly, the Commission will work with the utilities to make sure that they include reasonable standards for the evaluation of BVEM information in their RFPs and require bidders to agree to abide by such standards as a condition of receiving a contract.

119. Finally, we agree with RMELC/CBCTC that information provided by bidders to the utility related to their bids should be made available to the Commission, upon its orders, and to Staff and other subject matter experts, in accordance with non-disclosure agreements and Commission decisions addressing information claimed to be highly confidential. Current rules do not prohibit the robust, meaningful provision of information, and the Commission can accomplish explicit direction in particular circumstances through its decisions as appropriate and required in upcoming ERPs.

D. Social Cost of Carbon

120. As stated in the October 2019 Decision, SB 19-236 enacts new statutory provisions in § 40-3.2-106, C.R.S., that require the utilities to consider the cost of carbon dioxide emissions when determining the cost, benefit, or net present value of any plan or proposal submitted in certain proceedings before the Commission. The Commission further noted that

§ 40-3.2-106(4), C.R.S., sets forth specific requirements for the Commission's calculation of the cost of carbon dioxide emissions. The Commission also must modify the cost of carbon dioxide emissions based on escalation rates equal to or greater than the central value escalation rates established in the 2016 Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Starting in 2020, the Commission also must use a social cost of carbon dioxide of not less than $46.00 per short ton of emissions.

121. In the April 2020 Decision, the Commission reiterated that § 40-3.2-106(4), C.R.S., is clear: "The commission shall base the cost of carbon dioxide emissions on the most recent assessment of the social cost of carbon dioxide developed by the federal government." The Commission also clarified that the statute does not prohibit additional analysis for Commission consideration, including additional analysis of GHGs other than carbon dioxide or different types of analyses of even carbon dioxide emissions.

122. In proceedings before the Commission since the enactment of SB 19-236, the utilities and other parties to certain proceedings have demonstrated that the new statutory provisions governing the use of an SCC can be successfully implemented without the Commission promulgating new rules. In 19A-0660E, Black Hills' amendment to its last ERP to pursue what it calls Renewable Advantage, the utility is acquiring a 200 MW solar project pursuant to an approved settlement agreement that includes terms addressing the calculated SCC and carbon emission reductions by 2030. And in 20A-0287EG, Public Service's 2021 and 2022 DSM plan, the Commission likewise approved a settlement that will cause Public Service to use "the Commission's approach for calculating the social cost of carbon, including the escalation rate, based on the Commission's ruling in Public Service's next-filed 2021 Electric Resource Plan," or, in other words, its CEP.

123. We conclude that the promulgation of any SCC rules should commence, if required, after the completion of Public Service's next ERP proceeding that will include a CEP and after the conclusion of Tri-State's ERP in Proceeding No. 20A-0528E. However, due to the clear statutory requirements in § 40-3.2-106, C.R.S., the Commission's decisions, not rules, can best ensure that a 120-Day Report presented in Phase II of an ERP will require: (1) the utility to apply the cost of carbon dioxide emissions to the existing and new resources; (2) the presentation of net present value of revenue requirements that include the cost of carbon dioxide; and (3) the calculation of the net present value of the total cost of the carbon emissions. Likewise, at this time the Commission's Phase II decision can best address the net present value of the cost of carbon dioxide emissions and other factors as required by § 40-3.2-106(3), C.R.S.

E. Workforce Transition Plans

124. Sections 40-2-125.5 and 40-2-133, C.R.S., enacted by SB 19-236, require investor-owned electric utilities to include a workforce transition and community assistance plan (WTP) as part of an application filing with the Commission for approval of either a CEP or another filing proposing early retirement of an electric generating facility. The statute primarily sets forth the information that must be included in the filing and does not require the Commission to enter any specific findings or take other actions with respect to the information set forth in the "plan."

