Decision No. C20-0096

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19AL-0268E

IN THE MATTER OF ADVICE LETTER NO. 1797 FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO RESET THE CURRENTLY EFFECTIVE GENERAL RATE SCHEDULE ADJUSTMENT ("GRSA") AS APPLIED TO BASE RATES FOR ALL ELECTRIC RATE SCHEDULES AS WELL AS IMPLEMENT A BASE RATE KWH CHARGE, GENERAL RATE SCHEDULE ADJUSTMENT-ENERGY ("GRSA-E") TO BECOME EFFECTIVE JUNE 20, 2019.

DECISION PERMANENTLY SUSPENDING TARIFF SHEETS; GRANTING JOINT MOTION TO APPROVE PARTIAL SETTLEMENT AGREEMENT ON WILDFIRE MITIGATION; DENYING MOTION FOR RATES EFFECTIVE JANUARY 1, 2020; ESTABLISHING RATES; AND REQUIRING FILINGS

Mailed Date: February 11, 2020
Adopted Date: December 11 and 17, 2019

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I. BY THE COMMISSION

A. Statement

1. This Decision permanently suspends the effective date of the tariff sheets for rates filed by Public Service Company of Colorado (Public Service or Company) with Advice Letter No. 1797-Electric on May 20, 2019. We instead establish new rates that Public Service shall implement for effect in accordance with this Decision.

2. We authorize Public Service to increase its base rate revenues through a modified General Rate Schedule Adjustment (GRSA)—for incremental base rate cost recovery on an energy basis from residential and small commercial rate classes—or through a combination of a traditional GRSA, expressed as a percentage increase to all exiting base rate components, and a General Rate Schedule Adjustment-Energy (GRSA-E), expressed on an energy basis—for incremental base rate cost recovery from all other customer rate classes. The increase in base rate revenues shall be the net of the "roll-ins" of certain costs presently recovered through separate rate adjustment mechanisms.

3. The authorized increase in base rate revenues shall include the costs agreed to by the parties joining the Unopposed Partial Settlement Agreement on Wildfire Mitigation filed by Public Service on November 1, 2019.

4. The authorized base rate increase shall be implemented only on a temporary basis through the GRSAs and the GRSA-E. We direct Public Service to file by May 1, 2020 either a full Phase II electric rate case filing to eliminate the GRSAs and the GRSA-E or a notice of its binding commitment to file a combined Phase I and Phase II electric rate case by August 1, 2020.

5. We also direct Public Service to make a compliance tariff filing to implement the Revenue Decoupling Adjustment (RDA) as directed by the Public Utilities Commission (Commission) in Proceeding No. 16A-0546E.

6. We further direct Public Service to file a notice in this Proceeding to report to the Commission on whether it has reached consensus with interested stakeholders on a modified Certified Renewable Percentage.

B. Procedural Background

7. Public Service filed Advice Letter No. 1797 with supporting attachments and pre-filed testimony as a Phase I rate proceeding. The proposed effective date of the tariffs filed with Advice Letter No. 1797 is June 20, 2019.

8. Public Service initially sought a total increase in its base rate revenues of approximately $408 million, or 26.4 percent. However, approximately $249 million of that amount was the result of transfers from three ongoing riders: (1) approximately $79 million would move to base rates from the Clean Air-Clean Jobs Act (CACJA) Rider, which would be eliminated upon certain final reconciliations; (2) approximately $40 million would move to base rates from the Transmission Cost Adjustment (TCA); and approximately $131 million would be

recovered through a GRSA-E to collect costs associated with the Rush Creek Wind Project that are presently recovered through the Company's Electric Commodity Adjustment (ECA). In addition to the GRSA-E, Public Service would implement a standard GRSA of 13 percent. The proposed net increase in total revenues was projected to be approximately $158.3 million, or an overall bill impact of 5.7 percent.

9. The proposed rate increase was supported by Public Service's cost of service study that generates a total annual base rate revenue requirement of $1.95 billion. That amount was based on a proposed return on equity (ROE) of 10.35 percent, a cost of long-term debt of 4.18 percent, and a capital structure composed of 56.46 percent equity and 43.54 percent debt. These financing components were combined into an overall weighted average cost of capital of 7.66 percent.

10. A major driver of the proposed rate increase is $4.1 billion of investment that Public Service made in the last five years. In addition, Public Service sought what it calls a "capital reach" of about $593 million for the plant additions that will be in service by the end of 2019.

11. The tariff sheets filed with Advice Letter No. 1797 would continue the Company's Quality of Service Plan (QSP) for its electric operations. Public Service proposed "minimal adjustments" to the electric QSP, such as an extension through 2021 and a reduction in the required reporting from the current monthly, quarterly, and annual reporting to only annual reporting.

12. Public Service also sought to modify its ECA tariff to include provisions to facilitate the future recovery of costs associated with the Cheyenne Ridge Wind Project. Public

Service explains that these changes conform to the Cheyenne Ridge Wind Project Settlement Agreement recently approved by the Commission in Proceeding No. 18A-0905E.

13. By its Advice Letter No. 1797 filing, Public Service also sought to:

I Update tariff sheets to incorporate new rates for the Charges for Rendering Service and Maintenance Charges for Street Lighting Service;

II Eliminate the Transmission Time-of-Use (Schedule TTOU) as of January 1, 2017;

III Correct the wattage in the Parking Lot Lighting Service (Schedule PLL) tariff;

IV Remove the tariff for the Earnings Sharing Adjustment (ESA);

V Update the Short-Term Sales Margins in the ECA for Generation and Proprietary Books from calendar year 2015 to 2018;

VI Remove the Equivalent Availability Factor Performance Mechanism (EAFPM) from the ECA;

VII Revise Data Privacy in the Requests for Customer Data section of the General section of the Company's Rules and Regulations to more clearly reflect the reports available to customers and third parties;

VIII Clarify and simplify the tariff language in Other Meter Tests and Billing for Errors sections of the Standards in the Company's Rules and Regulations to better align with Commission Rules; and

IX Include tariff provisions addressing customer credit and payment plan options that apply in the event billing adjustments are made.

14. On May 31, 2019, by Decision No. C19-0462, the Commission set for hearing the tariffs filed with Advice Letter No. 1797 and suspended their effective date for 120 days pursuant to § 40-6-111(1), C.R.S.

15. By Decision No. C19-0621-I, issued on July 23, 2019, the Commission addressed the requests for intervention in this Proceeding and established the parties. The parties include: Staff of the Colorado Public Utilities Commission (Staff); the Colorado Office of Consumer Counsel (OCC); the Colorado Energy Office (CEO); the Colorado Energy Consumers (CEC); the

Department of Energy on behalf of the Federal Executive Agencies (DOE); CF&I Steel, L.P., doing business as Evraz Rocky Mountain Steel and Evraz NA, Inc.; City and County of Denver (Denver); City of Boulder (Boulder); Walmart, Inc. (Walmart); Climax Molybdenum Company; Ms. Leslie Glustrom; AARP; Energy Outreach Colorado (EOC); International Brotherhood of Electrical Workers, Local 111 (IBEW); Vote Solar; Southwest Energy Efficiency Project (SWEEP); Western Resource Advocates (WRA); and Sierra Club.

16. On August 23, 2019, by Decision No. C19-0709-I, the Commission established a procedural schedule with filing deadlines, hearing dates, and provisions governing discovery. The Commission adopted, without modification, the proposed schedule filed by Public Service on July 2, 2019, upon conferral with the parties. Decision No. C19-0709-I also established the dates for the evidentiary hearing from November 4 through 13, 2019, as proposed by Public Service. The Commission further extended the suspension period of the effective date of the tariff sheets filed with Advice Letter No. 1797 an additional 130 days pursuant to § 40-6-111(1), C.R.S. The proposed effective date the tariff pages was suspended until February 25, 2020.

17. On August 30, 2019, by Decision No. C19-0720-I, the Commission extended the deadline for the filing of Answer Testimony by two weeks, such that Answer Testimony was due no later than September 20, 2019. The Commission also modified the deadline for the filing of Rebuttal Testimony and Cross-Answer Testimony to October 11, 2019. All other deadlines and dates established by Decision No. C19-0709-I were retained.

18. On or before September 20, 2019, Answer Testimony was filed by Staff, OCC, CEO, CEC, DOE, Denver, Walmart, Ms. Leslie Glustrom, AARP, EOC, Vote Solar, SWEEP, WRA, and Sierra Club.

19. Public Service filed Rebuttal Testimony on October 11, 2019. In addition, CEO, CEC, DOE, Denver, Boulder, AARP, EOC, IBEW, Vote Solar, SWEEP, and WRA filed Cross-Answer Testimony.

20. On September 19, 2019, by Decision No. C19-0773-I, the Commission scheduled two hearings for the purpose of taking comment from members of the public. An initial hearing to accept public comments was scheduled for September 26, 2019 in Grand Junction, Colorado. Commissioner John Gavan was assigned as Hearing Commissioner for the sole purpose of conducting the public comment hearing on September 26, 2019. A second hearing to accept public comment was scheduled before the Commission *en banc* in Denver, Colorado, for November 6, 2019, during the course of the scheduled evidentiary hearing.

21. On October 25, 2019, Public Service filed a matrix for the evidentiary hearing scheduled to begin on November 4, 2019, showing the proposed order of the presentation of witnesses and corresponding estimates of cross-examination by the parties.

22. By Decision No. C19-0877-I, issued November 1, 2019, the Commission rejected the proposed order of witness and cross-examination matrix and ordered the parties again to confer, develop, and file a practicable cross-examination matrix by noon on November 1, 2019. The Commission found that the initially filed matrix: (1) scheduled ten full days of cross-examination, yet the hearing was scheduled for only seven days; (2) provided no time for the Commissioners to question the witnesses; and (3) failed to account for late starts on two hearing days on account of the Commissioners' regular weekly business meetings. The Commission also extended the hearing by two days to include November 14 and 15, 2019.

23. Post-hearing statements of position (SOPs) were filed on November 22, 2019, by Public Service, Staff, OCC, CEO, CEC, DOE, Denver, Boulder, Walmart, Ms. Leslie Glustrom, AARP, EOC, IBEW, Vote Solar, SWEEP, WRA, and Sierra Club.

24. On December 6, 2019, by Decision No. C19-0980-I, the Commission scheduled a special Commissioners' Deliberations Meeting for December 11, 2019, and a Technical Conference for December 16, 2019, for the purpose of reviewing the calculations of the final revenue requirement and base rates based on the Commission's oral deliberations on December 11, 2019.

25. The Commission initiated its deliberations adopting this Decision at the special Commissioners' Deliberations Meeting on December 11, 2019.

26. At the Technical Conference on December 16, 2019, Public Service presented modifications to its cost of service study to reflect the oral decisions the Commission made during its deliberations on December 11, 2019. Immediately prior to the start of the Technical Conference, Public Service filed an updated cost of service study, the recalculated total annual base rate revenue requirement, representative GRSAs and the GRSA-E, and the associated bill impacts. These filings were the basis of the Company's presentation at the Technical Conference.

27. The Commission concluded its deliberations to adopt this Decision at the Commissioners' Weekly Meeting on December 17, 2019. The Commission reviewed the results of the December 16, 2019 Technical Conference as part of those deliberations.

C. Motion for Rates Effective January 1, 2020

28. On May 20, 2019, the same date of the Advice Letter No. 1797 filing, Public Service filed a Motion for Rates Effective January 1, 2020.

29. Public Service argues that a January 1, 2020 effective date will conserve customer, Commission, and Company resources by eliminating the need for multiple true-ups. The Company also states that a January 1, 2020, effective date will also help to eliminate customer confusion that often ensues as a result of such true-ups. Public Service further explains that the Company's rates have been reduced to reflect the impact of the Tax Cuts and Jobs Act (TCJA) from January 1, 2018 through December 31, 2019, as approved in Proceeding No. 18M-0074EG. The Company suggests that having new base rates effective January 1, 2020 corresponds with the conclusion of that initial TCJA rate reduction. In sum, Public Service concludes that authorizing a January 1, 2020 effective date for rates will provide the most seamless and efficient path to providing customers the financial benefits provided under the TCJA-related settlements.

30. At the December 17, 2019 Commissioners' Weekly Meeting, we concluded that there was insufficient time to render a final written decision in this matter to accommodate rates for effect on January 1, 2020, as requested by the Company. The Motion for Rates Effective January 1, 2020, was thus denied.

D. Motion for Approval of Partial Settlement Agreement on Wildfire Mitigation

31. On November 1, 2019, Public Service filed an Unopposed Joint Motion to Approve Partial Settlement Agreement on Wildfire Mitigation. The settlement agreement was joined by Public Service, Staff, OCC, CEC, DOE, Denver, Boulder, AARP, Vote Solar, and WRA. The motion states that all other intervening parties in this Proceeding took no position on the settlement.

32. The motion explains that the settling parties entered into the agreement with the intent of resolving, as between them, all issues that have been raised or could have been raised in

this Proceeding with respect to wildfire mitigation. The motion explains that the settling parties agree that the compromises reflected in the agreement represent a just and reasonable resolution of the wildfire mitigation issues raised either by the Company's "Application" or by the settling parties' respective Direct, Answer, Cross-Answer, and Rebuttal Testimony in this Proceeding.

E. Hearings and Evidentiary Record

33. Commissioner John Gavan conducted the first public comment hearing on September 26, 2019, in Grand Junction, Colorado.

34. The evidentiary hearing commenced before the Commission *en banc* on November 4, 2019.

35. The second public comment hearing was conducted before the Commission *en banc* on November 6, 2019, in Denver, Colorado.

36. The evidentiary hearing concluded on November 14, 2019.

37. In addition to the public comments provided orally at the two public comment hearings, the administrative record for this Proceeding includes numerous additional written public comments.

38. During the course of the evidentiary hearing, Hearing Exhibits 100 through 187, 189 through 197, 199, 200, 202, 204, 206, 208, 211 through 213, 216 through 223, 225 through 235, 237, 241, 243, 244, 256 through 279, and 282 through 285 were offered and admitted into evidence. Administrative notice was taken of documents marked as Hearing Exhibits 207, 209, 210, 214, 215, 224, 236, 248 through 255, 280, and 286 through 288. Hearing Exhibit 203 was offered and rejected. The following numbers were not used: 188, 198, 201, 205, 238, 239, 242, 245, 246, 247, and 281.

F. Summary of Findings and Conclusions

39. We have carefully reviewed the extensive evidentiary record in this Proceeding, mindful of the public comments submitted in writing and offered orally at the two public comment hearings. Based on this review, our consideration of the SOPs filed by Public Service and the intervening parties, and our deliberations on December 11 and 17, 2019, we establish rates to recover Public Service's base rate revenue requirement that will cover the Company's expenses and provide the Company a reasonable opportunity to earn a fair rate-of-return.[1]

40. The updated cost of service study and bill impacts presented by Public Service at the December 16, 2019 Technical Conference lead us to conclude that: (1) the revenue requirement authorized by this Decision will be sufficient to ensure safe and reliable service to Public Service's retail electric customers; (2) the rate-of-return established by this Decision will allow Public Service to secure adequate financing at a reasonable cost; and (3) the rates authorized to go into effect to recover the increase in base rate revenues are just and reasonable.

II. LEGAL FOUNDATION AND BURDENS OF PROOF

A. Commission Jurisdiction

41. Rates and charges for utility service are to be just and reasonable pursuant to § 40-3-101(1), C.R.S. The Colorado Supreme Court has held that it is the primary purpose of utility regulation to ensure that the rates charged are not excessive or unjustly discriminatory.[2] Further, § 40-3-101(2), C.R.S., requires a utility to furnish, to provide, and to maintain such service, instrumentalities, equipment, and facilities as shall promote the safety, health, comfort,

[1] Commissioner Frances A. Koncilja disagrees with several of the findings and conclusions entered by this Decision, including the determination of the ROE, the CTY and the disallowance of the interest, fees, and penalties on disputed tax payments as explained in her partial dissent and special concurrence

[2] *Cottrell v. City & County of Denver*, 636 P.2d 703 (Colo. 1981).

and convenience of its patrons, employees, and the public, and as shall in all respects be adequate, efficient, just, and reasonable. *See also*, § 40-3-111, C.R.S.

42. The Commission is the agency charged with the duty of regulating the rates of public utilities within Colorado. § 40-3-102, C.R.S. *See also*, Colo. Const. Art. XXV. The Commission is authorized by statute to conduct hearings to investigate the propriety of proposed rate changes and to make such orders with regard to a proposed rate as may be just and reasonable.[3]

43. The establishment of just and reasonable rates involves a balancing of investor and consumer interests.[4] As regards the utility, to be just and reasonable, rates must generate revenues sufficient to meet the utility's cost of furnishing services, and provide its investors with a fair and reasonable return on their investments.[5] The Commission must ensure that the utility has adequate revenues for operating expenses and to cover the capital costs of doing business.[6] The revenues must be sufficient to assure confidence in the financial integrity of the utility, in order to maintain its credit and attract capital.[7] As regards to ratepayers, the Commission is charged with protecting the interest of the general public from excessive, burdensome rates.[8] The Commission must determine that every rate is just and reasonable and that services provided

[3] *See generally*, *Public Service Company of Colorado v. Pub. Utils. Comm'n*. 644 P.2d 933, 938 (1982); *Colorado Ute Electric Association v. Pub. Utils. Comm'n.*, 602 P.2d 861 (1979); *Consolidated Freightways Corp. v. Pub. Utils. Comm'n*, 406 P.2d 83 (1965).

[4] *Public Service Company of Colorado v. Pub. Utils. Comm'n*. 644 P.2d at 939.

[5] *Federal Power Commission v. Hope Natural Gas Co*, 320 U.S. 591 (1944); *Bluefield Water Works and Improvement Co. v. Public Service Company*, 262 U.S. 679 (1923). *See also*, *Peoples Natural Gas Div. of N. Natural Gas Co. v. Pub. Utils. Comm'n.*, 567 P.2d 377 (Colo. 1977).

[6] *Public Utilities Commission v. District Court*, 527 P.2d 233 (Colo. 1974).

[7] *Id*.

[8] *Id*.

"promote the safety, health, comfort and convenience of its patrons, employees, and the public, and as shall in all respects be adequate, efficient, just and reasonable.[9]

44. The Commission must consequently set rates that protect the right of a utility and its investors to earn a return reasonably sufficient to maintain the utility's financial integrity, and that protect the right of consumers to pay a rate that accurately reflects the cost of service rendered.[10]

45. The setting of just and reasonable rates goes to the very essence of the Commission's constitutional and statutory authority and duty under public utilities law.[11] "It is precisely the Commission's *raison d'être* to determine and prescribe just, reasonable, non-discriminatory, and non-preferential 'rates of every public utility in this state.' Both statutory and case law demonstrate that rate-making, both as to charge and design, is a vital part of the Commission's area of responsibility."[12]

46. The Commission must exercise reasoned judgment in setting rates.[13] Ratemaking is a legislative function[14] and not an exact science.[15] As a consequence, the Commission "may set rates based on the evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data."[16] Under the just and reasonable standard,

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[9] *Id.*

[10] *Id.*

[11] *Colorado-Ute Electric Association v. Pub. Utils. Comm'n*, 760 P.2d 627, 638 (Colo. 1988).

[12] *Id.* (quoting § 40-3-102, C.R.S.).

[13] *See Mountain States Tel. & Tel. Co. v. Pub. Utils. Comm'n.*, 513 P.2d 721, 726 (Colo. 1973).

[14] *City and County of Denver v Pub. Utils. Comm'n.*, 226 P.2d 1105 (Colo. 1954).

[15] *Pub. Utils. Comm'n. v. Northwest Water Corporation*, 551 P.2d 266 (Colo. 1963); *see also Colo. Office of Consumer Counsel v. Pub. Utils. Comm'n.*, 752 P.2d 1049, 1058-59 (Colo. 1988); *Montrose v. Pub. Utils. Comm'n.*, 629 P.2d 619, 623 (Colo. 1981); *Colorado Ute Elec. Ass'n. v Public Utilities Commission*, 602 P.2d at 864 (Colo. 1979); *Public Util. Comm'n. v. Northwest Water Corp.*, 451 P.2d 266 (Colo. 1969).

[16] *Colorado Office of Consumer Counsel v. Pub. Utils. Comm'n.*, 275 P.3d 656, 660 (Colo. 2012); *see also Colorado Municipal League v. Pub. Utils. Comm'n.*, 473 P.2d 960, 971 (Colo. 1970).

the Commission has the primary responsibility for balancing "the investors' interest in avoiding confiscation and the consumer's interest in prevention of exorbitant rates"[17] and for setting rates that protect both: (1) the right of the public utility company and its investors to earn a return reasonably sufficient to maintain the utility's financial integrity; and (2) the right of consumers to pay a rate which accurately reflects the cost of service rendered.[18] The utility's right to earn a reasonable return incorporates the principle that the Commission-authorized rate-of-return is not a guaranteed return, but instead, is a return that the utility has a reasonable opportunity to realize.

47. In the context of ratemaking, the Colorado Supreme Court recently reiterated that "it is the result reached, not the method employed, which determines whether a rate is just and reasonable."[19]

48. The Commission establishes rates to recover the utility's revenue requirements as determined by using the Commission-selected test year. The revenue requirement is the total revenues required by the utility to cover both its expenses and to have a fair or reasonable opportunity to earn a fair rate-of-return, and in return, to provide safe, reliable service to its customers.[20]

49. In past rate cases and as discussed below, the Commission has established regulatory principles and methods to determine a utility's revenue requirement. The Colorado Supreme Court has noted that "[s]ince rate setting is a legislative function which involves many questions of judgment and discretion, courts will not set aside the rate methodologies chosen by

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[17] *Colorado Municipal League v. Public Utilities Commission*, 687 P.2d 416, 418 (Colo. 1984).

[18] *Public Service Company of Colorado v. Public Utilities Commission*, 644 P.2d 933, 939 (Colo. 1982).

[19] *Glustrom v. Colorado Public Utilities Commission*, 280 P.3d 662, 669 (Colo. 2012).

[20] *e.g., Public Service Company of Colorado v. Pub. Utils. Comm'n.*, 644 P.2d 933 at 939.

the [Commission] unless they are inherently unsound."[21] Indeed, "the [Commission] is not bound by a previously utilized methodology when it has a reasonable basis, in the exercise of its legislative function, to adopt a different one."[22]

B. Burden of Proof and Burden of Going Forward

50. As the party that seeks Commission approval or authorization, Public Service bears the burden of proof with respect to the relief sought; and the burden of proof is by a preponderance of the evidence.[23] The evidence must be "substantial evidence," which the Colorado Supreme Court has defined as "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion … it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury."[24] The preponderance standard requires the finder of fact to determine whether the existence of a contested fact is more probable than its non-existence.[25] A party has met this burden of proof when the evidence, on the whole and however slightly, tips in favor of that party.

51. This standard for the burden of proof must be integrated with the understanding that in the context of a rate case, the Commission acts in its legislative capacity, and the key issues require policy-based decisions in order to adopt a particular regulatory principle or to change an existing regulatory principle. As such, the Commission "may set rates based on the

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[21] *CF&I Steel, L.P. v. Pub. Utils. Comm'n.*, 949 P.2d 577, 584 (Colo. 1997).

[22] *CF&I Steel*, 949 P.2d at 584; *Glustrom*, 280 P.3d at 669.

[23] § 24-4-107(7), C.R.S.; § 13-25-127(1), C.R.S.; 4 *Code of Colorado Regulations* 723-1-1500 of the Commission's Rules of Practice and Procedure.

[24] *City of Boulder v. Colorado Public Utilities Commission*, 996 P.2d 1270, 1278 (Colo. 2000) (*quoting CF&I Steel, L.P. v. Public Utilities Commission*, 949 P.2d 577, 585 (Colo. 1997)).

[25] *Swain v. Colorado Department of Revenue*, 717 P.2d 507 (Colo. App. 1985).

evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data."[26]

52. Because the Commission has an independent duty to determine matters that are within the public interest,[27] the Commission is not bound by the proposals of the parties. The Commission may do what it deems necessary to assure that the final result is just, reasonable, and in the public interest, provided the record supports the result, and provided the reasons for the policy choices made are stated.[28]

III. TEST YEAR AND VALUATION OF RATE BASE

1. Public Service's Position

53. Although Public Service initially sought approval of a "2019 capital reach" beyond the investments reflected in the underlying 2018 test year (2018 Historic Test Year or 2018 HTY), the Company ultimately proposes a 2019 Current Test Year (CTY) incorporating both actual and projected investment costs through the 2019 calendar year. Public Service's move to a 2019 CTY comes in response to an alternate form of the 2019 CTY proposed by Staff in its Answer Testimony, which the Company describes as a "thoughtful and constructive proposal which increased the precision of the matching principle utilized in Colorado."[29]

[26] *Colorado Office of Consumer Counsel*, 275 P.3d at 660.

[27] *Caldwell v. Pub. Utils. Comm'n.*, 692 P.2d 1085, 1089 (Colo. 1984).

[28] *See Colo. Office of Consumer Counsel*, 275 P.3d at 660-61*; Pub. Serv. Co. v. Pub. Utils. Comm'n.*, 26 P.3d 1198, 1207-08 (Colo. 2001) (holding that the Commission acted reasonably in its legislative capacity to accomplish its ratemaking function when it required Public Service to include a merger savings adjustment to benefit ratepayers because there was sufficient support in the record); *CF&I Steel, L.P.*, 949 P.2d at 586-87; *Colo. Office of Consumer Counsel v. Pub. Utils. Comm'n.*, 786 P.2d 1086, 1095-97 (Colo. 1990) (holding that the Commission did not act arbitrary or capriciously in setting rates, even though it did not accept any of the experts' opinions in full); *Pub. Serv. Co. v. Pub. Utils. Comm'n.*, 653 P.2d 1117, 1120 (Colo. 1982) (holding that the Commission did not abuse its discretion when it chose not to include out-of-test year debt cost because the decision was reasonable and based on the record).

[29] Public Service SOP, pp. 2-3.

54. Public Service stresses that the goal of this Proceeding is to set rates reflective of the costs being incurred by the Company when the new rates become effective. Public Service's 2019 CTY rate base includes approximately $102.5 million in distribution "new business" capital additions and the updated cost of service for the 2019 CTY also includes the associated revenues. However, the expenses in the cost of service study remain based on actual 2018 HTY values with certain *pro forma* adjustments, some of which are based on projections.

