Decision No. C20-0155

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19R-0408E

IN THE MATTER OF THE PROPOSED RULES IMPLEMENTING SENATE BILL 19-236 REGARDING INTEGRATED OR ELECTRIC RESOURCE PLANS FOR WHOLESALE ELECTRIC COOPERATIVES.

DECISION ADOPTING RULES

Mailed Date: March 10, 2020
Adopted Date: January 22, 2020

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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Colorado Public Utilities Commission amends the provisions in the rules governing Electric Resource Planning (ERP Rules) at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq.,* as they apply to wholesale electric cooperatives. The proposed amendments fulfill the requirement in Senate Bill (SB) 19-236, codified at § 40-2-134, C.R.S. (Section 134), that requires the Commission to adopt rules that address application filings from wholesale electric cooperatives for Commission approval of their integrated or electric resource plans (ERPs).

2. As discussed below, we adopt rules with revisions as attached to this Decision in legislative format (Attachment A) and in final format (Attachment B).

B. Notice of Proposed Rulemaking (NOPR)

3. On May 30, 2019, Governor Jared Polis signed into law SB 19-236. Section 134 as enacted by that bill, directs the Commission to promulgate new ERP Rules for Tri-State Generation and Transmission Association, Inc. (Tri-State), Colorado's single wholesale electric cooperative. In developing such rules, the Commission must consider, among other factors determined by the Commission, whether Tri-State: serves a multistate operational jurisdiction;

has a not-for-profit ownership structure; and has a resource plan that meets the energy policy goals of Colorado.

4. The Notice of Proposed Rulemaking (NOPR) issued in this Proceeding on July 31, 2019[1] explains that the Commission has been engaged in examining Tri-State's resource planning for more than a decade.[2] The Commission resolved to build on the stakeholder process already applicable to Tri-State by formalizing requirements in new ERP Rules for the presentation, disclosure, and transparency of information regarding Tri-State's resource planning.[3] The proposed rules set forth in the NOPR also would take into account the differences between Tri-State and Colorado's investor-owned electric utilities (IOUs) as required by Section 134. Such differences include Tri-State's multi-state operations, its cooperative ownership structure, and its ongoing efforts to secure full rate regulation at the federal level.

5. The NOPR stated that the proposed ERP Rules for Tri-State would include a Phase I process that provides interested stakeholders, such as Tri-State's member rural electric cooperatives and advocates for Colorado's energy policies, access to relevant information and opportunities to examine the resource options available to Tri-State in a formal application process overseen by the Commission. The proposed filing requirements for Phase I also would safeguard a role for competitive bidding which has served to bring cost-effective resources to Colorado through market forces, including renewable energy resources and, most recently, new energy storage technologies.[4] The proposed rules for a Phase II process would result in the

[1] Decision No. C19-0651, issued July 31, 2019, Proceeding No. 19R-0408E.
[2] Decision No. C09-0092, issued January 30, 2009, Proceeding No. 09I-041E.
[3] Decision No. C10-0101, issued February 4, 2010, Proceeding No. 09I-041E.
[4] Decision No. C18-0761, issued September 10, 2018, Proceeding No. 16A-0396E.

structured presentation of resource options obtainable to Tri-State, including their relative costs and their impacts on the environment and Colorado communities.

6. The Commission stated in the NOPR that the full set of proposed ERP Rules was intended to shine more light into Tri-State's existing generation resources and the underpinnings of its plans to transition to a cleaner energy portfolio. The proposed rules were also expected to ensure accountability of Tri-State's staff, board, and leadership in the areas of cost-effective resource acquisition and compliance with new Colorado laws mandating a significant reduction in carbon dioxide emissions, such as House Bill (HB) 19-1261 "Concerning the Reduction of Greenhouse Gas Pollution, and, in Connection Therewith, Establishing Statewide Greenhouse Gas Pollution Reduction Goals."

7. The NOPR further explained that this rulemaking proceeding would focus exclusively on ERP Rules for Tri-State. This clarification was necessary, because the Commission had issued a separate Notice of Proposed Rulemaking on February 27, 2019 through Decision No. C19-0197 in Proceeding No. 19R-0096E (ERP NOPR) to amend the Electric Rules in six areas: (1) the ERP Rules; (2) the Renewable Energy Standard 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 presently in 4 CCR 723-3-3665; (5) the provisions for utility purchases from Qualifying Facilities presently at 4 CCR 723-3-3900, *et seq.*; and (6) the Interconnections Standards and Procedures presently in 4 CCR 723-3-3667. Hearings in Proceeding No. 19R-0096E were conducted on April 29, 2019 through May 3, 2019 and on October 29, 2019. A decision adopting revised Electric Rules is pending.

8. Although the ERP NOPR included no proposed revisions to the language in Rule 3605 addressing "Cooperative Electric Generation and Transmission Association Reporting

Requirements," several comments filed in Proceeding No. 19R-0096E addressed in that proceeding, the applicability of a Commission-driven ERP process for Tri-State. The ERP NOPR further anticipated the potential need for the Commission to take into account statutory changes enacted by the 2019 General Assembly and signed into law.

9. In the NOPR issued in this Proceeding, the Commission explained that certain provisions in the ERP Rules under review in Proceeding No. 19R-0096E will also apply to Tri-State: Existing/Proposed Rule 3601. Overview and Purpose; Existing/Proposed Rule 3602. Definitions; Existing Rule 3614/Proposed Rule 3612. Confidential Information Regarding Electric Generation Facilities; Proposed Rule 3613. Best Value Employment Metrics; Existing Rule 3618/Proposed Rule 3616. Annual Reports; and Existing Rule 3619/Proposed Rule 3617. Amendment of an Approved Electric Resource Plan. The Commission added Existing Rule 3000. Scope and Applicability; Existing Rule 3001. Definitions; and Existing Rule 3002. Applications will also apply to Tri-State.

10. The Commission further clarified that, given the structure and contents of Rule 3605 as set forth in the NOPR, the following ERP Rules being reviewed in Proceeding No. 19R-0096E are not intended to apply to Tri-State: Existing/Proposed Rule 3603. Electric Resource Plan Filing Requirements; Existing/Proposed Rule 3604. Contents of the Electric Resource Plan; Existing/Proposed Rule 3606. Electric Energy and Demand Forecasts; Existing/Proposed Rule 3607. Assessment of Existing Resources; Existing/Proposed Rule 3608 Transmission Resources; Existing/Proposed Rule 3609 Planning Reserve Margins and Contingency Plans; Existing/Proposed Rule 3610. Assessment of Need for Resources: Proposed Existing Rule 3615/Proposed Rule 3611. Exemptions and Exclusions; Proposed Rule 3614. Phase I; and Proposed Rule 3615. Phase II.

1. Participant Comments

11. Initial comments in response to the NOPR were filed by the following interested stakeholders: Tri-State; Governor Polis' Colorado Energy Office (CEO); Colorado Independent Energy Association (CIEA); sPower Development Company, LLC; Sierra Club; United Power, Inc. (United Power); Southwest Energy Efficiency Project (SWEEP); Interwest Energy Alliance; and Western Resource Advocates (WRA).

12. Reply comments responsive to the initial comments were filed by: Tri-State, CIEA, Sierra Club, SWEEP, United Power, and WRA.

13. The Commission conducted a hearing on the proposed rules on October 15, 2019. Written comments offered at the hearing were included in the record in this Proceeding. Oral comments offered at the hearing were captured in a transcript.

14. Post-hearing comments were filed by Boulder County, CEO, and Tri-State.

15. Various towns and counties served by rural co-ops that are members of Tri-State also submitted written comments throughout this Proceeding. Numerous additional comments were filed by organizations such as Colorado Ski Country and The Western Way. Over 100 comments were filed by individuals regarding ERP Rules applicable to Tri-State in this Proceeding and in Proceeding No. 19R-0096E.

2. Responses to the NOPR

16. Tri-State generally supports the rules attached to the NOPR. Tri-State limits its comments primarily on what it calls "relatively minor changes" to the rules attached to the NOPR. Most of Tri-State's advocacy in this rulemaking targets the additional rule modifications advanced by the other participants in this proceeding.

17. CEO's recommendations mainly entail further rule revisions that often mirror its suggestions for the ERP Rules applicable to the IOUs under review in Proceeding No. 19R-0096E. CEO seeks to ensure that the ERP Rules for both the IOUs and Tri-State: (1) foster transparency; (2) allow for meaningful stakeholder engagement; (3) promote clean energy resources; (4) reduce the carbon intensity of Colorado's electricity generation; and (5) align resource planning with other state energy and environmental policies. CEO also seeks ERP Rules that will require Tri-State to work with its member cooperatives to help them meet their clean energy and greenhouse gas (GHG) reduction goals.

18. WRA similarly recommends that the rules for Tri-State mirror the language in the ERP Rules for IOUs whenever possible.

19. CIEA focuses its comments on requiring Tri-State to use competitive bidding "in equal force" to the electric IOUs.

20. Sierra Club argues for strengthened requirements regarding Tri-State's assessment of its generation fleet with a focus on the economics of, and the need for, its fossil-fueled generating units.

21. SWEEP advances proposals for Tri-State to partner with its rural co-op members to offer demand-side management (DSM) programs as a means to meet the state's environmental goals at the lowest cost.

22. United Power explains that a partial requirements contract with Tri-State, along with this ERP rulemaking proceeding, should provide an opportunity for United Power to advance the goals set by the Colorado Legislature and further the co-op's mission to provide reliable and cost-effective service. United Power states it has a specific interest in the projections

and modeling that will underlie the ERP process and the way Tri-State will seek to adjust its generation portfolio.[5]

C. Cost of Carbon Dioxide Emissions and Emissions Reductions

23. The Commission explained in the NOPR that SB 19-236 requires the Commission to consider the cost of carbon dioxide emissions, calculated in accordance with the most recent assessment of the social cost of carbon dioxide developed by the federal government, in various proceedings including application proceedings for the approval of an ERP filed by Tri-State. In Proceeding No. 19R-0096E, however, the Commission stated that because other types of electric utility proceedings are also required by SB 19-236 to use a specific cost of carbon dioxide emissions, new provisions to the Commission's Electric Rules are required to implement the newly enacted § 40-3.2-106, C.R.S. On October 7, 2019, the Commission proposed additional rule revisions regarding the cost of carbon dioxide emissions in Decision No. C19-0822-I issued October 7, 2019 in Proceeding No. 19R-0096E. A hearing on those proposed provisions was conducted on October 29, 2019.

24. Certain rules adopted by this Decision anticipate the promulgation of a new section of the Electric Rules in Proceeding No. 19R-0096E to implement the statutory provisions set forth in §§ 40-3.2-106(1) and 40-3.2-106(4), C.R.S. For example, the proposed revisions to Rule 3605 are based on the assumption that such new provisions will be adopted in Proceeding No. 19R-0096E (*e.g.*, Proposed Rule 3605(a)(IV)(H) depends on the Commission's calculation

[5] On November 6, 2019, United Power filed a formal complaint against Tri-State in Proceeding No. 19F-0621E related to a proposed charge for United Power to exit from Tri-State as a member of the wholesale electric cooperative. In its formal complaint pleading, United Power states that transitioning to a partial requirements contract with Tri-State is an alternative to United Power withdrawing from membership in Tri-State.

of the cost of carbon based on the most recent assessment of the social cost of carbon developed by the federal government).

25. The Commission also stated in Proceeding No. 19R-0096E that the new provisions in §§ 40-3.2-106(2) and 40-3.2-106(3), C.R.S., that relate specifically to an ERP application would be addressed within the series of ERP Rules. Therefore, the use of the statutorily-required cost of carbon in an ERP application proceeding for Tri-State is addressed by this Decision, as discussed below.