125. The information to be included in a WTP includes:

- The number of employed workers employed (including contractors) at the facility to be retired, including all workers that directly deliver fuel to the utility;
- The total number of workers whose jobs will be retained and whose jobs will be eliminated;
- With respect to the jobs that will be eliminated, the number of workers (total and by job classification): whose employment will end without being offered other

employment; who will retire as planned, be offered early retirement, "or leave on their own;" who will be retained by being transferred to another facility or offered other employment; and who will be retained to work in a new job classification; and

- If the utility is replacing the facility being retired with a new electric facility, the number of workers from the retired facility who will be employed at the new facility as well as the jobs at the new facility that will be outsourced to contractors or subcontractors.

126. In the October 2019 Decision, the Commission proposed a new section of the Electric Rules to implement the new statutory provisions set forth in § 40-2-133, C.R.S., and solicited comments. In the April 2020 Decision, the Commission incorporated clarifying changes into the proposed rules but chose not to promulgate additional rules advanced by some participants in this rulemaking, reasoning that it would gain valuable experience in the upcoming ERP for Public Service and that it would consider that experience in promulgating rule refinements in a future rulemaking.

127. In response, Public Service agrees that given the detailed statutory requirements, no further rules regarding workforce transition are warranted at this time. Public Service contends that limiting rules to the requirements of the statute at this time will allow it to maintain the flexibility to treat each situation and community flexibly while preserving the Commission's authority to determine how the WTP should be considered as part of the Commission's broader resource plan decision-making process. Moreover, Public Service agrees that the Commission will gain valuable relevant experience in Public Service's CEP filing that can inform future WTP rule refinements.

128. We conclude that no new rules are needed to implement the new statutory provisions requiring a workforce transition plan to be filed with a CEP or with certain other ERPs or resource-related proceedings as specified in SB 19-236. The comments collected in this

proceeding suggest that the provisions in the statute are clear, that the Commission can implement these provisions in the context of individual ERP proceedings, and that Commission rules to implement those provisions are unnecessary, at least at this time.

F. Retirement of Renewable Energy Credits (RECs)

129. Section 40-2-125.5(3)(a)(III), C.R.S., among the provisions governing a CEP pursuant to SB 19-236, states: "The qualifying retail utility shall retire renewable energy credits established under section 40-2-124 (1)(d), in the year generated, by any eligible energy resources used to comply with the requirements of this section."

130. In comments filed in this proceeding, WRA contends that this provision clearly requires that, upon approval of a CEP, any renewable resource that will assist the utility in achieving its 80 percent emission reduction by 2030 must begin retiring Renewable Energy Credits (RECs) in the year those RECs are generated. WRA notes, however, that Public Service interprets this provision as requiring such RECs be retired starting in 2030, rather than upon approval of the CEP. WRA argues that Public Service's interpretation is contrary to the intent of both S.B. 19-236 and H.B. 19-1261 and should be rejected.

131. COSSA/SEIA and CEO agree with WRA, including that WRA's statutory interpretation is correct.

132. Public Service, on the other hand, argues § 40-2-125.5(3)(a)(III), C.R.S., has no binding requirements until 2030—the first year where a clean energy target is in place. Public Service claims that "the plain reading" of the statute supports the proposition that RECs must be retired in the year generated to the extent an eligible energy resource is used to comply with a clean energy target, but it reads the statute to mean there is no clean energy target until 2030 and, therefore, no requirement to retire RECs in the year generated until that year.

133. Public Service further claims, contrary to WRA, COSSA-SEIA, and CEO, that the Commission should not adopt a rule in this proceeding. Public Service argues that the matter was raised late in the proceeding and includes that AQCC is currently considering this issue. However, as WRA points out in response, the matter was raised in response to the Commission including consideration of changes in 2019 legislation affecting the newly-enacted CEP requirements, and there has been multiple rounds of comment on the topic (including at the October 2020 public comment hearing). In addition, while AQCC commented in this proceeding that it would have guidelines by this fall, no guidelines have been finalized[54] and AQCC appears to be deferring the matter of interpretation of Public Utilities Law under Title 40 to the Commission.