55. Public Service acknowledges that the most "significant shift" and "substantial compromise" in the Company's position was not its embrace of the 2019 CTY—since the 2019 capital reach generally entails the same investments, albeit forecast at the time of the Advice Letter No. 1797 filing—but the adoption of a 13-month average valuation of rate base rather than a year-end valuation.[30] Public Service had originally calculated the value of its rate base at year-end with respect to its 2019 capital reach, with the exception of certain balances related to fuel, materials and supplies, and cash working capital. Public Service asserts, in agreement with Staff, that using a 13-month average rate base in concert with the 2019 CTY better adheres to the "matching principle," or the "well-recognized principle of regulatory matching between investments, revenues and expenses in a test year" when rates are in effect.[31] Public Service notes that the roll-in of CACJA Rider costs and Rush Creek Wind Project costs from the ECA will also be accomplished based on a 13-month average.

2. Positions of the Intervening Parties

56. Staff opposes Public Service's 2018 HTY with the 2019 capital reach, arguing that it violates the matching principle. Staff notes that while Public Service updated some costs such

[30] Public Service SOP, p. 3.

[31] Hearing Exhibit 103, Blair Direct, p. 51.

as transmission and generation expenses, the Company did not incorporate other impacts such as the change in revenues and associated distribution capital.

57. Staff proposes instead that rates should be set using a 2019 CTY rate base because it is forward-looking, conforms to the matching principle, addresses regulatory lag, and limits reliance on forecasted amounts. Staff further points to §§ 40-3-111(1) and 40-6-111(2), C.R.S., which allow the Commission to consider a current test year in the determination of rates.

58. Staff also supports the use of a 13-month average rate base valuation instead of a year-end valuation as proposed for the 2019 capital reach. According to Staff, the 13-month average better adheres to the matching principle, recognizing that plant is added and removed during the test year which evens out the impacts to the rate base. Staff states that, in contrast, a year-end valuation of rate base only provides a snapshot of rate base at a particular point in time and may introduce a distortion into the matching principle.

59. The OCC also opposes Public Service's 2019 capital reach, but unlike Staff, the OCC advocates for the use of the 2018 HTY with only known and measurable *pro forma* adjustments. The OCC argues that it has been the Commission's long-standing policy to approve an HTY with known and measurable adjustments, because that approach adheres best to the matching principle. The OCC argues that use of the HTY—in this case a 2018 HTY—is reflective of Public Service's future operations and will provide the Company a fair opportunity to earn its authorized return. The OCC points out that the 2019 capital reach proposed by the Company includes forecasted capital additions and most attendant aspects but fails to include forecasted expenses and revenues. The OCC also opposes the use of a CTY in this Proceeding, arguing that the Commission has denied such a proposal in the past because it did not include actual per-book financial information.

60. The OCC also opposes the use of year-end rate base and advocates for use of a 13-month average rate base for the 2018 HTY. OCC argues that Public Service has not made a sufficient showing that extraordinary circumstances exist to support the use of a year-end rate base, stating that the Commission has required the existence of extraordinary circumstances, such as earnings attrition, inflation, or capital growth, to support the use of year-end rate base in numerous prior rate case decisions. If the Commission denies use of year-end rate base, the OCC nevertheless recommends that Public Service be ordered to provide an amount for "new business" distribution plant, and then for the Commission to allow this amount in rate base valued on a year-end basis.

61. CEC likewise opposes Public Service's proposed 2019 CTY, describing it as an amalgamation of various measurement periods that defy a single clear description. CEC argues that the use of a 2019 CTY is further complicated by the effects of certain "single-issue trackers," riders, and special accounting arrangements. Similar to the OCC, the CEC recommends that the Commission adopt the 2018 HTY, while recognizing certain tracker and rider effects through the end of 2019. According to CEC, the 2018 HTY conforms to the Commission's consistent policy over the past several years when determining revenue requirements.

62. DOE also opposes the 2019 capital reach, arguing that the addition of the post-test year costs violates the HTY concept and causes a mismatch of revenues, expenses, and investment. DOE argues that the 2019 capital reach is based on Company budgets that may or may not be realized in actuality and that it ignores operational changes that also are occurring in 2019. Similar to the other intervenors, the DOE points to the exclusion of incremental revenue in 2019, which it describes as "cherry picking."

63. Notwithstanding its support of the use of the 2018 HTY, DOE recommends including in the revenue requirement the 2019 distribution capital investment and expenses related to the Company's Wildfire Mitigation Plan. DOE also supports Public Service's use of year-end rate base at the end of the 2018 HTY, arguing that year-end balances can be supported when revenues are determined based on the year-end number of customers. According to DOE, year-end balances also recognize the existing plant-in-service at the end of the 2018 HTY, including the costs of the Rush Creek Wind Project which was providing service to customers at that time.

64. AARP characterizes Public Service's proposed 2019 capital reach as an attempt to avoid intervenor objections to its failed multi-year rate plans and future test year proposals in prior rate cases. AARP argues that relying on an HTY, as was affirmed by the Commission *en banc* in Public Service's most recent gas rate case (Proceeding No. 17AL-0363G) is the best course of action.

65. Through Rebuttal Testimony, Public Service criticizes the OCC, CEC, AARP, and DOE who advocate against the 2019 capital reach, arguing that their positions are not forward-looking or reflective of when the new rates will be in effect. Public Service further contends that these parties do not take into account other circumstances, such as the Company's large investments in its Steel-for-Fuel initiative. Public Service characterizes the intervenor positions supporting the HTY as "orthodox" and reflecting an unwillingness to explore new concepts.

3. Findings and Conclusions

66. Public Service and Staff's agreement in this Proceeding that the Commission should adopt a 2019 CTY using a 13-month average rate base valuation represents a significant

compromise in principle by both parties. In agreeing to the 2019 CTY, Staff explains that a more forward-looking test period acknowledges the Company's investment in capital-intensive projects such as its Steel-for Fuel initiative and the costs for the Advanced Grid Intelligence and Security (AGIS) initiative that have already been approved by the Commission. Both Public Service and Staff also seem to agree that the 2019 CTY attempts to match the rate base and its attendant aspects, including investment, revenues, and expenses, more closely to the operating conditions at the time rates will be in effect using projections and forecasts in 2019.

67. Yet not all of the intervening parties agree with Public Service and Staff. The OCC, CEC, and DOE instead favor maintaining the Commission's long-standing principle of using an HTY with known and measurable adjustments, and they particularly object to the use of projections or forecasts with any of its components. These intervenors argue that the Commission's use of an HTY in prior proceedings has consistently led to just and reasonable rates. They contend that, in this Proceeding, using a 2018 HTY with actual reported costs ensures that the financial information used in the development of the revenue requirement is verifiable and auditable. They claim the use of projections or forecasts introduces risks from inaccuracies and runs counter to the historic cost principle.

68. We seek to balance the agreement reached between Public Service and Staff regarding the adoption of a 2019 CTY and the advocacy of the OCC, CEC, and DOE who favor the 2018 HTY, and conclude that the cost of service information available through August 2019 supports the adoption of a current test year consisting of the 12-month period ending August 31, 2019.[32] Our approval of a 2019 CTY ending August 31, 2019 recognizes the Company's leadership of the clean energy transition and the approximately $5 billion in investment that the

[32] Commission Frances A. Koncilja does not join in these findings and conclusions.

Company has made in generation, transmission, and distribution infrastructure.[33] The 2019 CTY ending August 31, 2019 further satisfies the regulatory matching principle as sought by the proponents of the 2018 HTY.[34]

69. We note that Public Service provided to the intervening parties numerous updates to its initially filed case during the course of this Proceeding, introducing actual financial information extending far into what has become the 2019 CTY. Before the closing of the evidentiary record in this Proceeding, Public Service provided: (1) actual capital additions through September 2019; (2) the Company's actual capital structure through August 2019; (3) a cost of both long-term and short-term debt through August 2019; and (4) actual revenues through September 2019. The attendant expenses in the cost of service remain based on actual 2018 HTY values with *pro forma* adjustments, some of which are based on projections. Certain rate base items including materials and supplies, inventory balances for fuels including coal, oil, and natural gas, and Accumulated Deferred Income Taxes (ADIT) balances are also projected.

70. We agree with the OCC and Staff that using a 13-month average rate base serves to increase the precision of the rate base and best adheres to the matching principle. Public Service is thus directed to calculate the 13-month average rate base for the approved test period beginning in August 2018 through August 2019.

[33] Hearing Exhibit 102, Jackson Rebuttal, p. 3.
[34] OCC SOP, p. 12.

IV. COST OF CAPITAL

A. Return on Equity

1. Public Service's Position

71. Public Service seeks a 10.20 percent authorized ROE, within a recommended range of reasonableness extending from 9.72 percent to 11.03 percent. The 10.20 percent level is a reduction from the Company's original request for an ROE of 10.35 percent in its initial Advice Letter No. 1797 filing.

72. The lower boundary of Public Service's range represents the mean of four rate-of-return models developed by the Company: Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Bond Yield Plus Risk Premium, and Expected Earnings models. Public Service's models use a proxy group of electric utility companies that the Company represents to be similar to Public Service, based on specified criteria used to evaluate the risks associated with their electric operations. The upper boundary represents the high end of the range of the DCF, CAPM, and Expected Earnings models.

73. Public Service depicts the current equity market as emerging from an unprecedented period of low interest rates. Public Service describes this condition as "anomalous" and argues that it causes the ROE model results to produce results that are unduly low. The Company states that high utility stock prices in the current market combined with low interest rates result in lower dividend yields and thus lower cost of equity estimates, especially with respect to the DCF model. Public Service argues that it is important for the Commission to consider multiple analytical approaches to moderate these effects, citing recent guidance by the Federal Energy Regulatory Commission (FERC).[35]

[35] Hearing Exhibit 132, Bulkley Direct, p. 29.

74. The results of Public Service's rate-of-return models are as follows:[36]

	Mean Low	Mean	Mean High
DCF Analyses			
Constant Growth DCF-90 day	8.70%	9.47%	9.79%
Multi-Stage DCF-90 day	8.42%	8.68%	8.96%
CAPM and Bond Yield Plus Risk Premium Analyses	**Current Risk-Free Rate (2.24%)**	**2019-2020 Projected Risk-Free Rate (2.40%)**	**2020-2024 Projected Risk-Free Rate (3.60%)**
Capital Asset Pricing Model—Value Line Beta	9.44%	9.50%	9.96%
Capital Asset Pricing Model—Bloomberg Beta	10.17%	10.22%	10.61%
Bond Yield Plus Risk Premium	9.61%	9.68%	10.20%
Expected Earnings Analysis			
Value Line 2021-2023 Projected ROE	11.07%		
Flotation Cost	0.08%		

2. Positions of the Intervening Parties

75. Staff recommends an ROE of 9.0 percent in a range between 8.02 percent and 9.0 percent. While Staff favors the use of the DCF and the Multi-Stage DCF (MSDCF) models, its recommendation is not based solely on those model results. Staff explains that its proposed ROE takes into account Public Service's strong financial health as well as the economic environment of low treasury rates and projections for weak economic growth. Staff notes that there have been downward trends of authorized ROEs for utilities both nationally and for those approved in Colorado. Staff also notes that there is no evidence that Public Service is having any difficulty gaining access to reasonably priced capital but instead there is evidence of strong demand for the Company's bonds.

76. Staff uses a proxy group of combination gas and electric utilities that it argues is more representative of Public Service's operations.

[36] Hearing Exhibit 133, Bulkley Rebuttal, Table AEB-R-7, p. 164.

77. Staff's advocacy surrounding the authorized ROE further demonstrates how the long-term growth rate component of the MSDCF model is highly influential on the final model results. Staff's long-term growth rate of 3.9 percent is the combination of a projected inflation rate and Gross Domestic Product (GDP) based on projections by the Congressional Budget Office (CBO). Staff argues that the CBO forecasts a much lower growth rate of only 1.9 percent over the next 30 years, in contrast with the 3.34 percent historical rate as proposed by the Company. This is the primary difference between Staff's recommendation and the Company's recommendation of 5.56 percent. Staff also rejects the inclusion of flotation costs because they are inherent in the price of the stock.

78. Staff's DCF and MSDCF rate-of-return model results are as follows:[37]

	Average Estimated ROE
DCF	9.00%
Multi-Stage DCF	8.02%

79. Public Service argues that Staff relies too heavily on DCF model results. Public Service argues that Staff disregards not only the alternative methodologies used by investors to estimate returns, such as the CAPM, Risk Premium and Expected Earnings analyses, but also authorized returns for electric utilities in other jurisdictions and the business risk specific to Public Service. Public Service further objects to Staff's proxy group, arguing that certain companies are not true comparisons to the Company's electric business. Public Service concludes that Staff's recommended 9.0 percent ROE does not recognize the Company's significant capital investment requirements that will impede its ability to earn its authorized return.

[37] Hearing Exhibit 179A, Sigalla Answer, Attachment FDS-4.

80. The OCC recommends an ROE of 8.8 percent in a range of 7.7 percent to 9.6 percent based on an average of four models. The OCC's models include the CAPM, DCF, and a "Commission-approved" MSDCF. The OCC further conducts an analysis of recently authorized ROEs across the nation. The OCC argues that recent trends in the capital markets are favorable to Public Service, with falling 30-year U.S. Treasury bond yields and strong demand for stocks, which together have led investors to require lower equity premiums. The OCC also points to declining capital costs, lower expected returns on equity used by the Company's pension group, and a benchmark to rates developed by the Colorado Division of Property Taxation.

81. The OCC's proxy group consists of nine electric utilities, about half of which are also included in Public Service's group. Similar to Public Service, the OCC uses a long-term growth rate based on historic GDP calculations from 1929 to the present, which causes nearly identical results from the MSDCF model. In contrast, the OCC's CAPM model deviates from the Company's due to the differences between actual and forecasted equity premiums. Like Staff, the OCC also opposes any consideration of flotation costs in the ROE calculation.

82. The OCC's rate-of-return model results are as follows:[38]

	Low ROE	**High ROE**	**Average Estimated ROE**
CAPM	7.1%	8.2%	7.7%
DCF	8.7%	9.1%	8.9%
MSDCF	7.9%	9.6%	8.8%
Recent Authorized ROEs	8.8%	10.5%	9.6%
Average			**8.8%**

[38] Hearing Exhibit 174, Fernandez Answer Table RAF-12, p. 88.

83. Public Service critiques various technical aspects of the OCC's analyses, such as the proxy group, the application and inputs for the DCF and MSDCF models, inputs for the CAPM model, use of allowed returns for other electric utilities in Colorado, and risk factors specific to Public Service. Public Service charges that the OCC's proxy group includes three electric-only utilities that are not representative of the Company. Public Service argues that the OCC's models yield results that are unreasonably low due to inputs disputed by Public Service, such as risk premiums and growth rates. Public Service concludes that the OCC's recommended ROE of 8.8 percent is not supportive of the Company's financial integrity.

84. CEC recommends an ROE of 8.9 percent in an estimated range of 8.5 percent to 9.0 percent. The CEC's recommendation is based on four types of models, including two DCF models using separate growth rate projections, the MSDCF, Risk Premium, and CAPM models. The CEC's proxy group matched that used by Public Service, however, the CEC notes that Public Service has less investment risk than the companies in the proxy group. The CEC points out that capital costs have steadily decreased in the last three years, and its ROE estimate of 8.9 percent is conservative and appropriate in the current market. Finally, the CEC performs an analysis of credit metrics demonstrating that the ROE would not harm the Company's credit rating.

85. The results of the CEC's rate-of-return models are as follows:[39]

	Average Estimated ROE
DCF Analyst Growth	8.48%
DCF Sustainable Growth	8.89%
Multi-Stage DCF	7.29%
Risk Premium	9.0%
CAPM	8.6%

[39] Hearing Exhibit 143, Gorman Answer, Table MPG-2, p. 22 and Table MPG-4, p. 37.

86. Public Service disagrees with several inputs and assumptions in CEC's models, particularly: the growth rates CEC uses in its DCF and MSDCF models, the market risk premium and risk-free rate in the CAPM model, and the calculations in the Risk Premium analysis. Public Service argues that all of CEC's model results fall far below national averages for similar utilities and that its recommended ROE of 8.9 percent would not support Public Service's financial integrity.

87. DOE recommends an ROE of 9.2 percent, which takes into account the results of its models as well as an assessment of Public Service's business and financial risks. The DOE produced five models, including the DCF model, a two-stage DCF model, CAPM, an "Empirical CAPM," and Risk Premium model. DOE employed the same electric utility proxy group as Public Service in all of its models. DOE argues that capital conditions are favorable with historically low interest rates and equity returns, which support lower ROEs. DOE further argues that Public Service does not face higher business risks than comparable electric utilities in terms of debt leverage and has lower financial risks than the overall proxy group.

88. The results of the DOE's rate-of-return models are as follows:[40]

	Average Estimated ROE
DCF	9.2%
Two-Stage DCF	9.2%
CAPM	8.4%
Empirical CAPM	9.4%
Risk Premium	9.3%

89. Consistent with its criticisms of the other intervenors' models, Public Service objects to several inputs and assumptions in DOE's models, such as growth rates in the DCF and

[40] HE 151, Lawton Answer Testimony at 6: Table 1 Cost of Equity Capital Model Results.

MSDCF models, assumptions in the CAPM and ECAPM models, and the calculations in the Risk Premium analysis. The Company argues that DOE's recommendations would have a negative impact on its financial integrity, stating, for instance, that a 9.2 percent ROE would not provide the necessary support for maintaining the Company's current credit rating.

90. Walmart states that the ROE established by the Commission should be carefully considered in light of customer impact, recently approved ROEs in Colorado, and recently approved ROEs nationwide. Walmart argues that Public Service's ROE recommendation is high compared to these benchmarks.

91. AARP states the ROE should be set no higher than the low end of the ROE range the Commission has been found to be reasonable in recent proceedings, between 9.0 percent and 10.0 percent.

3. Findings and Conclusions

92. One of the primary legal standards for setting a fair rate-of-return was established by the U.S. Supreme Court in the *Bluefield* and *Hope* cases cited previously. Under the *Bluefield* decision, a public utility is entitled to earn a return on the value of its property employed for the convenience of the public pursuant to a set of parameters set forth by the court to assess a reasonable return. That return should be equal to that generally being made at the same time and the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. The return should also be reasonably sufficient to ensure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties.

93. The *Hope* decision buttresses the *Bluefield* decision and emphasizes that returns should be sufficient to cover capital costs of the business, which includes debt service and equity dividends. The return should also be commensurate with returns available on alternative investments of comparable risk. However, of paramount importance, we should never lose sight of our duty to ratepayers to protect them from unreasonable risks.

94. Consistent with the *Hope* and *Bluefield* standards, one of the Commission's primary charges in this Proceeding is to establish a reasonable return for Public Service on the investments necessary to provide safe and reliable electric service to its retail customers. Although the Commission determines a specific ROE for purposes of calculating Public Service's revenue requirement and setting the resultant rates to be billed to its customers, the Commission establishes a range for the authorized ROE in acknowledgement that it is not a single model result or particular set of considerations that govern a reasonable outcome supportive of the Company's financial integrity and to allow it to fulfill its public utility service obligation.

95. The determination of the ROE encompasses a wide range of factors, including, but not limited to, the results of the various rate-of-return models, current and expected financial market conditions, Public Service's continuing ability to access capital at a reasonable cost to consumers, and the Company's own financial condition and risk profile that takes into account its use of rate adjustment mechanisms for cost recovery between rate proceedings and other regulatory mechanisms that contribute to the Company's overall financial stability. The ROE

authorized for Public Service also must be similar to the returns to investors in companies that have comparable financial characteristics and business risks.[41]

96. The rate-of-return models conducted by Public Service and the intervening parties are based on different proxy groups, of which only four utilities are shared in common. Companies selected as a proxy group of a utility should have characteristics in common to that utility. In order to ensure comparability and reasonableness of financial modeling results, the utilities selected in the proxy group should be exposed to similar risks. The disparity in proxy groups explains, in part, the dissimilar results presented in the cases in this Proceeding. The inputs to the various models also exhibit divergence, such as the rates used for long-term growth, GDP, dividend yields, bond yields, stock prices, market risk premiums, and beta coefficients. This divergence in model inputs also leads to a wide range of differences in model results.

97. The financial models commonly used in ROE determinations are the Capital Asset Pricing Model, Risk Premium Model, and Discounted Cash Flow Model. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method, on the reasonableness of the assumptions underlying the method, and on the reasonableness of the proxies used to validate the results. As pointed out by the intervenors, Public Service's selection of mean and mean-high results from the DCF and MSDCF models is intended to support the Company's position in favor of higher ROEs. Public Service's requested ROE is higher than its currently authorized ROE of 9.83 percent.[42] In contrast, the data inputs and model assumptions employed by the intervenors lead to lower ROEs, and some model results were excluded entirely by the intervenors themselves. We agree

[41] *Bluefield Waterworks and Improvement Co. v. Public Service Comm'n. of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[42] Decision No. C15-0292, issued March 31, 2015, Proceeding Nos. 14AL-0660E and 14A-0680E.

with Public Service and the other parties that, in principle, no single rate-of-return model should be relied on in the determination of the ROE. At the same time, all model results entered into the evidentiary record have some relevance and should be considered with varying degrees of weight.

98. It is uncontroverted based on the record in this Proceeding that Public Service enjoys a strong financial position relative to other utilities.[43] The Company's share price has nearly doubled since its last rate case proceeding. Public Service's earnings per share likewise have increased by 26 percent since 2015, and dividends per share increased by 27 percent since 2015.[44] These factors, coupled with the Company's strong credit rating, have put the Company in a solid position to attract capital.

99. Capital market conditions have also been favorable to Public Service. For example, it was established at hearing that in 2019 alone: the Federal Open Market Committee made three 25-basis point rate cuts to the Federal Funds Rate; Treasury bond yields declined; and utility bond yield spreads likewise declined.[45] Public Service achieved a substantially lower interest rate for its August 2019 bond issuance at 3.20 percent, as compared to its March 2019 bond issuance with an interest rate of 4.05 percent.[46]

100. We conclude that the evidence in this Proceeding also establishes that Public Service's risk profile is relatively low compared to other utilities. In all of the CAPM models produced by the parties in this Proceeding, the beta measure for Public Service (a measure of stock price volatility as compared to the overall market) is in the 0.5 to 0.61 range, which is

[43] As explained in her partial dissent, Commissioner Koncilja disagrees with this finding.
[44] Hearing Exhibit 179, Sigalla Answer, p. 108.
[45] Hearing Exhibit 143, Gorman Answer, p 26.
[46] OCC SOP, p. 6.

consistently on the low end of the range determined by the proxy companies.[47] As pointed out by Staff, Public Service has several cost recovery mechanisms that reduce regulatory lag and collect approximately 70 percent of the requested base rate increase in this Proceeding.[48] The adoption of a CTY by this Decision, which introduces hundreds of millions of dollars in additional investment into rate base as eligible for cost recovery through the rates, further marks a substantial financial benefit to Public Service, as does the continuation of trackers for pension expense and property taxes as discussed below. These factors, among others, have served to reduce Public Service's risk premium and place it in a sound position to raise capital.

101. In determining an ROE, it is the application of informed judgment, not the precision of financial models that is the fundamental determinant in selecting a specific ROE. While important to the outcome, the models should nonetheless not be used woodenly or as definitive proxies for the determination of the investor-required ROE. Models serve in the capacity as a rough gauge of the realm of reasonableness in setting the ROE. The results from the rate-of-return model results entered into the record of this Proceeding and the various factors cited above, such as the Company's strong financial integrity and its favorable position in the credit markets, and applying our informed judgment, we adopt a just and reasonable range for an authorized ROE for Public Service extending from 9.20 percent to 9.63 percent. The low end of this range reflects the intervening parties' compelling support for a downward adjustment from the Company's currently authorized ROE. The high end reflects the Regulatory Research Associates national average for electric ROEs awarded by state utility regulatory commissions in the first three quarters of 2019, a value that we note is midway between the ROEs recommended

[47] Hearing Exhibit 179, Sigalla Answer, pp. 48 and 57.

[48] Staff SOP, p. 5.

by the intervening parties at 9.0 percent and the ROE sought by Public Service of 10.2 percent[49] and thus reflects the "gradualism" sought by the Company and recognized by certain intervening parties.[50] Public Service's strong financial condition, its solid credit rating, its recent success in securing low-cost debt, its favorable cost recovery mechanisms, and the approval of a CTY by this Decision support our conclusion that the authorized ROE for Public Service should not exceed 9.63 percent. The range for the authorized ROE established by this Decision includes the value of authorized ROE the Commission recently established for setting base rates of Public Service's gas operations of 9.35 percent[51] as well as higher values that reflect the Commission's practice of recognizing higher ROEs for electric utilities as compared to gas utilities.[52]

102. Based on the weight of the evidence, and for the same general reasons set forth above in support of the reasonable range for the Company's authorized ROE, we direct Public Service to use an ROE of 9.30 percent for determining its revenue requirement and corresponding rates.[53] This ROE is reasonably sufficient to assure confidence in the financial soundness of Public Service and to maintain an investment grade credit rating while balancing the interests between shareholders and ratepayers.

103. Public Service, as most vertically integrated utilities, is increasingly compelled by financial, business and regulatory dynamics that include energy availability, ability to attract capital to raise funds in order to discharge its public utility duties, and to maintain investment grade creditworthiness, all imperative factors of *Hope* and *Bluefield*. Based on the risk factors

[49] Public Service SOP, p. 8 and Hearing Exhibit 262.

[50] Public Service SOP, pp. 7-8.

[51] Decision Nos. C18-0736-I, C18-1158, and C19-0232, issued August 29, 2018, December 21, 2018, and March 11, 2019, respectively, Proceeding No. 17AL-0363G.

[52] Public Service SOP, p. 9.

[53] Commissioner Frances A. Koncilja disagrees with the use of an authorized ROE of 9.30 for calculating revenue requirements and resulting rates.

discussed above, we find that the ROE range adopted in this Proceeding adequately compensates Public Service for these risks.

B. Cost of Debt

104. Public Service proposes a cost of long-term debt of 4.22 percent for determining its revenue requirement. The 4.22 percent value is the Company's average cost of long-term debt calculated from August 31, 2018 to August 31, 2019, including an August 2019 debt issuance of $550 million. The 4.22 percent is an increase to the Company's original recommendation of a 4.18 percent cost of long-term debt at the time of its initial Advice Letter No. 1797 filing, which was the Company's actual cost of long-term debt on March 31, 2019. Public Service states that its cost of debt is based on a yield-to-maturity calculation, where the debt expenses include interest and other fees associated with issuing the bonds.