26. Decision No. C19-0822-I issued in Proceeding No. 19R-0096E also stated that ERP application proceedings have served for decades as the primary cases in which cost-effective emission reduction strategies have been examined by the Commission. The Commission also stated that the legislation enacted from the 2019 General Assembly will cause carbon emission reductions to dominate the utilities' future ERP application proceedings. The Commission therefore sought from the Colorado Air Quality Control Commission (AQCC) within the Colorado Department of Public Health and Environment (CDPHE), information regarding the AQCC's promulgation of rules and regulations necessary to ensure progress toward a 26 percent reduction in statewide GHG pollution by 2025, a 50 percent reduction by 2030, and a 90 percent reduction by 2050, relative to 2005 statewide levels, pursuant to HB 19-1261. The Commission requested information on AQCC's timeline for promulgating the rules and regulations to achieve the minimum reductions in statewide GHG pollution and the specific goals that will apply to the state's electric utilities, including Tri-State. The Commission further discussed in Decision No. C19-0822-I the requirements in SB 19-236 for a Clean Power Plan that Public Service Company of Colorado (Public Service) must file as its next ERP, and other utilities may file as an ERP, pursuant to § 40-2-125.5(4), C.R.S.. A Clean Power Plan must

reduce carbon dioxide emissions by 80 percent from 2005 levels by 2030. § 40-2-125.5(2)(a), C.R.S.

27. In this Proceeding, by Decision No. C19-1023-I, issued on December 19, 2019, the Commission concluded that certain comments filed in Proceeding No. 19R-0096E or offered orally at the hearing on October 29, 2019 are relevant to the Commission's adoption of the ERP Rules that will specifically apply to Tri-State. Pursuant to Commission Rule 1501(c), of the Rules of Practice and Procedure, 4 CCR 723-1, the Commission administratively noticed the following filings in Proceeding No. 19R-0096E: the comments filed by Tri-State on October 21, 2019; the supplemental comments filed by Public Service on October 21, 2019; the comments filed by Sierra Club on October 21, 2019; the comments filed by CDPHE on October 22, 2019; and the supplemental comments filed by CEO on October 24, 2019. The Commission also administratively noticed the comments offered orally at the hearing in Proceeding No. 19R-0096E on October 31, 2019, as transcribed.

D. Tri-State's Proposed ERP Filing Deadline and Request for Pre-Rulemaking Proceeding

28. On May 31, 2019, the day after Governor Polis's signed Section 134 into law, Tri-State filed a Petition for Approval of a Variance to Extend the Filing of its Next Electric Resource Plan, and Request for Pre-Rulemaking Proceeding (Petition) in Proceeding No. 19V-0311E. Tri-State sought an extension of the deadline for filing its next ERP from October 31, 2019 to December 31, 2020. Tri-State argued that such an extension would allow sufficient time for: (1) both it and the Commission to engage with stakeholders; (2) the Commission to conduct a rulemaking proceeding focused on resource planning rules applicable only to Tri-State; (3) Tri-State to obtain and consider stakeholder input in connection with development of its next resource plan; and (4) Tri-State to develop and file its resource plan

pursuant to the new rules. In addition to the waiver from the filing deadline in the currently effective ERP Rules, Tri-State requested that the Commission open a miscellaneous proceeding for the purpose of soliciting input and information concerning resource planning rules for Tri-State consistent with Section 134.

29. By Decision No. C19-0629, issued July 24, 2019 in Proceeding No. 19V-0311E, the Commission granted Tri-State's request to waive the October 31, 2019 filing deadline for its next ERP. The Commission determined that Section 134 requires the promulgation of new rules for application filings from Tri-State for approval of its ERPs, which is a significant change from Tri-State's reporting requirements in the existing ERP Rules. However, the Commission denied Tri-State's request to establish a new deadline of December 31, 2020 for its next ERP filing. The Commission stated that a filing deadline for Tri-State's first application filing for approval of its ERP instead would be established in the course of the promulgation of rules applicable to Tri-State's ERPs pursuant to Section 134 (*i.e.*, this Proceeding).

30. The Commission also denied Tri-State's request that the Commission open a miscellaneous proceeding for the purpose of soliciting input and information concerning resource planning rules for Tri-State consistent with Section 134. The Commission determined, based on comments filed by other stakeholders such as CEO, WRA, and Sierra Club, that it was unnecessary to engage in any further stakeholder outreach prior to initiating a rulemaking proceeding to promulgate the new ERP Rules applicable to Tri-State pursuant to Section 134. The Commission concluded that Tri-State's Petition, the responses to the Petition submitted in Proceeding No. 19V-0311E, and the numerous comments filed in the ongoing rulemaking in Proceeding No. 19R-0096E together suffice for pre-rulemaking outreach prior to the Commission's issuance of a NOPR pursuant to Section 134.

31. The Commission further observed in Decision No. C19-0629 that Tri-State was moving quickly in its efforts to secure full rate regulation from the Federal Energy Regulatory Commission (FERC). The Commission directed Tri-State to file in Proceeding No. 19V-0311E any filing submitted to the FERC related to Tri-State's Board of Directors' actions to place Tri-State under wholesale rate regulation by the FERC; a notice regarding the addition of new members to Tri-State that causes the elimination of Tri-State's previous exception from FERC rate regulations under the Federal Power Act; and any additional information germane to Tri-State's compliance with resource planning, renewable energy, and environmental provisions under Colorado law.

32. Consistent with the last part of that filing directive, the Commission, on its own motion, filed in Proceeding No. 19V-0311E a copy of a news release that Tri-State had issued the same morning of July 17, 2019 announcing the development of a "Responsible Energy Plan." On July 23, 2019, Tri-State then filed a letter to the Commissioners from Duane Highly, Chief Executive Officer of Tri-State, explaining the development of the Responsible Energy Plan and referencing, for example, Tri-State's release of request for proposals (RFPs) for more renewable energy projects beyond the existing 475 MW of renewable energy resources serving its members.

33. On January 9, 2020, Tri-State issued another press release previewing its Responsible Energy Plan. The full Responsible Energy Plan was released the following week (although not filed in either this Proceeding or Proceeding No. 19V-0311E). The Responsible Energy Plan states that by 2024, Tri-State will bring over one gigawatt of new wind and solar resources on line and will close the Craig Station in Colorado and the Colowyo Mine by 2030.

E. Rule 3605. Cooperative Electric Generation and Transmission Association Requirements

1. 3605(a)(I) and (II): ERP Filing Dates

34. Proposed Rule 3605(a)(I) in the NOPR serves the same purpose as Rule 3603(a) in the ERP Rules: to set the filing dates for ERPs from Tri-State. The proposed rule in the NOPR required Tri-State to file an ERP every four years beginning June 1, 2020.

35. Tri-State argues that the ERP Rules under development in this rulemaking represent a substantial departure from the ERP process with which Tri-State has complied since 2010. Tri-State argues, that while these new regulatory requirements are similar to what the IOUs have been required to meet, the IOUs have had a significant amount of time to develop the necessary capabilities to comply with such requirements. Tri-State explains that given its resources, it will not have time to develop a robust ERP submittal consistent with the new rule requirements as proposed in the NOPR. Tri-State thus requests until at least December 1, 2020, to prepare and file its next ERP.

36. Most of the other participants in this rulemaking want the Commission to require Tri-State to file its next ERP before that date. Many of them also support the staggering of the ERP application filings submitted to the Commission by Tri-State, Public Service, and Black Hills Colorado Electric, LLC.

37. CEO recommends that the Commission adopt a rule that requires the opening of a proceeding four months prior to Tri-State's filing of its ERP in which the utility would submit the load forecast it intends to file in Phase I of the ERP, a loads and resources table with a projection of resource need, other modeling assumptions, and "at least three scenarios." CEO further proposes that Staff of the Colorado Public Utilities Commission (Staff) would then convene a stakeholder workshop in the pre-filing proceeding at which Tri-State would present its

preliminary scenarios and modeling assumptions. CEO further proposes that other workshop participants may propose alternative generic resources, scenarios, and assumptions that the utility may include in its filed resource plan.

38. Sierra Club also advances a proposal for a pre-filing workshop at which Tri-State would: (1) explain the modeling software it will use in the ERP proceeding; (2) present preliminary modeling results; and (3) solicit suggestions for additional modeling runs. Under Sierra Club's proposal, if Tri-State denies a stakeholder's request for additional modeling, the stakeholder may file a complaint with the Commission.

39. Tri-State opposes CEO's and Sierra Club's suggestions for rules governing a pre-filing process, arguing that Tri-State's status as a wholesale electric cooperative does not warrant a more burdensome process than what is required of the IOUs.

40. In addition to its requests related to its initial ERP filing under the new rules, Tri-State's comments appear to suggest its preference for filing its ERPs every five years. Tri-State opposes a three-year cycle as proposed by CIEA.

41. We find that Tri-State shall be the first of Colorado's three electric utilities to submit an application for approval of an ERP subject to the Commission's revised ERP Rules. In recognition of both the time Tri-State will need to complete its full ERP filing and the calls for prompt action, we require Tri-State's initial ERP application to be submitted in two parts. No later than June 1, 2020, Tri-State shall file an assessment of its existing resources pursuant to the requirements in Rule 3605(c). The application for approval of Tri-State's full ERP then would be filed no later than December 1, 2020.

42. This two-part filing approach will allow for Staff and other parties to Tri-State's initial 2020 ERP proceeding to conduct discovery and learn about Tri-State's generation fleet and the underlying financial requirements in the months leading to the later assessment of Tri-State's complete ERP filing. We conclude that the additional months of initial examination of Tri-State's generation fleet is essential to the Commission's ability to take up a full application filing made on December 1, 2020. To facilitate the examination of Tri-State's assessment of its existing resources, we adopt a new requirement in Rule 3605(c)(I)(J) that requires Tri-State to provide unit-level revenue requirements of utility-owned and contracted generation facilities, including capital costs, operations and maintenance costs, fuel costs, emissions costs, and energy and capacity payments for contracted facilities.

43. After the initial ERP application filing by Tri-State in 2020, Rule 3605(a) will require ERP filings every four years beginning June 1, 2023. The four-year cycle affords project developers regular opportunities to participate in competitive bidding for electric resource acquisitions while accommodating the regulatory oversight by the Commission as now required for Tri-State under Section 134. The June 1, 2023 filing date also allows for consideration of a timely ERP filing for additional resource changes prior to the important 2030 emissions reduction deadlines pursuant to SB 19-236 and HB 19-1261.

44. We decline to adopt rule requirements for any other "pre-filing stakeholder outreach." While we encourage Tri-State to engage with stakeholders prior to the filing of its ERPs, we are not persuaded that it is necessary to establish rules that govern a pre-filing process.

2. 3605(a)(III): Highly Confidential Information

45. Rule 3605(a)(III)[6] is modeled after Rule 3603(b) in the ERP Rules. The rule addresses a process by which the utility seeks extraordinary protection of information claimed to be highly confidential contained within an initial ERP filing.

46. The rule is opposed neither by Tri-State nor substantively by the other participants in the rulemaking. We therefore adopt Rule 3605(a)(III).

3. 3605(a)(IV): ERP Filing Contents

47. Rule 3605(a)(IV)[7] is modeled after Rule 3604 of the ERP Rules for the IOUs. Rule 3604 lists the minimum set of information that must be submitted by the utility in its ERP application filing that initiates Phase I of an ERP proceeding. Tri-State is well familiar with a handful of these same filing requirements, because the ERP reports filed by Tri-State pursuant to the existing ERP Rules must include the same types of information.

48. Extensive comments were submitted regarding proposed modifications to the required contents of an initial ERP application filing from Tri-State. In general, we have not been persuaded to modify the majority of filing requirements set forth in the NOPR. There are, however, three significant modifications to the filing requirements we adopt by this Decision based on comments submitted by Tri-State, CDPHE, and other rulemaking participants: the determination of the resource acquisition period (RAP); a required scenario addressing carbon dioxide emissions reductions; and, implementation of statutory requirements regarding the use of the social cost of carbon.

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[6] Because Rule 3605(a)(I) is expanded into Rules 3605(a)(I) and (II), Rule 3605(a)(II) in the NOPR corresponds to Rule 3605(a)(III) in the rules adopted by this Decision.

[7] Because Rule 3605(a)(I) is expanded into Rules 3605(a)(I) and (II), Rule 3605(a)(III) in the NOPR corresponds to Rule 3605(a)(IV) in the rules adopted by this Decision.