134. We conclude that the promulgation of rules is not needed prior to the filing of a CEP to address the implementation of § 40-2-125.5(3)(a)(III), C.R.S., concerning the retirement of RECs. Any necessary findings and conclusions in applicable proceedings will be governed by § 40-2-125.5, C.R.S. For example, this issue will be raised in the context of Public Service's upcoming ERP that includes a CEP. Particularly because no rules are necessary, and because this proceeding will not conclude before the commencement of that adjudication, we find it appropriate to address the implementation of REC retirement considerations within that adjudicated context.

G. Rules Governing Purchases from Qualifying Facilities

1. Rulemaking Developments

135. In the NOPR, the Commission observed that the section within the Electric Rules addressing Small Power Producers and Cogenerators has not been substantially modified for

[54] Comments before AQCC on its proposed guidelines were due October 16, 2020.

decades. The Commission concluded that it was appropriate in this rulemaking proceeding to review these "QF Rules" in their entirety and in conjunction with the other changes to the Electric Rules. Thus, a principal objective of this rulemaking is to examine whether it is necessary to clarify through rule modifications the role of the ERP competitive bidding process with respect to potential purchases of energy and capacity from QFs, while ensuring ongoing compliance with PURPA. The Commission acknowledged in the NOPR that several non-utility stakeholders have argued that certain provisions in the Commission's existing QF Rules are contrary to the requirements of PURPA. In contrast, the utilities and others argue that the existing QF Rules, combined with other provisions in the Electric Rules, are fully compliant with PURPA.

136. The proposed rule changes set forth in the NOPR with respect to the QF Rules were intended to preserve the ERP competitive bidding process as the primary means for a QF to secure a contract for the purchase of energy or capacity from the electric utilities. Consistent with PURPA, the Commission would determine in the Phase I ERP process whether the utility's Phase II competitive solicitation will be reasonably open to QF bids. If QFs have a reasonable opportunity to secure a purchase contract with the utility by means of the ERP competitive bidding, the Commission will rely on ERP competitive bidding as the means to a legally enforceable obligation for QFs. The proposed rule changes better clarify the link between ERP competitive bidding and QF contracts, in addition to addressing any gaps and inconsistencies across the full set of Electric Rules. The proposed rules also provide for a new tariff-based QF program that would arise when ERP competitive bidding becomes irregular, infrequent, or too expensive for owners and developers of small QFs. The proposed QF Rules also more explicitly addressed avoided costs for QF purchases, whether determined through competitive

bidding or by tariff, including recognition that the ERP competitive bidding process takes into account integration costs. In addition to these substantive changes, the NOPR proposed the complete elimination of most of the existing QF Rules because they are outdated or have been largely replaced by other processes or documents, some of which are no longer directly governed by the Commission's Electric Rules.

137. In the April 2020 Decision, the Commission further observed that the rulemaking participants remained sharply divided regarding the Commission's modified QF Rules as set forth in the NOPR. The utilities generally sought rules that would make ERP competitive bidding the "only" means for a QF to secure a legally enforceable obligation from the utility to purchase energy or capacity. In contrast, some QF proponents argued against competitive bidding as the primary means for QFs to secure a contract. The Commission explained in the April 2020 Decision that it continued to see merit in maintaining the Commission's current practice of tying the establishment of a legally enforceable obligation to a contract awarded to the QF based on a winning bid in a Phase II ERP competitive solicitation. The Commission further stated that it could determine that the means to secure a legally enforceable obligation for facilities smaller than 20 MW (but greater than 100 kW) also is a contract awarded to the QF based on a winning bid in Phase II of an ERP, placing the burden on establishing that the ERP is open to QF facilities smaller than 20 MW on the utility. The Commission explained that, upon consideration of the continuing opportunity for smaller QFs to compete in the Phase II bid solicitation process, the Commission may either: (1) maintain its existing practice of implementing PURPA requirements through ERP competitive bidding upon finding that the RFP bidding is accessible to facilities as small as 100 kW or some other level below 20 MW; or (2) supplement the competitive bidding with tariff-based provisions, as necessary.