105. Staff recommends a cost of long-term debt of 4.09 percent and a cost of short-term debt of 2.83 percent. Staff argues that the Company's long-term debt cost does not properly reflect the issuance of $550 million in August of 2019 at a cost of money of 3.32 percent. Staff argues that because its recommendation that the Commission adopt the 2019 CTY, it is appropriate to include all financing associated with that same period.

106. Staff also calculates a weighted average cost of short-term debt of 2.83 percent based on a period of 12 months from September 2018 to August 2019. During this period, there was an average short-term debt balance of $210 million, and short-term debt expenses totaled approximately $6 million. The short-term debt cost calculation also includes costs associated with Public Service's multi-year credit facility. Through Rebuttal Testimony, Public Service points out an error in Staff's calculation of short-term debt, namely, that Staff failed to include the interest expense related to months in the calculation that did not have a short-term debt

balance at the end of the month. According to the Company, the correct rate should be 3.33 percent.

107. The OCC recommends a cost of long-term debt of 4.17 percent, based on Public Service's actual cost of debt at the end of the 2018 HTY plus known and measurable changes within one year after the end of that test year. The OCC thus includes an issuance of $400 million of long-term debt at a rate of 4.05 percent on March 19, 2019, which results in its recommended cost of 4.17 percent. If the Commission decides that short-term debt should be included, the OCC argues that it is appropriate to include the short-term debt credit facility costs, which would increase the recommended rate to 4.18 percent.

108. CEC recommends a cost of long-term debt of 3.76 percent, which reflects a known and measurable issuance of new debt on August 7, 2019 at a net cost of approximately 3.31 percent. The CEC notes that Public Service did not include this issuance in its cost of debt calculation. Public Service points out through Rebuttal Testimony, however, that CEC included the principal amount of a $550 million bond in August 2019 but failed to include the annual interest cost in the total expense. According to the Company, this correction would change the debt cost to 4.09 percent.

109. Based on the evidence in this Proceeding, we direct Pubic Service to use a 4.09 percent cost of long-term debt and a 3.33 percent cost of short-term debt, consistent with the recommendations of most of the intervening parties who testified on this issue. The cost of long-term debt of 4.09 percent includes known issuances of debt made in March and August 2019, and is just and reasonable. These are discrete issuances with known costs of money, and do not necessitate the same application of an average as used with the capital

structure. Further, it was established that the August 2019 issuance of long-term debt was the most recent issuance at a significantly lower cost.

110. With respect to the cost of short-term debt, Staff agrees with Public Service's calculation of a rate of 3.33 percent. In contrast with its recommendation on the cost of long-term debt, Staff asserts that using a 13-month average methodology is appropriate for short-term debt in this case due to its consistently fluctuating levels and associated costs. The cost of short-term debt itself was unopposed by the intervening parties. Based on the evidence, we direct Public Service to use a cost of short-term debt of 3.33 percent.

C. Capital Structure

111. Through Rebuttal Testimony, Public Service proposes a capital structure comprised of 55.61 percent equity, 1.67 percent short-term debt, and 42.72 percent long-term debt. This represents a significant change to the Company's recommendation in the initial Advice Letter No. 1797 filing, in that Public Service agrees to Staff's inclusion of short-term debt provided that the Commission require the inclusion of Construction Work In Progress (CWIP) in rate base with an Allowance for Funds Used During Construction (AFUDC) offset. Public Service also agrees to use a 13-month average capital structure from August 31, 2018 to August 31, 2019.

112. Public Service emphasizes the importance of a capital structure that maintains its credit ratings, which currently stand at A- or the equivalent with the three credit rating agencies, Standard & Poor's, Moody's, and Fitch. Public Service argues that further reduction to the equity structure will reduce cash flows, and put the Company's financial integrity in jeopardy. If its recommended capital structure is not approved, Public Service alternatively recommends

approval of the DOE's recommended capital structure at December 31, 2018, comprised of 56.11 percent equity and 43.89 percent debt.

113. Staff recommends a capital structure of 55.57 percent equity, 42.62 percent long-term debt, and 1.81 percent short-term debt. Staff argues that the inclusion of short-term debt is appropriate because it is a significant source of capital used to fund ongoing operations. Staff asserts that money is "fungible," meaning that all funding sources contribute to all investments, and therefore should not be excluded. Staff points out that the operating entities in all of Xcel Energy's other state jurisdictions incorporate short-term debt in their capital structures. Staff asserts that the inclusion of short-term debt necessitates incorporating CWIP into rate base to maintain tenor with the investment.

114. The OCC recommends using a capital structure of 54.6 percent equity and 45.4 percent long-term debt because this was the structure recently approved in Public Service's gas rate case, Proceeding No. 17AL-0363G. In the alternative, the OCC recommends the actual "accounting book" capital structure of 54.3 percent equity and 45.7 percent debt as of December 31, 2018, the end of the 2018 HTY, which OCC argues is the structure that is reported to investors. The OCC points out that Xcel Energy, Public Service's parent company, allocates higher equity debt costs to its subsidiary Public Service and that the Company has the most costly equity percentage of all of the Company's regulated subsidiaries.

115. In response, Public Service opposes the OCC's capital structure recommendation because neither is it Public Service's current actual structure nor does it adhere to the matching principle. Public Service claims that the OCC's "consistency argument" is disingenuous with respect to arguments it made in prior proceedings. The Company further argues that an equity

ratio of 54.6 percent is not adequate to support the Company's financial metrics, or allow it to maintain its current credit ratings.

116. CEC recommends a capital structure of 54.27 percent equity to 45.73 percent long-term debt. The difference between the CEC's capital structure and the Company's is a correction made to Public Service's Operating Lease Agreement balance, part of the Company's Off Balance Sheet (OBS) debt. The CEC notes that Public Service's OBS debt rose tenfold from approximately $58 million in 2017 to $593 million in 2018, however, the Company's Securities and Exchange Commission (SEC) 10-K filing does not support this degree of increase in OBS debt.[54] The CEC argues its capital structure is reasonable and consistent with prior Commission orders. Public Service opposes CEC's recommended capital structure because it is a hypothetical structure, which is contrary to Commission precedent and is not adequate to maintain the Company's credit metrics.

117. DOE recommends a capital structure of 56.11 percent equity to 43.89 percent debt, consistent with the Company's request that if the 2019 capital reach is not approved, then the end of the 2018 HTY capital structure should be used. However, if a 56 percent equity ratio in the capital structure is approved, DOE argues that a potential downward adjustment to the cost of equity in the amount of 20 basis points is also warranted.

118. We approve a capital structure of 55.61 percent equity, 42.72 percent long-term debt, and 1.67 percent short-term debt, consistent with Public Service's request. Public Service represents this capital structure as the Company's actual structure based on month-end percentages for long-term debt, short-term debt, and common equity for the 12-month period

[54] Hearing Exhibit 143, Gorman Answer, pp. 75 and 76.

ending August 31, 2019.[55] The adopted capital structure is based on a 13-month average of those percentages, which the Company argues avoids the risk of setting a capital structure based on a point-in-time. In its SOP, Staff expresses consent with this approach to calculating the Company's capital structure, agreeing that the 13-month average better captures the relative shares that each type of debt contributes to the funding of the rate base. This capital structure should be adopted because it is balanced, attainable, and intended to support an investment grade rating and attract capital.

119. We find that including short-term debt in the capital structure is reasonable in this Proceeding. Because the short-term debt balances are averaged, the inclusion of short-term debt alleviates DOE's concern as to the variability of the balances that may render its inclusion undesirable. We also agree in principle with Staff that "money is fungible," and all sources of debt contribute to fund the rate base including short-term debt. We also find that short-term project costs in the CWIP balance should also be included, but with an AFUDC offset to earnings, which is an established regulatory principle that prevents double recovery of the balance.

120. Finally, a large amount of testimony was provided in regard to the decision on capital structure concerning possible actions by credit rating agencies. Public Service's credit rating stands at A- (or the equivalent) and has exhibited improvement.[56] Public Service's arguments that an equity ratio lower than 56 percent in the capital structure may result in a downgrade is generally unsupported, as no evidence was introduced from the rating agencies that affirmed such a downgrade would occur. We agree with the DOE that the Company's analysis

[55] Transcript, November 14, 2019, pp. 129-130.

[56] Hearing Exhibit 129, Soong Direct, p. 25.

did not include the effect of bonus depreciation, which would have the effect of improving cash flow. Also, the Commission has taken proactive steps with respect to the TCJA that further lend stability to the Company's cash flows. Public Service's claim of the danger of a credit downgrade is speculative and thus the Commission does not conclude that a threshold exists at which such a downgrade would occur.

D. Weighted Average Cost of Capital

121. Public Service's currently authorized Weighted Average Cost of Capital (WACC) is 7.55 percent, as determined in the approved settlement in Proceeding Nos. 14AL-0660E and 14A-0680E.[57]

122. Based on our decisions above, the authorized WACC shall be established at 6.97 percent.

V. WILDFIRE MITIGATION

123. In its initial Advice Letter No. 1797 filing, Public Service presented its Wildfire Policy and Wildfire Mitigation Proposal, which describe the Company's efforts to address the risks posed by wildfires throughout Colorado as it relates to its electric infrastructure. The Company presented specific capital additions and operations and maintenance (O&M) expenditures associated with these activities for 2019 and requested deferred accounting treatment for such activities over the 2020 through 2023 period. Public Service argues that continuing to invest in wildfire mitigation and grid resiliency is the most prudent course of action to moderate the risks associated with extreme weather events. The efforts regarding transmission infrastructure focus on: (1) the inspection and modeling of lines, including infrared inspections to

[57] Decision No. C15-0292, issued March 31, 2015, Proceeding Nos. 14AL-0660E and 14A-0680E.

identify thermal "hot spots" with priority in higher wildfire risk areas; (2) the replacement of high priority structural components that are or will be identified for defects; and (3) an expansion of the Company's vegetation management practices, including the Mountain Hazard Tree Program to remediate hazard trees adjacent to facilities from the mountain pine beetle. The efforts related to the Company's distribution system are directed at foothill and mountainous areas along the Front Range, in the mountains along the I-70 corridor, outside of Grand Junction, and in the mountainous areas in San Luis Valley. Public Service focuses on: (1) community outreach as well as the coordination and implementation of wildfire mitigation activities at the leadership level, which activities may include potential partnership and pilot efforts among the Company, communities, state and federal agencies, and other private and public entities; (2) pole inspections and infrared modeling; (3) the protection, replacement, and upgrading of distribution equipment; and (4) vegetation management.[58]

124. As stated above, Public Service, Staff, OCC, AARP, CEC, Denver, Boulder, the DOE, Vote Solar, and WRA joined in a partial settlement agreement regarding the Company's wildfire mitigation proposals. All other intervening parties in this Proceeding took no position on the settlement.

125. According to the terms of the agreement, Public Service is authorized to include incremental 2019 wildfire mitigation costs at the levels presented in the Company's Rebuttal Testimony, such as \$5.7 million in 2019 distribution capital additions and \$5 million in 2019 distribution and transmission O&M. Public Service further relinquishes, in this Proceeding, its request for deferred accounting treatment for the 2020 through 2023 distribution capital expenditures and 2020 through 2023 distribution and transmission O&M related to its wildfire

[58] Hearing Exhibit 101, Trammell Direct, pp. 77-78.

mitigation efforts. Public further commits to provide an updated, comprehensive Wildfire Mitigation Plan in support of any request to implement a Wildfire Mitigation Plan regardless of how the request is made such as, but not limited to, a deferred accounting request, a separate application, or through a more comprehensive rate review. Public Service agrees to hold semi-annual stakeholder meetings and outreach in the interim, leading up to an August 1, 2020 filing, consistent with the Company's proposal for stakeholder meetings as set forth in its Rebuttal Testimony.

126. We find good cause to approve the settlement on wildfire mitigation without modification.

VI. CONTESTED COST OF SERVICE ISSUES

A. Rate Case Expenses

127. Public Service seeks recovery of approximately $7.55 million of rate case expenses, inclusive of an estimated $1.36 million specifically related to this Proceeding.[59] The Company seeks recovery of the expenses from its 2017 rate case in Proceeding No. 17AL-0649E, from its 2016 depreciation case in Proceeding No. 16A-0231E, and from its 2016 Phase II rate case in Proceeding No. 16AL-0048E. With respect to the 2017 rate case, Public Service states that the associated expenses include the costs for settlement proposals related to the TCJA (Proceeding No. 18M-0074EG) and the costs related to the "bifurcated TCJA Proceeding" (Proceeding No. 18M-0401E). Public Service further seeks to recover the costs of

[59] Hearing Exhibit 134, Applegate Direct, p. 40.

its residential time-of-use (TOU) rate trial and residential demand rate pilot stemming from the implementation of the settlement agreement resolving the 2016 Phase II rate proceeding.

Proceeding No. 19AL-0268E	$1,358,296
Proceeding No. 17AL-0649E	$984,439
Proceeding No. 16A-0231E	$583,474
Proceeding No. 16AL-0048E	$380,067
Residential TOU Trial/Residential Demand Rate Pilot	$4,247,788
Total	**$7,554,064**

128. Public Service proposes to recover these rate case expenses over a three-year amortization period. The Company states that because the rate case expenses were paid at the time costs were incurred yet they have not been recovered from customers, the Company also should be compensated for the associated carrying costs. In other words, the rate case expense included in the revenue requirement would include a return on unreimbursed amounts at the authorized WACC.

129. Staff supports the three-year amortization to recover allowed rate case expenses and generally recommends that the Commission allow Public Service to recover actual expenses incurred in this Proceeding, except for certain expenses related to a webcast, food, mileage reimbursement, and legal costs the Company included in error. Staff also recommends, however, that the Commission deny the expenses related to the 2017 Electric Rate case, including the two TCJA-related proceedings, arguing that Public Service recovered sufficient rate case expense in 2018 from the rates still in effect from its 2014 Phase I rate case. Staff further recommends that the Commission condition recovery for the rate case expenses related to the 2016 Depreciation

case and 2016 Phase II rate case on Public Service's "adherence to the other principles it agreed to in the 2014 Rate Case settlement for its 2017 Rate Case."[60]

130. AARP argues that Public Service should be authorized to recover no more in rate case expenses than the percentage of revenue increase awarded by the Commission in this Proceeding. For example, if the Commission grants Public Service 70 percent of the revenue increase requested by its Advice Letter No. 1797 filing, the Company should recover no more than 70 percent of what it requests in total rate case expenses. AARP also argues that the Company should not be reimbursed for outside counsel and witness expenses. AARP notes that intervenors are not generally reimbursed for their rate case expenses, even where an intervenor wins on a specific issue.

131. CEC recommends that 50 percent of the expenses incurred for this Phase I rate case be removed from the revenue requirement. CEC argues that the Company's decision to conduct a Phase I rate case is clearly intended in substantial part to advance shareholder interests, and as such, the associated expenses should not be borne completely by ratepayers.

132. The OCC recommends that the Commission deny recovery of nearly all of Public Service's rate case expenses.[61] The OCC asserts that the Company has failed to provide sufficient and adequate facts upon which the Commission can make a determination that the amounts requested for legal services are just and reasonable. The OCC takes the position that, absent such information, the Commission does not have a sufficient basis on which to approve the amounts requested that would result in just and reasonable rates to be charged to ratepayers.[62]

[60] Staff SOP, p. 28.
[61] Hearing Exhibit 175, Skluzak Answer, p. 210.
[62] OCC SOP, pp. 27-28.

133. We agree with Staff regarding the proposed removal of $1,545 for webcast costs, $3,537 for food costs, $131 for mileage reimbursement, and $100,000 in legal expenses from the recoverable costs associated with this Proceeding. We also direct Public Service to remove $86,000 of costs associated with certain consulting services retained for this Proceeding, consistent with Staff's recommendation.[63] All other expenditures associated with this Proceeding are found to be recoverable and may be included in the amount for the proposed three-year amortization.

134. We find the intervening parties have failed to demonstrate that the rate case expenses related to the 2016 depreciation case ($583,474) and the 2016 Phase II case ($380,067) were improperly or imprudently incurred. We also allow Public Service to recover the costs associated with its 2017 rate case in Proceeding No. 17AL-0649E. Again, the intervening parties have failed to demonstrate that these rate case expenses were improperly or imprudently incurred. We thus direct Public Service to include these amounts in the three-year amortization of rate case expenses.

135. We deny inclusion in the three-year amortization of the approximately $4.25 million of costs associated with Public Service's residential TOU pilot and residential demand rate trial. Consideration of the recovery of those costs shall be deferred to a Phase I rate case filed following the conclusion of Proceeding No. 19AL-0687E. In accordance with Decision No. C16-1075 issued on November 23, 2016 in Proceeding No. 16A-0055E, the Commission will review the results of the Company's analysis of the residential-TOU trial in Proceeding No. 19AL-0687E as the basis for whether the associated tariff requires modification or should be discontinued.

[63] Staff SOP, p. 27.

136. Finally, in calculating its rate case expenses for recovery through base rates over three years, the Company shall not recover a return on yet unrecovered balances.

B. Productivity Through Technology/Stabilize & Optimize

137. Public Service includes in rate base approximately $149.3 million in capital additions for the Work and Asset Management (WAM) and General Ledger (GL) system implementation phase of the Productivity Through Technology (PTT) initiative. The Company also has included $16.3 million in capital additions and $654,000 of O&M expenses in the test year cost of service for the Stabilize & Optimize (S&O) phase of the initiative. According to Public Service, the S&O effort focuses on improving the end user experience and driving customer satisfaction associated with the S&O phase of the PTT initiative, for a total of $165.6 million.

138. Staff recommends denying 29 percent of the S&O phase costs, or $4.7 million, so that the cost of service includes total capital spending for the project within Xcel Energy's original estimate. In addition, Staff recommends denying the increased $654,000 O&M costs that will be ongoing. According to Staff, the continuing nature of these costs suggests that they instead should be part of the Company's normal course of business.

139. In response, Public Service argues that its requests for recovery of the PTT capital additions including those incurred during the S&O phase are well supported. The Company states that it has not run over-budget as alleged by Staff. The Company explains that it completed implementation of its new WAM and GL systems on time and under-budget. Public Service further states that the S&O phase was not included in the Company's PTT implementation budget, but rather is instead considered to operate within its own separate budget. Second, Public Service notes that the capital additions associated with the S&O phase of the Company's PTT

initiative consist of capital projects that are commonly and routinely implemented on the heels of a large enterprise-wide solution. Third, Public Service points out that Staff does not question the prudency of any PTT or S&O capital additions yet instead, proposes an alleged arbitrary disallowance of 29 percent of the Company's capital expenditures. Public Service further argues that although Staff recommends denying the inclusion of the $654,000 of O&M expenses, Staff has not argued that these costs are unnecessary, unreasonable, or imprudent. Public Service states that Staff acknowledges these costs will be ongoing and that they should be part of the Company's normal course of business. Further, Public Service states that although the $654,000 is specifically identified with the S&O phase of the PTT initiative, these types of expenses are representative of costs that will continue to be incurred going forward. Public Service argues that that inclusion of these costs is thus consistent with the concept of a test year.

140. We agree with Public Service that there was no compelling showing that these disputed capital costs were unnecessary, unreasonable, or imprudent. We also agree that the O&M expenses are reasonable and will continue to be incurred going forward, consistent with the ratemaking concepts of a test year. We therefore direct Public Service to include the associated capital additions and O&M expenses in the test year cost of service.

C. Employee Compensation Issues

1. Wage Increases

141. Public Service makes several adjustments to its per-books 2018 labor expense including expected wage increases.

142. CEC claims that Public Service treats a wage increase as if it had been in place for the entirety of the year, which overstates the wage expense actually incurred. In response, Public Service argues that the proposed wage adjustment is based on known wage increases the

Company will incur as an expense and that a portion of the increase will be paid to employees in 2020, during the time the rates from this rate case are effective.

143. The wage increase reflected in Public Service's revenue requirement is reasonable and shall be recovered through the rates established by this Decision.

2. Annual Incentive Program

144. Public Service's Annual Incentive Program (AIP) is performance-based compensation not added to the employee's base salary. An employee must re-earn the AIP each year, from 0 to 150 percent of a target amount, based on how well each individual employee and the Company as a whole perform against defined Key Performance Indicators. Year-end AIP amounts are conditioned on Xcel Energy achieving a certain level of earnings per share for that year.

145. Public Service maintains that it is appropriate to recover the costs of the AIP through rates to the extent that the compensation in such plans is not excessive and to the extent the goals of the AIP benefit customers. Public Service states that it is requesting only the target amount of AIP, which, in combination with an employee's base pay, raises the employee's compensation to be squarely in line with the market. Public Service contends that an employee's compensation is below market without the AIP.

146. Staff argues, as it has in previous rate cases, that the Commission should limit recovery of AIP expenses to no more than 15 percent of base salary, applied on a per-employee basis. Staff notes that the Commission has implemented this recommendation in past rate cases. The OCC likewise advocates that the revenue requirement be calculated on the premise that no employee receives more than 15 percent of base pay in AIP incentive compensation.

147. CEC states that while rewarding employees for financial performance can be entirely appropriate, the responsibility for funding such award should also rest on shareholders, who are the primary beneficiaries of meeting or exceeding financial targets. Accordingly, CEC recommends that shareholders be apportioned a 10 percent cost share of the AIP.

148. Through Rebuttal Testimony, Public Service argues the Commission would be funding employee compensation at a level well below market-competitive levels and below levels for utilities with similar revenues should the Commission adopt the intervening parties' proposals. Public Service also argues that the critics have not demonstrated that the compensation and benefits in the cost of service are out of line with market levels. Public Service further argues that the 15 percent cap is arbitrary and is unrelated to market compensation for jobs in the utility industry.

149. We accept the recommendations of Staff and the OCC to limit cost recovery of AIP compensation to 15 percent of base salary as applied on a per-employee basis. We note that this recommendation is consistent with recent Commission findings regarding the AIP in 2015 and 2017 gas rate proceedings. We also find Staff's testimony related to other jurisdictions having imposed caps on the AIPs of Xcel Energy subsidiaries to be persuasive. Further, the evidentiary record does not show that the Company has been finding it difficult to attract and retain employees as a result of the 15 percent cap on AIP compensation for ratemaking purposes.

3. Long-Term Incentive

150. Public Service's Long Term Incentive (LTI) is offered to executives, senior management, and other senior exempt employees to encourage high-level planning that produces long-term benefits. The program has three components: a portion related to total shareholder return, an environmental component related to reductions in carbon emissions, and a time-based

component that depends on an eligible employee remaining with the Company for a three-year vesting period.

151. Staff is unconvinced that compensating employees according to the Company's carbon emissions reductions provides benefits to ratepayers. Staff argues that costs alone provide a strong incentive for the Company to use carbon-free resources for generation. Staff thus concludes that the environmental component of the LTI likely provides an incentive for employees to do what they would have done anyway, simply on the basis of costs. Staff also argues that the connection between Company-wide emissions reductions and any individual employee's contribution to those reductions is tenuous. Staff is also unpersuaded that the time-based component of the LTI provides benefits to ratepayers. Staff suggests that all LTI costs be excluded from the cost of service.

152. The OCC argues that, regardless of whether LTIs are paid or not paid, progress towards reduced carbon and more renewables will take place. Therefore, ratepayers should not be paying for this portion of the LTI. The OCC also argues that simple job retention should be sufficient motivation for senior ranking employees to engage in long-term planning activities for the benefit of the Company. The OCC recommends that the entirety of the requested $4,784,674 in LTIs should be disallowed for recovery from ratepayers.

153. CEC recommends excluding $178,521 of the time-based long-term incentive compensation earned above the target, as identified by Public Service in discovery. CEC also argues that since the actual time-based incentive compensation awarded varies depending on the shareholder return, the amount awarded above the target is most appropriately borne by shareholders.

154. In Rebuttal Testimony, Public Service argues that the environmental incentive is necessary and beneficial to customers because reducing carbon emissions is important to many of the customers and communities served. The Company also argues that executives and those in senior management positions are who drive the Company's decisions on these issues and they affect the extent to which the carbon reduction goals are prioritized and are likely to be met.

155. Public Service further argues that without the LTI, executives and senior exempt employees would be paid below market, which would reduce their incentive to remain at the Company. And since payment of the LTI is contingent on the employee remaining with the Company for an extended period, it requires employee commitment beyond a single year, which helps ensure retention plus attention to long-term goals over simply short-term gain. The Company also argues that the time-based component of LTI helps ensure that employees are making long-term plans that align with the Company's strategic priorities and embarking on multi-year projects that create stability for Public Service's operations. According to Public Service, the retention of employees with the knowledge and skills necessary to guide, manage, and operate a utility are critical to providing a high level of service to customers.

156. We agree with Staff and the OCC that it is unreasonable to conclude that the environmental component of the LTI can be attributed to any individual employee. Recovery of the costs associated with the environment component of the LTI thus will be disallowed. We also agree with the CEC's argument that any amount above the target for the time-based component of the LTI should not be borne by ratepayers.

4. Equity Compensation (Board of Directors)

157. Equity compensation is non-cash compensation typically awarded to certain employees and members of the Company's Board of Directors as part of their overall

compensation package. Equity grants include, but are not limited to, stock options, restricted stock, and performance shares. Xcel Energy allocates equity compensation costs to Public Service for Board members. In this Proceeding, the Company seeks recovery of these equity compensation costs.

158. The OCC argues that such non-cash compensation should be paid for exclusively by investors rather than ratepayers. The OCC notes that Board members have a fiduciary duty to investors, not ratepayers, and argues that equity compensation programs are designed to align management and Board members with stockholder interests.

159. In response, Public Service argues that the OCC's position is based on the disputed premise that equity compensation does not benefit ratepayers. Public Service argues that the two relevant questions for the Commission are whether: (1) the equity compensation is market-competitive and appropriate; and (2) the level of compensation received by the Board is reasonable.

160. Xcel Energy and its operating companies are required to have a Board and these individuals should be compensated for their efforts. The costs associated with such equity compensation as demonstrated in this Proceeding are reasonable for recovery from ratepayers. There also has been no showing in the record that the level of compensation received by the Board is unreasonable. Therefore, we allow Public Service to include the equity portion of the Board's compensation in the revenue requirement.