49. Aside from these three substantive modifications, the filing requirements in Rules 3605(a)(IV)(G) through (K) appear to be uncontroversial and are therefore adopted. Tri-State and the other rulemaking participants also agree that the information required by Rule 3605(a)(IV)(N) regarding the costs and benefits of integrating renewable energy resources on the utility's system is necessary in an initial ERP filing and this rule is also adopted. Rule 3605(a)(IV)(O) is a new provision for both the IOUs and Tri-State that requires the filing of supporting technical studies with an initial ERP application filing. Likewise, Rule 3605(a)(IV)(P) is a new provision for both the IOUs and Tri-State requiring the utility to propose the contents of the report to be filed by the utility in Phase II. There is no opposition to these new rule requirements and we adopt them by this Decision.

a. 3604(a)(IV)(A): Resource Acquisition Period

50. The RAP in an ERP is defined as the first years of the ERP planning period. The RAP are the years for which the utility acquires specific resources to meet projected needs. The RAP has historically been the first six to ten years of the ERP planning period.

51. In response to the NOPR, several stakeholders objected to Tri-State being allowed to specify its preferred RAP rather than being required to propose a RAP for Commission approval based on parties' responses.

52. Some stakeholders suggest that the RAP for Tri-State's initial ERP extend to 2030. That date coincides with the state's GHG reduction goal for the electricity sector of 50 percent in HB 19-1261 and with the Clean Energy Plan target of 80 percent in SB 19-236.

53. In light of the importance placed on 2030 with respect to Colorado's emission reduction goals, we establish the RAP for Tri-State's initial ERP filing to extend from the start of

the ERP planning period through 2030.[8] For Tri-State's subsequent ERPs, the RAP would be proposed by Tri-State per a modified Rule 3605(a)(IV)(A) and the Commission would establish the RAP for Phase II purposes in its Phase I decision.

b. 3604(a)(IV)(L): Carbon Reduction Scenario

54. Since 2007, the IOUs have been required to present certain scenario portfolios in their initial ERP filings that show increasing amounts of energy efficiency and clean energy resources pursuant to Existing Rule 3604(k). Some of the participants in this rulemaking proceeding have argued that this "scenario rule" be retained for the IOUs and also applied to Tri-State, and perhaps expanded to reflect certain portfolios that now would relate to carbon reduction goals enacted from the 2019 General Assembly.

55. We conclude that instead of adopting a rule requiring 2007-vintage scenarios from Tri-State, it is necessary to adopt a new Rule 3605(a)(IV)(L) requiring the presentation of a specific scenario for the assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce Tri-State's carbon dioxide emissions by 80 percent from 2005 levels by 2030. Meeting this significant carbon emission reduction goal will be the primary focus of Tri-State's next ERP and the series of ERPs that will follow in accordance to the rules adopted by this Decision. The required scenario in which Tri-State achieves deep reductions in GHG emissions, combined with the Commission's obligations under Rule 3605(h)(II)(B), will cause the Commission to consider new clean energy and energy efficient technologies as required by Colorado statute.

[8] "Planning period" is a defined term in the ERP Rules in Rule 3602. Definitions.

c. 3604(a)(IV)(M): Proposals for Carbon Base Case and Alternative Portfolios

56. SB 19-236 requires an electric utility to model "an optimization of a base case portfolio of resources using the cost of carbon dioxide emissions," where "the cost of carbon dioxide emissions must apply to the evaluation of all existing electric generation resources and to any new resources evaluated or proposed as part of the resource modeling." In addition, the Commission "may require a utility to file or propose additional base cases. The utility may propose, and the Commission shall consider, alternative optimized portfolios of resources in addition to the base case, utilizing different levels of costs for carbon dioxide" § 40-3.2-106(2)(a), C.R.S. SB 19-236 further requires the utility to "present a calculation of the net present value of revenue requirement for the resources in each optimized portfolio" using the cost of carbon set by the Commission. § 40-3.2-106(2)(b)(I), C.R.S.

57. In the NOPR, the Commission proposed a rule that required the Commission to define the required "base case portfolio" in its Phase I decision. Rule 3605(g)(III) also included a provision specifying that the Commission would establish the cost of carbon.

58. Sierra Club recommends that the Commission provide additional details regarding the use of carbon costs in an ERP. However, Sierra Club provides no proposed rule language aside from a reference to the statutory requirements in § 40-3.2-106, C.R.S.

59. We adopt a new Rule 3605(a)(IV)(Q) that requires Tri-State's initial ERP filing to set forth a proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions established by the Commission. This rule will

also permit Tri-State to propose different costs of carbon to be used with respect to the alternative portfolios of resources.

60. Consistent with the requirement on Tri-State to propose a "baseline plan," we adopt a modified version of Rule 3605(g)(III)(C)(ii) proposed in the NOPR. As modified, the rule requires the Commission to define in its Phase I decision the base case portfolio and alternative portfolios for modeling in Phase II.

61. Tri-State shall then present, pursuant to Rule 3605(h)(I)(A)(ii) set forth in the NOPR, a calculation of the net present value of revenue requirement for each portfolio required by the Commission's Phase I decision, including the defined base case portfolio. Tri-State will present the net present value of revenue requirement for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio along with the emissions of each existing and new utility resource calculated using the cost of carbon set forth in the Phase I decision and calculated without using the cost of carbon dioxide emissions. Tri-State also shall present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide.

62. We note that after the Commission issued the NOPR in this Proceeding, it proposed in Proceeding No. 19R-0096E, a separate rule addressing the Commission's calculation of the cost of carbon in accordance with § 40-3.2-106(4), C.R.S. This new rule would be contained within its own section in the Electric Rules and would apply to Tri-State. Accordingly, we adopt a modified version of Rule 3605(g)(III)(C)(i) to clarify that, in addition to defining the

base case and alternative portfolios, the Commission shall identify in its Phase I decision the costs of carbon dioxide emissions to be used by Tri-State in Phase II.

4. 3605(b): Electric Energy and Demand Forecasts

63. Rule 3605(b) as proposed in the NOPR incorporates most of Existing Rule 3606 of the Commission's ERP Rules. Tri-State has long been required to meet the informational requirements regarding energy and demand forecasts set forth in Rule 3606.

64. The modified rules attached to the NOPR require Tri-State to provide energy and demand forecasts by state jurisdiction and by Tri-State member. Tri-State argues, however, that there is no regulatory need for the Commission to require information associated with specific Tri-State members located outside of Colorado. With respect to its members located inside Colorado, Tri-State further argues that it is appropriate to provide such information on an aggregated basis consistent with how Tri-State plans its system. Tri-State thus proposes to provide the specified information on a system and regional basis (*i.e.*, Eastern Colorado and Western Colorado).

65. Other rulemaking participants object to Tri-State's proposed revisions. United Power argues, for example, that the Commission must require detailed and complete information about each member cooperative to reach a fully-formed and reasoned analysis of Tri-State's future demand. WRA similarly argues that Tri-State's energy and demand forecasts should consider multiple scenarios that account for loads consistent with their existing all requirements contracts as well as potential partial requirements contracts for some Tri-State members.

66. We adopt Rules 3605(b)(I)(A) and (E) as set forth in the NOPR without Tri-State's requested revisions. Given the potentially dynamic nature of Tri-State's future membership and the budding advent of partial requirements contracts for Tri-State's members,[9] we conclude that it is necessary for the Commission to understand Tri-State's sales and demands on a disaggregated basis for purposes of reviewing and approving Tri-State's ERP.

67. Tri-State also seeks to modify the provision in Rule 3605(b) regarding system losses. Tri-State states that it does not allocate system losses on an individual state or member basis and that its losses instead are assessed by transmission providers under open access transmission tariffs. We understand Tri-State's position and modify Rule 3605(b)(I)(D) to account for the fact that Tri-State's information on losses may not be available at the state or member level.

5. 3605(c): Assessment of Existing Resources

68. Rule 3605(c) as proposed in the NOPR incorporates most of existing Rule 3607 of the Commission's ERP Rules. Rule 3607, defining the assessment of the utility's existing resources, has applied to Tri-State historically.

69. Rule 3605(c) includes new provisions for the benchmarking of the utility's resources against alternative resources available in the market and for addressing the provision of ancillary services by Tri-State's existing resources. These new provisions are modeled after similar new rules proposed for the IOUs in Proceeding No. 19R-0096E.

[9] Proceeding No. 18F-0866E, *Delta-Montrose Electric Association, Complainant, v. Tri-State Generation and Transmission Association, Inc., Respondent*; Proceeding No. 19F-0620E, *La Plata Electric Association, Inc., Complainant, v. Tri-State Generation and Transmission Association, Inc., Respondent*; Proceeding No. 19F-0621E, *United Power, Inc., Complainant, v. Tri-State Generation and Transmission Association, Inc., Respondent*.

70. Tri-State does not raise objections to the proposed additions to Rule 3605(c) in its comments in this Proceeding.

71. WRA supports a benchmarking process as identified in Rule 3605(c) but recommends additional requirements including: (1) identifying with greater specificity the data points that must be presented and considered as part of a benchmarking analysis; (2) developing a preferred format for the benchmarking information; (3) setting requirements for generic model runs with the initial ERP application filing; and (4) establishing explicit requirements for the presentation of portfolios that include early retirement of existing units for the Commisson's consideration in Phase II.

72. Sierra Club proposes that the Commission append to the benchmarking rule, requirements for computer modeling that, at a minimum, evaluate the potential retirement of each of Tri-State's existing generating units and potential retirements of combinations of its existing generating units.

73. At the hearing on October 15, 2019, SWEEP elaborated on its recommendation that a DSM potential study be part of the new ERP process for Tri-State. The study would be conducted by Tri-State working with its members and presumably other interested stakeholders. SWEEP suggests for the benefit of a thorough and comprehensive robust analysis, that Tri-State's initial ERP filing be delayed for a few months, if necessary, to allow for different levels of energy-efficiency and that demand-response be considered as part of Tri-State's plan.

74. In its post-hearing comments, Tri-State states that it is in the process of updating its Demand Side Management/Energy Efficiency Study, prepared by an outside consulting firm, to assist Tri-State in establishing attainable 20-year energy savings goals and associated funding

levels. Tri-State intends to include the results of this study as part of the ERP it prepares and files with the Commission.

75. Tri-State also states that its ability to implement DSM programs is entirely dependent on its members, because Tri-State has no direct relationship with its members' retail customers and depends on its members to take the lead in implementing DSM measures. Tri-State adds that its members also implement DSM programs without the participation of Tri-State, particularly related to active control of peak demand.

76. We adopt Rule 3605(c) as set forth in the NOPR with the addition of Rule 3605(c)(I)(J) as described above. We expect that a formal review of Tri-State proposals for meeting Colorado's significant emission reduction goals in a contested ERP proceeding will cause the provisions in Rule 3605(c)(II) to suffice for an initial benchmarking process for Tri-State's existing generation resources in an ERP context. With respect to DSM, we conclude that too little is known about Tri-State's ability to procure DSM as a utility resource to inform the crafting of specific DSM rules for Tri-State at this time. Nothing in the rules adopted by this Decision prohibits Tri-State or other stakeholders from addressing in Tri-State's ERP proceedings how DSM can serve as a new utility resource.

6. 3605(d): Assessment of Transmission Resources

77. Rule 3605(d) as proposed in the NOPR incorporates most of existing Rule 3608 of the Commission's ERP Rules. Rule 3608, defining the assessment of the utility's transmission resources,[10] has applied to Tri-State historically.

[10] Rule 3605(d) as proposed in the NOPR was titled "Transmission Resources" instead of "Assessment of Transmission Resources." We adopt the title "Assessment of Transmission Resources." Elsewhere throughout the rules, we adopt the term "assessment" instead of "evaluation."