2. FERC Order No. 872

138. FERC Order No. 872 sets forth minimum criteria to govern processes by which competitive solicitations are to be conducted in order for a competitive solicitation to be used to set QF rates. As codified and discussed throughout Order 872, FERC finds that transparent and non-discriminatory processes for competitive solicitation, include but are not limited to, the following factors:[55]

- [T]he solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards;[56]
- [S]olicitations must be open to all sources, to satisfy that purchasing [an] electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;
- [S]olicitations are conducted at regular intervals;[57]
- [S]olicitations are subject to oversight by an independent administrator;[58] and
- [S]olicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility through a post-solicitation report.[59]

139. FERC concludes that, if a utility acquires all of its capacity through a properly conducted competitive solicitation that adheres to these factors, and does not add capacity

[55] *See,* Order No. 872, at ¶ 413 and 427; 18 *Code of Federal Regulations* 292.304(b)(8).

[56] *See,* Order No. 872, at ¶ 431 (discussing use of non-disclosure agreement and processes to balance risks of competitive advantage and transparency requirements).

[57] FERC declines to "be overly prescriptive" as to what constitutes "regular intervals" but requiring utilities to review their capacity needs frequently, that the states are best situated to determine frequency of review, and that there "may be times when a utility's review of capacity needs reveals that no capacity is needed, and it would not make sense for a competitive solicitation to be mandated at such a time." Order No. 872, at ¶ 434.

[58] FERC declines to prescribe what constitutes an "independent administrator" but includes that the "substantive requirement of this factor is that the competitive solicitation not be administered by the purchasing electric utility itself or its affiliates, but rather by a separate and unbiased, and unaffiliated entity not subject to being influenced by the purchasing utility." Order No. 872, at ¶ 435.

[59] Certification requires a written, formally-issued finding by the state that the competitive solicitation and its results comply with PURPA and FERC's PURPA regulations, and must include the independent administrator's report to the same effect. Order No. 872, at ¶ 436.

through self-building and purchasing power from other sources outside of such solicitations, the competitive solicitations could be the "exclusive vehicle" for the purchasing electric utility to pay avoided capacity costs from a QF.[60] FERC further reaffirms that, when capacity is not needed, the avoided capacity cost rate can be zero.[61]

140. Through the September 2020 Decision, the Commission encouraged the rulemaking participants to provide additional comments and proposed redlines of further rule modifications to ensure the QF Rules adopted in this rulemaking clearly align with Order No. 872, to the extent appropriate, yet at the same time remain flexible.[62] The Commission noted, for example, FERC includes that certification of the competitive solicitation requires a written, formally-issued finding by the state that the competitive solicitation and its results comply with PURPA and FERC PURPA regulations – and must include the independent administrator's report to the same effect.[63] The Commission sought comment on whether the IE report and Commission orders can accommodate this requirement if FERC finalizes the rule discussed in Order No. 872, such that a Colorado rule change may not be necessary. More generally, the rulemaking participants were encouraged to consider and comment on whether this or any other direction should be codified in Colorado rules at this time, pending finalization of FERC's federal rule considerations regarding PURPA.

141. Comments following the September 2020 Decision seeking participant input on FERC Order No. 872 included two general discussions. On one side, the utilities and ratepayer interest organizations supported the Commission's competitive processes and note that FERC's

[60] Order No. 872, at ¶ 421.

[61] Order No. 872, at ¶ 423 (citing *City of Ketchikan, Alaska*, FERC ¶ 61293, at 62,061 (2001)).

[62] We do not propose additional changes to the ERP Rules or QF Rules at this time, except for the potential rule revisions addressed in this Decision.