5. Supplemental Incentive Program

161. Public Service's Supplemental Incentive Program (SIP) provides cash compensation to eligible employees who work in wholesale energy trading activities. The amount of the SIP expense in the cost of service is $668,857, excluding payroll tax expense.

Approximately 75 percent of this expense is associated with Public Service's "Proprietary Book," and the remaining 25 percent is associated with the Company's "Generation Book."

162. CEC states that the SIP expense should be borne primarily by shareholders rather than ratepayers and recommends they be shared between the Company and ratepayers in the same proportion as the associated short-term sales margins are shared. CEC concluded that since the SIP is designed to incentivize trading employees to maximize margins, it is equitable for shareholders to bear a proportionate share of the SIP expense.

163. The OCC argues that it is unnecessary for ratepayers to pay for incentives for energy trades and thus recommends that the Commission disallow recovery of the SIP.

164. Through Rebuttal Testimony, Public Service argues that because the wholesale trading program benefits both customers and the Company, the Company should not be barred from recovering market-level compensation expense for those employees. Public Service reiterates that the purpose of the SIP program is to allow the Company to provide certain eligible wholesale energy trading employees with a level of compensation that is competitive with market levels of compensation in the wholesale energy trading sector. Without the SIP program, the Company argues that it would not be able to attract, retain, and motivate the employees necessary to effectively operate a wholesale energy trading operation. Public Service further argues that ratepayers receive a significant benefit from the Company's ability to engage in wholesale trading activities, through the sharing of trading margins through the fuel clause.

165. We grant recovery of the SIP costs. Public Service's ratepayers benefit in the margin sharing mechanism currently in place related to the Company's wholesale trading program. We further agree with Public Service that the SIP allows for incentive compensation to be paid to the specialized labor that conducts these associated trades.

D. Investments in Rate Base

1. Finishing Superheater at Comanche 3

166. Sierra Club targets Public Service's proposal to include in rate base an $11.7 million investment to replace the finishing superheater (FSH) for the Comanche 3 generation unit. Sierra Club explains that Public Service determined that the FSH needed to be replaced due to multiple tube leaks associated with exfoliation, where scale builds up on the inside of the boiler tubes blocking the flow of steam used to cool the boiler tubes and causing short-term overheat failures and plant outages to remove the blocked sections. Public Service decided to remedy the problem by replacing the entire FSH with stainless steel.

167. Sierra Club argues that FSH replacement projects normally occur between 20 and 40 years after a coal plant enters service, not 5 years as is the case for the Comanche 3 unit. Sierra Club argues that based on the material provided by Public Service through discovery, the problem at Comanche 3 arose, at least in part, from the decision of the manufacturer, Alstom, to use particular metal alloys, in the superheater tubes.

168. Sierra Club recommends that the Commission exclude from rate base the $11.7 million in capital costs associated with the replacement of the FSH at Comanche 3 and to refund to customers the replacement energy costs attributable to the superheater outages. Sierra Club argues that Public Service acted imprudently regarding the FSH. Sierra Club takes the position that the original FSH at Comanche Unit 3 was defective and failed well before the expected useful life of a finishing superheater. Sierra Club argues that the flaw in the design of the finishing superheater should have been recognized and fixed before Comanche 3 was built. According to Sierra Club, Public Service should have known that the original finishing superheater would be prone to exfoliation because of the use of T91 and T92 alloys. Sierra Club

argues that a June 2007 EPRI study had supported the conclusion that, prior to the start of construction of the superheater at Comanche 3 in October 2007, T91 and T92 alloys were a "special case" because of their tendency to exfoliate at higher rates than other alloys and to exfoliate larger flakes that could block superheater tubes and lead to superheater overheating and failure. Sierra Club further argues that Public Service acted imprudently in responding to the failures of the original FSH by: (1) not making a warranty claim within the 24-month warranty period; and (2) failing to provide evidence that it obtained the maximum, feasible compensation it could obtain from Alstom for the problems with the original superheater.

169. With respect to the FSH-related outages, Sierra Club recommends that the Commission order Public Service to make a filing in this Proceeding calculating the incremental cost of replacement energy during the 15 outages plus the 79-day outage when a new superheater was installed. The Commission could then order the Company to refund to customers the amount of the incremental cost of replacement power procured during the 15 outages and the extended outage attributable to the failures of the original superheater.

170. In its SOP, the OCC supports the position of Sierra Club to disallow costs associated with the Comanche 3 FSH, except that the OCC proposes a different allocation of costs. OCC argues that Public Service selected an unproven design and materials and customers should not have to pay for this mistake. OCC notes that the finishing superheater lasted only five years when it should have lasted 30 years. The OCC recommends that customers pay for 5/30th of the cost of the faulty FSH and shareholders pay for 25/30th of the cost.

171. In its response to Sierra Club, Public Service argues that the Company's actions surrounding the FSH project at Comanche 3 and its associated capital investments were reasonable and prudent. Public Service explains that within 12 months of commercial operation,

Public Service identified the tube leaks in the FSH and its root cause analyses indicated that the they were due to operational issues attendant with operating new technology. The Company relied on Alstom's determination to use the T91 and T92 alloys in FSH tubes, and at the time the decision was made to pursue the project, Public Service concluded that it was reasonable to rely on Alstom's expertise and recommendations based on their reputation and when the T91 and T92 alloys were considered a leading material for high heat combustion. Public Service argues that the Company could not have avoided the need to replace the tubes due to exfoliation. Public Service states that it sought compensation from Alstom, but the issue was not covered under Alstom's warranty because the issue surfaced after the warranty expired. Public Service explains it nevertheless was able to negotiate a substantial discount for the replacement FSH with Alstom (44 percent of indicative pricing in 2014). Public Service concluded that it was more cost-effective to work with Alstom to replace the FSH rather than pursue claims against Alstom.

172. Sierra Club has made a persuasive case in support of a disallowance of the FSH investment costs. We agree with Sierra Club that Public Service should have recognized the flaw in the design of the FSH before Comanche 3 was completed, specifically that the FSH would be prone to exfoliation because of the use of T91 and T92 alloys based on the June 2007 EPRI study. Public Service mitigated the potential financial consequence of a later cost disallowance by securing a substantial discount from Alstom for the FSH replacement. But that action alone does not suffice to show that Public Service's actions with respect to the original FSH were prudent. Embracing state-of-the art design comes with risk, and the financial consequences of problems stemming from such risk should not be assumed to be the exclusive burden of ratepayers. Comanche 3 was proposed to the Commission as a source of substantial savings to

ratepayers due to an earlier in-service date and lower life cycle costs.[64] Implementation of Comanche 3 was further subject to a construction cost cap to ensure "that runaway Comanche 3 costs are not imposed on ratepayers" and as "incentives for Public Service to properly manage the project." Accordingly, we disallow recovery of the $11.7 million investment cost of the replacement FSH at Comanche 3.

173. We conclude that there is insufficient information in support of any further rate adjustment or refund associated with replacement power costs due to FSH issues at Comanche 3. A complete analysis of net increases in costs to ratepayers would require a more robust evidentiary record than is available here, including detailed information regarding the prevailing prices of replacement power relative to Comanche 3 generation in the historic dispatch order for each of the FSH-related outages.

2. SCR at Craig Unit 2

174. In its SOP, Sierra Club recommends that the Commission exclude from rate base the $18.493 million in capital costs for the Selective Catalytic Reduction (SCR) system installed on unit 2 of the Craig generation station. Sierra Club argues that Public Service failed to meet its burden to present credible and admissible evidence of why the project was needed and that the Company acted imprudently by failing to analyze whether there were lower-cost options for complying with the regional haze rule than installation of SCR. According to Sierra Club, Public Service seeks to evade responsibility for its decision to vote in favor of the SCR project by claiming that it had no other choice as a legal matter than to install SCR, which Sierra Club argues is simply not true. Sierra Club argues that the settlement terms upon which Public

[64] Decision No. C05-0049, issued January 21, 2005, Proceeding Nos. 04A-214E, 04A-215E, and 04A-216E.

Service relies for its position contains no provision that compels installation of SCR at Craig Unit 2 (Craig 2). Instead, the BART limits for Craig 2 are simply an emission rate, which could have been met by converting Craig 2 to gas or shutting it down and replacing it, instead of installing SCR. Sierra Club argues that Public Service should have analyzed whether it was cheaper to comply with the regional haze rule by converting the unit to burn gas or retiring and replacing Craig 2 rather than installing SCR. Sierra Club further rebuts Public Service by noting that Public Service has never considered in any electric resource plan (ERP) whether it would have been cheaper to retire and replace Craig 2 rather than install SCR.

175. Anticipating Sierra Club's position, Public Service states that the development of the Regional Haze State Implementation Plan was a statewide endeavor that included Colorado state agencies as well as numerous non-governmental actors like Public Service. Public Service states that it pursued a path blessed by state and federal environmental regulators "and turning that into a finding of imprudence by utility regulators would be not only improper but unprecedented."[65] Public Service reports in its SOP that the SCR was installed to satisfy federal Regional Haze Rule reduction requirements through Colorado's Regional Haze State Implementation Plan (Regional Haze SIP) approved by the federal Environmental Protection Agency. Public Service states that the Regional Haze Rule and Regional Haze SIP provide performance standards that must be met at Craig and they were met by retiring Craig 1 and installing an SCR on Craig 2.

176. We reject the Sierra Club's proposed disallowance of Public Service's share of the costs associated with SCR installed at Craig 2. Disallowing the cost on this record would penalize Public Service for meeting progressive emissions requirements and could result in this

[65] Public Service SOP at p. 16.

Commission penalizing Public Service for its vote to install SCR—something this Commission cannot do.

177. Colorado's regional haze implementation plan resulted from a statewide stakeholder effort and was approved by the Environmental Protection Agency (EPA). As the EPA observed when proposing to approve the plan:

> Although the State determined that 0.27 lb/MMBtu was NOX BART for Craig Unit 1 and Unit 2, the State adopted a more stringent emission limit for Craig Unit 2 in its SIP and a slightly less stringent limit for Unit 1. Tri-State and the State agreed to a NOX emissions control plan for Craig Unit 1 and Unit 2 *that is more stringent overall*. It consists of emission limits associated with the operation of SNCR for Unit 1 *and the operation of SCR for Unit 2*.[66]

178. The long and short of this is that Colorado developed an emission rate that removed nearly three times more NO_X per year than was required.[67] And that emission rate was developed around installing SCR at Craig 2. As we see it, Public Service paid its share of the SCR project to install the technology contemplated by the state's EPA-approved plan in order to continue to operate the facility in accordance with environmental regulations. As a minority owner (9.72 percent) in the Craig generation facility, once the Craig ownership group voted to approve the SCR project, Public Service was obligated to pay its share. On these facts, SCR was a prudent investment.

179. We are also concerned by Sierra Club's attempt to persuade this Commission to punish Public Service "for its decision *to vote in favor* of the SCR project . . . ."[68] Even if it

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[66] Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan, 77 Fed. Reg. 18,052, 18,068 (Mar. 26, 2012) (emphasis added).

[67] *Id.* at 18,067-68 (EPA acknowledging that Colorado was correct when it determined that installing the less efficient SNCR systems at Craig 1 and Craig 2 would satisfy its obligations under the haze rule, and providing a table illustrating that SNCR systems would remove just over 1,500 tons of NO_X/year, whereas one SNCR and one SCR system combined would remove more than 4,600 tons of NO_X/year.)

[68] Sierra Club SOP at p. 17.

could, this Commission is unwilling to punish Public Service for the way it voted at a meeting. We are particularly unmoved to do so where, as here, Sierra Club has cited no compelling Colorado law providing that in order to prove prudency Public Service must calculate and provide the cost of retiring or overhauling to a new fuel source each generation facility faced with a modest environmental compliance upgrade. As it is, the record indicates that Public Service undertakes a significant review of capital projects,[69] and that if a capital project cost more than a generating unit was worth, the Company would address that project outside its capital planning process.[70]

180. The OCC also recommends that the Commission disallow the cost of the SCR at Craig 2 in its cost of service. According to the OCC, Public Service did not provide the justification for the Craig 2 SCR in its direct case, such as why the installation of the controls was preferable to retirement.

181. In response to the OCC, Public Service explains that the project was necessary to satisfy federal Regional Haze reduction requirements and that as a minority owner in the Craig plant, Public Service was not directly involved in any negotiations or litigation surrounding the Regional Haze issues associated with Craig Units 1 and 2. Public Service further states that it did not seek a Certificate of Public Convenience and Necessity (CPCN) for the SCR on Unit 2 because, under Rule 3205(b) of the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* (CCR) 723-3, pollution control facilities valued at $50 million or less are deemed to occur in the ordinary course of business and do not require a CPCN.

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[69] Williams Direct Testimony, p. 18.

[70] Evidentiary Hearing Transcript, November 6, pages 53-56.

182. We disagree with OCC that Public Service was required to obtain a CPCN for its SCR investment at Craig 2. Public Service's share of the costs is below the $50 million threshold in Rule 3205, and Tri-State Generation and Transmission Association, Inc. (Tri-State), the plant operator with the largest share of Craig 2, is not required to file for a CPCN for pollution control projects, because: "Pollution controls are mandated by law and required by CDPHE, and most of the policy reasons for requiring CPCN applications do not apply to Tri-State with respect to pollution controls."[71] The $50 million is a bright line threshold and is intended, in part, to prevent expensive CPCN filings for projects whose costs may not merit such regulatory treatment. The Commission also considered, but ultimately rejected, a regulatory process by which each pollution control project would be subject to an initial determination of whether a CPCN was required or instead the project was done in the "ordinary course of business."[72]

3. Ennis Substation

183. Through Answer Testimony, the OCC recommends that the Commission disallow the approximately $7.9 million for the Ennis Substation project because the project has neither been approved by the Commission nor has the Commission made a finding that a CPCN is not required for the project.

184. In response, Public Service argues that the Ennis Substation project is properly supported as part of the Company's 2019 capital additions to distribution investment. Public Service explains that it did not include the project in its "Rule 3206 report" because it was an expansion of a distribution substation which, by a Commission rule, is deemed to occur in the

[71] Decision No. C16-0080, issued February 3, 2016, Proceeding No. 15R-0325E at ¶ 24.

[72] Decision No. R15-1245, issued November 25, 2015, Proceeding No. 15R-0325E.

ordinary course of business and thus does not require a CPCN. Public Service contends that the OCC misunderstands classification of distribution and transmission facilities as it relates to substation projects. Public Service argues that the facilities in dispute are designed to operate at distribution voltages and serve distribution level customers.

185. We agree with Public Service that the Ennis Substation project is a distribution project that is deemed to occur in the ordinary course of business by rule and Commission practice and does not require a CPCN. The project was designed to operate at distribution voltages to serve distribution level customers. We deny the OCC's proposed cost disallowance.

4. Two Basins Project

186. The Two Basins Transmission Project involves the relocation of three existing transmission lines exiting Public Service's North Substation. Public Service states the project was necessary to accommodate the Two Basins Storm Water Drainage Project (also known as the 39th Avenue Greenway and Open Channel Project) designed to provide 100-year storm protection for certain areas of Denver.

187. The OCC alleges that Public Service began construction on the project without prior approval from the Commission. The OCC reports that the Commission's decision finding that the project could be conducted in the ordinary course of business issued on June 30, 2017.[73] However, the Company's monthly expenditures on the project prior to that approval totaled approximately $5.8 million. The OCC recommends that the Commission find those expenditures were not prudently incurred because the Company did not comply with the relevant statutes and Commission rules.

[73] Decision C17-0539, issued July 10, 2017, Proceeding No. 17M-005E.

188. In response to the OCC's recommendation, Public Service explains that, through working with Denver, the Company determined the project needed to be placed in service by November 2017 to avoid causing unnecessary delay to the storm water drainage project and the nearby Interstate 70 expansion project. Public Service states that the project timeline was required by the Company's franchise agreement with Denver and that the nature of the project required no CPCN because it entailed the relocation of facilities done in the normal course of business. Public Service adds that regulatory process timelines do not always align with the timeline of business and customers' service needs. In this instance, Public Service determined its best course was to begin work in advance of any CPCN determination by the Commission, if required.

189. We reject the OCC's recommendation that would result in at least a partial disallowance of the costs of the Two Basins Transmission Project. The Commission found the project was to be completed in the ordinary course of business, and there is no evidence that associated costs were unreasonable or that the project was not in the public interest. The construction schedule appears to have been driven primarily by Denver's storm protection project requirements, and while the normal regulatory process is for a CPCN determination to be made prior to the start of construction, there was no indication of any risk that the Commission would find the affected electric utility project to be unneeded by the Commission. There is little merit in a regulatory practice of automatic disallowances simply because certain costs were incurred without prior determinations from the Commission.

5. Rush Creek Wind Project

190. Leslie Glustrom argues that the Rush Creek Wind Farm was too expensive and that Public Service took no action to address the alleged high costs prior to its construction. She concludes that it was clear in late 2017 that the \$29/MWh cost of Rush Creek, while perhaps a good price in 2013, was too high for a wind farm that would go into service in 2018 with wind costs falling dramatically. Ms. Glustrom recommends that the Commission disallow recovery of a significant amount of the associated expenditures, arguing that customers should not be required to pay significantly more for resources than is needed. She states that the Commission should prevent Public Service from abusing the competitive bidding process for the acquisition of new resources because it results in the Company owning resources that are significantly more expensive than if they had been put out for bid.

191. In response, Public Service argues that Ms. Glustrom fails to account for the fact that approximately \$5/MWh of the \$29/MWh cost figure are associated with the Rush Creek Gen-Tie (a 345 kV transmission line interconnecting the project), leaving approximately \$24/MWh for the generation component of the project and ignores that the gen-tie "unlocked an additional 800 MW of low-cost eastern Colorado wind, which was extensively litigated and approved in Proceeding No. 16A-0396E." Public Service argues that Ms. Glustrom's position and recommendations regarding Rush Creek represent an inappropriate collateral attack on a decision of the Commission contrary to § 40-6-112(2), C.R.S., is speculative, and unfounded "contrary to the regulatory compact."

192. We reject Ms. Glustrom's suggestion to disallow the recovery of costs associated with the Rush Creek Wind Project. The project was approved by the Commission on October 20, 2016 in Proceeding No. 16A-0117E by Decision No. C16-0958 in accordance with

the reasonable cost standard in § 40-2-124(1)(f)(I), C.R.S.[74] Ms. Glustrom failed to provide any persuasive evidence in support of her position. As described below, we authorize Public Service to implement its proposed GRSA-E (with certain modifications for the residential and small commercial rate classes) for the purpose of full recovery of the Rush Creek Wind Project costs on an annual basis as presently achieved through the ECA.

E. Accumulated Depreciation Reserve Adjustments

193. Through Answer Testimony, CEC proposes adjustments to the Company's revenue requirement to reflect the increase in depreciation rates from the 2016 depreciation case that the Company seeks to implement in this rate Proceeding.

194. Public Service argues through Rebuttal Testimony that the Company properly matched the level of depreciation expense to the level of plant at the end of 2018 and that the annualized level of depreciation expense will be recorded to the Accumulated Reserve for Depreciation during 2019, one year after the 2018 HTY. The Company also explains that when using a 13-month average for the valuation of rate base, there would be no annualization of depreciation expense at level. Accordingly, the Company's proposed adjustment to include 2019 capital additions was determined as a separate standalone adjustment from the annualization of depreciation expense for calendar year 2018.

195. Public Service also points out that the new depreciation rates will be implemented with the effective date of rates from this case, which is expected to be January 1, 2020. The

[74] Section 40-2-124(1)(f)(I), C.R.S., which was in effect when Decision No. C16-0958 was executed, authorized "…a qualifying retail utility to develop and own as utility rate-based property up to twenty-five percent of the total new eligible energy resources the utility acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007, if the new eligible energy resources proposed to be developed and owned by the utility can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market." This statute further states "…the qualifying retail utility shall not be required to comply with the competitive bidding requirements of the commission's rules".

annual level of depreciation expense and the corresponding amounts recorded to Accumulated Reserve for Depreciation reflecting the new depreciation rates thus will not be realized until the end of 2020.

196. We find that it is reasonable and necessary for Public Service to match the increase in depreciation expense in the revenue requirement with a decrease in the rate base on which the Company earns a return. We agree with the CEC that by failing to match the annualization of depreciation expense with the impact to the depreciation reserve, the Company increases the depreciation expense in the revenue requirement without decreasing the rate base on which it also earns a return. We thus require Public Service to adjust the accumulated reserve for depreciation to reflect the higher depreciation rates in the selected test year, as recommended by the CEC. We further require the companion adjustment to the accumulated reserve for depreciation for the adopted test year to reflect an annualization of the adjusted depreciation expense, as recommended by CEC.

F. Gains on Asset Sales

197. Public Service proposes to differentiate the treatment of gains and losses on sales between depreciable assets and non-depreciable assets. For depreciable assets, net gains and losses would be allocated between shareholders and customers based upon the percentage of the asset that has been depreciated. For example, if, at the time of a sale, customers already have paid 50 percent of the value of the sold asset through depreciation, then customers would receive 50 percent of the gain or bear 50 percent of the loss, and the Company would receive or bear the remaining 50 percent. For non-depreciable assets, however, Public Service would receive 100 percent of the gain and would bear 100 percent of the loss, since customers had not paid for any of the acquisition costs through depreciation. Public Service argues that since it is not

compensated for the additional risk of the delayed recovery or other attendant risks of invested money in non-depreciated assets, the Company should not have to share any gains from the sale of that property.

198. Staff recommends the Commission deny the Company's proposal to share the gains and losses of sales on depreciable assets and to retain gains and losses on land (the primary non-depreciable asset subject to sales). Staff instead recommends that 100 percent of net gains from the sale of assets occurring since the last rate case should be allocated to customers and amortized over three years. Staff also argues that the Company's customers have absorbed many of the risks on land sales by having to pay for the environmental clean-up costs of land previously sold. Since customers are at risk on land sales, they should receive the rewards of the land sales.

199. The OCC also opposes the Company's proposal and, like Staff, recommends that ratepayers be allocated 100 percent of gains and losses from the sale of assets, except for the Cameo land sale. For that transaction, the OCC argues in favor of allocating the entire land sale loss to the Company based on the evidence showing the Company sold the land for well below a recently appraised value. Regarding the Georgetown Green/Clear Lake property sale, the OCC points out the Commission has ruled on the treatment of the gains on three previous occasions, adopting the OCC's position. The OCC also argues in favor of disallowing the recovery of transaction costs through the determination of net proceeds due to an alleged lack of evidence. The OCC argues that the Company fails to meet its burden of proof to provide sufficient evidence in support of recovery of the transaction costs, recommending that the total amount of transaction costs of $476,465 be disallowed as deductions in the Company's calculations for the net gains or losses of each asset sale.

200. DOE argues that the Commission should be consistent with its past decision in Proceeding No. 17AL-0363G regarding the treatment of gains on sales.

201. In response, Public Service argues that its proposal for the treatment of the gains and losses from asset sales is good public policy and is consistent with the regulatory treatment of gains in other jurisdictions.

202. Public Service disagrees with Staff's assertion that the Company has requested that its customers bear the risk and responsibility for the diminution in value of utility property. Public Service likewise disagrees that customers have borne risks associated with real property simply because they pay property tax and other O&M expenses in their rates. The Company maintains that property taxes and O&M expenses are simply an input into what customers pay for electric service, according to the Company, those costs do not give rise to any investment risk on the part of customers. Public Service further contends that Staff does not acknowledge the risks to Public Service associated with the delayed recovery of investments in non-depreciable assets or how Public Service should be compensated for that cost. Public Service also argues that any authority to recover the costs of remediation of environmental hazards is separate from recovery of the diminution in value to Public Service's property as a result of the environmental hazard. Public Service also maintains that, although public utilities are rate regulated in Colorado, its customers do not own its property. Instead, customers pay for utility service at rate regulated prices without any taking of an ownership interest in the utility's property. The Company further argues that the treatment of gains (and losses) on sale of property should be considered on a case-by-case basis, noting that the Commission has allocated the gains on sale to both customers and the utility in the past. Public Service argues that it provided sufficient

information to meet its burden of proof in this case regarding the transaction costs associated with the sales of assets.

203. The Company also argues that the OCC's recommendations produce a one-sided outcome, where Public Service incurs all the losses associated with sales and where Public Service bears the responsibility for all transaction costs without reimbursement from customers. The Company also disagrees with the OCC that Public Service bears the responsibility for all federal income taxes on gains.

204. We will adopt consistent treatment of the gains on the sale of the Green/Clear Lakes property as decided by the Commission in Proceeding No. 17AL-0363G.[75] We also require that 100 percent of the losses attributed to the Cameo land sale be assigned to shareholders as recommended by the OCC. The record in this Proceeding indicates that the property could have been sold at a net gain as opposed to a loss.

205. We reject Public Service's general proposal to differentiate the treatment on the gain and loss on the sale of assets between depreciable assets and non-depreciable assets for the other sales relevant to the cost of service in this Proceeding. One hundred percent of net gains from the sale of assets shall be allocated to ratepayers and amortized over three years. Public Service is sufficiently compensated by ratepayers with respect to such assets because the Company earns a return on them. Ratepayers are also held responsible for associated property taxes, for other related O&M expenses, and, in the case of depreciable assets, for depreciation expenses.

[75] Decision No. C18-0736-I, issued August 29, 2018, Proceeding No. 17AL-0363G.

G. Pension and Post-Employment Benefits Issues

1. Pension Expense

206. Public Service requests an annual recovery of $16.6 million associated with its qualified pension expense and $0.7 million for a nonqualified pension expense.

207. Staff recommends that the non-qualified pension expense, which is associated with only highly compensated employees and has particular tax consequences, be excluded from the cost of service. Staff argues that Public Service has not adequately supported the request for recovery.

208. CEC similarly argues that it is not reasonable to ask ratepayers to fund the nonqualified pension plan. CEC states that the costs of these "exceptional pension benefits" are most appropriately borne by shareholders.

209. In response, Public Service argues that there is a false impression among the intervening parties that all of the employees eligible for the non-qualified pension benefit receive pension benefits in excess of $220,000 annually. The Company states that the Xcel Energy pension formulas typically produce total benefit amounts (qualified and non-qualified combined) that are less valuable than a $220,000 annual annuity. The Company goes on to note that fewer than five long-tenured executives are expected to have total benefit amounts (qualified and non-qualified combined) that exceed the value of a $220,000 annual annuity. Public Service also states that the goal of the non-qualified pension offering is to enable the Company to attract and retain experienced and knowledgeable employees to fill more highly paid positions as part of an overall market-competitive compensation package.