78. In response to the NOPR, Tri-State proposes modifications that it claims recognize “the interconnectedness of the transmission system.” Tri-State states that transmission transfer capabilities and injection constraints are “[r]outinely” the result of transmission systems not owned by Tri- State.[11]

79. We adopt Rule 3605(d) as set forth in the attachments to this Decision without the modifications sought by Tri-State. Tri-State’s proposed changes to Rule 3605(d) are simply unnecessary. For example, the term “capabilities” has been well understood by the IOUs, Tri-State, and other stakeholders for years and does not need to be changed to much narrower “line ratings” as suggested now by Tri-State. The additional language Tri-State proposes to append to the end of the rule addressing “limitations” and “constraints” ascribed to other utilities’ transmission systems is also unnecessary and could lead to diminished transparency

80. In addition to its requested modifications to Rule 3605(d), Tri-State proposes a clarifying addition to Rule 3605(g)(II)(G)(ii) regarding transmission-related information in the utility’s RFPs. We find merit in this clarification and adopt the change as reflected in Attachments A and B to this Decision.

7. 3605(e): Planning Reserve Margins and Contingency Plans

81. Rule 3605(e) as proposed in the NOPR incorporates Existing Rule 3609 of the ERP Rules with one modification: the utility will no longer be required to identify the estimated costs in developing a contingency plan.

82. We find good cause to adopt Rule 3605(e) as set forth in NOPR. Pursuant to existing Rule 3605 that has historically applied to Tri-State, the utility has long been required to provide a description of and justification for a desired level of reliability on its system. The

[11] Tri-State Initial Comments at p. 10.

NOPR expands the information Tri-State must provide to include a proposed reserve margin and a contingency plan. Tri-State does not object to the adoption of these additions in Rule 3605(e).

8. 3605(f): Assessment of Need for Additional Resources

83. Rule 3605(f) as proposed in the NOPR incorporates most of existing Rule 3610 of the Commission's ERP Rules, with the exception of Existing Rule 3610(c), which is discussed below. Rule 3610, defining the utility's resource need addressed by the ERP, has applied to Tri-State historically.

84. CIEA, Sierra Club, and WRA suggest that the Commission add to Rule 3605(f), the language in Rule 3610(c) of the ERP Rules currently in effect. In general, they argue that the Commission and Tri-State must consider broader emission reduction measures beyond the AQCC rules stemming from the 2019 General Assembly, including the likelihood of other new environmental regulations and the risk of higher future costs associated with the emission of GHGs. We agree with this suggestion and adopt Rule 3605(f)(III) for Tri-State.

9. 3605(g): Phase I

85. In Proceeding No. 19R-0096E, the Commission has proposed to restructure the existing ERP Rules applicable to the IOUs by grouping the provisions governing Phase I separately from the provisions governing Phase II. The Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources in Phase I, while in Phase II, the Commission determines a final cost-effective resource portfolio. This same organization is reflected in the proposed ERP Rules for Tri-State.

86. Tri-State generally accepts the Phase I process contemplated in the NOPR.

87. In contrast, CIEA requests that the Commission add to the ERP Rules for Tri-State the same provisions regarding the Commission's long-standing preference for

competitive bidding that apply to the IOUs in Existing Rule 3611(a).[12] CIEA also makes numerous additional suggestions for revisions to other rules related to competitive bidding (Phase I and Phase II). Tri-State objects to CIEA's suggestions, stating it instead supports the "balance struck" by the deliberately selected Phase I rules in the NOPR.

88. We adopt the Phase I provisions set forth in the NOPR as Rule 3605(g) without significant modification, other than the revisions addressed elsewhere in this Decision. Tri-State is correct in that the Commission crafted the Phase I rules in the NOPR in accordance with the requirement in Section 134 that the Commission consider Tri-State's multi-state and multi-jurisdictional operations and its co-operative, not-for-profit organizational and governance structure.

89. The Phase I rules proposed in the NOPR nevertheless safeguard a role for competitive bidding which has served to bring cost-effective resources to Colorado through market forces.

90. We further conclude that it is premature to include a competitive procurement mandate for Tri-State absent a better understanding of Tri-State's resources, operations, governance, finances, and owner co-op members. For example, a competitive procurement mandate may not be in the interest of certain Tri-State members seeking to develop co-op owned local renewable energy projects. After the Commission completes one or more ERP application proceedings for Tri-State, it is possible that a mandate for competitive procurement similar in

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

form to the Commission's preference for the IOUs will be found to have merit for Tri-State in a future rulemaking.

91. Because the ERP Rules adopted by this Decision do not mandate competitive bidding for Tri-State, it is unnecessary to promulgate rule-based exemptions and exclusions from competitive bidding and from ERPs generally. We also are not persuaded that the proposed exemption that Tri-State has advanced in Proceeding No. 19R-0096E for resources not located in Colorado has merit.

10. 3605(h): Phase II

92. The proposed rules for a Phase II process set forth in the NOPR are intended to result in the structured presentation of obtainable resource options, including their relative costs and their impacts on the environment and Colorado communities.

93. Tri-State generally accepts the Phase II process as developed in the NOPR.

94. We adopt the Phase II provisions set forth in the NOPR as Rule 3605(h) without significant modification. As a minor editorial change, we revise Rule 3605(h)(I)(C) to replace the inaccurate reference to a "120-day report" with a correct reference to the "ERP Implementation Report."

F. Conclusion

95. The statutory authority for the rules adopted by this Decision is found at §§ 24-4-101 et seq., 40-2-108, 40-2-123, 40-2-124, 40-2-127, 40-2-134, and 40-2-129, C.R.S.

96. We adopt the rule revisions shown in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) attached to this Decision, consistent with the discussion above.

II. ORDER

A. The Commission Orders That:

1. The Rules governing Electric Resource Planning as applied to wholesale electric cooperatives in the *Rules Regulating Electric Utilities* in 4 *Code of Colorado Regulations* 723-3-3605 are adopted by this Decision. The adopted rules are set forth in legislative format (Attachment A) and final format (Attachment B) and are available in the Commission's Electronic Filing System at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19R-0408E.

2. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted.

3. A copy of the final, adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State

4. 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.

5. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING January 22, 2020.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

FRANCES A. KONCILJA

JOHN GAVAN

Commissioners

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

ELECTRIC RESOURCE PLANNING

3600. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject ~~only~~ to ~~reporting~~ the requirements ~~as specified~~ in rule 3605.

* * * *

[indicates omission of unaffected rules]

3605. Cooperative Electric Generation and Transmission Association ~~Reporting~~ Requirements

This rule shall apply to ~~Pursuant to the schedule established in rule 3603,~~ each utility that is a cooperative electric generation and transmission association~~shall report its forecasts, existing resource assessment, planning reserves, and needs assessment, consistent with the requirements specified in rules 3606, 3607, 3609(a) and 3610. Each cooperative generation and transmission association shall also file annual reports pursuant to subparagraphs (a)(I) through (a)(VI) of rule 3618~~.

The statutory authority for this rule can be found at § 40-2-134, C.R.S.

(a) Electric resource plan filing requirements.

(I) Initial plan filing. Each utility shall file an assessment of existing resources pursuant to paragraph 3605(c) no later than June 1, 2020. The utility shall file the assessment as a report and also may submit prefiled testimony. The Commission shall open an adjudicatory proceeding to accept the report and shall establish a notice and intervention period for the determination of the parties. Parties may conduct discovery on the report and on any prefiled testimony submitted with the report. No later than December 1, 2020, the utility shall file an application for approval of the plan with all remaining required components of the plan in accordance with subparagraph 3605(a)(IV). The complete plan will initiate Phase I as set forth in paragraph 3605(g).

(II) Subsequent plan filings. Each utility shall file an electric resource plan pursuant to these rules every four years beginning June 1, 2023. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to subparagraph 3605(a)(IV). If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(III) Highly confidential information. Each utility shall contemporaneously file with its resource plan submitted under subparagraphs 3605(a)(I) and 3605(a)(II), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to subparagraph 3605(a)(III)(K) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

(IV) Plan components. The plan shall contain the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.

(A) The proposed resource acquisition period; however the resource acquisition period the initial plan filing submitted in accordance with subparagraph 3605(a)(I) shall extend through 2030. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire electric resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period was chosen in light of the assessment of the needs of the utility system.

(B) An annual electric demand and energy forecast developed pursuant to paragraph 3605(b).

(C) An assessment of existing resources developed pursuant to paragraph 3605(c).

(D) An assessment of transmission resources pursuant to paragraph 3605(d).

(E) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to paragraph 3605(e).

(F) An assessment of the need for additional resources developed pursuant to paragraph 3605(f).

(G) A description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(H) The cost of the projected carbon dioxide emissions using the carbon cost calculated by the Commission based on the most recent assessment of the social cost of carbon developed by the federal government.

(I) The annual water consumption for each of the utility's existing generation resources and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(J) The proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts.

(K) A list of the information related to the electric resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The protections sought by the utility for these items shall be specified in the motion(s) submitted under subparagraph 3605(a)(III). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(L) An assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.

(M) A proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions established by the Commission. The utility also may propose different costs of carbon to be used with respect to the alternative portfolios of resources.

(N) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, consistent with the amounts of renewable energy resources the utility proposes to acquire.

(O) Studies, including updates to studies relied upon by the utility in previous electric resource plans, commissioned or prepared by the utility to support the development of its electric resource plan.

(P) A detailed listing and explanation of the information the utility will provide in its ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(b) Electric energy and demand forecasts.

(I) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the planning period.

(A) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated by state jurisdiction and by member of the cooperative electric generation and transmission association.

(B) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(C) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(D) Annual and coincident summer and winter peak system losses of the cooperative electric generation and transmission association.

(E) The electric demand placed on the utility's system for each hour of the day by state jurisdiction and by member of the cooperative electric generation and transmission association. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(II) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(III) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the electric resource plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(IV) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(V) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

(c) Assessment of existing resources.

(I) Existing generation resource assessment. The utility shall describe its existing resources at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(A) Name(s) and location(s) of utility-owned and contracted generation facilities.

(B) Rated capacity and net dependable capacity of utility-owned and contracted generation facilities.

(C) Fuel type, average and marginal heat rates, quick start capability, minimum operating requirements, annual capacity factors and availability factors projected for utility-owned and contracted generation facilities over the resource acquisition period.

(D) Estimated in-service dates for utility-owned generation facilities not in service at the time the electric resource plan under consideration is filed.

(E) Estimated remaining useful lives of existing generation facilities and any significant new investment or maintenance expense relating to the existing generation facilities.

(F) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(G) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(H) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this subparagraph 3605(c)(I).

(I) The expected demand-side resources during the resource planning period from existing measures installed through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association; and, from measures expected to be installed in the future through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association.

(J) Unit-level revenue requirements of utility-owned and contracted generation facilities, including the following components: capital costs, operations and maintenance costs (fixed and variable), fuel costs, emissions and associated costs, integration and coal cycling costs, and energy and capacity payments (for contracted facilities).

(II) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of the generic resources.

(III) Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its transmission systems, including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

(d) Assessment of transmission resources.

(I) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(II) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to rule 3627 that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(III) For each transmission line or facility identified in subparagraph (d)(II), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(A) length and location;

(B) estimated in-service date;

(C) injection capacity;

(D) estimated costs;

(E) terminal points; and

(F) voltage and megawatt rating.

(IV) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(V) The electric resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

(e) Planning reserve margins and contingency plans.

(I) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(II) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under paragraph 3605(b), to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(III) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to paragraph 3605(f); or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under subparagraph 3605(h)(II).

(f) Assessment of need for additional resources.

(I) The utility shall assess the need to acquire additional resources during the resource acquisition period based on the electric energy and demand forecasts developed pursuant to paragraph 3605(b), the assessment of existing resources developed pursuant to paragraph 3606(c), planning reserve margins developed pursuant to paragraph 3605(e), and other factors including, but not limited to, the factors listed in subparagraph 3605(f)(II).

(II) In assessing its need to acquire resources, the utility shall also:

(A) determine the additional eligible energy resources, if any, the utility will need to acquire to allow each member of the cooperative electric generation and transmission association in Colorado to comply with the Commission's RES rules; and

(B) address statewide goals to reduce greenhouse gas emissions in accordance with rules promulgated and implemented by Colorado Air Quality Control Commission.

(III) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

(g) Phase I.

(I) Review on the merits.

(A) The utility's electric resource plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules of Practice and Procedure.