[63] Order No. 872, at ¶ 436.

determinations were largely supportive of, and based on, Colorado's successful ERP Rules. Utilities, particularly Black Hills, also request that the Commission go further in its rules to lower the limit of 20 MW given FERC's findings that smaller facilities have access to competitive bidding. On the other side, the OCC and COSSA, while generally supportive that the Commission's processes align with the FERC order, state concern over the IE role. The OCC argues that the Commission, rather than the utility should pay for the IE to avoid impropriety and bolster independence.

142. FERC affirmed Order 872 in denying rehearing on November 19, 2020. In confirming its prior order, FERC reiterated and clarified its decision that provided significant state flexibility in setting avoided cost rates.[64]

3. PURPA Implementation without Modified Electric Rules

143. As stated in the NOPR and following orders,[65] we aim to make the competitive solicitation foundational to Colorado's ongoing PURPA compliance. The Electric Rules currently in effect aim to achieve the goals of ensuring a frequent competitive solicitation process as encouraged further by FERC in Order No. 872. Colorado's competitive bidding processes as governed by the ERP Rules have been, and can continue to be, compliant with PURPA. Rule changes are not necessary to comply with the open and transparent practices identified in Order No. 872. Nevertheless, the Commission will continue to ensure that utility ERP competitive

[64] Current appeals in the 9th Circuit challenge FERC's clarifications, particularly of the "one-mile" rule, but do not stay FERC's determinations or rule applicability.

[65] Decision No. C19-0197, issued February 27, 2020, at ¶ 262 (including that "[t]he 'QF Rules' proposed here preserve the ERP competitive bidding process as the primary means for a QF to secure a contract for the purchase of energy or capacity from the electric utilities"); Decision No. C20-0207-I, issued April 2, 2020, at ¶¶173-176 (seeking further comment on QF Rules, and maintaining competitive bidding as the primary means to secure a contract provided competitive solicitation is reasonably open to QF bids as provided through the proposed rules).

solicitations meet the open, regular, and transparency goals identified by FERC and will remain vigilant in the upcoming review of the ERP filed with CEPs.

144. If the Commission, in consultation with the IE retained primarily for the Phase II process of the ERP, find that solicitations are not reasonably available to QFs, targeted solicitations or tariffs could be ordered following the ERP. The remaining IE concerns raised by the participants in this rulemaking can also be addressed through direction and scoping of the IE's role in the Commission's Phase I decision for implementation in Phase II.

4. Obligation to Purchase and Avoided Costs

145. The NOPR and the April 2020 Decision included a new section within the QF Rules that address an electric utility's obligation to purchase from QFs. The NOPR and the April 2020 Decision further proposed significant modifications to the provisions governing avoided costs as they relate to QFs.[66]

146. Public Service agrees competitive bidding should remain the primary means for QFs to secure contracts, with the limited exception of the tariffing approach discussed in the NOPR and the April 2020 Decision. Public Service remains concerned, however, that: (1) the proposed rules could lead to confusion about whether and when QFs that the Commission determines do have reasonable access to the competitive bidding process can invoke PURPA to purport to "put" power to a utility outside of that process; and (2) any gap in the Commission's QF-related rules could lead to attempts by QFs to "put" power to a utility at any time. Public Service further asks the Commission to prevent QFs from sitting out the ERP competitive bidding process and then purport to rely on the competitive bidding price when seeking to put

[66] Existing Rule 3902. Avoided Costs.

power to a utility. Public Service argues that allowing QFs that did not participate in the ERP bidding to then purport to displace winning bidders would distort valid competition on pricing and could subvert the competitive bidding model in its entirety. To deter potential abuses of the Commission's rules, Public Service proposes rule language that limits a legally enforceable obligation to winning bids in the ERP solicitations and to the utility's applicable tariff where the Commission has determined that competitive bidding is not reasonably accessible to QFs of a specified size smaller than 20 MW.