210. Public Service shall include in its revenue requirement the pension expense amounts it requests in this Proceeding, with the exception that the amount shall be adjusted to

remove amounts associated with incentives paid over 15 percent of base pay. This treatment is consistent with the Commission's decision recently rendered in Proceeding No. 17AL-0363G.[76]

211. We dismiss entirely the advocacy of OCC witness Ron Fernandez who asks the Commission to adopt new cost recovery policies that will encourage Public Service to move away from supporting its defined benefit pensions. The OCC asks the Commission to deny cost recovery of the costs associated with its "legacy pension plan" in this Proceeding, and, after two or three years, to deny recovery of all costs for defined benefit pension costs.[77] While there have been shifts by some companies to move away from their defined benefit pensions to defined contribution plans, those moves are not useful or relevant to our ratemaking considerations in this Proceeding. The OCC's suggestion to deny cost recovery of the pension is incomplete and ignores the nature of the unique, difficult, and dangerous work done on behalf of the Company and its ratepayers by members represented in this Proceeding by the IBEW. The OCC made no showing that the pension expenses for these workers are excessive or improperly negotiated. The OCC's advocacy on this point offered claims that are not well reasoned, yielding requests for which no foundation was provided and resulting in a poor use of the Commission's rate setting process as well as the resources of the parties.

2. Pension Tracker

212. Public Service has been allowed to defer pension expense amounts incurred above or below a baseline established pursuant to the 2015 settlement agreement in a previous rate case.[78] In this Proceeding, the Company seeks to address a pension tracker balance of

[76] Decision No. C18-0736-I, issued August 29, 2018, Proceeding No. 17AL-0363G.

[77] Hearing Exhibit 174, Fernandez Answer, p. 118.

[78] Decision No. C15-0292, Exhibit A, issued March 31, 2015, Proceeding Nos. 14AL-0660E and 14A-0680E.

$3,320,547 associated with 2015 through 2018 deferrals by amortizing the balance over a three-year period including a return.

213. Staff agrees with Public Service's recommendation to amortize the balance over three years but disagrees that the Company should earn a return on this regulatory asset. Staff argues that the tracker serves to reduce the Company's risk surrounding the recovery of pension costs.

214. CEC opposes the pension tracker and the recovery of the 2015 through 2018 deferred amount. CEC instead recommends that the Commission direct Public Service to calculate a 2019 pension expense deferral to be amortized over three years. Notably, the "2019 pension expense is projected to be lower than the 2015 Settlement Agreement baseline and should be a credit to customers, since the current Pension Expense Tracker is expected to be in place through the end of 2019."[79]

215. We find the arguments of Public Service and Staff to be persuasive regarding the continued use of a pension tracker. Public Service shall continue to use a tracker for the purpose of deferrals for consideration in a future rate proceeding.

216. We also direct Public Service to amortize over a three-year period, the pension tracker balance associated with 2015 through 2018 deferrals. However, Public Service shall not earn a return on the tracker balance amounts.

3. Prepaid Pension Asset

217. Public Service requests to include a prepaid pension asset of $31.3 million in its rate base. Public Service notes that due to the different timing requirements for pension

[79] Hearing Exhibit 142, Higgins Answer, p. 71.

contributions and pension expense recognition, and because the pension plan remains open to new participants, it is nearly impossible to avoid having either a prepaid pension asset or an unfunded liability at any given point in time. Public Service states that while the Commission is not bound to follow Generally Accepted Accounting Principles (GAAP), the Company's practice is to establish its pension expense in accordance with FAS 87 because that approach provides an objective standard by which the Commission can evaluate the reasonableness of the associated expense in the Company's revenue requirement. Public Service also argues that although the Company is subject to certain pension funding requirements, the timing of the Company's contributions is somewhat discretionary. The Company further argues that removal of the asset from rate base would discourage the Company from investing in the plan to improve funding levels.

218. Staff argues that the Company's prepaid pension asset does not benefit ratepayers and that including the asset in rate base encourages Public Service to grow the asset and to "increase ratepayer underfunding" of the pension plan. Staff estimates Public Service would earn $2.4 million annually if the Commission includes the prepaid pension asset in rate base, increasing the annual qualified pension costs to ratepayers by roughly 14 percent. Staff argues that this additional 14 percent would increase Public Service profits rather than help to fund the pension plan. Staff recommends that the Commission remove the prepaid pension asset from the Company's rate base in the cost of service study.

219. The OCC similarly argues that the Commission should disallow a return on the prepaid pension asset to be consistent with the Commission's ruling on the gas department's prepaid pension asset in the Company's last Phase I gas rate case in Proceeding No. 17AL-0363G.

220. CEC does not join in Staff's and the OCC's recommendation to remove the prepaid pension asset from rate base and instead recommends that the return on the prepaid pension asset be set equal to the Company's cost of long-term debt, just as it was in a previous 2015 rate case settlement agreement. CEC argues that, in a ratemaking sense, Public Service requires ratepayers to compensate the Company at a rate of 9.57 percent for proceeds to be invested in pension plans for an expected return of 6.84 percent.[80] CEC states that the upfront costs are clearly too high and represent a poor proposition for ratepayers.

221. Public Service responds that customers earn a return on the prepayments they make, such as the prepayment of deferred taxes, and that the Company otherwise typically earns a return on the prepayments it makes, such as payments for materials and supplies. Further, the Company maintains there is no requirement that the party advancing funds demonstrate a net benefit in order to earn a return on the prepayment. According to the Company, the standard ratemaking assumption is that the party who advances funds is entitled to a return on those funds to compensate it for the use of the capital and to induce that party to continue providing that capital. Public Service also disagrees with Staff's assertion that it does not benefit ratepayers for the Company to maintain a prepaid pension asset. According to the Company, the return on the asset reduces the pension expense included in rates.

222. The Company also disagrees with the CEC's position that the return be set at the cost of debt, arguing that such earnings are unreasonable because earnings are generally grossed up for taxes. The Company argues that the Commission has not previously assigned returns on an asset-by-asset basis and that the CEC provides no valid reason to treat the prepaid pension asset differently than other assets.

[80] Hearing Exhibit 142, Higgins Answer, p. 63.

223. We approve the creation of a second "legacy" prepaid pension asset, consistent with past practice. This prepaid pension asset shall be amortized over five years as proposed by Public Service.

224. We likewise direct the establishment of a second "new" prepaid pension asset and require Public Service to notify the Commission when the value of the new prepaid pension asset is $50 million or greater. We also require annual pension reporting in this Proceeding as has been used in the past.[81]

225. We reject the proposed inclusion of the prepaid pension asset in rate base, finding the arguments of Staff and the OCC to be persuasive. This directive is consistent with the treatment of the prepaid pension asset for other Colorado utilities, including Public Service's gas operations, pursuant to our decisions in Proceeding No. 17AL-0363G.[82]

4. Incentive Pension Impacts

226. Staff argues in Answer Testimony that because Public Service did not cap incentive pay at 15 percent of an employee's salary for purpose of determining the AIP component in its revenue requirement, the Company has likewise not removed the pension expense impact relating to employee compensation for AIP above the Company's target. Staff recommends that Public Service, rather than ratepayers, be held responsible for paying the impact on the Company's pension expense of incentive payment bonuses greater than 15 percent. The calculation should be made on an employee-by-employee basis, and Public Service should be responsible for paying for this calculation.

[81] Decision No. C15-0292, Exhibit A, Attachment F, issued March 31, 2015, Proceeding Nos. 14AL-0660E and 14A-0680E.

[82] Decision No. C18-0736-I, issued August 29, 2018, Proceeding No. 17AL-0363G.

227. In Rebuttal Testimony, as explained above, Public Service argues that incentive pay above 15 percent of base pay is necessary to bring the total compensation level for certain employees to market-competitive levels. The Company states that it thus follows that the pension expense should be calculated using the full amount of compensation. Further, Public Service maintains that any calculation associated with the pension impact made on an employee-by-employee basis must be performed by its consultant, Willis, and that such calculations will grow more complex and expensive with each passing year, because Willis will need to incorporate up to four years of information on an employee-by-employee basis. If the Commission requires such a calculation, customers should bear the cost of having the calculations done.

228. Consistent with the Commission's findings in Proceeding No. 17AL-0363G, ratepayers will not be held responsible for paying the qualified impact of the pension expense impact of incentive payment bonuses greater than 15 percent. Public Service shall reduce the cost of service for the pension impacts of incentive payments above 15 percent of base pay, and the Company shall be responsible for any costs incurred to produce the associated calculations on an employee-by-employee basis.

5. Retiree Medical Expense and Asset

229. The retiree medical expense included in the Company's revenue requirement is associated with a legacy program no longer offered to new Public Service employees. Public Service proposes to include $0 for retiree medical expense in the revenue requirement as a means to mitigate the growth in the prepaid retiree medical asset. The actuarially determined retiree medical expense for 2019 is negative $1.84 million, however.

230. Staff maintains that it makes no sense for Public Service to charge ratepayers a negative retiree medical expense when the Company also has a prepaid retiree medical asset on its books. Staff argues that the Company has more than sufficient funds currently in the Voluntary Employee Beneficiary Association (VEBA) trust to pay retiree medical expenses, partly because the Company has reduced the benefits paid to retirees. Staff alleges that Public Service wants to grow the regulatory asset associated with retiree medical benefits and yet has taken no steps to pay off the asset. Staff states that the Company failed to explain the dramatic increase in the asset since 2015. Staff recommends the Commission take steps to eliminate the prepaid medical retiree asset and suggests that the asset should be excluded from rate base, questioning why that trust should be considered a regulatory asset on which the Company seeks to earn a return.

231. CEC objects to Public Service's proposal to include $0 for retiree medical expense in the revenue requirement as a means to mitigate the growth in the prepaid retiree medical asset. CEC argues that the avoidance of an incremental increase to the prepaid retiree medical asset is not a compelling reason to deprive ratepayers of the benefits of a negative retiree medical expense.

232. Through Rebuttal Testimony, Public Service refutes Staff's assertion that the Company is trying to add to the prepaid retiree medical asset. The Company also maintains that including the negative pension expense in the revenue requirement would drive the prepaid retiree medical asset higher. Public Service explains that the growth in the asset has been caused by a reduction in the number of employees and retirees who are eligible for the benefit and by funding the VEBA trust at a level that matches the amount of retiree medical expense included in the cost of service, as required by the Commission's order in Decision No. C91-1514 issued

December 27, 1991 in Proceeding No. 91A-281E. Public Service further explains that the only way to reduce the prepaid asset would be either to make withdrawals from the account, which is not allowed, or to increase benefits to increase retiree medical expenses. From a GAAP perspective, Public Service claims there is no reason to try to reduce the asset.

233. Public Service also explains that it is seeking a WACC return on the prepaid retiree medical asset for the same reason it is seeking a WACC return on the prepaid pension asset, that is, it believes it is normal ratemaking practice for prepayments by the Company to be added to rate base and earn a WACC return.

234. Public Service's explanation that the asset was caused by a reduction in the number of employees and retirees who are eligible for the benefit is also reasonable. However, we remain concerned that there appears to be no plan to address the balance of the prepaid retiree medical asset going forward. Nevertheless, we are persuaded by the Company's explanation that including the negative pension expense in the revenue requirement would drive the prepaid retiree medical asset even higher.

235. We thus direct the Company to set the retiree medical expense in the cost of service to $0. We also deny the inclusion of the prepaid retiree medical asset in rate base, consistent with our decision in Proceeding No. 17AL-0363G.[83] The Commission has not included the asset in rate base before, and there is no persuasive reason to do so now.

6. Post-Employment Benefits

236. Public Service proposes to include in rate base a post-employment benefit liability as a credit to customers, applying a WACC return plus tax-gross-up on the balance, net of

[83] Decision No. C18-0736-I, issued August 29, 2018, Proceeding No. 17AL-0363G.

associated ADIT. Unlike the prepaid assets associated with the Company's pension and retiree medical plans, the balance associated with FAS 112 postemployment benefits (associated with workers' compensation and long-term disability) is in an accrued liability.

237. CEC argues that the prepaid pension asset, retiree medical asset, and the postemployment benefit liability be treated in a consistent manner. Therefore, it recommends that the return on each of these rate base items be set equal to the Company's cost of long-term debt, as described above.

238. We grant the inclusion of the post-employment benefit liability in rate base as a credit to customers, however, consistent with our other findings and conclusions regarding the return on such amounts, we will not allow a return on this item notwithstanding its inclusion in rate base. The Company's proposal to include the postemployment benefits in rate base as a credit to customers is warranted, given that this particular prepaid asset is an accrued liability. The CEC's argument to calculate a return on the amount based on the Company's cost of long-term debt is unpersuasive.

H. Taxes

1. Excess ADIT/Deferred Tax Asset

239. The reduction to the federal corporate income tax rate from 35 to 21 percent pursuant to the TCJA causes excess accumulated deferred income taxes (excess ADIT) to appear in Public Service's cost of service accounts for the test periods proposed by the parties in this Proceeding. Deferred income taxes arise due to timing differences between when income taxes are recognized for book purposes and when income taxes are ultimately paid.

240. In its SOP, CEC explains that the TCJA requires "protected" excess ADIT balances to be returned to customers no more rapidly than the rate at which the timing

differences reverse over the life of the related property (which is accomplished using the average rate assumption method, or ARAM). CEC further explains that Public Service also has a liability for "unprotected" plant-related excess ADIT, which is not subject to the ARAM requirement. Although it is not required to do so, CEC states that Public Service proposes to return the unprotected plant-related excess ADIT to customers using ARAM, which CEC argues would deny customers the timely return of these overpayments of future tax expense. CEC instead recommends that the Commission require Public Service to amortize the unprotected plant-related excess ADIT to customers over ten years rather than using the much longer ARAM period to achieve a more reasonable balance between ratepayers' interest in the prompt return of unprotected excess ADIT with the impact to Public Service's cash flow.

241. Public Service urges the Commission to reject CEC's adjustment to the non-protected portion of excess ADIT, arguing that the proposal would confer all of the tax benefits on customers who take service in the next ten years, even though the underlying assets will be in service and paid for by customers for decades to come. According to Public Service, adopting CEC's proposed adjustment on this issue would be unreasonable, unnecessary, and would unduly burden the Company's cash flow, potentially affecting the Company's credit metrics.

242. Staff objects both to Public Service's ARAM proposal and CEC's ten-year amortization. Staff's alternative is instead for the Commission to require Public Service use all remaining excess ADIT to create a deferred tax liability whose earnings would offset the deferred tax asset (DTA) expected from the treatment of the federal Production Tax Credits (PTCs) from the generation of the Rush Creek Wind Project and, in the future, from the generation of the Cheyenne Ridge Wind Project as well. Specifically, Staff recommends that the Commission direct Public Service to use its excess ADIT to create a regulatory liability for the

purpose of offsetting the DTA created when Public Service credits ratepayers for the PTC before applying these dollars as an offset to its income tax. Staff argues that crediting today's ratepayers with dollars that will eventually need to be repaid by tomorrow's ratepayers creates intergenerational inequity and does not serve the public interest. Staff further argues that Public Service benefits when the DTA is paid down, because paying down the DTA will make it more likely that Public Service will not be penalized by exceeding a DTA Annual Cap established by the settlement on the Cheyenne Ridge Wind Project and Public Service will have greater cash flow.

243. Public Service argues in its SOP that the Commission should not adopt Staff's proposal to address the DTA for two reasons. First, Public Service argues that the proposal is contrary to the Settlement Agreement in Proceeding No. 18A-0905E which set the DTA Annual Cap. Public Service thus argues that Staff's proposal represents a statutorily-prohibited collateral attack on Decision No. C19-0367 issued April 25, 2019 in Proceeding No. 18A-0905E. Second, Public Service argues that Staff's proposal fails on a practical level. Public Service argues that, while Staff assumed approximately $20 million in Colorado Renewable Investment Tax Credits (ITCs) when offering its proposal, the Company later established and Staff conceded that the $20 million revenue stream is not available because the Company can only record a benefit of $750,000 per year. Through Rebuttal Testimony, Public Service also takes the position that a regulatory liability is only appropriate for a benefit the Company has received and not yet passed onto customers—since the Company has not received the benefit of the Renewable Energy ITC, it is not appropriate to create a regulatory liability related to it and pay a return to customers on that regulatory liability. Public Service thus concludes that Staff's proposal relies on a significant overstatement of one of the revenue streams offsetting the DTA.

244. We deny Staff's primary proposal for using remaining excess ADIT to address DTA impacts. We agree with Public Service that Staff's proposal is contrary to the Settlement Agreement in Proceeding No. 18A-0905E which set the DTA Annual Cap and thus allows for the recovery of some amount of the associated carrying costs. While we understand how Staff might see how its proposal regarding excess ADIT could help Public Service from being penalized by exceeding the DTA Annual Cap, the proposal also could result in the denial of carrying cost recovery per the terms of the approved agreement. We also share Public Service's concerns that Staff's proposal may not be as beneficial as initially contemplated by Staff due to the requirement that Public Service consider a benefit of only $750,000 per year associated with the Colorado Renewable Energy ITC.

245. We further deny Staff's second alternative proposal suggested in its SOP to apply the excess ADIT to pay down the new pre-paid pension asset. Although this recommendation mirrors a settled term related to the initial treatment of TCJA impacts on Public Service's rates, the proposal is undeveloped in the record in this Proceeding.

246. Instead, we adopt CEC's proposal with respect to "unprotected" plant-related excess ADIT and require Public Service to return the amounts to ratepayers through an amortization over ten years. CEC's suggestion is consistent with the Commission's goal of ensuring that Colorado utility customers benefit from the utility's company's reductions in their federal corporate income taxes through lower utility rates for customers. The ten-year amortization also will reasonably address the cash flow concerns raised by the Company.

2. Property Taxes

247. Public Service takes the position that property taxes, at whatever level they may be assessed, are a necessary part of providing the utility service to its electric customers. Public

Service argues that it should not be penalized due to increases in property taxes as would result in a lag on cost recovery. Public Service states that a property tax tracker avoids that outcome and is the reason a property tax tracker has been in place for almost a decade.

248. Staff recommends including Public Service's forecast property taxes for 2020 based on 2019 plant balances in its cost of service and amortizing any outstanding property tax balance over three years. Staff also supports the continued using of the property tax tracker, explaining that the Commission has authorized Public Service to defer excess property tax for future recovery since the Company's 2011 rate case. Staff objects, however, to Public Service's proposal in this Proceeding to start earning a return on the balance of the property tax tracker as a regulatory asset. Staff argues that there is no reason for Public Service to start earning a return on a claimed regulatory asset now.

249. The OCC objects to the property tax tracker and recommends that the Commission deny its continued use. CEC likewise recommends that the property tax tracker be eliminated, arguing that it is another example of single issue rate-making.

250. We adopt Staff's proposal to include the Company's forecast property taxes for 2020 based on 2019 plant balances in the cost of service. In addition, we approve the three-year amortization of the existing deferral of outstanding property taxes. We agree with Staff and the Company that maintaining a tracker is reasonable. However, we reject Public Service's request to earn a return on the tracker balance.

3. State Tax Rate

251. Public Service proposes to use a "blended" state income tax rate of 4.66 percent to calculate its revenue requirement rather than the Colorado state income tax rate of 4.63 percent. Public Service's proposal reflects a weighted average calculation including

California's 8.64 percent rate, explaining that the Company trades energy in California, which requires the Company to file and pay taxes in California. Public Service argues that because the California energy trading drives the California income taxes and these trading margin benefits are shared with customers through the ECA, it is appropriate for Public Service to reflect the California tax in the cost of service. Public Service also states that while the Company does trade energy in other states, it is not required to pay taxes to those other states.

252. The OCC argues that California has one of the highest income tax rates in the country and that by only using California's tax rate in the weighted average calculation the Company has inflated the state income tax rate and thus has inflated its revenue requirement. The OCC recommends that the Commission continue to use the Colorado rate of 4.63 percent in all revenue requirement calculations. Staff echoes the OCC's concerns and makes the same recommendation.

253. We grant Public Service's request to include the California tax rate in a weighted average calculation for the state tax rate used in the Company's cost of service study. The state tax rate percentage shall be 4.66 percent.[84]

4. Colorado State Tax Violations

254. Public Service requests that the Commission grant deferred accounting treatment for the recovery of any fees, interest, or penalties that result from the State of Colorado's examination of the Company's tax payments. The Company is further seeking to amortize a related expense of $968,269 over three years in its cost of service study.

[84] Commissioner Frances A. Koncilja disagreed with these findings and conclusions.

255. The OCC recommends that the Commission deny the Company's request for deferred accounting treatment. According to the OCC, such fees, penalties, and interest are intended to punish a tax filer for violating the law, even if Public Service claims the alleged violations were inadvertent. The OCC also recommends that all fees, penalties, and interest associated with non-compliance of laws should be borne by the Company's shareholders and not ratepayers.

256. CEC likewise argues that shareholders should be responsible for these costs and argues that it is unreasonable to select these past-period costs as recoverable from customers in this case.

257. In response, Public Service rebuts that the disputed taxes support Public Service's utility operations and that it is appropriate for its customers to pay the related cost. The Company further argues there is no basis to disallow the costs. Public Service states that it goes to great lengths to comply with the complex state and home rule tax laws of the jurisdictions in which it operates and did not ignore the regulation change at issue in the state's audit.

258. We agree with the OCC that fees, penalties, and interest related to tax violations are intended to punish a tax filer for violating the law, even if the alleged violations are inadvertent. We therefore adopt the OCC's and CEC's position that fees, interest and penalties related to tax violations, however they may have occurred, should not be recovered from ratepayers.[85]

[85] Commissioner Frances A. Koncilja disagrees with these findings and conclusions.

I. Revenue Adjustments

1. Oil and Gas Revenues

259. Staff observes that the treatment of oil and gas royalty revenues booked by Public Service as non-utility income has been the subject of dispute in Public Service rate cases for a long time. In this Proceeding, Public Service seeks to retain this revenue and no longer share any portion of it. Intervening parties, however, seek a share of the proceeds for ratepayers.

260. Staff recommends the Commission retain the current 50/50 split between the Company and the customers, arguing that it is a reasonable compromise that evolved over time. On one hand, Public Service took the initiative to monetize the mineral rights, and therefore it should share in the benefits from that initiative. On the other hand, customers should also benefit from the monetization of the mineral rights because they have been paying the underlying costs.

261. The OCC argues that, as a regulatory principle, it is inequitable for the Company to earn its WACC on 100 percent of the underlying property and also to retain the royalty revenues. The OCC recommends that the Commission reject the Company's position and require that 90 percent of the revenues be credited to customers.

262. CEC likewise argues that a large majority—if not all—of the oil and gas revenues should flow to ratepayers in recognition of the fact that these revenues are an economic byproduct, albeit unexpected, of the land the Company acquired for a utility purpose and has included in rate base. Like the OCC, CEC recommends a split of 90 percent to customers.

263. DOE similarly suggests that the mineral rights were acquired as an ancillary part of the land because Public Service could not have known of the existence of mineral deposits when the property was acquired. According to DOE, ratepayers have been provided a return on

the full value of the property, while Public Service now seeks to benefit from receiving all of the mineral rights royalties from the property.

264. In response, Public Service argues that the lack of separation between surface and mineral estates does not provide a basis to set aside its proposal to retain 100 percent of the royalties. The Company argues that customers did not pay for any of the exploration, drilling, and production costs of the wells that are generating the revenues. Public Service further argues that the Company itself is managing the mineral rights and such management also leads to the royalty revenues.

265. We agree with the intervening parties that both Public Service and its customers should share in the benefits of the oil and gas royalty revenues. We direct Public Service to maintain the current 50/50 split in its cost of service study.

2. Weather Normalization

266. As explained by the intervening parties, weather normalization in a rate case such as this Proceeding is the process of adjusting the utility’s actual billings and revenue collections to reflect typical weather instead of any atypical weather that may have occurred during the selected test year. Weather normalization has traditionally been seen as necessary to set rates that recover the utility’s costs under normal weather conditions.

267. In its initial case filing with the submittal of Advice Letter No. 1797, Public Service uses a 30-year-average weather normalization. Public Service argues that the Commission approved a 30-year-average normal in previous litigated electric and gas rate cases and that a 30-year average matches the definition of normal weather from the National Weather Service. Public Service also argues that a 10-year or 20-year normal contributes to greater

year-to-year variances in weather normalized sales because the normal is less consistent between years.

268. In its SOP, Public Service states that the goal of a weather normalization ratemaking adjustment is to establish a representative, normal weather that avoids abnormal weather, variability, and large rate swings over time. Public Service states that the goal of weather normalization is not to predict future weather. Public Service states that the best path forward for the Commission is to use either a 30-year average weather normalization or a 20-year average weather normalization. Public Service also argues that its 30-year weather normalization is consistent with what the Commission has approved in previous litigated electric and gas rate reviews.

269. Staff recommends that the Commission direct Public Service to use a different approach to weather normalization than the method the Company seeks to use in this rate case. Staff claims that Public Service fails to account for the trend of a warming climate, arguing that warming temperatures result in a trend of increasing cooling degree days (CDDs) and decreasing heating degree days (HDDs) over time. Staff states that such a trend is already observable in weather data. By taking into account warming climate conditions in the Company's service territory, Staff recommends that weather normalized sales still will be lower than actual sales. In its SOP, Staff argues that the observed trend of increasing CDDs and decreasing HDDs suggests that a historical average will tend to lag behind current temperatures. Staff further argues that its trend-based weather normalization is the only approach presented in this Proceeding that addresses the inherent lag in historical averages of temperatures. Staff states that its approach is statistically valid, based on Public Service's own weather normalization practices. Staff explains that the trend-based approach makes adjustments to the Company's calculations only for those

months where the data establishes a trend at a very high confidence level (*i.e.*, 95 percent). Staff recommends that the Commission require Public Service to calculate weather normalized revenues in a technical conference following the decision on the weather normalization approach.

270. In response to Staff, Public Service argues in its SOP that Staff's proposal is plagued with "statistical deficiencies." The Company states that Staff's proposal is flawed because it: (1) lacks statistically significant trends for the five heating months; (2) inappropriately includes 2018 actual weather data (claiming that the time period used to define a normal should not include the time period being normalized); (3) uses 44 years of data; and (4) is unique based on the evidence in the record. Public Service argues that the weather normalization adjustment in this Proceeding has become conflated with whether there is a warming trend in temperatures due to climate change.