(B) The Commission may hold a hearing for the purpose of reviewing and rendering a decision regarding the contents of the utility's filed electric resource plan.

(II) Utility plan for meeting the resource need.

(A) The utility shall specify the portion of the resource need that it intends to meet through a competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(B) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. The utility shall specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility.

(C) Although the utility may propose a method for acquiring new utility resources other than competitive bidding, as a prerequisite, the utility shall nonetheless include in its electric resource plan filed under paragraph 3605(a) the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under paragraph 3605(f) exclusively through competitive bidding.

(D) The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources including a schedule of bid fees graduated by the size of the proposed resources.

(E) The utility shall also propose, and other interested parties may provide input as part of the electric resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits, including, for example, benefits associated with best value employment metrics.

(F) The utility shall propose a written bidding policy as part of its filing under paragraph 3605(a), including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner.

(G) Request for Proposals (RFPs).

(i) The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire resources pursuant to subparagraph 3605(g)(II). To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract.

(ii) The proposed RFP(s) shall include the bid evaluation criteria the utility will use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas and connecting to the utility's transmission system pursuant to paragraph 3605(d), including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(iii) The utility shall request from bidders the best value employment metrics for each bid resource and shall set forth criteria for the review of such metrics, based on objective performance standards, to be applied in the evaluation and selection of bids in accordance with § 40-2-129, C.R.S.

(iv) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility.

(III) Phase I decision.

(A) Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's electric resource plan.

(B) The Phase I decision approving or denying the electric resource plan shall address the contents of the utility's plan filed in accordance with paragraph 3605(a). If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; and components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria.

(C) The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(i) The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

(ii) In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

(iii) The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

(iv) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

(D) The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

(E) If the Commission declines to approve a utility's electric resource plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 90 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(h) Phase II.

(I) ERP Implementation Report.

(A) On or before the deadline established by the Commission, the utility shall file a report with the Commission presenting cost-effective resource plans in accordance with the Commission's Phase I decision. The utility shall identify its preferred cost-effective resource plan.

(i) The utility shall apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's Phase I decision.

(ii) The utility shall present a calculation of the net present value of revenue requirement for each portfolio required by the Phase I decision, including the defined base case portfolio. The utility shall present the net present value of revenue requirement for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Phase I decision and calculated without using the cost of carbon dioxide emissions. The utility also shall present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide.

(iii) The utility shall provide the Commission with the best value employment metrics information provided by bidders.

(B) Within 45 days after the filing of the utility's ERP Implementation Report, the parties in the electric resource plan proceeding may file comments on the utility's report.

(C) Within 60 days after the filing of the utility's ERP Implementation Report, the utility may file comments responding to the parties' comments.

(II) Phase II decision.

(A) Within 90 days after the receipt of the utility's ERP Implementation Report under subparagraph 3605(h)(I), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan.

(B) In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(C) In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

(D) In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

(E) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

(III) Upon completion of Phase II, the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own. At a minimum the utility shall address the public release of highly confidential and confidential information in its ERP Implementation Report and all documents related to that report filed by the utility and the parties. The utility shall file its proposal in the plan proceeding within 14 months after the receipt of bids to its RFP(s). Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(IV) Upon completion of Phase II, the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

ELECTRIC RESOURCE PLANNING

3600. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject to the requirements in rule 3605.

* * * *

[indicates omission of unaffected rules]

3605. Cooperative Electric Generation and Transmission Association Requirements

This rule shall apply to each utility that is a cooperative electric generation and transmission association.

The statutory authority for this rule can be found at § 40-2-134, C.R.S.

(a) Electric resource plan filing requirements.

(I) Initial plan filing. Each utility shall file an assessment of existing resources pursuant to paragraph 3605(c) no later than June 1, 2020. The utility shall file the assessment as a report and also may submit prefiled testimony. The Commission shall open an adjudicatory proceeding to accept the report and shall establish a notice and intervention period for the determination of the parties. Parties may conduct discovery on the report and on any prefiled testimony submitted with the report. No later than December 1, 2020, the utility shall file an application for approval of the plan with all remaining required components of the plan in accordance with subparagraph 3605(a)(IV). The complete plan will initiate Phase I as set forth in paragraph 3605(g).

(II) Subsequent plan filings. Each utility shall file an electric resource plan pursuant to these rules every four years beginning June 1, 2023. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to subparagraph 3605(a)(IV). If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(III) Highly confidential information. Each utility shall contemporaneously file with its resource plan submitted under subparagraphs 3605(a)(I) and 3605(a)(II), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to subparagraph 3605(a)(III)(K) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

(IV) Plan components. The plan shall contain the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.

(A) The proposed resource acquisition period; however the resource acquisition period the initial plan filing submitted in accordance with subparagraph 3605(a)(I) shall extend through 2030. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire electric resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period was chosen in light of the assessment of the needs of the utility system.

(B) An annual electric demand and energy forecast developed pursuant to paragraph 3605(b).

(C) An assessment of existing resources developed pursuant to paragraph 3605(c).

(D) An assessment of transmission resources pursuant to paragraph 3605(d).

(E) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to paragraph 3605(e).

(F) An assessment of the need for additional resources developed pursuant to paragraph 3605(f).

(G) A description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(H) The cost of the projected carbon dioxide emissions using the carbon cost calculated by the Commission based on the most recent assessment of the social cost of carbon developed by the federal government.

(I) The annual water consumption for each of the utility's existing generation resources and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(J) The proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts.

(K) A list of the information related to the electric resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The protections sought by the utility for these items shall be specified in the motion(s) submitted under subparagraph 3605(a)(III). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(L) An assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.

(M) A proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions established by the Commission. The utility also may propose different costs of carbon to be used with respect to the alternative portfolios of resources.

(N) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, consistent with the amounts of renewable energy resources the utility proposes to acquire.

(O) Studies, including updates to studies relied upon by the utility in previous electric resource plans, commissioned or prepared by the utility to support the development of its electric resource plan.

(P) A detailed listing and explanation of the information the utility will provide in its ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(b) Electric energy and demand forecasts.

(I) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the planning period.

(A) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated by state jurisdiction and by member of the cooperative electric generation and transmission association.

(B) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(C) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(D) Annual and coincident summer and winter peak system losses of the cooperative electric generation and transmission association.

(E) The electric demand placed on the utility's system for each hour of the day by state jurisdiction and by member of the cooperative electric generation and transmission association. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(II) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(III) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the electric resource plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(IV) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(V) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

(c) Assessment of existing resources.

(I) Existing generation resource assessment. The utility shall describe its existing resources at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(A) Name(s) and location(s) of utility-owned and contracted generation facilities.

(B) Rated capacity and net dependable capacity of utility-owned and contracted generation facilities.

(C) Fuel type, average and marginal heat rates, quick start capability, minimum operating requirements, annual capacity factors and availability factors projected for utility-owned and contracted generation facilities over the resource acquisition period.

(D) Estimated in-service dates for utility-owned generation facilities not in service at the time the electric resource plan under consideration is filed.

(E) Estimated remaining useful lives of existing generation facilities and any significant new investment or maintenance expense relating to the existing generation facilities.

(F) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(G) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(H) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this subparagraph 3605(c)(I).

(I) The expected demand-side resources during the resource planning period from existing measures installed through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association; and, from measures expected to be installed in the future through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association.

(J) Unit-level revenue requirements of utility-owned and contracted generation facilities, including the following components: capital costs, operations and maintenance costs (fixed and variable), fuel costs, emissions and associated costs, integration and coal cycling costs, and energy and capacity payments (for contracted facilities).

(II) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of the generic resources.

(III) Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its transmission systems, including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

(d) Assessment of transmission resources.

(I) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(II) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to rule 3627 that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(III) For each transmission line or facility identified in subparagraph (d)(II), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(A) length and location;

(B) estimated in-service date;

(C) injection capacity;

(D) estimated costs;

(E) terminal points; and

(F) voltage and megawatt rating.

(IV) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(V) The electric resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

(e) Planning reserve margins and contingency plans.

(I) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(II) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under paragraph 3605(b), to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(III) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to paragraph 3605(f); or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under subparagraph 3605(h)(II).

(f) Assessment of need for additional resources.

(I) The utility shall assess the need to acquire additional resources during the resource acquisition period based on the electric energy and demand forecasts developed pursuant to paragraph 3605(b), the assessment of existing resources developed pursuant to paragraph 3606(c), planning reserve margins developed pursuant to paragraph 3605(e), and other factors including, but not limited to, the factors listed in subparagraph 3605(f)(II).

(II) In assessing its need to acquire resources, the utility shall also:

(A) determine the additional eligible energy resources, if any, the utility will need to acquire to allow each member of the cooperative electric generation and transmission association in Colorado to comply with the Commission's RES rules; and

(B) address statewide goals to reduce greenhouse gas emissions in accordance with rules promulgated and implemented by Colorado Air Quality Control Commission.

(III) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

(g) Phase I.

(I) Review on the merits.

(A) The utility's electric resource plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules of Practice and Procedure.

(B) The Commission may hold a hearing for the purpose of reviewing and rendering a decision regarding the contents of the utility's filed electric resource plan.

(II) Utility plan for meeting the resource need.

(A) The utility shall specify the portion of the resource need that it intends to meet through a competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(B) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. The utility shall specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility.

(C) Although the utility may propose a method for acquiring new utility resources other than competitive bidding, as a prerequisite, the utility shall nonetheless include in its electric resource plan filed under paragraph 3605(a) the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under paragraph 3605(f) exclusively through competitive bidding.

(D) The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources including a schedule of bid fees graduated by the size of the proposed resources.

(E) The utility shall also propose, and other interested parties may provide input as part of the electric resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits, including, for example, benefits associated with best value employment metrics.

(F) The utility shall propose a written bidding policy as part of its filing under paragraph 3605(a), including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner.

(G) Request for Proposals (RFPs).

(i) The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire resources pursuant to subparagraph 3605(g)(II). To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract.

(ii) The proposed RFP(s) shall include the bid evaluation criteria the utility will use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas and connecting to the utility's transmission system pursuant to paragraph

3605(d), including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(iii) The utility shall request from bidders the best value employment metrics for each bid resource and shall set forth criteria for the review of such metrics, based on objective performance standards, to be applied in the evaluation and selection of bids in accordance with § 40-2-129, C.R.S.

(iv) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility.

(III) Phase I decision.

(A) Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's electric resource plan.

(B) The Phase I decision approving or denying the electric resource plan shall address the contents of the utility's plan filed in accordance with paragraph 3605(a). If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; and components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria.

(C) The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(i) The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

(ii) In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

(iii) The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

(iv) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

(D) The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

(E) If the Commission declines to approve a utility's electric resource plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 90 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(h) Phase II.

(I) ERP Implementation Report.

(A) On or before the deadline established by the Commission, the utility shall file a report with the Commission presenting cost-effective resource plans in accordance with the Commission's Phase I decision. The utility shall identify its preferred cost-effective resource plan.

(i) The utility shall apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's Phase I decision.

(ii) The utility shall present a calculation of the net present value of revenue requirement for each portfolio required by the Phase I decision, including the defined base case portfolio. The utility shall present the net present value of revenue requirement for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Phase I decision and calculated without using the cost of carbon dioxide emissions. The utility also shall present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide.

(iii) The utility shall provide the Commission with the best value employment metrics information provided by bidders.

(B) Within 45 days after the filing of the utility's ERP Implementation Report, the parties in the electric resource plan proceeding may file comments on the utility's report.

(C) Within 60 days after the filing of the utility's ERP Implementation Report, the utility may file comments responding to the parties' comments.

(II) Phase II decision.

(A) Within 90 days after the receipt of the utility's ERP Implementation Report under subparagraph 3605(h)(I), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan.

(B) In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(C) In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

(D) In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

(E) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

(III) Upon completion of Phase II, the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own. At a minimum the utility shall address the public release of highly confidential and confidential information in its ERP Implementation Report and all documents related to that report filed by the utility and the parties. The utility shall file its proposal in the plan proceeding within 14 months after the receipt of bids to its RFP(s). Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(IV) Upon completion of Phase II, the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

Decision No. C20-0304

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19R-0408E

IN THE MATTER OF THE PROPOSED RULES IMPLEMENTING SENATE BILL 19-236 REGARDING INTEGRATED OR ELECTRIC RESOURCE PLANS FOR WHOLESALE ELECTRIC COOPERATIVES.

DECISON ADDRESSING APPLICATION FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF DECISION NO. C20-0155 AND ADOPTING RULES

Mailed Date: April 28, 2020
Adopted Date: April 22, 2020

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I. BY THE COMMISSION

A. Statement

1. By Decision No. C20-0155, issued March 10, 2020, the Colorado Public Utilities Commission adopted amendments to the provisions in the rules governing Electric Resource Planning (ERP Rules) at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq.,* as they apply to wholesale electric cooperatives. The proposed amendments fulfill the requirement in Senate Bill (SB) 19-236, codified at § 40-2-134, C.R.S., that requires the Commission to adopt rules that address application filings from wholesale electric cooperatives for Commission approval of their integrated or electric resource plans (ERPs).

2. On March 30, 2020, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed an application for rehearing, reargument, or reconsideration of Decision No. C20-0155 (Application for RRR).

3. As discussed below, we grant, in part, and deny, in part, Tri-State's Application for RRR. We also adopt further rule revisions as attached to this Decision in legislative format (Attachment A) and in final format (Attachment B).

B. Sierra Club Motion for Leave to Reply to Tri-State's RRR

4. In its Application for RRR, Tri-State explains that, in general, the ERP Rules adopted by the Commission are "a reasonable implementation" of SB 19-236. Tri-State suggests that its Application for RRR is limited to a small number of discrete issues.

5. Tri-State requests that the Commission further modify the ERP Rules to: (1) establish a reasonable time limit for discovery related to Tri-State's June 1, 2020 initial filing; (2) afford Tri-State the same exemptions and exclusions from ERPs that are applicable to

investor-owned electric utilities; (3) ensure "appropriate treatment" of Tri-State's out-of-state resources; and (4) clarify that Tri-State may include energy storage systems in its ERP.

6. On April 7, 2020, Sierra Club filed a motion for leave to respond to Tri-State's RRR in two areas: the proposed six weeks of discovery related to Tri-State's June 1, 2020 initial filing and Tri-State's request to exclude out-of-state resources from Colorado ERP proceedings.

7. We deny Sierra Club's motion for leave to respond to Tri-State's Application for RRR. Pursuant to the Commission's Rules of Practice and Procedure, 4 CCR 723-1, replies to applications for RRR are not generally allowed; however, the Commission also has discretion on whether to accept replies to such pleadings upon consideration of a proper motion for leave to reply. In this instance, the Commission requires no additional information or argument from Sierra Club to rule on Tri-State's Application for RRR.

C. Discovery Related to June 1, 2020 Filing

8. Decision No. C20-0155 explains that Tri-State will be the first of Colorado's three electric utilities to submit an application for approval of an ERP subject to the Commission's revised ERP Rules. In recognition of both the time Tri-State will need to complete its full ERP filing and the calls for prompt action, the Commission requires Tri-State's initial ERP application to be submitted in two parts. No later than June 1, 2020, Tri-State must file an assessment of its existing resources pursuant to the requirements in Rule 3605(c). The application for approval of Tri-State's full ERP then would be filed no later than December 1, 2020.

9. In its Application for RRR, Tri-State states that it appreciates the structure under which it will file an assessment of existing resources in June 2020 followed by the remainder of the full application in December 2020. Tri-State states that this approach is reasonable in light of the timing suggested by the other rulemaking participants.

10. Tri-State explains that while the Commission will allow parties to conduct discovery on Tri-State's June 1 filing, it has not indicated the last date on which such discovery may be propounded. Tri-State is concerned that without an associated "cutoff date" during the period between June 1, 2020 and December 1, 2020, Tri-State could be inundated with discovery requests continuing through the filing of answer testimony sometime in 2021. Tri-State states that such a long discovery period would be burdensome and could compromise Tri-State's ability to timely prepare and file its full ERP application in December of this year.

11. Tri-State requests that the Commission modify the rules to specify that parties may serve discovery related to Tri-State's June 1, 2020 filing during the six-week period following the effective date of the Commission's decision regarding interventions. Tri-State argues that this timeline will allow interested parties time to intervene and propound discovery related to the June 1 filing while also ensuring that they do so in a reasonable and timely manner.

12. It is premature to limit discovery by rule in the specific manner that Tri-State seeks in its Application for RRR. We are reluctant to incorporate a rule outside our Rules of Practice and Procedure directly related to discovery standards. Rather, we are confident our discovery rules at Rule 1405 are adequate to address any discovery disputes that may arise as part of Tri-State's ERP process. Nonetheless, Tri-State raises a valid concern that excessive discovery could hinder Tri-State from meeting the deadline for its complete ERP filing of December 1, 2020.

13. The Commission will establish provisions governing discovery pursuant to Rule 1405, by procedural interim decisions rendered in the proceeding that is initiated by Tri-State's June 1, 2020 filing. We are mindful of Tri-State's concerns regarding potentially

burdensome discovery and will endeavor to ensure that Tri-State can meet the December 1, 2020 full ERP filing without being impaired by excessive discovery.

D. Exemptions from an Electric Resource Plan

14. Rule 3615 of the ERP Rules that apply to the investor-owned electric utilities in Colorado that states the following resources "need not be included in an approved resource plan prior to acquisition": (1) emergency maintenance or repairs; (2) newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 20 MW; (3) capacity and/or energy from other utilities or from non-utility generators pursuant to agreements for not more than a two-year term (including renewal terms) or for not more than 20 MW of capacity; (4) improvements or modifications to existing generation that change production capability by not more than 20 MW and have an estimated cost of not more than $30 million; (5) interruptible service; (6) modifications to, existing power purchase agreements provided the modification or amendment does not extend the agreement for more than four years, does not add more than 20 MW of capacity to the utility's system; (7) emission control equipment at existing generation plants; and (8) demand-side programs.[1]

15. Decision No. C20-0155 declines to adopt a similar rule for Tri-State.

16. In its Application for RRR, Tri-State requests that the Commission either include the proposed Rule 3611 exemptions in the ERP Rules for Tri-State or clarify that Tri-State will be allowed to make "small acquisitions" outside of an ERP process.

17. Tri-State argues that while provisions in Rule 3605 do not mandate competitive bidding for Tri-State, the lack of a mandate for competitive bidding does not mean that Tri-State

[1] Rule 3615 is under review for modifications in Proceeding No. 19R-0096E as "Proposed Rule 3611." Decision No. C19-0197, issued February 27, 2019, Proceeding No. 19R-0096E.

should not be allowed to acquire certain resources outside the ERP as provided for investor-owned utilities in proposed Rule 3611. Tri-State argues that the rules adopted by Decision No. C20-0155 provide only two paths for Tri-State to acquire resources: through the quadrennial ERP filing or through an interim ERP filing justified by changed circumstances. Tri-State states that without the exceptions provided to the investor-owned utilities in proposed Rule 3611, Tri-State would be dramatically constrained in its ability to flexibly acquire small resources in the periods between ERPs. Tri-State further states that it is occasionally presented with t ime-sensitive opportunities to acquire resources that would fall under the 20 MW exemptions provided for the investor-owned utilities in proposed Rule 3611. These resources generally represent one-off opportunities that would not otherwise be available and that would be difficult, and are likely impossible to integrate into a four-year ERP cycle.

18. We conclude that it is impractical and premature to identify what exemptions and exclusions are appropriate for Tri-State with respect to its future ERP filings without first completing an initial ERP proceeding pursuant to the new rules developed in this Proceeding. Nevertheless, Tri-State makes a valid point that it would be cumbersome and potentially problematic to require all resource acquisitions to be reviewed through the lens of the ERP Rules for Tri-State.

19. We therefore adopt new provisions in a new paragraph 3605(i) that allows Tri-State to engage in certain resource acquisitions without having to file an interim or amended ERP. The proposed rule addition will not require interim or amended plans for: (1) emergency maintenance or repairs made to utility-owned generation and energy storage facilities; (2) capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 20 MW; (3) capacity and/or energy from the generation

facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two-year term (including renewal terms) or for not more than 20 MW of capacity; (4) improvements or modifications to existing utility generation and energy storage facilities that change the production capability of the generation facility site in question, by not more than 20 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million; and (5) modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 20 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.

20. The new provisions in paragraph 3605(i) are intended for effect after the completion of the first ERP proceeding conducted pursuant to these new ERP Rules for Tri-State.

E. Out-of-State Resources

21. Decision No. C20-0155 briefly addresses Tri-State's request to exclude out-of-state resources in one sentence: "We also are not persuaded that the proposed exemption that Tri-State has advanced in Proceeding No. 19R-0096E for resources not located in Colorado has merit."[2]

22. In its RRR, Tri-State faults the Commission for not addressing whether and to what extent the Commission proposes to regulate Tri-State resources located outside Colorado through the ERP process. Tri-State argues that without a limitation with respect to state boundaries, provisions in the ERP Rules could put the Commission in the position of issuing

[2] Decision No. C20-0155 at ¶ 91.

determinations regarding out-of-state facilities that are infrequently used to serve Tri-State's wholesale customers in Colorado and over which the Commission has no underlying facilities jurisdiction. Tri-State further argues that requiring the inclusion of Tri-State's non-Colorado resources in the ERP may implicate economic protectionism with respect to Colorado-based resources. Tri-State points to subparagraph 3605(h)(II)(B) that requires the Commission to consider, among other factors, "employment and long-term economic viability of Colorado communities" in making its Phase II decision. Tri-States explains that while this requirement makes sense for in-state facilities, its application to non-Colorado facilities is problematic. Tri-State concludes that without a rule limiting the application of the ERP to in-state facilities, planned or existing non-Colorado facilities could receive "unfavorable regulatory treatment due exclusively to their out-of-state location."[3]

23. Tri-State thus requests that the Commission reconsider Tri-State's proposed exemption for out-of-state resources. Tri-State argues that this request relates specifically to the General Assembly's express instruction in SB 19-236 that the Commission consider Tri-State's "multistate operational jurisdiction" in drafting these ERP Rules for Tri-State.

24. We recognize that consideration of Tri-State's out-of-state resources will be one of the most challenging aspects of its ERP proceedings conducted pursuant to the rules promulgated here pursuant to SB 19-236. We conclude that it will be necessary to address such challenges by considering evidence and policy testimony put forward by Tri-State and the intervening parties to the ERP proceedings.

25. Tri-State's proposal to designate out-of-state resources off-limits to a Colorado ERP proceeding is also unhelpful, because it would likely not alleviate any controversies

[3] Tri-State RRR at p. 6.

surrounding such issues as projected carbon emission reductions and overall resource portfolio costs and benefits. Tri-State's advocacy has also been inconsistent on this issue both in this case and in Proceeding No. 19R-0096E, where Tri-State proposed that the Commission declare that one purpose of Tri-State's ERP is to minimize the net present value of revenue requirement on a system basis including all states in which the cooperative operates.

26. We further disagree with Tri-State that the rules adopted by the Commission through Decision No. C20-0155 fail to take into account Tri-State's multi-state operations. To the contrary, the rules promulgated by Decision No. C20-0155 include procedures that foster deliberate and extensive consideration of Tri-State's existing resources to determine, based on evidence, what plants in Tri-State's fleet serve its Colorado members and what plants do not regardless of their location inside or outside state boundaries. In our view, Tri-State's proposal for a blanket exclusion of out-of-state resources runs counter to the directive in SB 19-236 that the Commission consider its multi-state operations when promulgating ERP Rules applicable to Tri-State. We find Tri-State's concern of economic protectionism in considering its resource plan juxtaposed with out of state generation resources to be without merit. We are well aware of the Dormant Commerce Clause standards and have no intention of violating those provisions. The granting of Tri-State's RRR by excluding out-of-state resources from consideration in an ERP review would further cause Tri-State's ERP proceedings to be far less substantive than what the General Assembly likely intended by passing SB 19-236.

F. Energy Storage

27. In its Application for RRR, Tri-State states that it has a pumped storage resource and generally includes energy storage in its modeling exercises. Tri-State explains that it expects to continue to model energy storage in its resource planning process and may seek to include

energy storage as an option in its ERP filings with the Commission. Tri-State thus requests that the ERP Rules for Tri-State include language specifically allowing Tri-State to consider energy storage systems in its ERP consistent with what was provided for the investor-owned electric utilities in Decision No. C18-1124 issued in the rulemaking in Proceeding No. 18R-0623E issued on December 12, 2018.

28. Specifically, Tri-State asks the Commission to make the following three changes to Rule 3605 that apply exclusively to Tri-State: subparagraph 3605(c)(I) should mirror paragraph 3607(a) by referring to "generation facilities and energy storage systems," as necessary; subparagraph 3605(f)(II) should include a subpart (C) consistent with subparagraph 3610(b)(III); and subparagraph 3605(h)(II)(B) should include energy storage systems on the list of considerations for the Commission in its Phase II decision, consistent with what is provided in Rule 3613.

29. We agree with Tri-State that the energy storage-related modifications to the Commission's ERP Rules implemented in Proceeding No. 18R-0623E should be reflected, as appropriate, in the ERP Rules for Tri-State. We therefore modify the rules adopted by Decision No. C20-0155 as set forth in the attachments to this Decision, including: (1) subparagraph 3605(c)(I) that sets forth the requirements for the assessment of Tri-State's existing resources; subparagraph 3605(a)(IV) that defines the components of Tri-State's initial Phase I filing; subparagraph 3605(f)(II) that addresses the assessment of Tri-State's resource need; and paragraph 3605(g) requiring provisions for energy storage systems in the request for proposals for competitive bidding filed in Phase I of Tri-State's ERP.

30. We further clarify that Tri-State is authorized to consider energy storage systems in its ERPs.

G. Conclusion

31. The statutory authority for the rules adopted by this Decision is found at §§ 24-4-101 *et seq.,* 40-2-108, 40-2-123, 40-2-124, 40-2-127, 40-2-134, and 40-2-129, C.R.S.

32. In light of our decision to grant, in part, Tri-State's Application for RRR, we adopt the rule revisions shown in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) attached to this Decision, consistent with the discussion above.

II. ORDER

A. The Commission Orders That:

1. The application for rehearing, reargument, or reconsideration of Decision No. C20-0155 filed by Tri-State Generation and Transmission Association, Inc. on March 30, 2020 is granted, in part, and denied, in part, consistent with the discussion above.

2. The Rules governing Electric Resource Planning as applied to wholesale electric cooperatives in the *Rules Regulating Electric Utilities* in 4 *Code of Colorado Regulations* 723-3-3605 are adopted by this Decision. The adopted rules are set forth in legislative format (Attachment A) and final format (Attachment B) and are available in the Commission's Electronic Filing System at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19R-0408E

3. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted.

4. A copy of the final adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State.

5. 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.

6. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING April 22, 2020.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

____

JOHN GAVAN

____
Commissioners

COMMISSIONER MEGAN M. GILMAN NOT PARTICIPATING.

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

ELECTRIC RESOURCE PLANNING

3600. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject ~~only~~ to ~~reporting~~ the requirements ~~as specified~~ in rule 3605.

* * *

[indicates omission of unaffected rules]

3605. Cooperative Electric Generation and Transmission Association ~~Reporting~~ Requirements

This rule shall apply to ~~Pursuant to the schedule established in rule 3603,~~ each utility that is a cooperative electric generation and transmission association~~shall report its forecasts, existing resource assessment, planning reserves, and needs assessment, consistent with the requirements specified in rules 3606, 3607, 3609(a) and 3610. Each cooperative generation and transmission association shall also file annual reports pursuant to subparagraphs (a)(I) through (a)(VI) of rule 3618~~.

The statutory authority for this rule can be found at § 40-2-134, C.R.S.

(a) Electric resource plan filing requirements.

(I) Initial plan filing. Each utility shall file an assessment of existing resources pursuant to paragraph 3605(c) no later than June 1, 2020. The utility shall file the assessment as a report and also may submit prefiled testimony. The Commission shall open an adjudicatory proceeding to accept the report and shall establish a notice and intervention period for the determination of the parties. Parties may conduct discovery on the report and on any prefiled testimony submitted with the report. No later than December 1, 2020, the utility shall file an application for approval of the plan with all remaining required components of the plan in accordance with subparagraph 3605(a)(IV). The complete plan will initiate Phase I as set forth in paragraph 3605(g).

(II) Subsequent plan filings. Each utility shall file an electric resource plan pursuant to these rules every four years beginning June 1, 2023. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to subparagraph 3605(a)(IV). If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(III) Highly confidential information. Each utility shall contemporaneously file with its resource plan submitted under subparagraphs 3605(a)(I) and 3605(a)(II), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to subparagraph 3605(a)(III)(K) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

(IV) Plan components. The plan shall contain the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.

(A) The proposed resource acquisition period; however, the resource acquisition period for the initial plan filing submitted in accordance with subparagraph 3605(a)(I) shall extend through 2030. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire electric resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period was chosen in light of the assessment of the needs of the utility system.

(B) An annual electric demand and energy forecast developed pursuant to paragraph 3605(b).

(C) An assessment of existing resources developed pursuant to paragraph 3605(c).

(D) An assessment of transmission resources pursuant to paragraph 3605(d).

(E) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to paragraph 3605(e).

(F) An assessment of the need for additional resources developed pursuant to paragraph 3605(f).

(G) A description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(H) The cost of the projected carbon dioxide emissions using the carbon cost calculated by the Commission based on the most recent assessment of the social cost of carbon developed by the federal government.

(I) The annual water consumption for each of the utility's existing generation resources and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(J) The proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts.

(K) A list of the information related to the electric resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The protections sought by the utility for these items shall be specified in the motion(s) submitted under subparagraph 3605(a)(III). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(L) An assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.

(M) A proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions established by the Commission. The utility also may propose different costs of carbon to be used with respect to the alternative portfolios of resources.

(N) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, consistent with the amounts of renewable energy resources the utility proposes to acquire.

(O) Studies, including updates to studies relied upon by the utility in previous electric resource plans, commissioned or prepared by the utility to support the development of its electric resource plan.

(P) Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.

(Q) A detailed listing and explanation of the information the utility will provide in its ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(b) Electric energy and demand forecasts.

(I) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the planning period.

(A) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated by state jurisdiction and by member of the cooperative electric generation and transmission association.

(B) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(C) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(D) Annual and coincident summer and winter peak system losses of the cooperative electric generation and transmission association.

(E) The electric demand placed on the utility’s system for each hour of the day by state jurisdiction and by member of the cooperative electric generation and transmission association. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(II) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(III) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the electric resource plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(IV) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(V) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

(c) Assessment of existing resources.

(I) Existing resource assessment. The utility shall describe its existing generation facilities and energy storage systems at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(A) Name(s) and location(s) of utility-owned and contracted generation and energy storage facilities.

(B) Rated capacity and net dependable capacity of utility-owned and contracted generation and energy storage facilities.

(C) Fuel type, average and marginal heat rates, quick start capability, minimum operating requirements, annual capacity factors and availability factors projected for utility-owned and contracted generation and energy storage facilities over the resource acquisition period.

(D) Estimated in-service dates for utility-owned generation and energy storage facilities not in service at the time the electric resource plan under consideration is filed.

(E) Estimated remaining useful lives of existing generation and energy storage facilities and any significant new investment or maintenance expense relating to the existing generation facilities.

(F) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(G) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(H) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this subparagraph 3605(c)(I).

(I) The expected demand-side resources during the resource planning period from existing measures installed through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association; and, from measures expected to be installed in the future through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association.

(J) Unit-level revenue requirements of utility-owned and contracted generation facilities, including the following components: capital costs, operations and maintenance costs (fixed and variable), fuel costs, emissions and associated costs, integration and coal cycling costs, and energy and capacity payments (for contracted facilities).

(K) The performance characteristics of utility-owned energy storage systems including but not limited to: discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(L) The physical and performance characteristics of energy storage systems purchased from utilities and non-utilities including but not limited to: storage technology; discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(II) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of the generic resources.

(III) Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its transmission systems, including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

(d) Assessment of transmission resources.

(I) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(II) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to rule 3627 that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(III) For each transmission line or facility identified in subparagraph (d)(II), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(A) length and location;

(B) estimated in-service date;

(C) injection capacity;

(D) estimated costs;

(E) terminal points; and

(F) voltage and megawatt rating.

(IV) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(V) The electric resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

(e) Planning reserve margins and contingency plans.

(I) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(II) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under paragraph 3605(b), to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(III) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to paragraph 3605(f); or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under subparagraph 3605(h)(II).

(f) Assessment of need for additional resources.

(I) The utility shall assess the need to acquire additional resources during the resource acquisition period based on the electric energy and demand forecasts developed pursuant to paragraph 3605(b), the assessment of existing resources developed pursuant to paragraph 3606(c), planning reserve margins developed pursuant to paragraph 3605(e), and other factors including, but not limited to, the factors listed in subparagraph 3605(f)(II).

(II) In assessing its need to acquire resources, the utility shall also:

(A) determine the additional eligible energy resources, if any, the utility will need to acquire to allow each member of the cooperative electric generation and transmission association in Colorado to comply with the Commission's RES rules;

(B) consider the benefits of energy storage system may provide to increase integration of intermittent resources; improve reliability; reduce the need for increased generation facilities to meet period of peak demand; and avoid, reduce, or defer investments; and

(C) address statewide goals to reduce greenhouse gas emissions in accordance with rules promulgated and implemented by Colorado Air Quality Control Commission.

(III) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

(g) Phase I.

(I) Review on the merits.

(A) The utility's electric resource plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules of Practice and Procedure.

(B) The Commission may hold a hearing for the purpose of reviewing and rendering a decision regarding the contents of the utility's filed electric resource plan.

(II) Utility plan for meeting the resource need.

(A) The utility shall specify the portion of the resource need that it intends to meet through a competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(B) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. The utility shall specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility.

(C) Although the utility may propose a method for acquiring new utility resources other than competitive bidding, as a prerequisite, the utility shall nonetheless include in its electric resource plan filed under paragraph 3605(a) the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under paragraph 3605(f) exclusively through competitive bidding.

(D) The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources including a schedule of bid fees graduated by the size of the proposed resources.

(E) The utility shall also propose, and other interested parties may provide input as part of the electric resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits, including, for example, benefits associated with best value employment metrics.

(F) The utility shall propose a written bidding policy as part of its filing under paragraph 3605(a), including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner.

(G) Request for Proposals (RFPs).

(i) The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire resources pursuant to subparagraph 3605(g)(II). To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract.

(ii) The proposed RFP(s) shall include the bid evaluation criteria the utility will use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas and connecting to the utility's transmission system pursuant to paragraph 3605(d), including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; any physical and performance requirements for energy storage systems or instructions for bidders to explain characteristics of energy storage systems, including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations; methodologies or credit mechanisms to value energy storage services provided to the utility system; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(iii) The utility shall request from bidders the best value employment metrics for each bid resource and shall set forth criteria for the review of such metrics, based on objective performance standards, to be applied in the evaluation and selection of bids in accordance with § 40-2-129, C.R.S.

(iv) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility.

(III) Phase I decision.

(A) Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's electric resource plan.

(B) The Phase I decision approving or denying the electric resource plan shall address the contents of the utility's plan filed in accordance with paragraph 3605(a). If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; and components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria.

(C) The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(i) The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

(ii) In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

(iii) The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

(iv) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

(D) The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

(E) If the Commission declines to approve a utility's electric resource plan, either in whole or in part, the utility shall make changes to the plan in response to the

Commission's decision. Within 90 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(h) Phase II.

(I) ERP Implementation Report.

(A) On or before the deadline established by the Commission, the utility shall file a report with the Commission presenting cost-effective resource plans in accordance with the Commission's Phase I decision. The utility shall identify its preferred cost-effective resource plan.

(i) The utility shall apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's Phase I decision.

(ii) The utility shall present a calculation of the net present value of revenue requirement for each portfolio required by the Phase I decision, including the defined base case portfolio. The utility shall present the net present value of revenue requirement for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Phase I decision and calculated without using the cost of carbon dioxide emissions. The utility also shall present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide.

(iii) The utility shall provide the Commission with the best value employment metrics information provided by bidders.

(B) Within 45 days after the filing of the utility's ERP Implementation Report, the parties in the electric resource plan proceeding may file comments on the utility's report.

(C) Within 60 days after the filing of the utility's ERP Implementation Report, the utility may file comments responding to the parties' comments.

(II) Phase II decision.

(A) Within 90 days after the receipt of the utility's ERP Implementation Report under subparagraph 3605(h)(I), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan.

(B) In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(C) In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

(D) In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

(E) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

(III) Upon completion of Phase II, the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own. At a minimum the utility shall address the public release of highly confidential and confidential information in its ERP Implementation Report and all documents related to that report filed by the utility and the parties. The utility shall file its proposal in the plan proceeding within 14 months after the receipt of bids to its RFP(s). Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(IV) Upon completion of Phase II, the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

(i) Resource acquisitions not requiring interim or amended plans. The following resources need not be addressed by an interim or amended electric resource plan subsequent to Commission approval of a plan filed pursuant to paragraph 3605(a):

(I) emergency maintenance or repairs made to utility-owned generation and energy storage facilities;

(II) capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 20 MW;

(III) capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two-year term (including renewal terms) or for not more than 20 MW of capacity;

(IV) improvements or modifications to existing utility generation and energy storage facilities that change the production capability of the generation facility site in question, by not more than 20 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million; and

(V) modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 20 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

ELECTRIC RESOURCE PLANNING

3600. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject to the requirements in rule 3605.

* * *

[indicates omission of unaffected rules]

3605. Cooperative Electric Generation and Transmission Association Requirements

This rule shall apply to each utility that is a cooperative electric generation and transmission association.

The statutory authority for this rule can be found at § 40-2-134, C.R.S.

(a) Electric resource plan filing requirements.

(I) Initial plan filing. Each utility shall file an assessment of existing resources pursuant to paragraph 3605(c) no later than June 1, 2020. The utility shall file the assessment as a report and also may submit prefiled testimony. The Commission shall open an adjudicatory proceeding to accept the report and shall establish a notice and intervention period for the determination of the parties. Parties may conduct discovery on the report and on any prefiled testimony submitted with the report. No later than December 1, 2020, the utility shall file an application for approval of the plan with all remaining required components of the plan in accordance with subparagraph 3605(a)(IV). The complete plan will initiate Phase I as set forth in paragraph 3605(g).

(II) Subsequent plan filings. Each utility shall file an electric resource plan pursuant to these rules every four years beginning June 1, 2023. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to subparagraph 3605(a)(IV). If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(III) Highly confidential information. Each utility shall contemporaneously file with its resource plan submitted under subparagraphs 3605(a)(I) and 3605(a)(II), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to subparagraph 3605(a)(III)(K) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

(IV) Plan components. The plan shall contain the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.

(A) The proposed resource acquisition period; however, the resource acquisition period for the initial plan filing submitted in accordance with subparagraph 3605(a)(I) shall extend through 2030. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire electric resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period was chosen in light of the assessment of the needs of the utility system.

(B) An annual electric demand and energy forecast developed pursuant to paragraph 3605(b).

(C) An assessment of existing resources developed pursuant to paragraph 3605(c).

(D) An assessment of transmission resources pursuant to paragraph 3605(d).

(E) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to paragraph 3605(e).

(F) An assessment of the need for additional resources developed pursuant to paragraph 3605(f).

(G) A description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(H) The cost of the projected carbon dioxide emissions using the carbon cost calculated by the Commission based on the most recent assessment of the social cost of carbon developed by the federal government.

(I) The annual water consumption for each of the utility's existing generation resources and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(J) The proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts.

(K) A list of the information related to the electric resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The protections sought by the utility for these items shall be specified in the motion(s) submitted under subparagraph 3605(a)(III). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(L) An assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.

(M) A proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions established by the Commission. The utility also may propose different costs of carbon to be used with respect to the alternative portfolios of resources.

(N) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, consistent with the amounts of renewable energy resources the utility proposes to acquire.

(O) Studies, including updates to studies relied upon by the utility in previous electric resource plans, commissioned or prepared by the utility to support the development of its electric resource plan.

(P) Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.

(Q) A detailed listing and explanation of the information the utility will provide in its ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(b) Electric energy and demand forecasts.

(I) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the planning period.

(A) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated by state jurisdiction and by member of the cooperative electric generation and transmission association.

(B) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(C) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(D) Annual and coincident summer and winter peak system losses of the cooperative electric generation and transmission association.

(E) The electric demand placed on the utility's system for each hour of the day by state jurisdiction and by member of the cooperative electric generation and transmission association. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(II) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(III) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the electric resource plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(IV) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(V) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

(c) Assessment of existing resources.

(I) Existing resource assessment. The utility shall describe its existing generation facilities and energy storage systems at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(A) Name(s) and location(s) of utility-owned and contracted generation and energy storage facilities.

(B) Rated capacity and net dependable capacity of utility-owned and contracted generation and energy storage facilities.

(C) Fuel type, average and marginal heat rates, quick start capability, minimum operating requirements, annual capacity factors and availability factors projected for utility-owned and contracted generation and energy storage facilities over the resource acquisition period.

(D) Estimated in-service dates for utility-owned generation and energy storage facilities not in service at the time the electric resource plan under consideration is filed.

(E) Estimated remaining useful lives of existing generation and energy storage facilities and any significant new investment or maintenance expense relating to the existing generation facilities.

(F) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(G) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(H) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this subparagraph 3605(c)(I).

(I) The expected demand-side resources during the resource planning period from existing measures installed through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association; and, from measures expected to be installed in the future through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association.

(J) Unit-level revenue requirements of utility-owned and contracted generation facilities, including the following components: capital costs, operations and maintenance costs (fixed and variable), fuel costs, emissions and associated costs, integration and coal cycling costs, and energy and capacity payments (for contracted facilities).

(K) The performance characteristics of utility-owned energy storage systems including but not limited to: discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(L) The physical and performance characteristics of energy storage systems purchased from utilities and non-utilities including but not limited to: storage technology; discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(II) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of the generic resources.

(III) Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its transmission systems, including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

(d) Assessment of transmission resources.

(I) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(II) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to rule 3627 that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(III) For each transmission line or facility identified in subparagraph (d)(II), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(A) length and location;

(B) estimated in-service date;

(C) injection capacity;

(D) estimated costs;

(E) terminal points; and

(F) voltage and megawatt rating.

(IV) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(V) The electric resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

(e) Planning reserve margins and contingency plans.

(I) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(II) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under paragraph 3605(b), to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(III) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to paragraph 3605(f); or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under subparagraph 3605(h)(II).

(f) Assessment of need for additional resources.

(I) The utility shall assess the need to acquire additional resources during the resource acquisition period based on the electric energy and demand forecasts developed pursuant to paragraph 3605(b), the assessment of existing resources developed pursuant to paragraph 3606(c), planning reserve margins developed pursuant to paragraph 3605(e), and other factors including, but not limited to, the factors listed in subparagraph 3605(f)(II).

(II) In assessing its need to acquire resources, the utility shall also:

(A) determine the additional eligible energy resources, if any, the utility will need to acquire to allow each member of the cooperative electric generation and transmission association in Colorado to comply with the Commission's RES rules;

(B) consider the benefits of energy storage system may provide to increase integration of intermittent resources; improve reliability; reduce the need for increased generation facilities to meet period of peak demand; and avoid, reduce, or defer investments; and

(C) address statewide goals to reduce greenhouse gas emissions in accordance with rules promulgated and implemented by Colorado Air Quality Control Commission.

(III) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

(g) Phase I.

(I) Review on the merits.

(A) The utility's electric resource plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules of Practice and Procedure.

(B) The Commission may hold a hearing for the purpose of reviewing and rendering a decision regarding the contents of the utility's filed electric resource plan.

(II) Utility plan for meeting the resource need.

(A) The utility shall specify the portion of the resource need that it intends to meet through a competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(B) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. The utility shall specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility.

(C) Although the utility may propose a method for acquiring new utility resources other than competitive bidding, as a prerequisite, the utility shall nonetheless include in its electric resource plan filed under paragraph 3605(a) the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under paragraph 3605(f) exclusively through competitive bidding.

(D) The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources including a schedule of bid fees graduated by the size of the proposed resources.

(E) The utility shall also propose, and other interested parties may provide input as part of the electric resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits, including, for example, benefits associated with best value employment metrics.

(F) The utility shall propose a written bidding policy as part of its filing under paragraph 3605(a), including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner.

(G) Request for Proposals (RFPs).

(i) The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire resources pursuant to subparagraph 3605(g)(II). To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract.

(ii) The proposed RFP(s) shall include the bid evaluation criteria the utility will use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas and connecting to the utility’s transmission system pursuant to paragraph 3605(d), including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; any physical and performance requirements for energy storage systems or instructions for bidders to explain characteristics of energy storage systems, including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations; methodologies or credit mechanisms to value energy storage services provided to the utility system; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(iii) The utility shall request from bidders the best value employment metrics for each bid resource and shall set forth criteria for the review of such metrics, based on objective performance standards, to be applied in the evaluation and selection of bids in accordance with § 40-2-129, C.R.S.

(iv) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility.

(III) Phase I decision.

(A) Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's electric resource plan.

(B) The Phase I decision approving or denying the electric resource plan shall address the contents of the utility's plan filed in accordance with paragraph 3605(a). If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; and components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria.

(C) The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(i) The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

(ii) In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

(iii) The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

(iv) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

(D) The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

(E) If the Commission declines to approve a utility's electric resource plan, either in whole or in part, the utility shall make changes to the plan in response to the

Commission's decision. Within 90 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(h) Phase II.

(I) ERP Implementation Report.

(A) On or before the deadline established by the Commission, the utility shall file a report with the Commission presenting cost-effective resource plans in accordance with the Commission's Phase I decision. The utility shall identify its preferred cost-effective resource plan.

(i) The utility shall apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's Phase I decision.

(ii) The utility shall present a calculation of the net present value of revenue requirement for each portfolio required by the Phase I decision, including the defined base case portfolio. The utility shall present the net present value of revenue requirement for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Phase I decision and calculated without using the cost of carbon dioxide emissions. The utility also shall present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide.

(iii) The utility shall provide the Commission with the best value employment metrics information provided by bidders.

(B) Within 45 days after the filing of the utility's ERP Implementation Report, the parties in the electric resource plan proceeding may file comments on the utility's report.

(C) Within 60 days after the filing of the utility's ERP Implementation Report, the utility may file comments responding to the parties' comments.

(II) Phase II decision.

(A) Within 90 days after the receipt of the utility's ERP Implementation Report under subparagraph 3605(h)(I), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan.

(B) In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(C) In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

(D) In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

(E) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

(III) Upon completion of Phase II, the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own. At a minimum the utility shall address the public release of highly confidential and confidential information in its ERP Implementation Report and all documents related to that report filed by the utility and the parties. The utility shall file its proposal in the plan proceeding within 14 months after the receipt of bids to its RFP(s). Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(IV) Upon completion of Phase II, the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

(i) Resource acquisitions not requiring interim or amended plans. The following resources need not be addressed by an interim or amended electric resource plan subsequent to Commission approval of a plan filed pursuant to paragraph 3605(a):

(I) emergency maintenance or repairs made to utility-owned generation and energy storage facilities;

(II) capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 20 MW;

(III) capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two-year term (including renewal terms) or for not more than 20 MW of capacity;

(IV) improvements or modifications to existing utility generation and energy storage facilities that change the production capability of the generation facility site in question, by not more than 20 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million; and

(V) modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 20 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.