147. CIEA does not dispute the Commission's rationale for selecting the Phase I Decision to make a determination regarding the applicability of ERP solicitations for QF procurements for facilities smaller than 20 MW. However, CIEA suggests that the Commission consider a means of confirmation of its QF-related decision in Phase I, either through the Phase II 120-Day Report or by the IE, that the competitive solicitation and bid evaluation process was fair, transparent, and sufficiently available to QFs. CIEA also encourages the Commission to consider a tool to order targeted solicitations where it determines QF capacity was not sufficiently afforded an opportunity to bid, in lieu of complicated avoided cost litigated proceedings.

148. Early in this proceeding, the QF developer sPower argues in response to the NOPR and the rules attached to the April 2020 Decision that the Commission's proposed QF Rules do not comply with PURPA or the FERC regulations implementing PURPA. Specifically, sPower argues that PURPA and the FERC's regulations require utilities to purchase "any energy and capacity which is made available from a qualifying facility"[67] at an avoided cost rate and that PURPA requires the Commission to implement this "must buy obligation" through

[67] sPower's April 23, 2020 filing at p. 61.

means separate and in addition to the proposed requirement that QFs larger than 20 MW bid in the ERP competitive solicitations. sPower argues that requiring a QF to win a competitive bidding process before it may sell its energy and capacity to a utility is logically and legally incompatible with PURPA's must-buy requirement. According to sPower, the FERC's regulations give the QF—not the utility and not the Commission—the right to determine whether it will sell its energy and capacity on an "as available" basis or "pursuant to a legally enforceable obligation."[68] sPower's pleadings proposed QF Rules also violate PURPA because they fail to recognize the unique rights afforded to QFs by subjecting QFs to an RFP requirement that does not recognize a QF's federally-mandated right to a contract.

149. sPower's advocacy in this and other proceedings[69] hinged on its claim that Colorado's long-standing competitive bidding process simply could not underlie PURPA compliance. Following Order No. 872 and the Commission's September 2020 Decision explicitly seeking stakeholder response, the Commission received no further comments from participants arguing that competitive solicitation could not be used as the primary means to determine avoided costs, so long as the Commission continues to meet criteria that ensures open and transparent bidding practices.

150. We conclude that Colorado can meet the standards of Order No. 872 by addressing in the Phase I and II decisions whether the utility's ERP was sufficiently available to QFs under the currently effective Electric Rules. The Commission can effectively incorporate through decisions, rather than necessarily adopting rules that are likely to be immediately

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[68] *Id.* at p. 118.

[69] *See, e.g.,* NOPR, at ¶ 261 (citing a series of applications seeking legally enforceable obligations to purchase energy and capacity from QFs owned by sPower with the combined nameplate capacity that totaled approximately 1,400 MW, which is larger than the resource need addressed in Public Service's most recent ERP).

outdated and at the same time not fact-specific, the suggestions raised by CIEA regarding the linkages necessary between QF bidding opportunities and the ERP process. As explained above, Order No. 872 states that FERC "support[s] the use of competitive solicitations as a means to foster competition in the procurement of generation and to encourage the development of QFs in a way that most accurately reflects a purchasing utility's avoided costs." Order No. 872 further advances that states are afforded flexibility to use a "properly structured" competitive solicitation to determine avoided cost rates for QFs. In making its determination, FERC rejected arguments, including those from sPower, that competitive solicitations could not be the primary means for PURPA compliance, so long as fundamental transparency, regularity, open access, and independence principles were met.

151. We expect the investor-owned electric utilities to address QF participation in their proposed RFP solicitations in their initial ERP application filings that contain a CEP so that the parties and ultimately the Commission can address the QF matter in its Phase I decision following the Phase I adjudicated process. Furthermore, if the Commission finds in its orders approving a CEP or other ERP that QFs did not have a viable opportunity to secure a contract through the competitive bidding process, other means will be pursued to address that potential deficiency relative to PURPA requirements such as those examined in this rulemaking proceeding. These options, including tariff considerations or targeted solicitations, can appropriately be raised through the adjudicated process and rules are not required to ensure these procedural backstops are available, if necessary.

5. Interconnection and Operations

152. The NOPR and the April 2020 Decision proposed to eliminate most of the existing QF Rules following those addressing utility obligations to purchase and avoided costs.