271. While the OCC recognizes that any weather normalization adjustment needs to be based on sufficient data "to not be too heavily influenced by the immediately recent weather,"[86] the adjustment should nonetheless capture the impact of a demonstrated warming trend on electricity sales. The OCC thus proposes using the last ten years of weather data, from 2009 to 2018, as the basis for the weather normalization. In its SOP, the OCC argues that Public Service's 30-year weather analysis minimizes a current warming trend which in turn minimizes the billing determinants and maximizes the resulting rates to be charged to ratepayers. The OCC argues that the Company benefits the most if a weather normalization adjustment understates this warming trend while, in reality, higher than normal temperatures are expected.

[86] England Answer Testimony at p. 23.

272. In response to the OCC, Public Service argues that the OCC's proposal is results-oriented rather than grounded in a defensible foundation and fails to produce stable results over time. Public Service further contends that the OCC's ten-year approach is statistically flawed because it includes the test period in calculating the ten-year normal.

273. WRA recommends in its SOP that the Commission reject the Company's proposed weather normalization, arguing that using a 30-year weather normalization period obscures the warming trend Colorado is experiencing as a result of climate change and results in the Company potentially over-earning above its revenue requirement if the number of CDDs during the time the new rates are in effect exceed weather-normalized predictions. Put another way, WRA states that because the Company's 30-year weather normalization yields a revenue deficiency adjustment of $23.7 million, the Company could expect to earn an additional $23.7 million if actual weather patterns and the number of CDDs and customer electricity use remain unchanged from the 2019 test year to future years. WRA further suggests that if load growth increases due to a warming trend, the earnings result is accentuated. WRA supports the ten-year weather normalization period proposed by OCC. According to WRA, using a ten-year weather normalization period will better reflect weather conditions and the associated electricity sales the Company can reasonably expect to experience.

274. We reject Public Service's proposed weather normalization adjustments based on 30-year or 20-year averages. We agree with Staff that historical averages will tend to lag behind temperatures that will be experienced during the period when the new rates from this Proceeding will be in effect. We also share WRA's observation that the Company could expect to earn revenues based on a weather normalization adjustment if actual weather patterns and the number of CDDs and customer electricity sales are similar to the adopted 2018 or 2019 test year rather

than a purported "normal." We note, for instance, that Public Service's annual report filing to the SEC for 2018 explains that the Company's net income was approximately $551.7 million for 2018, compared with approximately $494.1 million for 2017, and that the increase was caused, in part, from higher electric margins "reflecting favorable weather and sales growth."[87]

275. While we appreciate Staff's efforts in this Proceeding in presenting an alternative approach to weather normalization to address warming conditions, we are not prepared to endorse this "statistical trending" framework without a better understanding of its relative strengths and weaknesses, particularly given the criticisms raised by Public Service and the lack of consensus regarding the approach among the intervening parties. We encourage Staff to continue its work in this area, because this Proceeding has demonstrated a serious shortcoming of all of the approaches to weather normalization presented by the parties.

276. We agree with Staff that because there is significant variation in weather and weather conditions that are outside of Public Service's control, weather normalization adjustments have become standard in utility rate cases, such that not undertaking weather normalization due to the flawed approaches advanced in this Proceeding would be unusual.[88] Yet, as described above, we also share Staff's reservations about the sufficiency of adopting a 20-year average approach as sufficient, even though moving from a 20-year approach from a 30-year approach is "a step in the right direction."

277. For this Proceeding, we adopt the OCC's method for applying a ten-year average for weather normalization including the actual weather data entered into the record of this Proceeding through August 31, 2019.

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[87] Hearing Exhibit 159, Glustrom Answer, Att. LWG-2, p 16.

[88] Transcript, November 13, 2019, p. 125.

3. Customer Growth Revenue Adjustment

278. With respect to the 2019 CTY, Public Service objects to Staff's proposed $11.3 million adjustment to the test year base revenue to account for growth in customer counts. Public Service argues that Staff's customer count adjustment is both crude and flawed. Public Service argues that customer count growth varies by class and that sales and revenue do not keep pace with customer growth due to factors such as declining use per customer and changes in large customers' operations.

279. At hearing, Staff appeared to step away from its proposed revenue adjustment upon further review of information provided by Public Service.[89]

280. In light of Staff's reconsideration, we do not adopt its customer growth revenue adjustment for the 2019 CTY.

J. Other Items

1. Notice to Customers

281. AARP argues that $19,480 of costs associated with the Company's noticing to its customers of its Advice Letter No. 1797 filing and the associated proposed rate increase should be disallowed, because Public Service failed to inform customers subsequent to its initial customer notice that the proposed tariffs were set for hearing and suspended, thus providing additional time for customers to provide public comments to the Commission. In its SOP, AARP further requests that the Commission inform Public Service that it expects the utility to follow the requirements for customer notification in a timely and accurate fashion.

[89] Transcript, November 13, 2019, p. 122.

282. In response to AARP, Public Service argues that it was not necessary for the Company to further communicate to customers that the Commission had suspended the advice letter initiating this rate case in order for the Company to recover the costs of noticing.

283. We deny AARP's request. Public Service's notice to customers regarding its Advice Letter No. 1797 filing was sufficient, and we agree with Public Service that the Company was not required to notify customers further that the Commission has set the filed rates for hearing and suspended their effective dates. We note that the Commission has accepted numerous public comments throughout this Proceeding and convened two public comment hearings.

2. Investor Relations Costs

284. The OCC argues that Public Service's investor relations expenses were spent for the benefit of shareholders and not ratepayers. Such costs include the expenses incurred by the Company to maintain investor accounts, to issue shares for its benefit plans, and to communicate with investors. The OCC recommends that the Commission remove the $242,765 of associated expenses from the Company's cost of service.

285. Public Service responds by arguing that the communications to and from investors and the financial community help ensure that the Company receives timely feedback related to debt and equity securities issuances, credit rating information, public financial documents, and financial releases. Public Service concludes that its customers benefit from low borrowing rates as investors provide financing for capital projects.

286. The OCC makes a persuasive argument regarding shareholder benefits from the Company's investor relations activities. However, we also agree with Public Service that ratepayers also receive benefits from these same activities. Accordingly, we will allow for

recovery of 50 percent of the investor relations costs to be included in the revenue requirement. The remaining amount shall be recovered from shareholders.

3. Generation Overhaul Expenses

287. In Answer Testimony, CEC explained that utilities such as Public Service typically incur generation overhaul expenses associated with the need to refurbish, replace parts, or otherwise maintain their generating units. CEC stated that Public Service identifies $180 million in production O&M expense in the test period but does not separately identify what portion of this expense is related to generation overhaul. CEC also alleged that the Company was not willing to provide the breakout generation overhaul expenses in discovery in this rate case as it had done in the past. CEC argued that it is necessary to examine carefully such expenses in a cost-of-service study, because the overhaul schedule for a generating facility generally follows a multi-year cycle, where, for a given plant, a year in which expense for a planned overhaul is high may be followed by years of little or no expense. Thus, for ratemaking purposes, it is preferable to use a normalization technique for such expenses because the actual overhaul expense in a given test period may not be representative of annual overhaul expense over time. CEC argued therefore that Public Service failed to meet its burden of proof that its test period production O&M expense is just and reasonable, since it was impossible to tell what portion of the total expenses should be normalized to account for the year-to-year variability in generation overhaul expense.

288. In response to CEC, Public Service argued that the term “generation overhaul expense” does not match a FERC account and therefore is not an expense category the Company separately tracks as part of its routine accounting practices. Public Service also explained that the Company has implemented a new general ledger accounting system and, as a result, was not

able to readily pull generation overhaul expenses for each of the four years requested by CEC. Public Service argued that CEC's request amounted to a request for a special study that would take two or more weeks to produce. Public Service nevertheless produced the study for its Rebuttal Testimony and claimed that the results show reasonable non-labor generation overhaul costs for its plants.

289. In its SOP, CEC concludes that the actual generation overhaul expense in the test period was ultimately shown by Public Service to be reasonably consistent with the historical average, and so a normalization adjustment is not required in this case. However, CEC suggests that the Commission require Public Service to provide information regarding its historic generation overhaul expense in future rate proceedings.

290. We agree with CEC that historic information on actual generation overhaul expenses is necessary in a rate case proceeding for assessing the reasonableness of the related cost components within any given test period. We therefore require Public Service to provide information in its future rate case filings regarding its historic generation overhaul expense.

4. Other Regulatory Assets

291. We grant the continuation of deferred accounting for certain AGIS costs, consistent with the base levels provided in the Company's Direct Testimony. This treatment is consistent with the terms of the settlement in Proceeding No. 16A-0588E in which the settling parties proposed deferred accounting for O&M expenditures and capital investments beyond the first rate case where those costs could be included in base rates.[90]

[90] Decision No. C17-0556, issued July 25, 2017, Proceeding No. 16A-0588E.

292. We further allow Public Service to recover project costs associated with the Company's Innovative Clean Technology (ICT) program as initially proposed in the Company's initial Advice Letter No. 1797 filing. Public Service shall amortize the deferred capital and O&M costs associated with the ICT projects and earn a full return at the WACC on the unamortized balance. This approach is consistent with the terms of the settlement approved in Proceeding No. 15A-0847E.[91] We further authorize Public Service to continue to record ongoing O&M expenses associated with the Stapleton and Panasonic Projects incurred in 2019 and going forward in a separate deferred accounting mechanism for consideration of recovery in a future rate case.

VII. PERFORMANCE-BASED REGULATION

1. Quality of Service Plan

293. Public Service's current QSP for its electric operations was approved in 2006 for effect on January 1, 2007 in Proceeding No. 05A-288E.[92] The current QSP evolved as a modified form of the QSP originally proposed in 1996 to ensure that the Commission continued to be provided with meaningful information regarding the operation of the Company's electric distribution system, customer complaints, and telephone response time by the Company's call center. The current QSP stems from Public Service's original QSP associated with the Company's 1996 merger with Southwestern Public Service Company. The purpose of the original QSP was "to maintain [the Company's] historical or existing level of service by discouraging cost savings at the expense of quality of service."[93]

[91] Decision No. C16-0196, issued March 8, 2016, Proceeding No. 15A-0847E.

[92] Decision No. C06-1303, issued November 6, 2006, Proceeding No. 05A-288E.

[93] Decision No. C96-1235, issued November 29, 1996, Proceeding Nos. 95A-531EG and 95I-464E.

294. The tariff sheets that implement Public Service's QSP for its electric operations were submitted with the Company's initial Advice Letter No. 1797 filing with certain modifications. Public Service proposes to extend the use of the existing performance measures through 2021 and to reduce the required reporting from the current monthly, quarterly, and annual reporting to only annual reporting.

295. Staff recommends that the Commission accept the Company's proposed modification to only the reporting requirements of its QSP. Likewise, the OCC takes no issue with continuing the existing QSP for another two years given that the QSP provides bill credits only and no positive incentives to Public Service.

296. We approve the proposed extension of the electric QSP through 2021 and reduce the required reporting to only annual reports. The Company's proposed modifications to its QSP for its electric operations are minimal and uncontested.

2. EAF Performance Mechanism

297. Public Service proposes to eliminate the Equivalent Availability Factor Performance Mechanism (EAFPM). The EAFPM was initially approved by the Commission in Proceeding Nos. 14AL-0660E and 14A-0680E as a benchmarking plan for certain generation plants in the Company's fleet to "provide an incentive for the Company to maintain the generation plants for optimum availability in order to achieve a cost effective unit dispatch."[94] The EAFPM is measured by comparing the weighted average of the Equivalent Availability Factor of the core of Public Service's coal and combined cycle gas generating units against certain historical thresholds. If Public Service's weighted average EAF is at or below the lower

[94] Decision No. C15-0292, issued March 31, 2015, Proceeding Nos. 14AL-0660E and 14A-0680E.

threshold, the Company is assessed a penalty of $3 million, if Public Service's weighted average EAF is at or above the upper threshold, the Company receives a $3 million incentive. To the extent the weighted average EAF is within the lower and upper threshold amounts, there is no impact to the Company.

298. While Staff agrees with Public Service that the EAFPM has served its function, Staff argues that continued implementation of the EAFPM remains in the public interest for the same reasons that the Commission initially approved the performance mechanism. Staff thus recommends that the Commission reject the Company's request to discontinue the EAFPM and to require instead that the EAFPM continue with a new reward threshold of 88.08 percent and a penalty threshold of 84.32 percent. These new thresholds are calculated using the same formula for the EAFPM but using data for the five-year period 2014 through 2018. Staff also recommends that the Commission modify the incentive mechanism to provide an incentive of $1.5 million for greater plant availability than the established standard and a $3 million penalty for less plant availability than the established standard. Staff argues that this asymmetric incentive and penalty structure is intended to signal to Public Service that the Commission would rather penalize poor availability performance than reward the Company for what it should already be doing—maintaining its availability—without an incentive. Staff recommends that the updated EAFPM be in effect until the Company's next Phase I electric rate case.

299. Staff clarifies in its SOP that the EAFPM does not require Public Service to run any particular generating facility in order to avoid a penalty. Rather, the EAFPM helps to ensure that such facilities remain available in case they are needed, thereby ensuring that the Company does not need to buy power from other markets. Staff also states that it is open to removing

generating units from the EAFPM three years before their scheduled retirement so the Company is not required to spend money on obsolete facilities.

300. In response to Staff, Public Service stands behind its proposal to discontinue the EAFPM. Public Service states that its generating fleet is changing and the EAFPM does not account for how the Company's system is currently operating or how units are dispatched in the most economical way. Public Service also argues that it is facing diminishing returns and that with the upward trend in weighted average EAF over the last five years, "there comes a point in time when the Company can no longer increase and improve its availability without significant investment, or maintain availability within a prescribed dead band."[95] Public Service further argues that Staff's proposal for the EAFPM fails to take into account planned overhauls and the cyclical nature of when they occur. Public Service then argues that in order to maximize renewables and "to continue to be a clean power provider,"[96] the Company increasingly will curtail and cycle the plants subject to the EAFPM. Public Service concludes that the incentive under the EAFPM would be to keep units offline and not expose them to potential events that could impact availability "as they fall off the system."[97] Finally, Public Service argues that the EAFPM "incentivizes the Company to use its fossil assets as originally designed" contrary to the carbon reduction benefits sought by the Colorado Energy Plan and the new statewide reductions in carbon emissions in Senate Bill (SB) 19-236.

301. In its SOP, Public Service goes on to argue that if the Commission were to reinstate the EAFPM, there could be a contradictory incentive for the Company to make additional investments in facilities near retirement in order to meet the minimum threshold and

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[95] Applegate Rebuttal at p. 74.
[96] *Id.* at p. 75.
[97] *Id.*

avoid penalties. The EAFPM, even with the wider dead band proposed by Staff, remains inconsistent with the Company's carbon objectives. The Company recommends that the EAFPM be considered holistically alongside other performance-based ratemaking or performance incentive mechanisms.

302. Sierra Club and WRA largely agree with Public Service regarding the proposed discontinuing of the EAFPM.

303. Sierra Club argues in its SOP that the EAFPM is inconsistent with the goal of minimizing revenue requirements, because the EAFPM does not account for whether a unit is economic to operate in the first place. Sierra Club further argues that the EAFPM is inconsistent with the statutory mandate for Public Service to reduce carbon emissions, because the EAFPM makes no distinction between units that emit large quantities of carbon dioxide and which Public Service will likely need to retire or dispatch less, and units that can be dispatched and still meet the carbon reduction goals in SB 19-236. Sierra Club states that the EAFPM should be discontinued because it incentivizes the Company to spend more money to keep all of its coal units available even though those units will likely need to be used less, if at all, in coming years.

304. In its SOP, WRA states that sinking major O&M expenditures and capital improvements into retiring units to ensure they are always operationally available, as potentially encouraged by the EAFPM, could result in an outcome that is not in the best interest of ratepayers and is contrary to the original intent of the EAFPM mechanism itself. However, if the EAFPM is reinstated, WRA recommends that the Commission exclude retiring thermal units from the EAFPM calculations as clarified by Staff.

305. The OCC agrees with Public Service on the proposed discontinuance of the EAFPM. OCC concludes that Public Service only benefitted from the existence of the EAFPM

and, because the Company has committed to no erosion in plant performance, there is no need to continue the EAFPM.

306. We conclude that Public Service raises valid criticisms regarding the continued use of the EAFPM. We are also concerned about the Company's warning that an EAFPM could cause it to make additional investments in fossil-fuel facilities in order to meet the minimum threshold and avoid penalties, particularly if the retirement date is unknown until a future ERP. We further agree with Public Service that the way the plants in its generation fleet will operate is changing and that a single performance metric for such plants may no longer be appropriate. The EAFPM was an elegant performance measure that served multiple purposes when it was initially approved. The EAFPM was adopted when there were less formal state policy on carbon emissions and when coal and gas resources subject to the EAFPM were presumed to be least cost in the dispatch order. In this Proceeding, we agree with Public Service that the Company will likely curtail and cycle the plants subject to the EAFPM, and it is unclear how such changes in plant operations, if otherwise reasonable, may affect plant availability. We thus support elimination of the EAFPM as proposed by Public Service.

3. Generation Investments

307. Sierra Club argues that continued operation of uneconomic coal plants would lead to higher than necessary revenue requirements and would foreclose opportunities to accelerate de-carbonization of Colorado's energy system consistent with the goals of Colorado's energy policy. Sierra Club recommends that the Commission introduce elements of performance-based regulation to encourage least-cost planning and decision-making, which it argues will ultimately lead to lower costs, lower revenue requirements, and lower rates.

308. Sierra Club further requests that the Commission's final order include a statement that Public Service runs the risk of having current and future capital expenditures being deemed imprudent at units if the Company cannot provide evidence that it is lower-cost to run the unit, after the additional capital costs are considered, than to retire and replace the unit (unless there is some other, compelling reason to continue to operate an uneconomic unit, such as maintaining reliability). Sierra Club argues that Public Service does not consider whether it would be cheaper to retire and replace a unit than undertake potential capital projects at that unit in its capital planning process. Sierra Club argues that this failure to consider retirement as an alternative to any capital projects, no matter how expensive the project or how poor the economics of the unit, is imprudent and leads to unjust and unreasonable rates. For example, Sierra Club seeks a Commission order requiring Public Service to justify its decisions to keep its coal plants online and continue to invest capital in such plants, starting with Hayden and Craig.

309. Public Service argues that many of Sierra Club's issues are within the realm of resource planning issues outside of a general rate case such as this one. Public Service explains that its overarching objective is ensuring the Company can continue to provide reliable electric service, yet the Company also takes into consideration the planned retirement date of a plant or unit in developing its capital budgets. Public Service claims that it has a number of prudency checks on its capital budgeting and spending to ensure that projects are prudently undertaken and align with the Company's objectives of providing safe, reliable, and cost-effective electric service. Projects are reviewed based on several factors, including safety, environmental, availability, maintenance and work productivity, efficiency, renewables, and financial merit. Public Service states that while projects for soon-to-be retired units are evaluated using these same criteria, a unit's retirement date may impact the scoring of and weight applied to each

criterion, potentially resulting in a lower probability of a project related to a soon-to-be retired unit being completed. In its SOP, Public Service repeats the argument that the Company cannot stop investing in generating units merely because a facility's retirement date is approaching and cannot unilaterally decide to stop investing in a unit absent a determination that the unit should early retire through the resource planning process. Public Service states that the Company retains its obligations to provide safe, reliable, and cost-effective service.

310. Consistent with its recommendation that the Commission adopt elements of performance-based regulation in its final order in this rate case proceeding, Sierra Club states in its SOP that several publicly available studies have suggested that some, or all, of Public Service's existing coal units are more expensive to operate than alternatives such as market purchases, wind, or solar (including solar plus storage). Sierra Club adds that, given that ERPs occur only every four years, the Company needs ratemaking incentives to review the economics of its units in between ERPs, so that in between ERPs it is not making unnecessary capital investments in units that would be cheaper to retire and replace. According to Sierra Club, a simple and inexpensive step toward improving the ratemaking framework is to require Public Service to regularly report to the Commission and the public data on the economics of its existing generating units. Sierra Club warns that if the Commission waits until its future investigation of performance based regulation to require Public Service to provide relevant data, the delay will slow down the process of considering performance incentives as required by SB 19-236. Sierra Club asks the Commission to require Public Service to begin compiling and publicly reporting for each unit all of these proposed reporting metrics within 90 days of its final order in this rate case.

311. In its SOP, Boulder expresses support of a requirement that Public Service compare the total cost of operating and maintaining existing generation facilities to the costs of new renewable energy generation resources in future ERPs.

312. Public Service questions whether Sierra Club's performance-based regulation proposal is a "doable ask from a public policy and practical perspective."[98] The Company also argues that Sierra Club is "getting ahead of the existing resource assessments"[99] at issue in the ongoing ERP rulemaking in Proceeding No. 19R-0096E. Public Service further commends the Sierra Club's "questions" but posits that the answers should be examined as part of the Commission's upcoming investigation into PBR.

313. The Commission is expanding the purpose of an ERP to examine the economics of existing generation plants and to explore potential early retirements for purposes of both rate relief and carbon emission reductions in the ongoing rulemaking in Proceeding No. 19R-0096E. We therefore agree with Public Service that Sierra Club's recommendations go beyond the requirements of this particular rate case. We are also unsure of whether the performance metrics proposed by Sierra Club for reporting purposes are what the Commission will need for future ratemaking purposes in a rate case. Therefore, we decline to adopt Sierra Club's proposals.

VIII. DECOUPLING

314. Public Service seeks permission from the Commission to defer implementation of the RDA mechanism approved in 2017 in Proceeding No. 16A-0546E.[100] The Company argues it has been approximately two years since the conclusion of that earlier proceeding, yet the

[98] Jackson Rebuttal at p. 68.

[99] *Id.*

[100] Decision Nos. R17-0337 and C17-0557, issued May 2, 2017 and July 11, 2017, respectively, Proceeding No. 16A-0546E.

approved RDA mechanism has an express sunset date of December 31, 2023. Public Service explains that the RDA would not be implemented until early 2020 if implemented upon the conclusion of this rate case. Public Service also argues that it is currently obtaining information from its residential TOU trial and residential demand rate pilot programs that can help to inform any implementation of decoupling, including whether it should be implemented at all or if it should be implemented with modifications. Public Service further admits that another reason to suspend the implementation of the RDA mechanism is that the Company is experiencing a delay in the deployment of Advanced Metering Infrastructure (AMI).

315. Staff, CEO, SWEEP, Vote Solar, and WRA generally argue that the Commission's intent was that the RDA be implemented after the next Phase I rate case. The Commission instructed Public Service to produce the decoupling formula "on the updated tariff sheets filed by Public Service after its next Phase I rate case, when the Company implements its decoupling proposal."

316. CEO argues that waiting an extra five years to collect data from the AMI meters in order to implement decoupling is illogical, when the Company could implement the RDA in 2020 and gather data about its impacts, as was intended by the Commission when it approved the RDA. SWEEP likewise states that four years is ample time to provide the valuable information on decoupling cited by the Commission. In addition, a four-year pilot is consistent with, if not longer, than decoupling pilot programs carried out in other states. Vote Solar argues that Public Service does not attempt to explain why this marginal reduction in the time period warrants the indefinite deferral of the entire mechanism.

317. Staff, SWEEP, and Vote Solar further argue that the Company, the Commission, and all participating stakeholders were aware of the TOU rate trial and demand rate pilot at the

time that all parties discussed and the Commission rendered a decision on decoupling. Staff states that the Commission itself noted in Decision No. C17-0557 that decoupling could work as the tool to ensure that the Company is held harmless from its investigation into energy TOU rates and demand rates for residential customers.[101] By tracking fixed cost recovery from the residential class on an annual basis and comparing these amounts to the amounts authorized in the most recent rate case, the RDA would ensure that the Company does not over-recover or under-recover its Commission-authorized levels of fixed costs from customers participating in either the TOU trial or demand rate pilot.

318. SWEEP also states that moving residential customers to TOU rates, if approved, will create additional uncertainties regarding customer bills and Public Services' revenue collection. Thus, implementation of revenue decoupling in conjunction with residential TOU rates will facilitate TOU rate implementation by ensuring that the Company receives its approved revenue in the customer class, and no more or no less. SWEEP also points out that when approving the decoupling pilot's sunset date of December 31, 2023, the Commission cited full implementation of Integrated Volt-VAr Optimization (IVVO) in 2022 and the deployment of AMI, both approved in Proceeding No. 16A-0588E.[102] IVVO uses data from AMI and other connected devices on Public Service's distribution systems to automate and optimize distribution voltage regulating and control devices. IVVO has the ability to save energy by reducing line losses while also reducing customer energy usage and demand by up to 2 percent. SWEEP notes that the energy reductions through IVVO are not funded through the Company's Demand-Side Management (DSM) programs, and Commission approval of IVVO was linked to the approval

[101] Decision No. C17-0557, issued July 11, 2017, Proceeding No. 16A-0546E.
[102] Decision No. C17-0556, issued July 25, 2017, Proceeding No. 16A-0588E.

of the RDA or a similar mechanism. Finally, SWEEP argues that the delay in AMI deployment will provide little or no change in the data available to the Commission on customer energy usage than was envisioned during the prior decoupling proceeding.

319. CEO is concerned that Public Service may not implement decoupling at all, or the Company instead may seek to modify the approved RDA, which, according to CEO, is unnecessary and should be discouraged because the Commission has already found that decoupling is in the public interest and the reasons the Company initially provided when it proposed decoupling still stand. CEO argues that Public Service has not demonstrated that circumstances have changed significantly. Average usage per customer is still likely declining, "which diminishes Public Service's opportunity to recover its Commission authorized fixed costs,"[103] because the factors that contribute to that decline still exist. CEO argues that not implementing the approved RDA in the manner ordered by the Commission would be contrary to Decision No. C17-0557.

320. In response to the intervening parties, Public Service argues that the Company should not implement the approved RDA mechanism just for the sake of utilizing a decoupling mechanism in Colorado. The Company also argues that the intervening parties fail to account for the changed circumstances and long delay since the RDA mechanism was initially approved. The changed circumstances, according to Public Service, include that under the original timing for RDA mechanism implementation, the RDA would have been in place contemporaneous with the residential TOU trial and residential demand rate pilot programs. Public Service further states that AMI will provide an additional source of detailed information about customer usage, none of which was available at the time of the decoupling proceeding and all of which can inform a

[103] Hearing Exhibit 144, Hay Answer, p. 6.

modification of the RDA or whether the use of any decoupling tool is in the best interest of Public Service's electric customers. Public Service concludes that it is willing to file a Phase II rate case or combined Phase I and Phase II rate case no later than August 1, 2020 and that, as part of that rate case filing, the Company would address the RDA, including whether to modify it or implement it at all, as part of a more holistic look at rate design.

321. We agree with Staff, CEO, WRA, Vote Solar, and SWEEP that Public Service has failed to put forward a sufficient evidentiary basis to justify its request to defer implementation of decoupling to a future time. The Company has offered various and changing rationales for postponing the implementation of the approved RDA at different points in this Proceeding. None of these rationales is persuasive, and Public Service thus fails to justify delaying or re-litigating the previously approved RDA mechanism. As Staff states in its SOP: "In reality, however, there are no meaningfully changed circumstances now that were either not addressed at the time the decoupling pilot was authorized or that impact decoupling."[104]

322. We also agree with SWEEP and Vote Solar that the RDA mechanism is to be implemented as a pilot that will be subject to annual reports and further review by the Commission to determine the future of a decoupling implementation after 2023. We find it appropriate for the Commission analyze the real-world impacts of decoupling following the RDA pilot rather than re-litigating a now-settled matter based on the Company's assertions about the impacts it may have.

[104] Staff SOP, p. 24.

323. We direct Public Service to file its compliance tariff filing to implement the RDA as directed by the Commission in Proceeding No. 16A-0546E no later than 30 days following the compliance tariff filing submitted to implement final rates in this Proceeding. The compliance filing for the RDA shall be filed as a new advice letter proceeding on not less than 14 days' notice and shall comply with all applicable rules. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date. Public Service shall put into effect the RDA mechanism and study its implementation through the period ending December 31, 2023.

IX. CERTIFIED RENEWABLE PERCENTAGE

324. In this rate case Proceeding, Public Service seeks approval of its proposed Certified Renewable Percentage (CRP). The CRP involves the retirement of Renewable Energy Certificates (RECs) above Public Service's Renewable Energy Standard (RES) compliance requirements, so that the total RECs retired in each calendar year will be equal to the total renewable energy delivered to the Company's retail customers. Public Service states this incremental retirement of RECs in each calendar year will allow retail customers to better account for and claim the renewable energy delivered from the Company's system in their efforts to satisfy their own specific renewable energy goals.

325. Public Service explains that the CRP measures the renewable energy delivered to customers in each calendar year that is paid for through their rates. The Company states that, in contrast, the RES is simply a minimum threshold of renewable energy generation that it must meet each year. Public Service argues that the RES should not prevent customers from counting the renewable energy as delivered to them and that they are paying for purposes of meeting their own prescribed individual standards. The Company adds that conversations held over the last

year with multiple customers and communities, particularly those with aggressive renewable energy goals, have shown a strong interest in the CRP as a tool to help them measure and meet their goals.

326. Through Direct and Rebuttal Testimony, Public Service reveals that the CRP essentially is a formula that clarifies how the Company intends to treat its RECs. The Company states that RECs serve as the unit of accounting for the utility RES compliance and also typically are used by customers for their own renewable energy programs and goals. Public Service states that it is accepted best practice that RECs must be retired on behalf of a customer in order for the customers to be able to substantiate claims of renewable energy purchases. RECs help ensure that the renewable energy being claimed by one customer is not counted somewhere else.

327. Staff argues that the Company's current use of RECs, while treated as accepted practice, creates a level of uncertainty around the amount of renewable energy provided annually on the Company's system and diminishes the timely recognition of the annual environmental benefits RECs convey beyond the Company's compliance with the RES. Staff agrees with Public Service that retiring RECs annually in the year they are generated will more accurately reflect the level of renewable energy generation on the Company's system and the associated environmental benefits provided to retail customers. Staff concludes that the CRP is a reasonable determination of the amount of renewable energy baseline that can be claimed uniformly by all retail customers while accounting for RECs transferred to other entities.

328. While they support the general concept of the CRP, CEO, Vote Solar, and WRA argue that the CRP may not accurately represent the actual amount of renewable energy generated on the utility system in a particular year and thus fails to support accurately the amount of renewable energy that customers claim for that year. For instance, CEO notes that the RECs

used to meet the RES requirement could be created in the year for which the Company is reporting or they could be "vintage RECs" (*i.e.*, RECs created up to five years earlier than the reporting year). Hence, the CRP also could be a function of the RECs generated from renewable energy on the system in the reported year as well as RECs generated from energy that was created on the utility's system in any one of the prior four years.

329. CEO, Vote Solar, and WRA argue that the inclusion of vintage RECs could be problematic for customers who want to claim a certain amount of renewable energy in a given year to demonstrate compliance with a corporate or social sustainability report or another type of renewable energy target for that year. CEO recommends that in calculating the CRP, Public Service should only use or retire RECs generated in the year for which it is calculating the CRP. In addition, CEO recommends the Commission direct Public Service to represent more accurately the percent of renewable energy that is part of the mix of energy being supplied to the retail customer when the Company explains the benefits and limitations of the CRP to its customers and shareholders. Vote Solar argues that customers do not want to acquire or claim the renewable energy attributes from electricity generated as much as five years prior. WRA adds that a strict approach to eliminate the potential for double counting of RECs would retire only current year RECs corresponding to the Company's claims for renewable energy on its system in a given year.

330. Denver suggests an alternative CRP formula so as not to remove renewable energy subscriptions (*i.e.*, Windsource sales and Renewable*Connect sales). Denver argues that this modified formula also provides an accurate counting of the available renewable energy attributes that customers can claim.

331. OCC argues that it is not clear whether Public Service plans to continue REC sales upon implementing the CRP. OCC raises a concern that the Company could decide to reduce REC sales in order to have a higher CRP for customers to claim. Because ratepayers share in the revenues gained from REC sales, OCC takes the position that Public Service should only implement the CRP if the Company also maximizes the revenue from REC sales.

332. In response to the intervening parties, Public Service argues that the variety of potential changes to the CRP recommended in Answer Testimony could not all be accommodated in one proposal. Public Service also argues that some parties went far beyond the intent of the Company in proposing certain changes to the CRP. For instance, some parties suggested retiring all RECs in the year (or early in the next year) that they are generated. According to Public Service, this requirement could drastically reduce the Company's bank of RECs that it manages for customers. Public Service argues that a bank of RECs provides flexibility with regard to RES compliance should an unforeseen loss of renewable energy generation occur or a potential increase in the RES. The Company further states that an elimination of its REC bank would effectively end or significantly reduce REC sales. Based on the feedback from Denver, however, Public Service proposes to remove the subtraction of voluntary renewable programs sales (for which RECs are retired) from the denominator of the CRP formula.

333. Public Service states in its SOP that its adjusted CRP proposal balances multiple competing interests and is the product of two years of development and engagement with customers and the sustainability marketplace. Public Service points to many commercial, community, and institutional customers with near-term (*e.g.*, 2020 and 2025) sustainability goals who would receive value

from the CRP. Public Service states that the CRP can evolve as customers and the Company gain experience with the program, but it is important to implement CRP now for customer engagement. The Company further states that it is amenable to scheduling a check-in at a future time to review the CRP formula.

334. CEO, Vote Solar, WRA, Denver, and Boulder nonetheless ask the Commission not to approve the CRP. Instead, they recommend that the Commission express approval for the concept and direct Public Service to work more with the interested stakeholders to refine the mechanics of the CRP. In addition, they request that the Commission direct Public Service to file its revised CRP as either a stand-alone application or a stand-alone advice letter. They add that CRP should not be brought forward in another rate case because the Company is not seeking recovery of any CRP costs.

335. We conclude that Public Service has not supported the need for Commission approval of the CRP. Section 40-2-124(1)(d), C.R.S., as implemented by Rule 3659(n) in 4 CCR 723-3, affords Public Service unrestricted ownership of RECs, provided that the Company meets the RES using eligible energy resources without exceeding the associated retail rate impact.[105] We are further persuaded by the Company's Rebuttal Testimony that the CRP "is a voluntary information offering from the Company designed to produce formula-based data and statistics

[105] Decision No. C12-0081, issued January 27, 2012, Proceeding No. 11A-510E.

about a customer's electric service" and that the CRP "does not involve anything to be collected or enforced, nor is it a term or condition about one's electric service."[106]

336. Nevertheless, we agree with several of the parties that some amount of additional time may permit interested stakeholders to reach agreement with Public Service on a revised CRP formula. We also do not want the parties' advocacy surrounding the CRP to go to waste. We see merit in a CRP that is easy for customers to understand and is offered soon into the marketplace without controversy. We agree with CEO the CRP formula is confusing and that how Public Service intends to use the CRP for customer engagement remains unclear.

337. We therefore direct Public Service to file a notice in this Proceeding no later than 60 days after the Mailed Date of this Decision to report to the Commission on whether the Company has reached consensus with interested stakeholders on a modified CRP.

X. IMPLEMENTAION OF FINAL RATES

A. General Rate Schedule Adjustment

338. How Public Service should implement new rates determined by the Commission in this Proceeding emerged as one of the most complicated and controversial issues in this Proceeding. The issue also appears to be unique to Colorado, because public utilities commissions in other states generally do not allow for Phase I rate cases, or cases where a utility is authorized to collect more revenues in total but also where issues surrounding rate class cost allocations and rate design are deemed off limits. In Colorado, class cost allocations and rate design are traditionally the main subjects of a Phase II rate case. To bridge the Phase I and Phase II cases, the Commission typically authorizes a GRSA which causes an "across-the-board"

[106] Hearing Exhibit 137, Ihle Rebuttal, p. 31.

rate change where each component of the Company's base rates for all rate classes is adjusted by a uniform percentage amount.

339. Public Service explained in its initial Advice Letter No. 1797 filing that it was seeking an increase in its base rate revenues of approximately 26.4 percent. Because a significant portion of these revenues are already or will soon be recovered through rate riders, the net increase in total revenues was about 5.7 percent, or $158.3 million. Public Service proposed that the base rate revenue increase would translate into two GRSAs: a traditional GRSA of 13 percent and a separate additional GRSA-E of $0.00455/kWh to collect approximately $130 million annually of the costs of the Rush Creek Wind Project.

340. Staff maintains the use of a traditional GRSA best serves the public interest. Staff argues that the GRSA is a simple mechanism that is easy to understand because it is applied to each rate class in the same manner. Staff further views it as inappropriate to single out just one of the components of the revenue requirement for special allocation treatment. Staff further implies that the rate design currently in place properly represents class load shapes and resulting cost allocations.

341. CEC also supports the use of only a traditional GRSA, arguing that it best maintains the class allocations and rate designs approved in the previous Phase II proceeding, where cost allocation and rate design are fully vetted. CEC argues that by allocating the incremental revenue requirement to all classes and rate schedules equally – and equally ignoring cost causation for all customers and all the incremental costs – the GRSA ensures that rates generally continue to reflect cost of service.

342. The OCC takes the general position that if a GRSA rider is implemented, the GRSA be volumetric only. The OCC explains that a volumetric GRSA allows the Company to

recover the authorized amounts, but lessens the impacts on low-income customers by maintaining the approved and current monthly customer charge (also known as the Service and Facilities Charge), which would otherwise increase with a GRSA.

343. EOC concludes that the Commission should decrease the reliance on the GRSA in the future and require that Phase I and Phase II rate cases be filed together or within a short time of one another, such that they are completed in a matter of weeks from one another rather than months, or even years as had been the case for most of this past decade.

344. DOE similarly requests that the Commission adopt as its policy of general applicability that going forward, all electric and gas utility general rate case applications must include both the revenue requirement and the rate design in the same proceeding, that is all of the elements of a combined Phase I and Phase II proceeding.

1. Rush Creek Wind Project

345. Public Service argues that the GRSA-E addresses unique circumstances relating to the rolling in of the Rush Creek Wind Project into base rates. While Public Service takes the general position that a GRSA maintains a prior rate design, Public Service argues that it does not make sense to change the allocation of Rush Creek Wind Project costs temporarily by including it in the GRSA, particularly given the impact that would have on residential and small commercial customers.

346. Staff recommends that the Commission reject the use of a GRSA-E and instead adopt a single traditional GRSA applicable evenly to all rate components. Staff argues that it is inappropriate for the Commission to single out just one of the components of the revenue requirement for special allocation treatment. Staff notes that of the approximately $3.9 billion of investment at issue in this case, some $1 billion relates to the Rush Creek Wind Project and that

the balance (other production, transmission, and distribution) are costs generally related to be "capacity-related." Staff explains that residential and small commercial customers have "peakier" loads than other customer classes yet the capacity-related costs are not being treated differently.

347. CEC also recommends that the GRSA-E be rejected, arguing instead in favor of the entire incremental revenue requirement above base rates as determined in this case be recovered exclusively through a single GRSA as has been done in the past. CEC argues that until there is a Phase II rate case, each customer class should experience an equal percentage increase over base rates. CEC argues that the GRSA-E is "selectively disadvantageous to certain customer classes such as Transmission General Service, which would receive more than twice the share of Rush Creek Wind Project cost recovery under the GRSA-E as it would under the conventional GRSA."[107] CEC notes that there is no GRSA "carve out" that excludes new costs associated with the distribution function from being allocated to transmission voltage service customers in a Phase I case. CEC argues that an all-energy allocation of Rush Creek costs in the next Phase II proceeding is completely unsupported by the evidence in this case, which did not include any class cost of service studies (CCOSS). CEC argues that whether the fixed capital costs associated with the Rush Creek Wind Project should be allocated or recovered entirely on an energy basis is an issue for the Commission to decide based on the evidentiary record established in the next Phase II rate case, where allocation is at issue. Nevertheless, CEC claims that this same record shows that wind generation facilities like the Rush Creek Wind Project contribute both capacity and energy to Public Service's system and that the Company relies on the capacity from its wind generation facilities to meet its capacity needs. CEC concludes that

[107] Higgins Answer Testimony pp. 73-74.

the proposed GRSA-E would allocate and collect the capital costs of the Rush Creek Project on an all-energy basis, whereas the Commission has previously found that an all energy rate is less able to track the cost of service than a demand-energy rate.

348. DOE similarly argues that the Rush Creek Wind Project is a production facility and its costs should be recovered as any other production facilities and thus opposes the GRSA-E since the rate is based upon energy. DOE argues that the manner of cost recovery for Rush Creek should be dealt with in Phase II "of this Proceeding, when the issue of cost causation and benefit can be fully explored based on record evidence."[108] DOE claims that the proposed GRSA-E "should not seek to anticipate the outcome of Phase II of this Proceeding."[109]

349. In contrast, Denver and Boulder support Public Service's proposed recovery of the Rush Creek Wind Project costs through the GRSA-E and opposes the recovery of those costs as proposed by Staff, the CEC, and DOE through the GRSA. Both cities point to EOC's analysis indicating that the GRSA treatment of the Rush Creek costs would result in a disproportionate share of rates falling upon street lighting, residential, and small commercial customers.

2. EOC's Proposals

350. In its Answer Testimony, EOC argued that a GRSA unfairly shifts costs to the residential rate class and to the fixed customer charge specifically. For example, EOC argued that many of the cost increases that the Company has experienced since its last Phase II rate case in 2016 are unrelated to customer costs. Nevertheless, a 13 percent GRSA would raise the residential monthly customer charge by approximately 70 cents. EOC also argues that the record in this case demonstrates that the roll-in of costs today being collected in three riders (ECA,

[108] Morgan Answer Testimony p. 14.
[109] *Id.*

TCA, and CACJA) to a GRSA would constitute an unjust and unnecessary rate allocation that will unquestionably be reversed in Public Service's next Phase II rate design case.

351. EOC supported the separate volumetric-based GRSA-E to recover the costs of the Rush Creek Wind Project costs. EOC further proposed an extension and modification to the Company's proposal to cause more of the revenue requirement deficiency to be collected in the same manner as such revenue is currently being charged to customers and will be charged to customers following a Phase II. EOC recommended a "GRSA-DE", as a modification to and broadening of the GRSA-E, where the "GRSA-D" part of the rate would be similar in structure to the GRSA-E for the Rush Creek Wind Project costs, in that it would not be a percentage rate, but would instead maintain the current riders as demand or energy charges based on the customer class. As an alternative, the Commission could order a conversion of the proposed GRSA costs to a volumetric rate ($/kWh) that is added together with the GRSA-E to produce one GRSA line item on residential customer bills.

352. At hearing and in its SOP, EOC echoed, in form, the arguments of the proponents of the GRSA, contending that, in the absence of a Phase II CCOSS, the Commission should preserve the status quo of each rider's approved cost allocation. EOC notes that the proposed "rider roll-ins" represent 69 percent of the base rate revenue requirement at issue in this Proceeding. EOC states that in the absence of a Phase II rate design review, costs that have been collected in riders that are approved for roll-in to base rates should continue to be collected by their approved allocation methodology, unless or until the Commission finds a different allocation is appropriate based on a CCOSS vetted in a Phase II proceeding. CEC states that while some parties claim a single GRSA is "simpler" than the continuation of the three riders, the GRSA in reality shifts costs away from approved allocations between classes and charges

without a CCOSS. EOC claims that the time for using a GRSA has now passed, lacking both legal and ratemaking foundations and now distracts from revenue requirement determinations and just and reasonable rate design.

353. In response to EOC, Public Service asks the Commission to reject the continued use of the three riders out of hand, because the proposal was first raised at hearing. Public Service argues that the proposal should have been raised in pre-filed Answer Testimony, but was not, thereby creating due process concerns coupled with a lack of substantial evidence in the record. Public Service claims that the proposed GRSA-E stems from a unique and specific set of circumstances and argues that the GRSA-E should not open the door to a GRSA-D for the CACJA Rider and TCA costs. Public Service argues that rider roll-ins have been included as part of Company rate reviews and a GRSA-D brings into question matters of rate design that would be more appropriately addressed in a Phase II rate case. Public Service further warns that if the Rush Creek Wind Project is recovered through the "regular GRSA," project costs will not be allocated on an energy basis for a period of time until the next Phase II rate review, with real cost impacts to residential and small commercial customers. Regarding EOC's proposed "GRSA-DE," Public Service argues that it runs counter to the rate design goals of administrative simplicity and customer understandability. Public Service characterizes EOC's proposal as a "complex and incomplete rate accommodation for low energy users."[110]

354. In its SOP, Boulder states that it is not opposed to Public Service's proposal to roll the TCA, CACJA, and Rush Creek riders into base rates; but until there is a CCOSS study in the next rate case, Phase II, Boulder recommends that these costs continue to be collected as they are now. Boulder thus supports EOC's proposal, whether that occurs through modified GRSA

[110] Jackson Rebuttal p. 179.

subaccounts or through a continuation of the current riders. Boulder argues that, due to the impact on rates for residential, small commercial and streetlight customers, Boulder requests that the Commission approve the proposed GRSA-E and -D or, in the alternative, maintain the current recovery method for TCA, CACJA, and Rush Creek costs until those costs may be appropriately allocated in a rate case Phase II proceeding. Boulder states that moving the collection of the costs from the ECA and the Renewable Energy Standard Adjustment (RESA) to the GRSA would mean a shift from collection based on energy consumption to collection based on the total bill, without the benefit of a Phase II allocation. Boulder supports EOC's suggestion that the Commission approve the rolling in of the TCA, CACJA, and Rush Creek costs into base rates as part of the next Phase II proceeding.

355. With respect to EOC's proposed GRSA-DE proposal, CEC claims that the proposed GRSA-DE isolates only some of the costs driving the increase in base rates in this Proceeding. CEC further notes that a GRSA results in certain costs, like the Company's significant investment in distribution facilities, to be paid by some customer classes despite the likelihood that such costs would not be allocated to them in a Phase II proceeding based on cost causation principles.

356. DOE similarly argues that EOC's proposed GRSA-D, which could collect on a demand basis the CACJA and TCA rider amounts pending completion of a Phase II proceeding, also would reflect a rate design without satisfying the regulatory and analytical requirements applicable to rate design. DOE states that it does not object to the use of an asymmetrical volumetric charge applicable to the residential and small commercial class only to collect the amount allocated to the class under the GRSA. DOE argues that an asymmetrical volumetric charge would address EOC's concern that conservation be encouraged through price signals and

that customer fixed charges not be raised to the detriment of low-income customers. More generally, DOE requests that the Commission adopt as its policy of general applicability that going forward, all electric and gas utility general rate case applications must include both the revenue requirement and the rate design in the same proceeding, that is all of the elements of a combined Phase I and Phase II proceeding.

3. Findings and Conclusions

357. We reject the continued use of the three rate adjustment mechanisms for the continued collection of TCA, CACJA, and ECA (Rush Creek Wind Project) revenue requirements as proposed by EOC. While we agree that the continued use of the three riders would preserve certain cost allocations that have already been reviewed and approved by the Commission, three of the primary requests of Public Service in this rate case are to terminate the ECA collection of Rush Creek Wind Project costs, to terminate the CACJA rider altogether (at least after one final reconciliation), and to roll-in some of the TCA revenue requirements into base rates, a practice that has become standardized since the inception of the TCA. These "rider roll-ins" were contemplated in settlement agreements and previous Commission decisions to occur in the context of a base rate revenue requirement proceeding, and we are not compelled to deviate from that approach in this particular case.

358. Before Public Service filed Advice Letter No. 1797, the Commission had already noted that, with respect to the Rush Creek Wind Project, "the bill impacts from cost recovery through the combination of the ECA and RESA mechanisms are likely different from the bill impacts from GRSA collections through base rates."[111] Public Service argues in this case that the GRSA-E addresses unique circumstances relating to the rolling in of the Rush Creek Wind

[111] Decision No. C18-0280, issued April 26, 2018, Proceeding No. 17AL-0649E at ¶ 74.

Project to base rates. We agree with Public Service that it does not make sense to change the allocation of Rush Creek costs temporarily by including it in the GRSA, particularly given the impact that would have on residential and small commercial customers. While we would have preferred that Public Service had responded to the Commission's statements above by filing this Proceeding as a combined Phase I and II rate case, absent a Phase II record, we adopt the GRSA-E approach for the uninterrupted recovery of Rush Creek Wind Project costs until the completion of the next Phase II rate case.

359. The balance of the base rate revenue change granted by this Decision shall be addressed through a traditional GRSA, with two exceptions. In accordance with the suggestions of EOC, OCC, and DOE, we direct Public Service to translate the revenue amount that would be allocated to the residential and small commercial rate classes under a traditional GRSA into volumetric charges ($/kWh) for each class. This would prevent an effective increase in the customer charge as set forth in the base rate tariff sheets for these two rate classes, which best maintains the rate designs approved in the Company's previous Phase II proceeding. Second, we direct Public Service to add the GRSA costs converted into a $/kWh charge to the GRSA-E to produce a single GRSA for application on residential and small commercial customer bills as suggested by EOC. This second exception meets the rate design goals of administrative simplicity and customer understandability.

360. The roll-in of the Rush Creek Wind Project portion of the ECA revenue requirement shall be calculated to ensure the recovery of the full amount of costs on an annual basis. Likewise, the roll-in of the revenue requirement for the CACJA Rider costs also shall be set to accommodate the elimination of the rider as proposed by Public Service. Consistent with the recommendation of Staff and Public Service, the roll-in of the revenue requirement for the

TCA should be at the year-end 2018 level. We authorize Public Service to adjust the TCA revenue requirements going forward to ensure full cost recovery of eligible transmission investments on a current basis, consistent with the discussion above.

B. Contested Changes to Rates and Tariffs

1. Transmission Cost Adjustment (TCA)

361. Public Service is allowed to recover transmission investment costs for each year on a current basis through its TCA as a result of the Commission's approval of the comprehensive settlement resolving Public Service's last completed Phase I electric rate case in Proceeding No. 14AL-0660E.[112] This means that transmission investment costs forecast to be incurred in 2019 are collected through rates in effect throughout 2019.

362. In this Proceeding, the OCC argues that Public Service should only be allowed to recover its actually incurred transmission-related expenses through the TCA rather than its forecasted expenses. The OCC argues that Public Service does a poor job forecasting transmission expenditures and that prior to the settlement reached in Proceeding No. 14AL-0660E, transmission costs have been traditionally recovered based on actual expenses rather than forecasted expenses.

363. In response, Public Service argues that the OCC's proposal is "inconsistent directionally with the goals of the Company, this Commission, and the State of Colorado."[113] Public Service also emphasizes the cost true-up element of the TCA, stating that the rider helps to ensure that customers pay only for the Company's actual transmission investments given the multi-year nature of many transmission projects and certain unplanned investments.

[112] Decision No. C15-0292, issued March 31, 2015, Proceeding Nos. 14AL-0660E and 14A-0680E.

[113] Applegate Rebuttal Testimony p. 23.

364. We deny the OCC's recommendation to modify the Company's TCA. We agree with Public Service that the OCC's proposal is inconsistent with the state energy policy goals. Given Public Service's size and the geographic span of its transmission system, we conclude that current cost recovery offered by the TCA serves to encourage important transmission investment across the state, including the necessary transmission investment that enabled exceptionally low bids for renewable energy resources in the Company's most recent ERP in Proceeding No. 16A-0396E.[114]

2. Demand Side Management Cost Adjustment

365. Public Service recovers an amount of its expenditures on DSM programs through base rates. The DSM Cost Adjustment (DSMCA) recovers the incremental cost of current DSM programs beyond the amount recovered through base rates.

366. In this Proceeding, Staff opposes the inclusion of any DSM costs in base rates. Staff argues that including all of the costs in the DSMCA is necessary for transparency. In its SOP, Staff recommends removing the roughly $89 million of DSM costs in base rates and collecting these costs exclusively through the DSMCA. Staff states that collecting all DSM costs through the DSMCA rather than through a combination of base rates and the DSMCA will have a "zero-dollar impact," meaning that it will neither increase nor decrease ratepayers' bills.

367. In its Rebuttal Testimony, Public Service does not object to the treatment of DSM costs as proposed by Staff, but it claims not to understand fully the point of the transfer of costs from base rates to the DSMCA. Public Service states that the design and treatment of DSM costs was agreed to in the Company's 2009 rate case in Proceeding No. 09AL-299E. Public Service

[114] Decision No. C18-0761, issued September 10, 2018, Proceeding No. 16A-0396E.

notes that while Staff's proposal would not cause an increase in bills, it would result in a 186 percent increase in the DSMCA charge presented on the bill.

368. In its SOP, SWEEP opposes Staff's recommendation. SWEEP explains that when the Commission first implemented the current practice for recovering DSM costs in the early days of Public Service's DSM programs, the Company had explained that a DSMCA collecting all DSM cost would only reflect the "gross costs" of the DSM programs, and customers would never see the avoided cost benefits of DSM programs as a line item on their bills. According to SWEEP, recovering all DSM costs through the DSMCA would make the costs of DSM programs appear larger than they actually are, and SWEEP argues that this rationale holds equally true today. SWEEP states that Staff makes no attempt to address or rebut the long-standing rationale for why Public Service currently recovers DSM costs through the DSMCA and base rates, which is to avoid sending a confusing signal to customers that overstates overall DSM costs. SWEEP further argues that Staff's recommendation would not achieve the goal of making overall DSM costs more transparent to customers, since the 186 percent increase to the DSMCA would make the overall costs of Public Service's DSM programs appear larger than they actually are.

369. We conclude that Staff's recommendation regarding the DSMCA is unsupported and unnecessary. Staff has not established that there is a lack of transparency that needs to be corrected. Staff also has not explained why it is necessary to isolate all DSM-related costs in a single line item, when there is no such requirement for any of the other resources used by Public Service to be presented in such a fashion. Finally, Staff also has not made a persuasive case to show how a 186 percent increase in the DSMCA on consumer bills is in the public interest.

C. Uncontested Changes to Rates and Tariffs

1. Electric Commodity Adjustment

370. Public Service Company seeks to modify its ECA tariff to include provisions to facilitate the future recovery of costs associated with the Cheyenne Ridge Wind Project. Public Service explains that these changes to the ECA conform to the Cheyenne Ridge Wind Project Settlement Agreement recently approved by the Commission in Proceeding No. 18A-0905E. This proposal appears to be uncontested.

371. We grant Public Service's request. Initial cost recovery of Cheyenne Ridge Wind Project through the ECA costs is consistent with the Commission's approval of the settlement in Proceeding No. 18A-0905E.[115]

2. Other Rate and Tariff Changes

372. Advice Letter No. 1797 and Public Service's supporting Direct Testimony explain additional changes that the Company seeks to make to its tariff sheets in Colo. PUC No. 8 Electric, such as:

XI. Updated tariff sheets to incorporate new rates for the Charges for Rendering Service and Maintenance Charges for Street Lighting Service,

XII. Updated Table of Contents, Reserved for Future Filing Index, General Definitions, and Territory Served,

XIII. The elimination of the Transmission Time-of-Use (Schedule TTOU),

XIV. A correction in wattage in the Parking Lot Lighting Service (Schedule PLL) tariff,

XV. Removal of the tariff for the Earnings Sharing Adjustment (ESA),

XVI. Updated Short-Term Sales Margins in the ECA for Generation and Proprietary from calendar year 2015 to 2018,

XVII. Revised data privacy provisions in the Requests for Customer Data section of the General section of the Company's Rules and Regulations

[115] Decision No. C19-0367, issued April 25, 2019, Proceeding No. 18A-0905E.

to more clearly reflect the reports available to customers and third parties,

XVIII. Clarified and simplified tariff language in Other Meter Tests and Billing for Errors sections of the Standards in the Company's Rules and Regulations to better align with Commission Rules, and

XIX. Tariff provisions addressing customer credit and payment plan options that apply in the event billing adjustments are made.

373. We conclude, based on the record in this Proceeding, that the tariff changes listed above are uncontested. We approve these tariff changes, finding that they are sufficiently supported and reasonable. Public Service is authorized to implement these changes to Colo. PUC No. 8 Electric in its compliance tariff filing as described below.

D. Technical Conference

374. On the afternoon of December 16, 2019, Public Service presented modifications to its cost of service study to reflect the decisions the Commission made during its oral deliberations in this Proceeding at the special Commissioners' Deliberations Meeting on December 11, 2019 at a Technical Conference scheduled by Decision No. C19-0980-I, issued on December 6, 2019. Public Service's Technical Conference presentation was based on the Company's cost of service study developed for its Rebuttal Testimony and included in the evidentiary record as Hearing Exhibit 104 (specifically Attachment DAB-14 to the Rebuttal Testimony of Public Service witness Deborah Blair). Public Service explained approximately 22 changes to the cost of service model caused by the Commission's oral deliberations. Public Service filed its updated cost of service study immediately prior to the start of the Technical Conference on December 16, 2019.

375. As explained above, Public Service proposed a base rate revenue increase net of the rider roll-ins of $108.3 million in its Rebuttal Testimony.[116] At the Technical Conference, Public Service demonstrated that the Commission's oral decisions reduced the proposed base rate revenue increase by $66.8 million, for a net increase of $41.5 million. Whereas Public Service supported a revenue deficiency of $353.3 million in its Rebuttal Testimony, the Commission established a base rate revenue deficiency of $286.4 million based on its oral deliberations.[117]

376. Public Service also presented updated bill impacts corresponding to the base rate increase caused by the Commission's oral deliberations on December 11, 2019 implemented pursuant to the GRSAs as described in this Decision. For residential customers, the total bill impact on annualized rates is 1.53 percent, or a monthly bill increase of approximately $1.03.[118] This compares to the $3.07 monthly increase for residential customers corresponding to the cost of service study and GRSA proposals in the Company's Rebuttal Testimony.[119] For small commercial customers, the total bill impact on annualized rates from the updated cost of service study presented at the Technical Conference would be 1.95 percent, or a monthly bill increase of approximately $1.95. This compares to the $4.87 monthly increase for small commercial customers as proposed in the Company's Rebuttal Testimony.

E. Compliance Procedures

377. We direct Public Service to file an advice letter compliance filing to modify the tariff sheets in Colorado PUC No. 8 consistent with the findings, conclusions, and directives in this Decision.

[116] Hearing Exhibit 104, Blair Rebuttal, p. 13.
[117] Updated Attachment DAB-14 Technical Conference filed by Public Service on December 16, 2019.
[118] Bill Impacts Technical Conference filed by Public Service on December 16, 2019.
[119] Jackson Rebuttal, p. 106.

378. Public Service shall include in the compliance advice letter filing a modified Sheet No. 132 setting for the GRSA and GRSA-E calculated as directed by this Decision and consistent with the Company's presentation at the December 16, 2019 Technical Conference. Public Service shall also include modified tariff sheets for the TCA, ECA, and CACJA Rider consistent with the roll-in amounts authorized by this Decision, any other modifications to these tariff sheets approved by this Decision (*e.g.*, the modification to the ECA to allow cost recovery of the Cheyenne Ridge Project), and the ongoing implementation of the rider upon the effective date of the modified tariff (*e.g.*, updated revenue requirement calculations for the recovery of incremental transmission investment costs through the TCA relative to a modified base rate recovery level).

379. Because an updated cost of service study was presented in detail at the December 16, 2019 Technical Conference, and because many of the other proposed changes to Colorado PUC No. 8 were uncontested during the period in which the effective date of the modified tariff sheets was suspended, we authorize Public Service to file the advice letter compliance filing on not less than two business days' notice.

F. Phase II Rate Case Filing

380. Through Rebuttal Testimony, Public Service states that it is willing to file a Phase II rate design case or combined Phase I and Phase II rate case no later than August 1, 2020.

381. Staff argues the Commission instead should require Public Service to file a Phase II rate proceeding within 60 days of the issuance of the final order in this Proceeding to cause any GRSA or GRSA-E to be eliminated as quickly as possible.

382. The OCC similarly argues that Public Service should be directed to file a Phase II rate case within 60 days of a final order in this Proceeding. The OCC states that the filing of a combined Phase I and II case on August 1, 2020 would result in rates for effect as late as April 2021. The OCC argues that this result is unacceptable, because it would prevent ratepayers from having a Phase II rate case completed within a reasonable period of time after this Phase I rate case.

383. In its SOP, DOE recommends the Commission direct Public Service to file by May 1, 2020, either a Phase II rate case or a notice with the Company's binding commitment to file a combined Phase I and Phase II case by August 1, 2020.

384. We find DOE's proposal to be reasonable. Public Service shall file by May 1, 2020 either a Phase II electric rate case in a new advice letter proceeding or a notice in this Proceeding of its binding commitment to file a combined Phase I and Phase II electric rate case by August 1, 2020.

XI. ORDER

A. The Commission Orders That:

1. The effective date of the tariff sheets filed by Public Service Company of Colorado (Public Service) on May 20, 2019 with Advice Letter No. 1797 is permanently suspended and shall not be further amended.

2. The tariff sheets filed with Advice Letter No. 1797 are permanently suspended and shall not be further amended.

3. The Unopposed Joint Motion to Approve Partial Settlement Agreement filed by Public Service on November 1, 2019 intended to resolve, as between the parties joining in the

agreement, all issues that have been raised or could have been raised in this Proceeding with respect to wildfire mitigation is granted, consistent with the discussion above.

4. The Motion for Rates Effective January 1, 2020 contained in the Omnibus Motion filed by Public Service on May 20, 2019, is denied, consistent with the discussion above.

5. Public Service shall file an advice letter compliance filing to modify the tariff sheets in Colorado PUC No. 8 consistent with the findings, conclusions, and directives in this Decision. Public Service shall file the compliance tariff sheets in a separate proceeding and on not less than two business days' notice. The advice letter and tariff sheets shall be filed as a new advice letter proceeding and shall comply will all applicable rules. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date. The advice letter and tariff must comply in all substantive respects to this Decision in order to be filed as a compliance filing on shortened notice.

6. Public Service shall make a compliance tariff filing to implement the Revenue Decoupling Adjustment (RDA) as directed by the Commission in Proceeding No. 16A-0546E no later than 30 days following the compliance tariff filing submitted to implement final rates in this Proceeding. The compliance filing for the RDA shall be filed as a new advice letter proceeding on not less than 14 days' notice and shall comply will all applicable rules. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date.

7. No later than 60 days after the Mailed Date of this Decision, Public Service shall file a notice in this Proceeding to report to the Commission on whether it has reached consensus

with interested stakeholders on a modified Certified Renewable Percentage, consistent with the discussion above.

8. Consistent with the discussion above, Public Service shall file by May 1, 2020 either a Phase II electric rate case as a new advice letter proceeding or a notice in this Proceeding of its binding commitment to file a combined Phase I and Phase II electric rate case by August 1, 2020.

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

10. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS AND WEEKLY MEETINGS
December 11, 2019 and December 17, 2019.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

JOHN GAVAN

Commissioners

ATTEST: A TRUE COPY

Doug Dean,
Director

COMMISSIONER FRANCES A. KONCILJA
PARTIALLY DISSENTING AND SPECIALLY
CONCURRING WITH CERTAIN DECISIONS.

XII. COMMISSIONER FRANCES A. KONCILJA PARTIALLY DISSENTING AND SPECIALLY CONCURRING WITH CERTAIN DECISIONS

1. I respectfully dissent from the position of the majority with respect to the current test year (CTY), the rate of return on equity (ROE) as well as the decision to disallow interest, fees, and penalties on disputed tax payments to state and local taxing authorities. I also write this special concurrence with respect to the unanimous decision to reject certain positions of Sierra Club, Leslie Glustrom, and the Office of Consumer Counsel (OCC).

2. I fear that the majority decision to reduce the ROE from its current 9.83 to 9.3 is incorrect, not supported by the record, and changes the Public Utilities Commission (Commission or PUC) policy of incrementalism or gradualism with no public discussion and little to no explanation. Further, the decision sends the wrong message to Public Service Company of Colorado (Public Service, Company, or PSCO), the rating agencies and the capital markets, and will likely undercut the efforts of Public Service to support the clean energy goals of Colorado. In the past, this Commission has followed the policy of "incrementalism" or "gradualism"—meaning we raise and lower rates in small steps to minimize the risk that we got it wrong and to minimize the shock to the rating agencies. The majority provided no information at the deliberations meeting as to why they were not following this policy. I have no problem with change, but the change should be thoughtful and discussed in public so that the participants in these rate cases, as well as the public, understand and can take into account the thinking and philosophy of the bench and present testimony and argument in response.

3. The CTY as adopted by the majority, was done during the deliberations, has little to no support in the record, was not vetted by the parties, and will likely have unintended

consequences, some of which were made clear in the Technical Conference. Decisions as to test years are complicated matters and should not be developed on the fly.

4. As I stated at the deliberations meeting, the various models presented by the parties—Discounted Cash Flow (DCM), single and multi-stage DCM, Capital Asset Pricing, and Risk Premium, are tools for this Commission to use in determining the ROE. These models resulted in this case in a huge range of recommendations. (*See* Summary at p. 18, Table AEB-R-1 of rebuttal testimony of Public Service witness Anne E. Bulkley). Ms. Bulkley testified that an authorized ROE of 8.8 percent to 9.2 percent would place the return for Public Service in the bottom decile of allowed ROEs for integrated electric utilities since 2017. If PSCO must compete nationally for investors and if those investors can get a higher rate-of-return in other states, it is likely that PSCO will have a harder time attracting investment. Is this the message that the Colorado PUC wants to send? There should have been discussion and consideration of these issues at the deliberations. There was none.

5. There seemed to be no awareness by the majority that even with an ROE of 9.83, the current ROE, that PSCO had under earned for the last two years. (*See* page 89 of Bulkley rebuttal.) Certainly this merited discussion, but there was none. Instead, the majority focuses on the share price of Public Service, earnings per share and dividends. However, there was no discussion at the deliberations and no questions asked of the various witnesses as to the relationship of the under earning, to these metrics and how the Commission should consider dividends and share prices in setting rates.

6. None of the Commissioners, myself included, asked any questions of Ms. Bulkley. Many of the witnesses on ROE were sandwiched into the fifth day of testimony,

Friday, November 8, 2019. Thus the hearing was managed in such a way that the most important witnesses were given the least amount of time and attention by the Commissioners.

7. I believe that the decision of the majority as to the test year is also flawed. The ongoing dispute over test year is whether or not the utility can use a future test year to estimate revenues and expenses. We have seen this dispute play out again and again. The company asks for a future test year, there is suspicion that the company is not accurately projecting costs and revenues and so this Commission has rejected those attempts. In a recent case, the Chair suggested that the parties look at a different approach. That is exactly what PSCO and Commission Trial Staff (Trial Staff) did—Trial Staff suggested a compromise using a CTY. As set forth on pages 16 and 17 of O'Neill Answer Testimony, PSCO agreed with that approach in its rebuttal case, but modified some calculations. The majority in this Decision, creates a variation of the CTY with I believe, little to no factual basis and understanding of the effect of this new approach. One only has to look at the results of the Technical Conference to see some of the flaws

8. The OCC, at pages 23 and 24 of their SOP argued for 10 years of weather normalization (WN), as opposed to 30 years. The OCC concluded that using ten years of WN would lower the revenue requirement and thus save ratepayers money. At the Technical Conference, using the August CTY as developed by the majority and the 10 years as requested by the OCC, resulted in a material increase to rate base of $12.42 million, not a reduction. It would appear that either the OCC was mistaken in its analysis of the use of the shorter period for WN or the months used, CTY negates the savings and instead will cost ratepayers over $12.42 million.

9. The decision as to test year is highly complex and technical. The parties have available to them the models used by PSCO. The Commission and its Advisors do not have access to these models unless they are filed publicly in the case as opposed to being provided in discovery. I can find no indication in the public filings that the model was available to the Commission or to its Advisors. I believe that this approach that the Commission creates a new test year that was not vetted or agreed to by the parties and not based on the technical modeling tools is subject to appeal and reversal in the district court as being arbitrary and capricious. I am hopeful that although Trial Staff rarely files requests to reconsider of Commission decisions, that trial staff will, in these unique circumstances, analyze and, if necessary, critique the CTY as adopted by the majority.

10. I believe that the majority decision almost guarantees that Public Service will file another rate case this year, with all of the associated costs and allocations of resources—costs that ratepayers ultimately pay. One of the goals of a rate case should be to make decisions that incentivize and disincentive the Company from filing serial rate cases

11. Several parties during the course of this rate case distracted the Commission from the important issues by raising issues that had no basis in fact or law and were, in my opinion, frivolous. Requiring PSCO and this Commission to deal with these types of issues in a rate case, makes the rate case more expensive and results in less time being spent on the important issues—namely the test year and the ROE. Sierra Club and Mrs. Leslie Glustrom have been important advocates in the State of Colorado for reducing carbon emissions. However, their goals in this rate case seems to have been to second guess decisions and or settlements made years ago and or statutory changes made years ago, such as Clean Air Clean Jobs, to starve the operation of the generation facilities that use coal and other fossil fuels and to punish Public Service for building

these facilities by requesting that the Commission order a lower rate-of-return for these investments.

12. They attempted this with no legal basis, few facts, sometimes outrageously incorrect facts, and no expert testimony that reducing maintenance of the coal and natural gas facilities would still result in safe operations. Put another way, some of the intervenors were willing to put the health and safety of workers and the surrounding communities at risk in an effort to starve and close down these fossil fuel plants. Efficiency of the plants and operating reserves are relevant in resource planning and should include expert testimony from engineers as to safety and reliability but in resource planning proceedings.

13. Mrs. Glustrom, is one of the most committed and dedicated private citizens on the issue of climate change that I have been privileged to meet. She does this with no pay, only out of love and commitment to the issues of climate change. As I have said before, she is, at times, better and more articulate than some of the lawyers who appear before the Commission. However, the continual attacks on recovery for Comanche 3 have no basis in fact or law.

14. Comanche 3 was built by Public Service pursuant to a 109-page Comprehensive Settlement Agreement entered into in 2004 by numerous parties, including the Colorado Governor's Office of Energy Management and Conservation, Western Resource Advocates, the Colorado Coalition for New Energy Technologies, Southwest Energy Efficiency Project, Environment Colorado, Colorado Renewable Energy Society, the City and County of Denver (Denver) and Tri-State Generation and Transmission Association, Inc. It was approved on January 21, 2005 by the Commission through a 65-page Decision (which included a dissent by then Chairman Gregory Sopkin) –Decision No. C05-0049 in Proceeding No. 04A-214E. In summary, just about every environmental group in existence in the State of Colorado in 2004

approved the building of Comanche 3. Simply put, there is no legal basis to undo it at this time and no legal basis to punish financially Public Service for building Comanche 3 which is what Mrs. Glustrom asks us to order. These decisions were made years ago and asking the Commission to revisit them, with no legal basis, is a waste of everyone's time, including Mrs. Glustrom.

15. The advocacy of Sierra Club through its witness Paul Chernick is similarly flawed. As the Decision explains at the section titled "SCR at Craig Unit 2," the installation of scrubbers at Craig was done pursuant to a multi-party, multi-agency agreement that reduced NOx emissions three times more than was required. To now ask that this Commission punish Public Service for incurring these costs is quite frankly outrageous. Simply put, Mr. Chernick did next to no factual or legal research on these issues, but decided to throw it all against the wall to see what stuck.

16. On the morning of our deliberations, we affirmed a decision that the Commission had made admonishing an attorney in a transportation case for presenting an incomplete exhibit. I agreed with that decision. I suggested that we should also admonish these intervenors for doing something similar. The Commission should insist upon responsible fact based analysis from parties and intervenors. This standard should not change depending on who the party or intervenor is. Once the Commission allows parties to present shoddy evaluations and requests, we lose credibility and other parties will try the same thing. Requests must be fact based and legal based.

17. Section 40-6-112(2), C.R.S., and the cases decided pursuant to that statute make clear that collateral attacks of Commission decisions are prohibited.

18. The OCC and its advocacy is very important in these rate cases. By law, OCC has a statutory right of intervention. Reluctant as I am to criticize, much of the advocacy of the OCC in this case was not production and in fact, was a distraction, with positions that were legally and or factually incorrect and served only to increase the costs of this rate case. While the Decision deals with rate case expenses and pension benefits, I believe additional information is appropriate.

19. OCC witness Fernandez spent almost 100 pages of his testimony challenging the inclusion of costs for the legacy pension benefit for the members of the International Brotherhood of Electrical Workers, Local 111 (IBEW) with absolutely no evidence that this negotiated benefit for the lineman was excessive. Mr. Fernandez spent pages lamenting that bankruptcies of large companies had been caused by defined benefit pension plans, complaining the state employees no longer received defined benefit pension plans, referred to the defined benefit plans of the IBEW as "gold plated"—and using similar purple prose. At the hearing, he took the incredible position that even if the Commission rejected these costs in rate base, he was not arguing to terminate these benefits for the electricians, because the shareholders might bear the cost. Mr. Fernandez ignored or did not read the company testimony as to who was actually covered by these costs, instead asserting that highly compensated individuals were covered by this plan.

20 Of course, the fundamental question was and is—are these benefits excessive? The IBEW presented its witness, Mr. Meisinger, business Manager for the IBEW, who testified that this benefit had been bargained for in the collective bargaining agreement that new employees were not provided similar benefits, and the labor mediator actually issued a finding that the total benefits package questioned by the OCC and Mr. Fernandez was not excessive.

Even after having access to Mr. Meisinger's cross-answer testimony, the OCC did not modify its position or withdraw its flawed conclusions. Instead the IBEW was required to spend over $50,000 in this rate case and Mr. Meisinger had to wait five days to present his testimony, five days he would rather have spent working for his union members. Mr. Meisinger testified that the OCC's position was more hostile to the union and its members than Public Service had been during the labor negotiations. Certainly OCC can do better than this. The irony is that submitting over 100 pages of irrelevant and incorrect argument makes a rate case more expensive because the Company and the Commission must analyze these flights of fancy.

21. Another OCC witness, Mr. Neil, presented testimony that was incorrect as a matter of law. Even after having the opportunity to review the answer testimony of Keith Hay of the Colorado Energy Office, and Jonathon Rogers of Denver (Denver requested that the Commission admonish OCC witness Neil), Mr. Neil and the OCC did not withdraw his testimony. Instead Mr. Neil came up, at the hearing, with one of the most tortured definitions or use of a little four-letter word—the preposition "with" that would have had my third grade teacher, Sister David Anthony, pulling out the ruler. According to Mr. Neil, his statement that the Commission should order "with" followed by conditions does not really mean "accompanied by" or "possessing the feature". Instead it means—I still have no idea what.

22. In his answer testimony, Mr. Neil recommended that the Commission require PSCO to sell Renewable Energy Certificates (RECs) in the wholesale market before RECs can be allocated to the Certified Renewable Percentage before retiring RECs and for the Company to sell RECs directly to retail customers. As pointed out by Mr. Keith Hay in the Cross-Answer Testimony of the Colorado Energy Office (*See* pages 10 to 13), REC sales are voluntary and thus any savings are speculative; the proposal of the OCC is inconsistent with Commission

Rules 3659(c), 3654, 3655, and 3661, 4 *Code of Colorado Regulations* 723-3, as well as § 40-2-124(d), C.R.S. The recommendation of the OCC is inconsistent with the public policy of the State of Colorado which allows for the banking of RECs for compliance with potential federal greenhouse reduction or renewable energy standards. Jonathon Rogers, the renewable Energy Specialist for the City and County of Denver, agreed at page 11 of the cross-answer testimony that Mr. Neil's testimony should be rebuked.

23. The OCC, through witness Skluzak, challenged and requested that the Commission disallow almost all of the rate case expenses. It is in the public interest to question rate case expenses. However, Mr. Skluzak did not attempt to answer the fundamental question—why are the cases getting more expensive? Is it because the Company is profligate? Is it because the issues are more complicated? Is it because the Commission is allowing more interventions and so there are more parties? PSCO witness Jackson testified in rebuttal that there were over 14 parties, 29 witnesses, and numerous discovery requests. (I would note that some of the discovery requests that I reviewed, such as one submitted to IBEW, were way far out there and in my opinion, not calculated to leave to the discovery of admissible evidence.) Instead, Mr. Skluzak presented almost 100 pages of testimony and numerous exhibits that did not deal with these ultimate questions. Submission of a large compilation of rate case expenses from the 2010 time period from other states, has little to no probative value and in fact, is a waste of everyone's time.

24. The Commission and the Company were left with this Alice down the rabbit hole experience of the OCC questioning the amount of time that PSCO, its attorneys, and its witnesses spent on this case, while at the same time OCC was submitting hundreds of pages of irrelevant and or incorrect testimony and then asking that the Company receive almost no

recovery for rate case expenses. A focus by OCC on duplication of efforts, and or testimony, quantification of the amount of time spent on discovery would have been helpful. Trial Staff did that and the Commission, as a result, rejected some of the rate case expenses.

25. I make several suggestions for the Commissioners to consider in the future when it hears rate cases *en banc*. First, return to the policy of denying most permissive interventions and support the Administrative Law Judges when they deny the types of interventions that were a distraction in this case. Second, group together all ROE witnesses and then all Test Year witnesses—allowing PSCO to first present its policy witness, then its ROE witness, followed by the ROE witnesses from other parties, and then allow the Company a rebuttal. Handle the test year witnesses in the same fashion. While this may create some logistical problems for some witnesses, I think it would work better for the Commission and would ensure that the bulk of time is spent on the major issues, saving the smaller issues for the last days of hearings and or Fridays, when everyone wants to leave town.

26. In summary, the decision of the majority setting an ROE of 9.3 (lower than any utility we regulate, including Black Hills Colorado Electric, LLC) fails to take into account the leadership of PSCO in Colorado and nationally in advancing clean energy goals, and fails to take into account that PSCO has kept customer rates in Colorado in the 50th percentile. The majority also fails to take into account the substantial movement by PSCO in its rebuttal case—agreeing with Staff to use a 13-month average test year, agreeing to include the lower interest rates for short term debt in the debt calculation, and using the CTY as proposed by Staff which reduced the revenue request by over $50 million. Instead, the message to PSCO is to agree to no reduction in your rebuttal case, and litigate everything in Denver District Court. In my opinion, these are not productive messages to give to PSCO or any regulated utility and are counter-

productive to the public interest and public benefit in having the largest investor-owned utility in Colorado embrace the clean energy goals of the state and the nation.

27. Rate cases of this magnitude are difficult to manage and to decide. As the result of the Open Meetings Law of Colorado and the fact that we have only three commissioners, our opportunities to discuss issues of great import to Colorado citizens is limited to our interaction on the bench. It is, at times, awkward and humbling to have public discussions about these technical financial and operating issues. I value the opportunity to hear and discuss these matters with my fellow commissioners and wish that there had been greater opportunity to try and resolve these issues on a unanimous basis. However, I must respectfully issue this partial dissent.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

FRANCES A. KONCILJA

Commissioner