The Commission instead proposed to add certain provisions applicable to QFs related to interconnections and to link the QF's operations to the same contracts and model contracts used by the utility pursuant to its ERP competitive bidding.

153. In general, the rulemaking participants agree that the existing provisions in the Electric Rules which include QF specific interconnection procedures are outdated and unnecessary.

154. Because we decline to modify the Electric Rules in this proceeding, we clarify that the RFPs and model contracts that the utilities use for their ERP competitive solicitations can continue to govern interconnections and operations for QFs.

6. Independent Evaluator

155. FERC Order No. 872 specifies that in order for a competitive solicitation to be used as the sole basis for establishing QF rates, such solicitations must, among other things, be overseen by an "independent administrator" or in the Commission's terminology, the IE.

156. The OCC and COSSA/SEIA argue that the cost of the IE should be paid by the Commission to ensure its independence. Under FERC's order, the independent entity must "administer and score" the competitive solicitation. However, FERC declined to be overly prescriptive as to what constitutes an "independent administrator," responsible for administering the competitive solicitation. FERC clarified that the entity must be separate, unbiased, and an unaffiliated entity not subject to being influenced by the purchasing utility.

157. The selection of an IE for the ERPs, including the ERPs that contain a CEP, will be an issue discussed by the parties in the Phase I proceeding and the Commission necessarily will address the selection of an IE in its Phase I Decision. As it does under the current rules, the Commission will set forth a scope of work for the IE in its Phase I decision, and can ensure this

scope of work is in compliance with FERC Order 872. In addition, through its orders, the Commission can ensure that the IE's scope of work will include, as necessary, a determination on whether the bid solicitation and evaluation process provided fair access to QFs.

158. We disagree with OCC and COSSA that argue the IE's independence is hampered through the payment structures enacted in Colorado. While the terms of payment to the IE will be contained within a contract with the particular utility filing its ERP, the IE does not act as an employee or agent of the utility in any way. In fact, the IE is a watchdog "advisor" per the Commission's current rule processes. The utility is ultimately fully reimbursed for the cost of the IE through its ratepayers. Therefore, the Commission rules and orders dictate the scope and direction of work the IE performs, ensure its independence, and ratepayers to each respective utility, not the companies, ultimately pay for the IE's services and advisements in ERP proceedings. This approach is also entirely consistent with normal commercial approaches to private energy project development and finance, where project owners routinely engage and pay for independent engineers to conduct detailed due diligence on behalf and for the benefit of third-party financing entities.

159. In addition, the IE duties and scope of work for Public Service's ERPs have been significantly greater than the IE scope of work for Black Hills' past ERPs. Therefore, paying the IE as an advisor out of the Commission's fixed utility funds is impractical, and at the same time unfair to ratepayers of the respective companies. The OCC's arguments are not only inaccurate on the claims that the payment structure impedes the independence of the IE, or ever has, but would force Black Hills customers to pay for the more expensive IE work conducted by the IE in Public Service proceedings. We therefore find it prudent to maintain the current payment

structure that, consistent with Order No. 872, maintains independence of the IE that serves as an advisor to the Commission in the case, and at the same time avoids burdensome ratepayer costs.

H. Modeling and Analysis in Upcoming Clean Energy Plan Proceedings

160. The Commission affirmed in the NOPR its interest in continuing to apply some form of a scenario planning process. The Commission also sought comment on whether the Commission should promulgate new rules to incorporate a form of scenario planning to be applied within an ERP proceeding and whether the Commission should endeavor to develop different sets of assumptions about the future for exploring possible risks that may arise from those assumptions in an ERP context. In seeking comment on these proposals, the Commission also expressed interest in maintaining and improving upon the transparency of the inputs and outputs of the modeling used to develop the scenarios.

161. The extensive review of the legislation from the 2019 General Assembly conducted in this proceeding since the initial hearings in 2019 has led us to conclude that much of the focus of Phase I in the forthcoming ERP proceedings for the approval of a CEP will be the determination of resource need or, more likely, multiple possible resource needs to be experienced during the resource acquisition period and the planning period. As discussed above, the state-mandated emission reduction targets in HB 19-1261 and SB 19-236 will be among the most significant drivers of resource need determinations in the ERPs that include a CEP. Due to multiple factors causing variability in future resource needs beyond emission reduction requirements, however, the investor-owned electric utilities will be compelled to provide a much more robust analysis of their existing resources and alternative demand scenarios as compared to past ERPs.

162. For example, we anticipate utilities will necessarily address beneficial electrification across our state in the near future as it affects resource planning. At the February 23, 2021 interagency workshop with CEO and CDPHE scheduled in Proceeding No. 21M-0061E, we discussed the potential benefits to all stakeholders from examining electrification of transportation and buildings over the next 20 years in the pending ERP proceeding to be filed by Public Service pursuant to SB 19-236. While such analysis relates to the Polis Administration's Roadmap discussed at length in this proceeding regarding the modeling and analysis of demands and resource needs, we expressed additional interest in the validation and clarification of opportunities for HB 19-1261 implementation beyond the approval of the forthcoming CEPs.

163. At the interagency workshop, CEO and CDPHE presented Colorado's Greenhouse Gas Pollution Reduction Roadmap to implement the major components of the climate legislation from the 2019 General Assembly and HB 19-1261 specifically. CEO also presented near term actions related to the electrification of transportation by 2030 and the reduction of GHG emissions from residential, commercial, and industrial fuel use. As part of our discussion with CEO and CDPHE during the interagency workshop, we raised the uncertainty facing the electric utilities stemming from unprecedented demands that will be placed on their systems in the future as other sectors of Colorado's economy decarbonize pursuant to HB 19-1261.

164. We noted, for example, that ERPs tend to focus on acquisitions of utility-scale resources over a near-term resource acquisition period. Going forward, however, beneficial electrification could increase total electric demands in Colorado by unprecedented amounts,

which will have large impacts on the design, economics, and emissions associated with the electric system beyond the Commission's approval of the utilities' CEPs.

165. The Commission anticipates that, while rules are unnecessary immediately to address CEPs contained in impending ERP adjudications, it will need to continue developing resource planning policies and procedures as statewide emission reductions required by HB 19-1261 are pursued. Nevertheless, the upcoming ERPs that include CEPs present a unique opportunity for the Commission and the various stakeholders to examine a diverse set of relevant scenario analyses. A goal of the Commission will be to create a better and more resilient understanding of how Colorado's electric resource needs and emissions through 2030 and through 2050 will be impacted by beneficial electrification of transportation and buildings. In addition, we expect that understanding the timing and mechanisms that cause changes in resource needs will also be highly significant. For example, if electric vehicles are charged at times when solar or wind generation might otherwise be curtailed due to insufficient demand by end-users, then such vehicles can increase penetration of cost-effective renewables and lower electric rates by spreading the fixed electric system costs over a larger sales base. Conversely, if electric vehicle charging occurs during system peak, additional generating resources will likely be needed.

166. Although we close this rulemaking proceeding without further amending the Electric Rules to define any specific scenario planning process for ERP proceedings, we reiterate that the forthcoming filing of CEPs pursuant to SB 19-236 will offer Colorado a remarkable occasion to use ERP modeling and scenario analysis to inform how Colorado can cost effectively achieve its emission reduction goals over the next two decades. We encourage the utilities, CEO, Staff, and all other parties to the CEP proceedings to assist us in seizing this opportunity.

II. <u>ORDER</u>

A. The Commission Orders That:

1. The Notice of Proposed Rulemaking in Decision No. C19-0197, issued on February 27, 2019, and published in the March 10, 2019 edition of *The Colorado Register* shall terminate without modifications to the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado* Regulations 723-3, consistent with the discussion above.

2. This Proceeding is closed.

3. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Decision.

4. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING March 24, 2021.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners