Decision No. C22-0642

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 22AL-0046G

IN THE MATTER OF ADVICE LETTER NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES TO BECOME EFFECTIVE FEBRUARY 24, 2022.

DECISION PERMANENTLY SUSPENDING TARIFF SHEETS, ESTABLISHING RATES AND REQUIRING FILINGS

Mailed Date: October 25, 2022
Adopted Dates: September 28 and 30, 2022
October 5 and 19, 2022

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I. BY THE COMMISSION

A. Statement

1. This Decision establishes new base rates for utility natural gas service provided by Public Service Company of Colorado (Public Service or Company).

2. To achieve this purpose, we permanently suspend the effective date of the tariff sheets for rates filed by the Company with Advice Letter No. 993-Gas on January 24, 2022. Public Service shall instead implement base rates determined in accordance with this Decision for effect

November 1, 2022. We accordingly direct Public Service to make a compliance tariff filing to implement these authorized base rates and also to modify the tariff sheets laying out the terms and conditions for utility gas service consistent with this Decision.

B. Procedural Background

3. On January 24, 2022, Public Service filed Advice Letter No. 993-Gas with supporting attachments and pre-filed testimony of 23 witnesses as a combined Phase I and Phase II rate proceeding. The proposed effective date of the tariffs filed with Advice Letter No. 993-Gas is February 24, 2022.

4. Public Service initially sought a total increase in its base rate revenues of approximately $214.6 million, based on a 2022 current test year (CTY). However, approximately $107.5 million of that amount was the result of transferring the General Rate Schedule Adjustment – Pipeline System Integrity Adjustment (GRSA-P) into base rates. The Company also sought to increase annual revenues to account for “capital step increases” of approximately $40 million in 2023 and $41 million in 2024.

5. The proposed increase in base rate revenues was supported by Public Service’s Phase I cost-of-service study (COSS) that generates a total annual base rate revenue requirement of $825 million, an increase of some $233 million over the base rate revenue requirement authorized in its most recent Phase I rate case, the 2020 Phase I rate case.[1]

6. Public Service states that the main driver of the requested increase in base rate revenue is annual capital spending of approximately $400 million to $450 million per year for safety, reliability, new business, and mandatory relocations. The Company states that its current

[1] *See* Proceeding No. 20AL-0049G.

rates reflect investment levels from September 2019 and that over three years will pass by the time new rates from this Proceeding take effect

7. Public Service initially calculated its proposed revenue requirement on a proposed return on equity (ROE) of 10.25 percent, a cost of long-term debt of 3.73 percent, a short-term cost of debt of 0.79 percent, and a capital structure composed of 55.66 percent equity, 43.13 percent long-term cost of debt, and 1.21 percent short-term debt. These financing components were combined into an overall weighted average cost of capital (WACC) of 7.33 percent.

8. The average monthly bill impacts of Public Service's proposed rate increase from 2022 to 2024 are an increase of $8.13 (13.0 percent) for Residential customers and $34.76 (13.8 percent) for Small Commercial customers.

9. Public Service's Advice Letter No. 993-Gas also proposes new cost allocations across customer classes and modified designs for the Company's base rates. This "Phase II component" of the rate case follows the terms of a settlement agreement reached in Proceeding No. 19AL-0309G, the Company's 2019 rate case (2019 Rate Case), where, as part of that agreement, the parties engaged in a stakeholder process to examine several cost allocation and rate design issues related to service the Company provides to other Colorado gas utilities.

10. The rate case filing also causes an examination of the allocation of the PSIA-related costs across customer classes. Public Service states if the PSIA costs were allocated in the same manner as other transmission and distribution main investments, residential and small commercial customers would experience a relatively larger share of total cost responsibility. The Company instead proposes to maintain consistency with how PSIA costs were allocated in the PSIA rider that was terminated in an earlier proceeding.

11. In addition to revising base rate revenue for all natural gas sales and transportation services, Advice Letter No. 993-Gas seeks approval of: line extension policies; a revenue decoupling mechanism; modified depreciation rates; modified Gas Transportation Terms and Conditions; and an extension of the Company's Quality of Service Plan (QSP) through 2024.

12. On February 11, 2022, by Decision No. C22-0091, the Commission set for hearing the tariffs filed with Advice Letter No. 993-Gas and suspended their effective date for 120 days, to June 24, 2022, pursuant to § 40-6-111(1), C.R.S.

13. By Decision No. C22-0232-I, issued on April 15, 2022, 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 the Utility Consumer Advocate (UCA); A M Gas Transfer Corporation (AM Gas); Atmos Energy Corporation (Atmos); Black Hills Colorado Gas, Inc. (Black Hills); Climax Molybdenum Company (Climax); Colorado Natural Gas, Inc. (CNG); Energy Outreach Colorado (EOC); the Federal Executive Agencies (FEA); International Brotherhood of Electrical Workers, Local #111 (IBEW); Onward Energy Management, LLC (Onward Energy); Tiger Natural Gas, Inc. (Tiger); WoodRiver Energy, LLC (WoodRiver); and Western Resources Advocates (WRA), Natural Resources Defense Council (NRDC), and Southwest Energy Efficiency Project (SWEEP) (collectively, Conservation Advocates). By Decision No. C22-0299, United Energy Trading, LLC (UET) was granted intervention.

14. In addition, through Decision No. C22-0232-I, the Commission directed Company to file Supplemental Direct Testimony addressing the Company's credit ratings and financial integrity, capital additions related to new customer demand and system growth, and customer-owned yard lines (COYLs). The Company was also directed to update its 15-year rate

forecast. The Commission also requested that parties address line extensions and depreciation rates through testimony.

15. By Decision No. C22-0232-I, the Commission referred discovery disputes and motions for extraordinary protection of information claimed to be highly confidential to an Administrative Law Judge for resolution.[2]

16. Through Decision No. C22-0275-I, issued on May 4, 2022 we provided clarification of the Supplemental Direct Testimony ordered in Decision No. C22-0232-I.

17. On April 20, 2022, by Decision No. C22-0247, 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 April 18, 2022. Decision No. C22-0247 also established the dates for the evidentiary hearing from August 17 through 19, August 22 through 26, and August 29 through 31, 2022, 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. 993-Gas an additional 130 days pursuant to § 40-6-111(1), C.R.S. The proposed effective date the tariff pages was suspended until November 1, 2022.

18. On April 14, 2022, UCA filed a Motion to Sever, requesting a Commission decision severing the request by Public Service to implement a revenue decoupling adjustment (RDA) mechanism for its Residential and Small Commercial customer classes in this Proceeding. UCA

[2] On July 26 and July 27, 2022, Tiger filed three Motions to Compel Public Service's Discovery Responses (Tiger's Motions to Compel). On July 27, 2022, Tiger filed a Motion for Sanctions. On August 9, 2022, Tiger filed a Motion to Submit Reply Briefs in Support of Motion to Compel Re: "In Path" Requirement and in Support of Motion for Sanctions (Motion to Submit Reply Briefs). By Decision No. R22-0481-I, Tiger's Motions to Compel were granted in part, and denied in part, and Tiger's Motion for Sanctions and Motion to Submit Reply Briefs were denied.

argued that the request for the RDA is untimely because the Commission has not yet completed the rulemaking in Proceeding No. 21R-0449G (Gas Rulemaking Proceeding) and that a Demand Side Management Strategic Issues (DSM SI) proceeding is a prerequisite of the Commission's decision on a gas revenue decoupling mechanism. Atmos and Public Service filed responses on April 28, 2022, arguing for denial of UCA's Motion to Sever.

19. By Decision No. C22-0299, issued on May 17, 2022, UCA's Motion to Sever was denied.

20. On May 31, 2022, Staff filed a Motion to Extend Deadlines to Submit Answer Testimony, Rebuttal Testimony, and Cross Answer Testimony by One Week (Motion to Extend). Staff indicated the Public Service's calendar year historical test year was received on May 19, 2022 and the accompanying class cost-of-service study (CCOSS) was received on May 23, 2022 and required additional time for analysis prior to filing Answer Testimony.

21. On June 6, 2022, Public Service filed a response to the Motion to Extend arguing that Staff had not adequately justified its request.

22. By Decision No. C22-0351, issued on June 8, 2022, Staff's Motion to extend was denied.

23. In accordance with the procedural scheduled established by Decision No. C22-0247, Answer Testimony was filed by Staff, UCA, Atmos, AM Gas, Conservation Advocates, FEA, Tiger, and WoodRiver on or before June 15, 2022.

24. On June 30, 2022, by Decision No. C22-0394, the Commission scheduled a hearing on August 18, 2022 for the purpose of taking comment from members of the public.

25. Public Service filed Rebuttal Testimony on July 13, 2022. Public Service presented a recalculation of its proposed base rate revenue increase, lowering it from approximately $214.6 million in the Advice Letter No. 993-Gas filing to approximately $202 million.

26. UCA, Atmos, and Conservation Advocates filed Cross-Answer Testimony, and Tiger filed “Supplemental Answer Testimony” on July 13, 2022.

27. On July 27, 2022, the deadline for the filing of prehearing motions, Staff filed a Motion to Strike Portions of the Rebuttal Testimony of Stephen G. Martz (Staff’s Motion to Strike). Public Service also filed a Motion to Strike Certain Attachments and Intervenor Testimony (Company’s Motion to Strike). Public Service requested that the Commission strike portions of the Answer Testimony of Staff witness David Pitts, UCA witnesses Cory Skluzak and Joseph Periera, Conservation Advocates witnesses Dylan Sullivan and Meera Fickling, and Atmos witness Paul Raab. The Company also sought to exclude the Supplemental Answer Testimony of Tiger witness Kenneth Thomson.

28. On August 4, 2022, UCA filed a Response to the Company’s Motion to Strike.

29. On August 5, 2022, Staff, Atmos, Conservation Advocates, and Tiger filed responses to the Company’s Motion to Strike, and the Company filed a Response to Staff’s Motion to Strike.

30. By Decision No. C22-0456-I, issued on August 12, 2022, the Commission denied Staff’s Motion to Strike and granted, in part, and denied, in part, Public Service’s Motion to Strike. The Commission further granted UCA’s request to use certain confidential information in this Proceeding from Public Service’s Storm Uri cost recovery proceeding, Proceeding No. 21A-0192EG.

31. The Commission held the evidentiary hearing *en banc* from August 17 through 29, 2022.

32. On August 18, 2022, the Commission held a remote hearing to accept public comments as scheduled by Decision No. C22-0394.

33. Post-hearing statements of position (SOPs) were filed on or around September 14, 2022, by Public Service, Staff, UCA, AM Gas, Atmos, Conservation Advocates, Climax, FEA, Onward Energy, Tiger, UET, and WoodRiver.

34. The Commission initiated its deliberations adopting this Decision at the special Commissioners' Deliberations Meetings on September 28 and 30, 2022.

35. By Decision No. C22-0593-I, issued on September 30, 2022, the Commission scheduled a technical conference on October 7, 2022. Public Service was further directed to update its COSS and CCOSS and to design new base rates to replace those on the tariff sheets filed with Advice Letter No. 993-Gas based on oral deliberations on September 28 and 30, 2022 and to file the updated COSS, CCOSS, and proposed rate by October 6, 2022.

36. At the technical conference on October 7, 2022, Public Service presented modifications to its COSS and CCOSS to reflect the oral decisions the Commission made during its deliberations on September 28 and 30, 2022. The Company also presented base rate values for each of its customer classes based on the modified COSS and CCOSS.

37. The Commission concluded its deliberations to adopt this Decision at the Commissioners' Weekly Meetings on October 5 and 19, 2022. The Commission reviewed the results of the October 7, 2022 Technical Conference as part of those deliberations.

C. Evidentiary Record

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

39. During the course of the evidentiary hearing, Hearing Exhibits 1800, 130, Rev.1, 130, Attachment RSK-2, Rev. 1, 137-HC, Rev.1, 137, Rev.1, 151, 156, 157, 172, 174, 177, 180, 190, 191, 192, 200, 201, 202, 203, 204, 250, 251, 252, 306, 307, 308, 310, 311, 314, 315, 316, 318, 319, 320, 321, 328, 328-HC, 329, 329-HC, 330-HC, 332, 334-HC, 336, 337, 338, 339, 340, 341, 342, 343, 344, 346, 347, 348, 349, 350, 351, 352, 353, 354, 355, 356, 357, 358, 359, 360, 361, 362, 363, 403, 405, 603-Corrected, 607, Rev.1, 612, 613, 619, 620, 621, 626, 627, 628, 629, 634, 635, 636, 637, 638, 644, 646, 648, 655, 657, 702, 703, 1000, Rev.1, 1031, 1062, 1084, 1088, 1089, 1090, 1091, 1208, 1209, 1210, 1211, 1703, 1704, 2038-HC, 2039-HC, 2047, 20148-HC, 2049, 2050, and 2053 were offered and admitted into evidence. Administrative notice was taken of documents marked as Hearing Exhibits 170, 171, 322, 323, 404, 406, 501, 610, 611, 1206, 1207, 1212, and 1501.

D. Updated Cost of Service Models and Technical Conference

40. The updated cost of service studies, rates, and bill impacts filed by Public Service on October 6, 2022 and presented by the Company at the October 7, 2022 Technical Conference lead us to conclude that the base rates established by this Decision will: (1) be sufficient to ensure safe and reliable service to Public Service's gas customers; (2) allow Public Service to secure adequate financing at a reasonable cost and to provide the Company with a reasonable opportunity to earn a return commensurate with the returns of other enterprises of comparable risk ; and (3) are just and reasonable and non-discriminatory.

41. Public Service proposed a base rate revenue increase of approximately $202 million in its Rebuttal Testimony. At the Technical Conference, Public Service demonstrated that the Commission's oral decisions reduced the base rate revenue increase by $33.7 million. When adjusting these amounts to account for the roll-in of costs recovered through the Company's PSIA, the result of the Commission's oral deliberations would be a net increase in base rate revenue of $64.2 million.

42. Whereas the base rate values on the tariff sheets Public Service filed with Advice Letter No. 993-Gas reflect a net increase of $107.1 million, the base rate values the Company filed on October 6, 2022 and presented at the Technical Conference correspond to the recalculated net increase of $64.2 million.

43. Public Service filed and presented updated bill impacts corresponding to the recalculated base rates increase caused by the Commission's oral deliberations. For residential customers, the total bill impact on annualized rates corresponding to the $64.2 million increase in base rate revenues is 2.9 percent, or a monthly bill increase of approximately $2.09. This compares to the $4.16 monthly increase for residential customers shown in Advice Letter No. 993-Gas. For small commercial customers, the total bill impact on annualized rates from the updated cost of service studies presented at the Technical Conference would be 3.1 percent, or a monthly bill increase of approximately $12.95. This compares to the $19.09 monthly increase for small commercial customers shown in Advice Letter No. 993-Gas.

44. The Commission discussed the information filed on October 6, 2022 and presented by Public Service at the October 7, 2022 technical conference in its deliberations on October 19, 2022.

II. LEGAL FOUNDATION AND BURDENS OF PROOF

A. Burden of Proof and Burden of Going Forward

45. 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.[3] 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."[4] The preponderance standard requires the finder of fact to determine whether the existence of a contested fact is more probable than its non-existence.[5] A party has met this burden of proof when the evidence, on the whole and however slightly, tips in favor of that party.

46. 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 evidence as a whole" and "need not base its decision on specific empirical support in the form of a study or data."[6]

47. Because the Commission has an independent duty to determine matters that are within the public interest,[7] the Commission is not bound by the proposals of the parties. The

[3] § 24-4-107(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500 of the Commission's Rules of Practice and Procedure, 4 *Code of Colorado Regulations* (CCR) 723-1.

[4] *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)).

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

[6] *Colorado Office of Consumer Counsel v. Pub. Utils. Comm'n.*, 275 P.3d 656, 660 (Colo. 2012).660.

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

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.[8]

B. Commission Jurisdiction

48. 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.[9] 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, 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.

49. 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.[10]

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[8] *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).

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

[10] *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).

50. 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 ratemaking, both as to charge and design, is a vital part of the Commission's area of responsibility."[12]

51. 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, 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

[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).

[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 at 939.

rate-of-return is not a guaranteed return, but instead, is a return that the utility has a reasonable opportunity to realize.

52. As explained in greater detail below, the Commission establishes rates in consideration of the utility's annual revenue requirements as calculated by over a Commission-selected test year. The revenue requirement is the total revenues sought 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.[19]

53. 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 the [Commission] unless they are inherently unsound."[20] 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."[21]

54. Furthermore, 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."[22]

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

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

21 CF&I Steel, 949 P.2d at 584; *Glustrom v. Colorado Public Utilities Commission*, 280 P.3d 662, 669 (Colo. 2012)..

22*Glustrom*, 280 P.3d at 669.

III. ESTABLISHMENT OF BASE RATES

55. The establishment of just and reasonable rates involves a balancing of investor and consumer interests.[23] The Commission must 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.[24]

56. As regards to 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.[25] The Commission must ensure that the utility has adequate revenues for operating expenses and to cover the capital costs of doing business.[26] The revenues must be sufficient to assure confidence in the financial integrity of the utility, in order to maintain its credit and attract capital.[27]

57. As regards to ratepayers, the Commission is charged with protecting the interest of the general public from excessive, burdensome rates.[28] The Commission must determine that every rate is just and reasonable and that services provided "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.[29]

58. The Commission has established regulatory principles and methods to determine a utility's revenue requirement and to establish rates at levels necessary for the utility to have a fair

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

[24] *Id.*

[25] *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).

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

[27] *Id*.

[28] *Id*.

[29] *Id*.

or reasonable opportunity to earn a fair rate-of-return when providing safe, reliable service to its customers.[30] The utility costs and profit levels are roughly approximated by examining the utility's presentation of its revenue requirements over Commission-selected twelve-month period, or test year.

59. The purpose of this Proceeding is to establish base rates, the most significant rates, and charges billed to a utility's retail customers. Base rates for gas service fund the bulk of the utility's investments in transmission and distribution infrastructure as well as its investments in meters, services, computer systems, and other equipment and facilities needed to provide natural gas service to consumers. Base rates thus provide utilities a substantial source of revenue to cover the costs of providing service. Base rates are also the mechanism by which utilities collect sufficient revenues to ensure financial soundness of the utility, provide a reasonable return to their shareholders, and to cover the costs of debt payments that finance the investments necessary to fulfill the utility's obligation to serve and meet regulatory standards of service consistency. The capital, operating, and financing costs to achieve these objectives are interrelated and themselves represent a balance of interrelated inputs to the determination of just and reasonable rates. As explained below, the combination of costs intended to be recovered through base rates form the basis for a calculated revenue requirement and represent an expected level of cash flow determined to be within a range necessary to meet these larger objectives.

60. Base rates work in conjunction with other types of rates, including rate adjustment mechanisms, such as Public Service's Gas Cost Adjustment (GCA). Rate adjustment mechanisms and surcharges are designed to recover revenue requirements not included in the utility's base rate revenue requirements. Rate adjustment mechanisms tend to change annually, quarterly, or even

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

more frequently depending on the volatility of the costs included in the revenue requirements addressed by the rate adjustment mechanisms. In contrast and by design, base rate revenue requirements are not volatile and are instead presumed to be long-lasting.

61. Base rates are also distinguishable from rate adjustment mechanisms in that base rates are generally not reconciled to revenue collections from retail customers or to deviations from costs included in the underlying base rate revenue requirement, thereby balancing various risks and rewards between ratepayers and shareholders. This feature of base rates embodies important regulatory principles, particularly with respect to incentives for the utility to control its costs between base rate proceedings in the mutual interest of customers and investors.

62. As stated above, the Commission establishes base rates by examining changes in the utility's underlying revenue requirements. The revenue requirement is determined by examining the utility's costs of providing service. In support of an increase in rates, the utility files a cost-of-service study (COSS). The costs typically assessed by a COSS are those the utility incurs over a one-year period called a test year. The Commission explained that it uses the test year:

> to evaluate and to adjust (as necessary) the interrelationships of a utility's revenue, expense, and capital investment to determine whether the utility has a revenue excess or deficiency. These components should correspond to each other over the same time period or according to the same operating conditions. This is known as the 'matching principle', and it is designed to ensure 'that the cost of service reflects the operational relationships and interplay between rate base, expenses, and revenues in a manner that is representative of the period when the resulting rates will be in effect.'[31]

[31] Decision No. R19-1033, issued December 27, 2019, Proceeding No. 19AL-0075G at p. 32 (¶ 70) (citing Decision No. C11-1373 issued in Proceeding No. 11AL-382E on December 22, 2011 at p. 20 (¶ 51)).

Cost-based base rates derive from the calculated annual base rate revenue requirements, such that under normal expected circumstances, the utility collects the costs underlying the COSS for the test year, as adjusted.

63. Each Commission order adopting base rates is made pursuant to § 40-3-101(1), C.R.S., based on findings that the rates are just and reasonable. A gas utility's base rates thus evolve through a sequence of advice letter filings and, when necessary, Commission orders with related findings to the justness and reasonableness of the Company's rates and charges.

64. Due to the numerous and variable inputs and assumptions required to complete a COSS, to calculate billing determinants, and to establish base rates, the evidentiary record in a base rate proceeding can support a continuum of just and reasonable rates as final outcomes from the rate case. Such a range is recognized by the foundational selection of the test year[32] as well as the "matching principle." However, for practical purposes—such as for customer billing—specific values for rates and charges must be set forth on the utility's tariff schedules. The results of a utility's COSS are thus further allocated to each of the Company's base rate customer classes (*e.g.*, Residential, Small Commercial, Firm Transportation) using another cost-of-service study, or the class-allocated cost-of-service study (CCOSS). The necessary precision required to establish the specific rates set forth on a utility's base rate tariff sheets conceal the spread of alternative revenue outcomes that the Commission can support as just and reasonable with respect to the COSS and CCOSS inputs and assumptions as well as billing determinants within a given rate case evidentiary record.

[32] "Ultimately, the choice of test year is a matter of choosing regulatory policy; this choice is not fact-dependent." Decision No. R13-1307, issued October 22, 2013, Proceeding No. 12AL-1268G at p. 49 (¶ 134).

65. Notably, the Commission's decision establishing base rates does not establish a specific level of base rate revenues that the utility is entitled to recover, dollar-for-dollar, on an annual basis from retail customers. The relief granted to a utility in a base rate proceeding instead is limited to allowing for the changed base rate levels for application on customer bills prospectively. Commission decisions establishing modified rates at the end of a base rate proceeding do not entitle the utility to a specific level of base rate revenue collections. Rather, the decisions authorize the utility to charge those rates approved in the base rate proceeding.

66. We emphasize that the findings, conclusions, and directives that address components of the underlying COSS and CCOSS only provide general guidance so that the Company may implement the rates we have deemed just and reasonable. Consistent with the discussion above, in this Proceeding we are establishing just and reasonable rates, not adopting the components of the COSS or CCOSS.

IV. TEST YEAR, VALUATION OF RATE BASE, AND CONTESTED CAPITAL INVESTMENTS

A. Selection of Test Year and Valuation of Test Year Rate Base

1. Public Service's Proposed Current Test Year (CTY)

67. Public Service's request for an increase in revenue collections from base rates is premised primarily on a COSS using inputs and assumption for a Current Test Year (CTY), i.e., the twelve months ending December 31, 2022. The rate base for the CTY is valued at a 13-month average. Public Service explains that within the CTY, its operations and maintenance (O&M) expenses are based on historical data and the rate base reflects actual plant additions through June 2021 with forecasted additions through December 2022. Public Service argues that the CTY and capital step increases are a move toward more current cost recovery. Public Service further argues that the adoption of the CTY and capital steps will reduce regulatory lag. Public Service notes that

it will continue to make investments in its gas utility system for safety and reliability purposes. As The CTY base rate revenue requirement presented in the Company's Direct Testimony totals approximately $825 million.

68. In addition to initially raising rates to cover the CTY, Public Service also requests to increase revenues to account for "capital step" increases of approximately $40 million in each year 2023 and 2024. Public Service defines a capital step as plant additions primarily driven by operational investments in the Company's gas system. The Company maintains that its proposal to set rates using the CTY and then to adjustment for the two capital steps will allow the Company to avoid the need for rate cases through November 2025.

69. As a ratepayer protection mechanism, Public Service proposes a true-up to the CTY revenue requirement in June 2023, in the event the Company does not make the forecasted investments included in the CTY rate base. Similar true ups are also proposed for each of the capital steps if actual investments are less than the expected approximately $40 million in 2023 and 2024.

70. Public Service contends that in past proceedings where the Commission has adopted a historic test year (HTY), the HTY was used when the Company also implemented its Pipeline Safety and Integrity Adjustment (PSIA). The PSIA provided Public Service current cost return for much of its capital investments being made when the base rates setting using an HTY were in effect. The Company argues that 30 percent of the Company's future investments will be PSIA-type projects, and the adoption of an HTY in this Proceeding would preclude timely cost recovery.[33]

[33] Public Service SOP at pp. 8-9.

71. Public Service also emphasizes the regulatory lag inherent in an HTY, noting that the test years proposed by Staff and UCA result in about 16 months of regulatory lag. Public Service also states that if the rate base for an HTY was valued at year-end, the effect would be to reduce the claimed 16 months of regulatory lag by six months.[34]

2. Positions of the Intervening Parties on Test Year

72. Staff encourages the Commission to approve an HTY ending December 31, 2021, limiting cost recovery to new capital additions with known and measurable investments. Staff argues that a 2021 HTY is appropriate because it relies on booked and fully audited costs, as well as known and measurable adjustments.

73. Staff rejects the CTY and contends the record in this Proceeding does not support forward-looking ratemaking. Staff labels the CTY a future test year (FTY) and notes that the Company has an advantage in choosing what data to disclose in an FTY, skewing the Commission's ability to review of costs as compared to the 2021 HTY. Furthermore, Staff questions the Company's ability to provide accurate forecasts as is required for a CTY.

74. Staff further maintains that the proposed capital step increases include cost recovery of some 1,300 projects and argues that tracking and analyzing these projects is unrealistic. As to the Company's proposal to stay out of rate cases until 2025, Staff argues that the best protection for ratepayers is allowing for recovery of actual investments, not a true-up process.

75. UCA characterizes the Company's proposed CTY and capital step increases as a multi-year plan (MYP) and argues that the forecasts underlying the capital step increases are unreliable. In support of its position, UCA cites Xcel Energy's January 25, 2022 Form 8-K, which

[34] Public Service SOP at p. 7.

notes that forward-looking statements are assumptions, subject to a number of risks, and could vary materially from actual results. UCA supports the adoption of the 2021 HTY.

76. Conservation Advocates also reject the Company's proposed CTY and capital step increases, calling the approach a "blank check" for capital investments through November 1, 2025.[35] Conservation Advocates note that the CTY is a shift from the Commission's practice of setting rates based on HTYs and contends it is premature to allow forward-looking cost recovery before the Company has provided forward-looking system planning.

77. Staff, UCA, and Conservation Advocates recommend that the rate base for the 2021 HTY be calculated as a 13-month average instead of at year end. Staff contends an average rate base is consistent with previous Commission decisions and more accurately reflects plant being placed into or taken out of service over the year. Staff asserts that the Commission has only approved year-end rate base when special circumstances have been present, a condition Staff contends does not exist in this proceeding.

78. FEA holds that the 2023 and 2024 capital step increases are contrary state policy goals for emissions reductions because, without further Commission review, investments could be made that are inconsistent with state policies for the reduction of greenhouse gas emissions. FEA also contends that the investments Public Service would make based on the capital step increases could become stranded assets, again as the result of the implementation of state emission reduction policies.

79. Climax opposes the 2023 and 2024 capital step increases, concluding that they amount to a rate case for certain expenditures without regard to other aspects of utility operations.

[35] Conservation Advocates SOP at p. 7.

3. Findings and Conclusions on Test Year

80. We are unpersuaded by the Company's arguments in support of its proposed CTY and agree with intervening parties that using the 2021 HTY for modeling and estimating the Company's base rate revenue requirement provides the necessary protections for ratepayers as it is based on a full examination of actual investment costs. We further conclude that a review of the revenue requirement based on a 2021 HTY will lead to the establishment of base rates that enable Public Service and its investors to cover the costs of its ongoing operations and to earn a return reasonably sufficient to maintain the utility's financial integrity.

81. In light of the evidence presented in this Proceeding as a whole and our review of the COSS results provided by the Company in its Rebuttal Testimony and at the technical conference, we approve a year-end valuation of the rate base. We agree with Public Service that a year-end valuation appropriately mitigates the regulatory lag inherent in the adoption of the HTY as presented by the Company in this Proceeding.

82. We reject the proposed capital step increases for 2023 and 2024. We are concerned that the Company has not demonstrated sufficient restraint in its proposed capital spending and agree with Conservation Advocates' characterization that authorizing the capital step increase is akin to signing a "blank check."[36] Based on Public Service's presentation of its expected capital spending over the next two years, we recognize that the Company may see grounds for filing another base rate case to address future investment. However, we are not persuaded that the Company's CTY combined with the capital step increases is a reasonable alternative to using an HTY to establish base rates in this Proceeding. Public Service retains the right to file another base rate case should it be required based on priorities for necessary investment.

[36] Conservation Advocates SOP at p. 7.

B. PSIA Deferral

83. In Proceeding No. 21A-0071G, the Commission approved a Joint Motion to Approve Non-Unanimous Comprehensive Settlement Agreement (PSIA Settlement),[37] which terminated the Pipeline Safety Integrity Adjustment (PSIA) rider and established a process to wind-down and transfer to base rates costs currently recovered through the PSIA. As its name indicates, the PSIA rider recovered costs associated with pipeline replacements and other safety-related investments.

84. Through the PSIA Settlement, a capital only PSIA deferral mechanism was established for calendar year 2022, through which Public Service was allowed to track depreciation expense associated with new capital investments in specified high-risk PSIA Projects and Sub-Projects (PSIA Deferral).

85. Public Service requests that if the Commission selects an HTY in this Proceeding, the Company be allowed to continue the PSIA Deferral for two years additional years, 2023 and 2024 because it would preserve cost recovery of "vital safety investments."[38].

86. We decline to authorize the continuation of the PSIA Deferral. The continuation of deferrals is inconsistent with the terms of the PSIA Settlement terms establishing 2022 PSIA Deferral as a temporary mechanism with a certain end date. We also conclude that the record in this Proceeding does not support continuing the PSIA Deferral for the reasons stated by the Company. Again, Public Service retains the right to file another base rate case should it be required based on priorities for necessary investment.

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[37] *See* Decision No. C21-0715.

[38] Public Service SOP at p. 9.

C. Staff's Contested Capital Investments

87. Staff recommends excluding the following projects from rate base. Staff has raises concerns that certain projects do not satisfy the ratemaking requirements of "known and measurable" investment, "used and useful" facilities, and regulatory prudency.

88. Public Service argues that Staff has misapplied these ratemaking concepts in its review of the Company's capital investments and further claims that Staff's analyses contain factual errors. Public Service emphasizes that all of these contested projects result from well-established system modeling, planning, and engineering methods.

1. Tungsten-to-Blackhawk

89. Staff recommends denial of $11.1 million for the Tungsten-to-Blackhawk project. Staff contends Public Service sought cost recovery for the project before defining the scope, leading to changes in project costs. Staff further argues the Company did not provide sufficient information to support the project, and Staff also recommends the Commission require a Certificate of Public Convenience and Necessity (CPCN) for the facilities.[39]

90. Public Service states that this project was part of the settlement approved by Decision No. R20-0673 in Proceeding No. 20AL-0049G (2020 Gas Rate Case), which was approved by the Commission without a CPCN requirement.[40] Through that agreement, most of the costs were included in base rates, with $11.1 million to be recovered in this instant Proceeding. The Company explains that the cost difference resulted from a change in the pipeline route, and, because less hard rock was encountered than expected, construction costs were lower.[41]

[39] Hrg. Exh. 604C Ramos Answer at p. 8:9-12
[40] Hrg. Exh. 134 Martz Rebuttal at p. 28:9-19.
[41] Hrg. Exh. 134 Martz Rebuttal at pp. 27:15-34:7.

2. Tiffany Compressor Station

91. Staff recommends disallowance of $3.8 million in investments from October 2019 through December 2021 for the Tiffany Compressor Station.[42]

92. Public Service notes that the identified investments total $2.6 million and contends that the Tiffany Compressor Station provides significant reliability improvement and are either already in service or will soon be in service.[43]

3. Winter Park Tie and Granby Take-Off to YMCA Valve Set

93. Staff recommends disallowance of $26.9 million related to Winter Park Tie and Granby Take-Off to YMCA Valve Set projects. Staff argues that before filing for cost recovery in the future, the Commission should direct the Company to file an application for approval of a retroactive CPCN that includes a Fraser Valley Master Improvement Plan.[44]

94. Public Service faults Staff for confusing the costs for Granby project as Winter Park costs and vice-versa and for mis-identifying the capital additions for each project. Public Service also rejects Staff's linking of the two projects because of geographic and temporal proximity. Public Service shows that the two projects are distinct and have been designed and constructed to reflect their individual needs. Public Service further notes that Granby and Phase 1 of Winter Park are already in-service, and Phase II of Winter Park will be completed this year.[45]

95. Public Service further questions the purpose of retroactive CPCNs and notes that CPCN filing requirements are part of the ongoing Gas Rulemaking Proceeding. Public Service

[42] Hrg. Exh. 604C Ramos Answer at p. 9:4-9.
[43] Hrg. Exh. 134 Martz Rebuttal at pp. 34:11-35:5.
[44] Hrg. Exh. 604C Ramos Answer at p. 10:21-22.
[45] Hrg. Exh. 134 Martz Rebuttal at pp. 39:12-46:2.

states that it is likely that modified rules will require the Company to provide information on planned reliability projects in the context of gas infrastructure plans starting as early as 2023.

4. Transmission Pipeline Markers

96. Staff recommends disallowance of costs associated with the installation of Light Detection and Ranging (LIDAR) caps on existing pipeline markers and replacing missing or damaged pipeline markers, totaling $1.8 million from July 2020 through June 2021 and $2.2 million through December 2022. Staff also suggests the Commission require the Company to file an application for authorization for cost recovery of the LIDAR cap related investments. Staff contends that federal requirements for transmission markers do not require LIDAR technology and that the Company has used physical signage without LIDAR caps for more than 40 years. Staff further argues that Public Service makes no claim as to code compliance issues or cost savings associated with installation of LIDAR caps. [46]

97. Public Service maintains that the Pipeline Marker program is well underway, enhances public and employee safety, improves data accuracy, and assists with risk management and damage prevention work. Public Service argues that the LIDAR cap is an addition to physical signage that enhances GIS data, makes helicopter and drone flight planning more accurate to ensure accurate leak surveys, and provides an element of physical security to ensure the line is legally marked should physical signage be removed. As such, the Company urges the Commission to reject Staff's arguments to deny $4.0 million in program costs through the end of 2022 as well as Staff's request that the Company be required to file an application for this program.[47]

[46] Hrg. Exh. 604C Ramos Answer at p. 36:1-14.
[47] Hrg. Exh. 135 Garnder Rebuttal pp. 14:7-16:16.

5. Roundup 10 Well Packer Installation

98. Roundup gas storage wells are used to inject and withdraw gas to a natural underground storage formation so as to be available during high load periods. Packer assemblies confine and control the flow of gas. Staff recommends disallowance of $728,000 in costs associated with the Roundup 10 Well Packer Installation on the basis that the Company has not justified that it is used and useful.[48]

99. Public Service notes that the investments were placed into service in 2020 consistent with the Company's established capital asset accounting policies and the work was done according to Federal Code requirements.

6. Auraria Campus Steam Conversion and Contribution in Aid of Construction (CIAC)

100. Staff objects to $843,000 in capital additions for the Auraria Campus Steam Conversion Project, questioning why the customer was not required to pay the costs of the project instead of the Company making and paying for the investment. Staff also argues that the Company provided no information about project scope or used and useful justification.[49] Staff recommends disallowance of $2.2 million in Distribution CIAC for the Auraria Campus Steam Conversion Project because the Company did not provide information as to project scope or used and useful justification.

101. Public Service explains that the Auraria Campus Steam Conversion was completed during the last few months of 2019 and clarifies that the customer did make a significant payment for the project. Public Service explains that the Distribution CIAC is a timing placeholder for

[48] Hrg. Exh. 604C Ramos Answer p. 8:13-9:3.

[49] Hrg. Exh. 604C Ramos Answer p. 9:15-17 and p. 52:1-2.

payments associated with specific project as those payments are received form the customer. As payments are received, the entries are moved to the specific accounting structure for the project. The Company explains that Staff has erred by looking at a specific six-month window in time, so that the prior and future timing impacts are not accurately reflected.[50]

7. Findings and Conclusions

102. We deny Staff's request to remove these costs from the Company's COSS and the determination of revenue requirements. The Company's direct case supports these costs in each respect. Staff fails to provide clear and sufficient evidence that these costs should be disallowed. Specifically, Staff has made no showing of any violated statute, rule, or Commission decision.

103. We further conclude that no applications for CPCNs or other application filings are warranted for these contested projects. Staff fails to provide any specific analysis regarding whether these projects were not conducted in the normal course of business or otherwise violate any statute or rule. Staff has not made a sufficient showing of any violation of regulatory principles, revealed in part by the errors in Staff's analysis as demonstrated by Public Service. We note, for example, that the settlement in the 2020 Gas Rate Case directly addresses the costs of the Tungsten-to-Blackhawk project and does not require a CPCN. As for the LIDAR caps, an application for a safety program that has been underway for more than two years is unnecessary.

104. Although Staff has not persuaded us to deny the recovery of these costs based on the record in this Proceedings or to require future proceedings for further review of these specific contested projects, we find—to Staff's credit—merit in a robust review of major capital investment projects on a prospective basis. The Commission encourages and expects sufficient detail in

[50] Hrg. Exh. 134 Martz Rebuttal at p. 67:1-14.

requests for project approval and continues to examine the promulgation of rules that establish a more robust, prospective planning process in the Gas Rulemaking Proceeding.

D. Buried Service Valves

105. Conservation Advocates recommend rejection of $2.9 million for repair of 1,000 buried service valves.[51] Conservation Advocates argue that the spending was not justified because the Company has not clarified whether the valves need to be "renewed" or if they could be made accessible in a cheaper way or making home or business owners responsible for the valves.[52] Conservation Advocates suggests the Commission deny this request beyond 2022 until more information is provided by Public Service.

106. Public Service maintains it only replaces valves when necessary and when other solutions are not possible. Importantly, Public Service notes that buried service valves pose a safety risk if the valves become inaccessible and that PHMSA requires buried valves be remediated. The Company rejects Conservation Advocates' proposal that home or business owners be given the responsibility of uncovering the service valve or paying to have the buried valve remediated.[53]

107. We deny Conservation Advocates' request to remove the costs associated with buried service valves. Public Service provides sufficient justification for remediation of these valves and has indicated the Company will only do so when other solutions are not feasible, and the Conservation Advocates proposal that home or business owners bear the responsibility for these valves is not practical.

[51] Conservation Advocates SOP at p. 44.
[52] Hrg. Ex. 1202 Sullivan Answer Rev. 1 at pp. 18:10-19:19.
[53] Public Service SOP at p. 22.

E. Shared Corporate Services and Business Systems

108. Staff recommends disallowing recovery of $26.7 million in capital investments for certain building, furniture, and parking lot investments placed into service between October 1, 2019 and December 31, 2021. Staff contends Public Service "pointedly declined to provide project information or justification for new building construction or building expansions."[54] Staff further recommends the Commission require the Company to file a copy of its "Major Building Renovation Investment Plan" for years 2020-2029 prior to requesting cost recovery for any further major building renovations.[55]

109. Public Service responds that none of the investments questioned by Staff are discretionary and that all are necessary for the safe and continued operation of the Company's buildings and facilities. Public Service notes that it responded to Staff's request for more information explaining the need for the projects. Public Service further notes that a cost-benefit study would be difficult conduct because while the costs are easily identified, the benefits of something such as a parking lot replacement is more challenging to quantify. Public Service urges the Commission to reject Staff's recommendation that it file a "Major Building Renovation Investment Plan" for 2020 through 2030 because the Company has a budgeting process that allows for project prioritization and that because investment plans can and do change, flexibility is important.[56]

110. We deny Staff's request to disallow capital investments for certain building, furniture, and parking lot investments. However, we do agree with Staff that the Company should file its Master Building Infrastructure Plan for planned investments between 2022 and 2030, to the

[54] Hrg. Exh. 604C Ramos Answer at p. 75:7-11.
[55] Hrg. Exh. 604C Ramos Answer at pp. 75:15-76:7.
[56] Hrg. Exh. 142 Dietenberger Rebuttal at pp. 29:18-31-3.

extent that such a plan already exists as implied by the Answer Testimony of Staff witness Marianne Ramos. We understand that investment plans change depending on circumstances, especially over an extended period. We also do not intend to hold Public Service to a cost-benefit for these types of investment. However, Public Service acknowledges that the associated costs are easily identified, and we conclude that the reporting of such information would provide the necessary transparency into the Company's planned expenditures for these types of investments. Public Service shall file that the Master Building Infrastructure Plan for planned investments between 2022 and 2030 in this Proceeding no later than February 1, 2023 or, in the event that such a plan does not exist list of anticipated major projects related to the Company's buildings with projected timing and costs.

F. Gas Gathering Assets

111. Staff recommends disallowance of some $424,000 in capital additions and O&M expenditures associated with the Company's Gas Gathering, Gas Production, and Gas Products because Staff cannot determine if certain Gas Gathering assets were used and useful in the HTY. Additionally, Staff recommends Public Service be required to file a separate application for cost recovery and future regulatory treatment of all remaining Public Service-owned gas gathering assets.

112. Staff acknowledges that Proceeding No. 22A-0140G, which addresses Public Service's request to abandon and sell four gas gathering systems in Garfield, Mesa, and Rio Blanco Counties, represents much of the Company's equipment for gas gathering, gas production, and product extraction facilities. However, Staff takes the position that there may be other equipment that has not been identified that should be addressed in this Proceeding.

113. UCA likewise recommends disallowance of costs associated with the four gas gathering systems at issue in Proceeding No. 22A-0140G, raising questions as to whether the assets are used and useful and under the Commission's jurisdiction. UCA contends the assets should be removed from rate base in this Proceeding regardless of the outcome of Proceeding No. 22A-0140G because the evidence shows the assets are not and have not been used and useful.

114. Public Service refutes Staff's and UCA's arguments, saying that the assets used and useful because they currently provide, or could provide, transportation service and noting that UCA put forward similar arguments in Proceeding No. 22A-0140G in a request for summary judgement that was denied by the presiding administrative law judge (ALJ). Public Service further explains that Staff's proposal for a separate application has also been filed in Proceeding No. 22A-0140G, which the Company addressed in that other proceeding.[57]

115. We deny Staff and UCA requests to exclude costs associated with these gas gathering assets from the Company's estimation of its revenue requirements using the HTY. We also deny Staff's request for a separate filing, since the same underlying issues surrounding the sale of these assets are before an ALJ in Proceeding No. 22A-0140G. Addressing the same issues or making exclusions from the COSS in this proceeding would be premature and misplaced. We expect that the outcomes from Proceeding No. 22A-0140G will be reflected in the costs reviewed in a future rate proceeding.

[57] Public Service SOP at p. 25

V. COST OF CAPITAL

A. Return on Equity

1. Public Service's Position

116. Public Service contends that under the *Hope* and *Bluefield* standards, a utility must be given an opportunity to earn a return commensurate with the returns of other enterprises of comparable risk.[58] Public Service asserts that with the termination of the PSIA and Colorado's carbon emission reduction goals, its gas utility operations face higher risk than other publicly traded gas utilities in the United States. The Company also argues it has not earned its authorized ROE in any year since 2010, and, on average, has earned 185 basis points less than the authorized ROE.[59]

117. In its Direct Testimony, Public Service requests that the Commission approve an authorized ROE of 10.25 percent. The 10.25 ROE ties to the Company's CTY and other inputs and assumptions to its COSS and calculated level of revenue requirements. Public Service requests an authorized ROE at a point value of 10.75 percent if the Commission approves an HTY. Both the 10.25 percent requested for the CTY and the 10.75 percent for the HTY are within the Company's proposed "range of reasonableness" extending from 10.0 percent to 11.0 percent.[60]

118. In support of the substantial increase in its ROE above the currently authorized ROE of 9.2 percent, Public Service argues that its risk profile has changed, in part due to the elimination of the PSIA because the Company's system safety and integrity investments will now be recovered in the normal course of business through base rates. The Company states that between

[58] Public Service SOP at p. 15.
[59] Hrg. Exh. 110 Bulkley Direct at p. 68:5-9.
[60] *Id*.

2019 and 2021, the PSIA-recovered costs associated with 34 percent to 38 percent of the Company's total annual gas capital investments. Absent the PSIA or future test years, Public Service expects there to be an increase in the frequency of gas rate cases. Public Service further argues that its risk profile has changed because required emission reduction actions will include programs to assist customers to reduce their emissions through reduced usage of natural gas commodity. The Company states that these activities may result in revenue erosion and pressure on the Company's financial metrics.

119. Public Service presented and assessed results from the application of standard methods to estimate an ROE to arrive at the requested point ROEs and the range of reasonableness. The Company used input data to these analysis for a group of other utilities, or a proxy group, whose expected returns are intended to compare reasonably to the Company's returns due to comparable business and financial risk profiles. The Company developed and presented results from the Constant Growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), an Empirical CAPM, and the Bond Yield Plus Risk Premium (Risk Premium).

120. In order to choose utilities for its proxy group, Public Service chose publicly traded utility companies that, among other characteristics: (1) collect most of their revenues from regulated natural gas utility operations; (2) provide quarterly dividends; and (3) have investor-grade credit ratings. The Company chose seven utilities for its proxy group. Xcel Energy, Public Service's holding company and that entity that raises equity for Colorado gas utility operations, was excluded from the analysis.

121. Public Service maintains that it "faces somewhat higher regulatory risk than the proxy group, particularly if the capital step proposal is not authorized"[61] because the PSIA rider has been eliminated and because the uncertainty surrounding the opportunity to use a fully forecasted test year. Public Service further contends "[t]his increased risk has been demonstrated historically through the inability of Public Service to earn its authorized ROE for its gas business and supports an authorized ROE above the median or mean results of the proxy group."[62] Public Service further contends its risk profile may be adversely affected in two significant and related ways as compared to the proxy group. First, the Company's high capital expenditures increase the risk of under- or delayed recovery of the invested capital. Second, an inadequate return on those capital investments would put downward pressure on key financial credit metrics.

122. In its SOP, Public Service argues the national average authorized ROE for gas utilities must also be appropriately considered when setting the Company's ROE.[63] Public Service argues that the evidence in this Proceeding supports the conclusion that authorized ROEs have begun increasing to reflect higher risk-free rates and higher inflation rates. Public Service states that since July 1, 2022, the national average authorized ROE for gas utilities has been 9.55 percent, which is 55 basis points higher than the 9.0 percent ROE recommended by Staff and UCA, as discussed below, and 15 basis points higher than the 9.40 percent ROE recommended by FEA, also discussed below. Public Service contends that the ROE recommendations of Staff and UCA cannot be reconciled with the commensurate-return standard set forth in *Hope* and *Bluefield*.

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[61] Hrg. Exh. 110 Bulkley Direct at p. 72:9-11.

[62] Hrg. Exh. 110 Bulkley Direct at p. 72:11-13.

[63] Public Service SOP at pp. 14-15.

2. Positions of the Intervening Parties

123. Staff proposes a range for ROE of 9.00 to 9.20 percent, based on Staff's Constant Growth and Multi-Stage DCF models.[64]

124. Staff argues that the Company's proxy group does not represent Public Service because the utilities in the proxy group are smaller than Public Service.[65] Staff also finds Public Service's proxy group to be inappropriate because it includes: (1) two utilities with a beta of 1.0—a measure of volatility or systematic risk that is not comparable to the Company; (2) one utility with a BBB credit rating, a level that is also not commensurate with credit rating that Public Service seeks to maintain; and (3) two utilities with no credit rating at all.

125. UCA recommends an ROE of 9.0 percent, based on its CAPM, Constant Growth DCF, and Multi-Stage DCF analyses. Contrary to Public Service's position regarding the Company's risk profile, UCA contends Public Service has reduced risk because its rate structure has substantially shifted financial risks to ratepayers.[66] UCA also points to recent authorized ROEs in other utility rate cases as support for its recommended ROE.[67] UCA Witness Fernandez states that 2022 authorized returns, through August 26, 2022, averaged 9.42 percent.[68]

126. FEA determines that a reasonable ROE range is 9.0 percent to 9.8 percent, with a midpoint estimate of 9.4 percent. In arriving at this range, FEA used the Company's proxy group but removed one utility—South Jersey Industries—because it is the target an acquisition by an investment fund.[69]

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[64] Hrg. Exh. 600 Sigalla Answer at p. 70:14-15.
[65] Hrg. Exh. 600 Sigalla Answer at p. 81:1-10.
[66] Hrg. Exh. 302 Fernandez Answer at p. 93:6-8.
[67] Hrg. Exh. 302 Fernandez Answer at p. 50:19-21.
[68] Hrg. Transcript, August 29, 2022 at p. 245:19-20.
[69] Hrg. Exh. 700 Walters Answer at p. 59:1-3 and p. 30:10-13.

3. Findings and Conclusions

127. We find that a reasonable authorized ROE for Public Service is within the range of 9.2 percent to 9.5 percent. This determination is arrived at by weighing all the evidence in the record related to the cost of equity, including the testimony addressing the various proxy groups, each of the ROE models, the discussion of the financial credit metrics presented by the Company, and the oral testimony at hearing concerning current economic and other factors influencing risk and expected returns.

128. Interest rates have steadily risen and are expected to continue to rise. Therefore, it is not reasonable for the range to extend below 9.2 percent as suggested by Staff and UCA. At the same time, the range cannot extend as high as the Company's requests for an ROE above 10.0 percent. The authorized ROEs established elsewhere nationally, and historic ROEs awarded to Public Service and other Colorado utilities relative to national averages instead support a top end of the range at 9.5 percent.

129. The range for the authorized ROE established by this Decision further considers the impacts of regulatory lag related to investments already made by Public Service. For example, the range takes into account our selection of the HTY and the valuation of the HTY rate base at year-end. The range further takes into account the consideration of reasonable returns on future investments as well as other elements of this Decision.

B. Cost of Debt

130. Public Service proposes a 3.8 percent cost of long-term debt based on the 13-month average information as of December 31, 2022.[70] For short-term debt, the Company proposes 2.26 percent, which is the average for 2022, based on actual values through May 31, 2022.[71]

131. Staff contends the Company's forecasted debt issuance is not accurate and recommends to setting rates using actual costs with known and measurable adjustments. Staff also argues against using a 13-month average to calculate debt costs, contending the Commission typically uses a year-end standard. Staff presents the calculation of debt costs at 3.84 percent for long-term debt and 2.40 percent for short-term debt which represent the actual cost of debt as of June 30, 2022.[72]

132. UCA recommends a cost of long-term debt of 3.70 percent, based on the actual cost of debt as of December 31, 2021. UCA recommends against use of short-term debt in determining the Company's rate of return. UCA contends that the amount and cost of Public Service's short-term debt has been volatile in the past.[73] However, if the Commission includes short-term debt costs, UCA recommends Public Service's December 2021 actual cost of short-term debt of 0.24 percent.[74]

133. Based on the evidence in this Proceeding, we direct Public Service to use a 3.8 percent cost of long-term debt as proposed by Public Service and a 2.3 percent cost for short-term debt. We find these debt cost levels best reflect the anticipated costs of borrowing when the new base rates established by this Decision will be in effect. We further agree with Public Service that

[70] Hrg. Ex. 109 at Table PAJ-D-3.
[71] Hrg. Ex. 139 Attachment PAJ-15
[72] Hrg. Exh. 600 Sigalla Answer at pp. 116:15-119:13
[73] Hrg. Exh. 302 Fernandez Answer at p. 45:15-17 and p. 46:16-48-16.
[74] Hrg. Exh. 302 Fernandez Answer at p. 50:7-9.

a 13-month average results in a reasonable measure of debt costs, in part due to volatility of these costs as highlighted by the Company.[75]

C. Capital Structure

1. Public Service's Position

134. Public Service proposes a capital structure of 55.66 percent equity, 43.62 percent long-term debt, and 0.72 percent short-term debt, based on actual data through May 31, 2022, and projected data through the end of the year.[76] The proposed equity ratio of 55.66 percent is nearly equivalent to the Company's current equity ratio of 55.62 percent

135. Public Service explains that the current equity ratio supports the Company's credit rating and overall financial integrity. The Company explains that its equity ratio is managed to that level through a combination of equity infusions from its parent Company, Xcel Energy, and dividends returned to the parent from Public Service operations. However, the Company also contends that it consistently has not been able to earn the authorized return as set by the Commission, largely due to regulatory lag associated with historic test years.

2. Positions of the Intervening Parties

136. UCA recommends the Commission adopt Xcel Energy's actual capital structure as the capital structure for the Company for the purpose of setting base rates in this Proceeding. UCA states that at the end of the HTY, Xcel Energy had a consolidated capital structure, which includes all of its subsidiaries, of 41.8 percent equity and 58.2 percent long-term debt.[77]

[75] Public Service SOP at p. 15.
[76] Public Service SOP at p. 10.
[77] Hrg. Exh. 302, Fernandez Answer at 28, Table RAF-9.

137. UCA recommends the move to Xcel Energy's capital structure be taken in three steps, moving the Company's equity ratio one-third of the way towards the Xcel Energy equity ratio with each rate case. UCA maintains that a shift to Xcel Energy's capital structure will not have an impact on Public Service's credit ratings.[78] If the Commission declines to implement UCA's proposal, UCA recommends adopting the actual economic capital structure allocated to Public Service and without short-term debt, of 53.7 percent equity and 46.3 percent debt.[79]

138. Through Rebuttal Testimony, Public Service rejects UCA's proposal as not representative of the Company's actual capital structure either at a point in time or on an average basis. Furthermore, Public Service argues that the UCA's proposed capital structure will negatively impact its cash flow and credit quality, leading to a "multiple notch credit rating downgrade."[80]

139. Staff recommends an equity ratio of 55.0 percent, 44.13 percent long-term debt, and 0.87 percent short-term debt. Staff contends that of all Xcel Energy gas subsidiaries, Public Service has the highest percent of equity in its capital structure. Noting that all the subsidiaries have the same S&P credit rating, Staff argues that a lower equity ratio did not negatively affect their credit ratings or their ability to serve customers; however, the other Xcel Energy subsidiaries are obtaining service at a lower cost than Colorado customers.[81] Staff suggests that lower equity ratios for Public Service are achievable, but Staff also states that a gradual approach will allow both financial markets to adjust and the Commission to understand that market response in terms of credit metrics and overall financial health.

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[78] Hrg. Exh. 302 Fernandez Answer at p. 24:1-25:21.
[79] Hrg. Exh. 302 Fernandez Answer at p. 29:1-7.
[80] Hrg. Exh. 130 Johnson Rebuttal at p. 6:14-7-4.
[81] Hrg. Exh. 600 Sigalla Answer at p. 63:1-16.

140. Staff further notes that Moody's considers cash flow measures to be a more important rating driver than authorized ROEs, and notes that "regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures."[82]

141. FEA does not propose a specific capital structure but recommends that if the Company's proposed equity ratio is adopted, the authorized ROE should be in the lower half of FEA's proposed range.

3. Findings and Conclusions

142. We have given substantial consideration to the effect of capital structure and other financial metrics on the Public Service's credit ratings in order to balance the various factors that influence an optimal credit rating for Public Service with an optimal rate structure for customers. While the record in this case shows that Public Service's common equity ratio is higher than the equity ratio of any other Xcel Energy operating company, we recognize that this reflects many factors, including regulatory lag.

143. We find that there is no fundamental regulatory justification for establishing a specific equity ratio for Public Service, except that a move from the Company's current capital structure to one with a different equity ratio may have a positive or negative impact the Company's financial credit metrics.[83]

144. Public Service's testimony in this Proceeding indicates that Xcel Energy manages Public Service's capital structure primarily in relation to the authorized equity ratio established for

[82] Hrg. Exh. 600 Sigalla Answer at p. 33.
[83] Hrg. Trns: August 18, 2022 at p. 156:18-25.

the Company by the Commission. This management is achieved by allocating dividends and capital contributions to the Company as a subsidiary.

145. The record in this Proceeding does not provide specificity nor precision in terms of capital structure, reflecting various inherent uncertainties.

146. We therefore approve a range for the equity ratio extending from 52 percent to 55 percent. As with our determination of a range for the cost of equity, the range for the equity ratio takes into account the adoption of an HTY, the valuation of rate base at year-end, the uncertainty inherent in the record here, and the other factors considered in rending this Decision.

D. Weighted Average Cost of Capital (WACC))

147. Public Service's weighted average cost of capital (WACC) is calculated as the combination of the authorized capital structure and the specific authorized costs of capital within that structure. Because the WACC represents the general return on rate base for ratemaking purposes, the WACC enters the COSS for the purpose of determining revenue requirements for the test year.

148. Public Service seeks a WACC of either 7.53 percent for the CTY or 7.66 percent for the HTY.

149. The intervening parties suggest far lower values: 6.43 percent for UCA; 6.67 percent for Staff; and 6.73 percent for FEA.

150. Consistent with the discussion above related to the ranges authorized for ROE and equity ratio, we set the WACC at 6.7 percent. This rate of return on rate base balances the interests of the Company and ratepayers consistent with the tenets of *Hope* and *Bluefield*. We further conclude that a 6.7 percent WACC, in combination with the ranges for the ROE and the equity

ratio, will permit Xcel Energy to satisfy the financial metrics and preserve the Company's credit quality.

VI. CONTESTED COST OF SERVICE ISSUES

A. Depreciation Expense

1. Public Service's Initial Position

151. Through its Advice Letter No. 993-Gas filing, Public Service proposes to continue using the depreciation rates approved in the Company's Phase I gas rate case in Proceeding No. 17AL- 0363G for the capital assets in the following categories: production, storage, transmission, and distribution. The Company also proposes the adoption of new depreciation rates for common utility general plant based on a 2021 depreciation study. That same depreciation study was filed in Public Service's 2021 electric rate case, Proceeding No. 21AL-0317E, and the parties to that case agreed to the depreciation rates recommended by Alliance for the same common plant. Public Service states that the overall impact from those newer depreciation rates on the annual depreciation expense is $1.5 million for the CTY.

152. Public Service also responds through Direct Testimony to the requirement in Decision No. C21-0715 from Proceeding No. 21A-0071G to present in this specific rate case an evaluation of the "useful life" assumptions underlying the Company's depreciation rates for the various categories of capital plant investments. The Commission order the evaluation to include consideration of Senate Bill (SB) 21-264 and other recently-enacted state environmental laws, as well as the impact those laws may have on Public Service's ability to recover its investment in gas distribution and transmission infrastructure over time.[84]

[84] *See* Decision No. C21-0715, Proceeding No. 21A-0071G.

153. Public Service states that it is premature to undertake any reassessment of remaining lives and associated depreciation policies for its gas capital investment. Public Service argues that SB 21-264 and other recently-enacted laws are clear that a gas utility system will continue to be needed throughout the current emissions reduction goal period applicable to the Company. Public Service also argues that continued investment to meet peak demand and maintain the safety and integrity of its gas system is not incompatible with the statutorily mandated emission reductions, stating that utility gas pipelines will be needed and included as part of long-term gas infrastructure planning for the foreseeable future. Public Service concludes that if material adoption of beneficial electrification occurs, the appropriate recovery period of gas distribution assets can continue to be assessed in future rate proceedings.[85]

2. Supplemental Direct Testimony

154. Through Decision No. C22-0232-I, the Commission directed Public Service to provide Supplemental Direct Testimony assessing cost of incremental investment using a 30-year depreciable life for those new plant additions. The Company replied with two analyses: (1) an update of the Company's 15-year rate model when applying a 30-year depreciation life for new plant, which shows an incremental annual depreciation expense of $36 million in 2024 and causes a 4 percent increase in residential rates in 2036; and (2) a depreciation study that moves the largest three categories of assets on the gas system to a 30-year life for the 2022 through 2024 investments proposed in this Proceeding, which shows a similar incremental depreciation expense of $34.5 million.

155. Public Service also presented alternative approaches to calculating depreciation expenses based on (1) the use of different methods (*i.e.*, Equal Life Group, or ELG, versus the

[85] Hrg. Exh. 102 Berman Direct at p. 60.

currently applied Average Life Group, or ALG) and (2) limiting the life of assets to 2050. Public Service explains that the ELG approach, which groups items with similar lives, would accelerate depreciation relative to the Company's current ALG method by approximately $15.8 million, or just under half the cost of changing to a 30-year service life. Public Service notes that the Public Utilities Commission of Texas relies on the ELG approach as being "more equitable to short-lived and long-lived customers [because it] creates a higher level of intergenerational equity between different asset groups and customer groups."[86] The Company further notes that the ELG method is also used by Atmos for setting rates in Colorado.

156. In addition, Public Service suggests that the development of a regulatory asset to collect increased depreciation would be more manageable than increased depreciation rates in terms of implementation to achieve similar results. A regulatory asset would allow the Commission time to consider the effects of modifying its approach to depreciation in the context of SB 21-264 related proceedings.[87] The Company further acknowledges that the resulting regulatory liability would result in incremental revenue that would improve cash flow and therefore improve credit metrics, with all else being equal.[88]

3. Positions of the Intervening Parties

157. Staff contends that Public Service's current depreciation schedules distort ratepayer decision-making, encouraging investment in gas consuming appliances with the belief that gas costs are less expensive than they really are.

[86] Hrg Transcript August 22, 2022 at p. 199.

[87] Hrg. Exh. 124 Berman Supplemental Direct at p. 21:16-21.

[88] Hrg. Exh. 600 Att. FDS-12.

158. Staff suggests that the Commission adopt a $15 million increase in depreciation expenses in recognition of future impacts of environmental statutes and corresponding regulations. Staff explains that the additional $15 million adopted in this rate Proceeding will help ensure gradualism over time.

159. If the Commission selects the regulatory asset approach suggested by Public Service, Staff recommends guidelines including that: (1) ratepayers earn a return equal to the Company's WACC, adjusted monthly, on the regulatory liability, and (2) the regulatory asset is temporary, terminating at the Company's next rate case.

160. Conservation Advocates suggest the Commission shorten asset lives to 30 years in recognition of the state's aggressive carbon reduction goals, to reduce the risk of burdening future customers with stranded costs, and to send more accurate economic signals about the cost and risk of gas system expansion.

4. Findings and Conclusions

161. We conclude that the continued use of what can be viewed as a 57-year weighted average depreciation life on future capital plant investments is no longer reasonable given the uncertainty about the future trajectory of the gas utility business as reflected by the record in this Proceeding, including through the diverging views of the parties of that future trajectory. We are also unpersuaded by Public Service's arguments that it is premature to examine depreciation expenses in this Proceeding as a result of the enactment of SB 21-264 and of other recent legislation that will require significant reductions in greenhouse gas emissions from the gas utility sector in Colorado. The record before us, as well as the rapidly evolving regulatory regime for gas utilities, require the Commission to consider some action in the present with respect to depreciation. Notably, SB 21-264 specifically recognizes that changes to gas utility depreciation

schedules may be required to align a utility's cost recovery with statewide policy goals of reducing greenhouse gas emissions while minimizing costs and risks.[89] Considering changes to gas utility depreciation schedules in the instant rate case, where costs, risks, and depreciation schedules are already at issue, is in line with the legislative directive in SB 21-264.

162. We further recognize that if we adopt higher depreciation rates, or otherwise cause the COSS to cause the same effect as higher depreciation rates, customers will face increased rates in the near term as a result of the associated increase in revenue requirements. It is difficult to adopt such an approach when ratepayers are already facing the pancaking of rate increases and higher gas commodity costs. However, we are persuaded by Staff's suggestion that taking a directional step toward higher depreciation expenses is reasonable and gradualism is appropriate in this instance.[90] Taking no action now causes there to be less opportunity to apply gradualism later.

163. We conclude that it is reasonable to direct Public Service to recalculate the depreciation expense for the HTY using the ELG approach. Based on information presented by Public Service at the technical conference on October 7, 2022, a move to using the ELG approach for setting depreciation rates will cause a $15.8 million increase in revenue requirements based on the HTY. This is roughly in line with Staff's proposal to increase depreciation expenses by $15M per year. The increase in the depreciation expense caused by the move to the ELG approach fosters the gradualism we seek to accomplish during the time when the impacts of various potential factors related to the useful lives of facilities become better understood in relation to Public Service's

[89] § 40-3.2-108(4)(c)(XII), C.R.S.

[90] Staff SOP at p. 26.

necessary actions to achieve significant reductions in greenhouse gas emissions over the next decades.

164. During the course of the evidentiary hearing, we also examined the net salvage value embedded in the calculation of the Company's depreciation rates. Public Service explained that sizable negative salvage value accelerates depreciation and provides additional cash to pay for disposal of prior infrastructure investment. The Company contends that "collecting negative net salvage expense over the life of the asset is the universal practice among utilities; indeed, Public Service knows of no utility that approaches it differently. To adopt a radical new approach – without assurance of later recovery and without knowledge of how it would affect the Company's credit metrics – could create unanticipated consequences, not only for Public Service individually but also for the entire regulatory environment in Colorado."[91] The Company concludes that the elimination of net salvage would create intergenerational inequity and negate the WACC return customers earn.[92]

165. No action is required to address net salvage values in this Proceeding. However, it is necessary for the Commission to gain a better understanding of the potential for large negative net salvage values to cause negatively valued rate base when capital investment has slowed, and significant amounts of assets are retired for environmental or other reasons. We raise the issue here to indicate to the Company that net salvage values are closely examined in the Company's next gas rate case filing. We will be further interested to understand any relationship of shortened depreciable lives of assets to the net salvage value, when calculated over the same, shortened time period.

[91] Public Service SOP at p. 30.
[92] Public Service SOP at p. 31.

B. Rate Case Expenses

166. Public Service requests recovery of actual expenses incurred to develop, file, and litigate this Proceeding and offers $2.2 million as a placeholder value for such expenses until actual amounts are determined. The $2.2 million figure includes outside legal, consulting, customer noticing, and hearing costs.

167. Public Service contends that the rate case expenses for this case are higher than those of the Company's previous gas rate case[93] because this case was litigated, not settled, and there were more witnesses and contested issues. Public Service argues that legislation has made the gas business is increasingly complex and the Commission's directives have required additional studies and testimony. Public Service also points to the large number of discovery requests propounded intervenors in this case as adding to expenses.[94]

168. Public Service itemizes the expenses for this Proceeding as:[95]

Legal Counsel	$1,919,500
Consulting	$238,000
Customer Noticing	$40,000
Hearing Costs	$42,525
Miscellaneous Expenses	$6,000
Total	$2,246,025

169. Staff recommends an allowance of $1.4 million for total rate case expenses. Staff voices concern about the Company's outside legal expenses and the cost of the contract for the Company's witness cost of capital witness Ann Bulkley, noting that outside legal and consulting fees make up 96 percent of the expenses for this case.

[93] *See* Proceeding No. 20AL-0049G.
[94] Public Service SOP at p. 29.
[95] Hrg. Exh. 119 McKoane Direct at p. 30 Table MAM-D-5.

170. Staff expresses concern that the invoices for legal costs were redacted which precluded any analysis as to whether the billed hourly rates were reasonable. Without such an analysis, Staff suggests limiting outside legal costs to the lesser of $1.2 million or actual incurred costs. Staff also proposes limiting the recovery of Ms. Bulkley's fees to the lower of $114,000 or actual costs. Staff further asks that the Commission disallowing $9,900 for the pension consultant's services for a memo on aggregate cost method for ratemaking because that was not included in the Company's initial rate case expense estimate.

171. Staff rejects Public Service's proposal to receive a return on outstanding balances associated with rate case expenses and requests that the Company be required to track expense recovery. Staff proposes a 36-month amortization period for rate case expenses.

172. UCA recommends a disallowance of $1.1 million in rate case expenses. Specifically, UCA recommends a 50/50 sharing of outside legal costs and Ms. Bulkley's fees.

173. Public Service maintains that its rate case expenses are prudently incurred that it is entitled to recovery. The Company argues that similar disallowances recommended by Staff and UCA previously been denied by the Commission, and that neither provides evidence that would warrant Commission accept those disallowances in this Proceeding. However, Public Service offers a compromise of recovery of actual rate case expenses amortized over 24 months with no return.[96]

174. We authorize recovery of rate case expenses for this Proceeding not to exceed $2 million, amortized over three years, with no return. Going forward, we encourage Public Service to better manage its expenses related to rate cases for the reasons articulated by UCA and Staff.

[96] Public Service SOP at p. 29.

C. Failed Meter Program

175. Staff recommends removing the Failed Meter Replacement Program from the cost of service, questioning the backlog of some 280,000 meters and the Company's request of $69.4 million for replacements from July 2020 through December 2024. Additionally, Staff questions the relevance of the Company's Meter Sample Program, particularly the use of a small sample as provided in the American National Standards Institute (ANSI) standard and homogeneity of the tested lots. Staff suggests a separate application proceeding should be filed for the assessment of the associated costs.

176. UCA agrees with Staff's proposal to remove costs related to the Failed Meter Lots from the cost of service in this proceeding and for a separate application filing.

177. Public Service objects to any disallowances from its COSS analysis of revenue requirements associated with its Failed Meter Replacement Program and the associated Meter Sample Program. If the Commission accepts Staff's and UCA's recommendations that the program be reevaluated in a separate proceeding, Public Service requests it be authorized to proceed with the current Failed Meter Exchange program, arguing that retroactive changes that affect cost recovery for past meter replacements is inappropriate.[97]

178. Public Service explains that the first failed gas meter lots occurred in 2015. Although the program began in 2008[98] in Proceeding No. 08A-280G, it takes several years for a lot to be considered failed under the sampling program. The Company further explains that, although replacements would have begun in January 2017, in 2016 the Company paused the exchanges to examine emerging gas meter designs that had not been fully examined within the

[97] Public Service SOP at p. 24.

[98] Hrg. Exh. 134 Attachment SGM-7, Decision No. R09-0683 in Proceeding No. 08-280G.

industry and tested by the Company's Meter Performance & Standards organization. Public Service continues that the program began again in 2021, with the Company addressing the backlog of meters that had failed meter reading tests. The Company emphasizes the failures are not leaking or posing environmental threats, but rather are incorrectly measuring use.[99]

179. Public Service notes that it has been following ANSI standards and argues that no evidence has been presented that the meters in question meet the tolerance bands of those standards. The Company also states that it files its Meter Sampling Program results each April for the test cycle ending the previous December 31 so the Commission can monitor the program, and that the Company has met with Staff periodically to discuss the reports in greater detail.[100]

180. We deny the requests to disallow the costs of the Failed Meter Program. The program was previously approved by the Commission, and the Company has been filing annual reports on the status of the tests. Nevertheless, we are troubled that this program dates to 2008 apparently without substantial review. We are further concerned about the cost of the large backlog of replacements. Therefore, we direct Public Service to confer with Staff and UCA following the conclusion of this Proceeding in anticipation of a future filing for the purpose of a review and potential update to the Failed Meter Program and the process for future meter replacements. Public Service is required to file an application for approval of the continuation of its Failed Meter Program no later than six months from the effective date of this Decision.

D. Recovery of Manufactured Gas Plant (MGP) Costs

181. The Commission has previously granted approval for Public Service's deferred accounting for costs incurred related to the Company's historic manufactured gas plants. The

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[99] Hrg. Exh. 134 Martz Rebuttal at p. 60:5-6.
[100] Hrg. Exh. 134 Martz Rebuttal at p. 55:11-16.

eligible costs include expenditures related investigating, litigating responsibility for, and remediating possible environmental contamination at, or originating from, the Rice Yards and Crown Tar Works Sites. Recovery of any additional deferred costs will be addressed in a future proceeding.

182. In this Proceeding, Public Service seeks approval of a 36-month amortization period if the Company's CTY is approved, or an 18-month amortization period if the Commission instead approves an HTY. Public Service states that those periods approximate the expected interim period between rate cases, depending on the test year convention. Public Service further requests that it be allowed to include the unamortized balances in rate base and to earn a WACC return on them or to pay a WACC return on them, depending on whether they represent a net addition to or reduction from rate base.

183. Staff agrees with Public Service that amortized recovery of MGP expenses are appropriate in this case with the use of an HTY. Staff states that while the deferred accounting mechanism for MGP costs increases complexity, it is appropriate in these circumstances to provide rate certainty and to reduce regulatory lag.

184. We grant Public Service's request to amortize the deferred MGP costs over 18 months and earn a WACC return on them.

E. Pre-Paid Pension

185. Public Service requests inclusion of a prepaid pension asset of $56.8 million in rate base. The amount is equivalent to the 2022 13-month average balance of the tracked costs for use with the proposed CTY. If the Commission opts for an HTY, the Company requests to include $56.2 million in rate base. The Company maintains the prepaid pension asset benefits customers

and requests WACC on the balance, consistent with the Denver District Court Order ruling on the Commission's decision on exceptions in Proceeding No. 17AL-0363G.[101]

186. Staff rejects the proposal to include the prepaid pension asset in rate base, arguing that the Court determined that its decision might have been different if the Commission had found that Public Service made contributions considerably in excess of those required by federal law. Staff contends that, in this case, none of the prepaid pension asset was required under federal law or required to meet the Company's fiduciary duty to fund the pension obligation, as was confirmed by Public Service Witness Schrubbe at hearing.[102] Furthermore, Staff contends the prepaid pension asset is not used and useful because it can and does lose money as an investment, with ratepayers bearing greater costs when the investment loses money.

187. We will not adopt Staff's arguments. Consistent with the District Court Order, we authorize the Prepaid Pension Expense to continue to be included in rate base and earn a return a return equal to the Company's WACC.

F. Pension Expense

188. Public Service requests continued use of its amortization schedule from the 2015 rate case, resulting in annual collection of $4 million in addition to the pension expense calculated under federal standards. The Company notes that this helps to reduce the prepaid pension asset balance.

[101] *Public Service Co. of Colorado v. The Public Utilities Commission of the State of Colorado*, Case No. 19CV31427, at 16 (Dist. Ct. Denver Colo. March 12, 2020).

[102] Staff SOP at p. 22.

189. Staff recommends increasing the amount to about $8 million annually. Staff also recommends limiting pension expense attributable to incentive compensation to 15 percent of an employee's base pay, calculated on an employee-by-employee basis.[103]

190. Public Service does not object to Staff's proposed increase in the pension expense to $8 million, noting that decreasing the prepaid pension asset could minimize disagreements regarding this asset in future rate cases. However, the Company questions the rationale for increasing the amortization. Public Service states that increasing the amortization will increase customer rates and will create intergenerational equity concerns as current customers will pay amounts that will be credited to future customers when the regulatory liability is returned to customers.[104]

191. Public Service objects to limiting the pension expense to attributed to incentive compensation to 15 percent. The Company argues that the incentive pay above 15 percent of base pay brings total employee compensation to market-competitive levels. However, if the Commission chooses to impose a 15 percent cap, Public Service request to be allowed to calculate the amount on an aggregate basis.[105]

192. We agree with Public Service that amortizing $4 million annually is appropriate. We do not find sufficient evidence in the record to support Staff's proposal to double the amortization and thereby increase customer rates. We further agree with Staff's recommendation to limit the pension expense to 15 percent of an employee's base pay. While we are inclined to allow Public Service to make this adjustment as calculated on an aggregated basis for the purposes

[103] Hrg. Exh. 601 Ghebregziabher Answer at p. 68:406.
[104] Public Service SOP at p. 31.
[105] Public Service SOP at p. 64

of this rate case, we learned at the technical conference on October 7, 2022, that Public Service had conducted an employee-by-employee study of the application of a 15 percent cap and provided to the parties in discovery. The results of that study were used in the updates to the cost of service studies filed on October 6, 2022 and presented at the technical conference. We therefore clarify that the employ-by-employ calculation may be applied in the derivation of the revenue requirements used as the basis for setting rates.

G. Retiree Medical Expense

193. Public Service does not seek recovery of retiree medical expense because the actuarially determined amount is negative $686,000 and its inclusion would increase the prepaid retiree medical asset. The Company requests the retiree medical expense instead be set at $0, consistent with prior proceedings. The Company maintains that this is an important benefit for its long-tenured bargaining employees.

194. Staff recommends to excluding the retiree medical expense from the cost of service because although the amount would be set at $0 now, that could change in the future.

195. We authorize the retiree medical expense to be included in the cost of service at $0, for the reasons put forward by Public Service, consistent with previous proceedings.[106]

H. Pre-Paid Retiree Medical Asset

196. Public Service requests inclusion of the prepaid retiree medical asset in rate base with WACC return. In relation to its CTY, the Company notes the 13-month average balance of the prepaid retiree medical asset at the end of 2022 will be $19.2 million.

[106] *See e.g.*, ¸ Proceeding No. 17AL-0363G, Decision No. R18-0318-I at ¶ 230.

197. Staff objects to the inclusion of the prepaid retiree medical asset in rate base, suggesting that it be amortized over a set period. The Company disagrees with this proposal, noting that customers would pay some $1.1 million in WACC, but amortization costs would be approximately $2.7 million.

198. We authorize the prepaid retiree medical asset in rate base with a return at the Company's WACC for the reasons put forward by Public Service. While we acknowledge the merit to amortizing the asset more quickly, we decline to do so at this time so as to not increase customer rates. We direct Public Service, in the Company's next rate case, to put forward analysis and options for amortizing the prepaid retiree medical asset with an end goal of eliminating it from rate base in a reasonable timeframe.

I. Compensation Issues

1. Board Equity Compensation

199. Public Service requests authorization to recover $234,000 for board equity compensation, stating that providing Board compensation through cash and equity is consistent with industry practices. Public Service explains that the board equity compensation has increased in recent years because several board members left and were owed for their service and because there were additional board members during the transition period when the new members were added prior to the departure of the existing members.

200. Staff recommends allowing 50 percent of the compensation cost because there is insufficient evidence to allow an allocation of costs based on benefits to shareholders and ratepayers. Staff also notes an increase of 34 percent in requested board equity compensation since

the Proceeding No. 20AL-0049G. Staff argues the 50/50 split is consistent with Commission decisions in recent gas and electric rate cases.[107]

201. UCA recommends rejecting the board equity compensation request on the grounds that Board members have a fiduciary duty to investors, not ratepayers. Noting that the Commission has allowed 50 percent recovery in some previous rate case decisions, UCA suggests it also supports Staff's proposal to share costs on a 50/50 basis with shareholders.

202. We authorize recovery of 50 percent of board equity compensation. We acknowledge that the Company is required to have a board and the board should be compensated. However, a sharing of compensation expense between investors and ratepayers is appropriate, as the Commission has found in previous proceedings[108] and consistent with Staff's Answer Testimony.

2. Annual Incentive Program

203. Public Service requests recovery of $4.4 million for Annual Incentive Pay (AIP) as a part of its market-based compensation for employees.

204. Staff and UCA recommend capping the amount allowed for recovery at 15 percent per employee, consistent with recent Commission decisions. Staff also notes that a 15 percent cap is consistent with Xcel Energy's subsidiaries in other jurisdictions. Furthermore, Staff contends that there is no evidence that the Company has had trouble attracting or retaining employees and the 15 percent cap reasonably balances ratepayer and shareholder interests.

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[107] Hrg. Ex. 601 Ghebregziabher Answer at pp. 75:10-76:05.

[108] *See e.g.*, Proceeding No. 20AL-0049G, Decision No. R20-0673 at ¶ 67.

205. We agree with Staff and UCA that capping the amount allowed for recovery at 15 percent per employee is appropriate and is consistent with the trend of recent Commission decisions.

3. Long-Term Incentive

206. Public Service requests recovery of $566,000 for Time-Based Long-Term Incentive (LTI) and $311,000 for environmental LTI compensation, arguing that these are part of eligible employees' market-based compensation and denial would mean the Company is recovering less than the compensation it pays employees.

207. Staff recommends denial of recovery of LTI costs, consistent with other Xcel Energy jurisdictions. Additionally, Staff notes that the Commission has previously denied Environmental LTI and there is no evidence that this proceeding is different from past proceedings in this regard. Likewise, Staff contends the Company offered no evidence that LTI improves employee performance or benefits ratepayers.

208. We agree with Staff's arguments and deny recovery of both time-based and environmental LTI.

4. Employee Recognition

209. Public Service requests $251,000 for its Recognition Program. The Company argues this program is necessary to attract, motivate, and retain employees and that the Program benefits customers through a stable workforce.

210. Staff acknowledges the benefit of the Recognition Program, but contends shareholders benefit as well as customers because the stable workforce improves the Company's efficiency and revenue. Therefore, Staff recommends a 50/50 sharing of Recognition Program costs between shareholders and ratepayers.

211. Public Service rejects Staff's 50/50 proposal, noting the Commission has allowed full recovery of these expenses in prior proceedings and Staff failed to provide any evidence to support a 50/50 split of expenses.[109]

212. We agree with Public Service and authorize recovery of Recognition Program expenses. The Recognition Program benefits ratepayers as it helps the Company maintain a stable and competent workforce and the Commission has allowed full recovery of these expenses in recent rate cases in the past for that same reason.

J. Trackers and Deferred Assets

213. Public Service requests 36-month amortization periods for the trackers established in previous rate cases if the Commission authorizes the CTY. Public Service argues that three years for cost recovery aligns with the Company's proposed period to stay out of rate case filings. Should the Commission instead authorize an HTY, Public Service requests an 18-month amortization period for each tracker.

214. UCA objects to continuing any of the previously approved trackers because the costs for each tracker represents costs that can be recovered by the revenue requirements and allowing recovery between rate cases erodes ratepayer protections. UCA contends that trackers are appropriate if expenses are highly variable, a condition that none of the existing trackers meets at this time.

[109] Public Service SOP at p. 30.

1. Pension Tracker

215. Public Service proposes to continue its pension tracker with a baseline for qualified pension expense of $4.9 million and non-qualified pension expense of $262,000. Staff supports the Company's proposal.

216. UCA recommends eliminating the pension tracker because pension expenses have varied by less than one percent in recent years.

217. Public Service rejects UCA's argument, contending that UCA Witness Scott England's calculation is flawed because he compared the total Public Service amount for qualified pension expense with the Gas Department's specific tracker balance. Public Service argues that when comparing actual qualified pension expense and the approved tracker balance for the Gas Department, the difference ranges from four to eight percent most years.

218. We authorize the pension tracker to continue, amortized over 18 months, with no return.

2. Property Tax Tracker

219. Public Service proposes to continue the property tax tracker with a $64.3 million baseline going forward. Staff agrees with that proposal.

220. UCA argues that because property taxes have increased at a steady rate, the tracker should be eliminated.

221. Public Service notes that if the tracker is discontinued as UCA suggests, the Company would be faced with the cost of regulatory lag for property taxes. The Company notes that if regulatory lag is intended to cause the Company to control costs, it has no such option with property taxes.

222. We authorize the property tax tracker to continue, amortized over 18 months, with no return.

3. Commission Administration Fees

223. Public Service requests a deferred account to track the increase in the annual administration fee used to fund the Commission, from 0.25 percent to 0.45 percent of revenue as permitted by SB 21-272.[110]

224. Staff agrees that SB 21-272 allows the Company to implement a deferred account to track changes in fees between rate proceedings but maintains the Company should not earn a return on these balances.

225. UCA disagrees that the changes in annual administration fees are significant enough to warrant a tracker but concedes that the statute allows the Company to establish a deferred account to track these fees.

226. We authorize Public Service to create a deferred account for the annual administrative fee as required by § 40-2-113(3), C.R.S.

4. Damage Prevention

227. Public Service proposes to continue its Damage Prevention Program originally approved in 2015 and continued in Proceeding No. 17AL-0363G. Expenses associated with the program would also continue to be tracked, with a regulatory asset to defer the difference between actual costs incurred for damage prevention and the amount of damage prevention expense in rate base. Public Service notes that the costs arising from damage prevention are driven by customers

[110] Section 40-2-113(3), C.R.S.

and contracts, not Public Service, and that the Company is mandated to respond to requests for damage prevention locates. The program had a balance of $8.4 million at the end of June 2021.[111]

228. UCA makes no recommendation but notes that the capitalized costs of the program are included in base rates and that the costs in the tracker are O&M. UCA states that this underscores UCA's position that no return should be allowed.[112]

229. We authorize continuation of the Damage Prevention Program deferred asset, without return, amortized over 18 months.

K. Weather Normalization

230. As part of the determination of revenue requirements, base rate revenue for the HTY is adjusted in the COSS so that test period billing units reflect energy sales and demands for "normal weather" instead of the actual weather that occurred in 2021. Public Service applied the weather normalization approached approved in the 2020 Gas Rate Case, similarly, using a 10-year average for weather including the test year period.

231. UCA recommends a 20-year weather normalization period rather than the 10-year period used by Public Service. UCA contends that there are asymmetric risks associated with weather conditions: if weather is colder, customers use more gas, leading to excess recovery by the utility that ratepayers cannot recoup; if the weather is warmer, customers use less gas, and the utility sees revenue decreases which it can recoup through a rate case. UCA contends that a longer weather normalization period smooths out these variations and reduces the probability of over-recovery.

[111] Hrg. Exh. 119 McKoane Direct at pp. 14:2 – 15:14
[112] Hrg. Exh. 303 England Answer at pp. 40:3-41:9

232. Public Service characterizes UCA's proposal as seeking to increase the probability that test year sales are set too high. Public Service contends this is a shift from the Commission's decisions setting weather normalization at 10 years in both the Company's recent electric Phase I rate case, Proceeding No. 19AL-0268E, and its 2020 Gas Rate Case, and as such should be rejected.[113]

233. We deny UCA's proposed 20-year weather normalization period and authorize Public Service to use the 10-year weather normalization approach consistent with recent Commission decisions.

VII. CLASS COST OF SERVICE AND RATE DESIGN

A. PSIA Cost Allocation

234. In transferring the PSIA costs from the PSIA rider to base rates, Public Service replicated in its CCOSS the same commodity-based allocation for costs across rate classes as caused by the PSIA when it was implemented. Public Service maintains that this is consistent with the PSIA Settlement, requiring that PSIA costs be transferred from the rider to base rates without intra-rate class bill impacts. The Company points out that this usage-based methodology avoids some $14.6 million being assigned to the residential class.

235. Staff recommends PSIA cost allocation based on design-day methodology, citing alignment with cost causation principles. Staff recognizes that the PSIA moved away from design-day cost allocation when it was implemented, but Staff encourages the Commission to return to that methodology, consistent with other transmission and distribution mains investment. Staff rejects arguments that the PSIA Settlement requires allocation on a usage basis.

[113] Public Service SOP at pp. 31-32.

236. Atmos, Climax, and FEA likewise contend that the PSIA costs should be allocated based on design day demand consistent with the Company's treatment of other transmission and distribution facilities. Atmos emphasizes the cost allocation process for developing a CCOSS, following the functions used to assign costs to different FERC accounts. Atmos argues that allocating costs based on how the costs were previously recovered and on avoiding rate impacts results in rates that are not just and reasonable.

237. Public Service argues that PSIA costs were incurred specifically for PHMSA compliance and not for not meeting peak load requirements. The Company further states that because PHMSA-driven costs do not relate directly to peak load requirements, allocating PSIA costs based on peak day quantity is inconsistent with cost causation and the principles of stability and fairness.[114]

238. We acknowledge the arguments of parties urging design day methodology, consistent with other transmission and distribution facilities. We nevertheless find merit in upholding the objective of the PSIA Settlement to avoid intra-rate class bill impacts at this time. A demand-based methodology would likely result in increased Residential rates, contrary to that agreement. We therefore approve the allocation of PSIA costs used in Public Service's CCOSS to achieve the same usage-based allocation across rate classes as caused by the PSIA when it was implemented.

B. Transmission-Only Rate

239. Atmos requests the Commission require Public Service to create rates for Atmos and other similar customers (*i.e.*, Black Hills and CNG) that exclude costs for Public Service's distribution system, arguing that distribution systems are not used or useful to serve a customer

[114] Public Service SOP at p. 34.

such as Atmos. Atmos contends the Commission can require a transmission-only rate using average costs of only the assets used to provide service to a particular customer or customer class and that it is unjust, unreasonable, and oppressive to require Atmos to pay for the distribution system, leading to rates that are 50 percent higher than if the distribution system costs were removed.[115]

240. Public Service encourages the Commission to reject Atmos's request for a transmission-only rate as unreasonable. Public Service notes that in the 2019 Gas Rate Case, a stakeholder process was developed to allow evaluation of class allocation of distribution and transmission costs with respect to LDC customers and Public Service provided LDC customers with information regarding assets used to serve LDC customers. Public Service faults Atmos for not using that information in this proceeding to develop LDC-specific rates and instead seeking what Public Service contends is a 50 percent reduction in its rates.[116]

241. We are unpersuaded by Atmos' arguments and deny Atmos' request for a Transmission Only rate. Public Service's transportation rates reflect the costs of Public Service's entire statewide system allocated to transportation service customers. Atmos' request is essentially to carve it and the other gas utilities that use Public Service's system into their own rate class, a rate class defined primarily as transportation customers who do not use the Company's distribution system assets. Atmos' proposed approach to setting rates for this new rate class essentially takes the CCOSS Public Service presents for all of its customers and simply eliminates a significant cost category from the derivation of rates, costs associated with the distribution system, for that subset of transportation customers including Atmos.

[115] Atmos SOP at p. 10.
[116] Public Service SOP at p. 35.

242. We agree with Public Service that while the cost to serve each customer is different, the foundational principle of charging averaged rates is appropriate and should be continued as it relates to LDC customers.[117]

C. Compressor Station and Regulator Equipment Cost Allocation

243. FEA argues that Public Service has improperly classified and allocated compressor station equipment and regulator equipment as 100 percent commodity-related. FEA recommends the costs for the equipment instead be allocated on a design day demand basis. FEA argues that compressor stations and regulators are designed to meet the peak day customers' demands and, as such, compressor station equipment and regulator equipment are sized according to the size of mains and the demands on the system. FEA concludes that the size of compressor station equipment and regulator equipment does not change, regardless of whether customers' demands vary from peak day throughout the year.

244. Public Service argues that FEA's request should be denied. Public Service explains that although the Company sizes its distribution pipelines to meet maximum peak demand, compressor stations and regulating equipment primarily serve typical daily loads, balancing system pressure constantly throughout the year. The Company further asserts that compressors and regulating equipment are most closely related to total annual volumes than system peak demand, such that those costs should not be allocated based on peak demand.

245. We agree with Public Service and deny FEA's request to direct Public Service to allocate compressor station and regulator equipment cost on a demand basis.

[117] Hrg Exh. 149 Wishart Rebuttal at p. 25:10-13.

D. Classification of Operating Income

246. Atmos requests the Commission order Public Service to correct the classification and allocation of operating income and income taxes "to align the allocation of operating income and rate base to the various customer classes." Atmos states that the allocation should be based on the required operating income from each individual class of service (*i.e.,* operating income in excess of expenses) set at a level to equal the required return on rate base plus income taxes at a total jurisdictional level. Because Public Service did not set operating income by rate class according to this approach, Atmos concludes that the Company's CCOSS improperly allocates cost recovery responsibility across rate classes. Atmos further states that the Company did not dispute its proposed method or accuracy of this proposed adjustment.

247. Public Service responds that Atmos' recommendation should not be adopted, as it is not consistent with how the Company has performed the CCOSS in the past and it has an immaterial impact on class cost responsibilities.

248. We agree with Public Service and deny Atmos' request.

E. Interruptible Rate Class Consolidation

249. Although Staff requested Public Service conduct a separate base rate cost allocation analysis for Schedule IG for interruptible gas sales customers and Schedule TI for interruptible gas transportation customers prior to consolidating these rate schedules. The Company provided the requested analysis in its Rebuttal Testimony. In its SOP Staff states it does not oppose the consolidation but reminds the Commission that Public Service will need to derive the consolidate rate based on the conclusions and findings reached regarding the Company's overall cost of service and the cost allocation adopted for the class cost of service.

250. Public Service states that the combination of IG and TI customers into a single rate class has no material impact on cost responsibilities and should be approved and explains that the interruptible portion of the Company's total base rate revenue requirement is approximately three percent.[118]

251. We direct Public Service to consolidate its Schedules IG and TI into a single tariff, as proposed by the Company.

F. Class Costs of Service Study and Rate Classes

252. For clarity, we approve Public Service's cost allocators and rate classes used in its CCOSS with the exception of any changes explicitly required by this Decision.

G. Residential Services and Facilities Charge and Rate Design

253. Most of Public Service's residential customers take service under Schedule RG. Public Service proposes to maintain the existing $12.00 per month charge (the Service and Facilities or S&F charge) if its proposed RDA is denied, but the Company does not object to a $10.00 S&F charge if full decoupling is approved.

254. Staff and Conservation Advocates recommend decreasing the Schedule RG S&F charge, suggesting a charge between $4.00 per month and $8.00 per month if an RDA is approved.[119] Public Service objects, explaining that a lower monthly customer charge would increase volumetric rates and would undermine rate acceptability and stability because of the differing impacts for low-use and high-use customers and seasonal bills.[120]

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[118] Hrg. Ex 148 Harrison Rebuttal at p. 12:5-6 and p. 13:4-10.

[119] Staff SOP at p. 41.

[120] Public Service SOP at p. 35.

255. UCA conditionally supports the Company’s proposed S&F charge of $12.00 per month, because it represents an acceptable split between costs collected through the fixed and variable charges and results in just and reasonable S&F charges. However, UCA’s support is based on potential rate shock tied to whether the Commission adopts an HTY, the way rate base is valued, and the decision on volumetric cost allocation for PSIA-related costs.

256. At the technical conference on October 7, 2022, Public Service presented the calculation of the usage charge for Schedule RG when the S&F charge is reduced from the current $12.00 per month to $8.00 per month. The Company noted that how the 33 percent reduction in the monthly customer charge resulted in a dramatic increase in the usage charge, from approximately $0.19/therm to roughly $0.35/therm.

257. We conclude that a $10.00 per month S&F charge achieves the proper balance between the competing interests of the parties. The $2.00 per month reduction will serve our primary interests in providing some degree of relief to residential customers in light of high commodity costs when the new base rates take effect and in making bills more sensitive to achieved reductions in usage. However, the reduction of the charge to $10.00 per month will nevertheless preserve to a significant degree the benefits to Public Service associated with fixed cost recovery and seasonal revenue collections.

H. Approval of Rate Design for Classes Other than Schedule RG

258. For clarity, we approve Public Service’s proposed S&F charges for the rate schedules other than Schedule RG (Residential General) as set forth in the Company’s Direct Testimony. We direct Public Service to derive the accompanying usage and demand charges, as applicable, for the rate schedules other than Schedule RG consistent with the rate design framework proposed in the Company’s Direct Testimony.

VIII. REVENUE DECOUPLING

A. Request for Revenue Decoupling per HB 21-1238

259. Public Service proposes a Revenue Decoupling Adjustment (RDA) for its Residential (RG) and Small Commercial (CSG) gas customers. Public Service makes this request pursuant to HB 21-1238, as codified at § 40-3.2-103(5)(b)(I), C.R.S., that states:

> Upon petition by a regulated gas utility, the commission shall remove disincentives to the implementation of effective gas DSM programs through the adoption of a rate adjustment mechanism that ensures that the revenue per customer approved by the commission in a general rate case proceeding is recovered by the gas utility without regard to the quantity of natural gas actually sold by the gas utility after the date the rate took effect. The commission shall separately calculate, for the rate class or classes to which a rate adjustment mechanism applies, the regulatory disincentives removed through that mechanism and collected or refunded by the gas utility through a tariff rider.

260. Public Service seeks "full" decoupling associated with revenues collected from all Residential and Small Commercial customers regardless of whether customer usage was affected by more than participation of its "effective gas DSM programs," such as the impacts of on sales and revenues from weather.

261. As a consumer protection measure the Company proposes a "soft" cap, limiting RDA adjustments to three percent annually with amounts beyond three percent remaining eligible for refund or recovery in the next two years. Public Service argues that this soft cap feature prevents unexpectedly large RDA adjustments in any particular year.

262. In its SOP, Public Service argues that the Colorado General Assembly not only mandated the Commission approve decoupling upon request by a utility, but also provided clear direction regarding the form and details of the mechanism to be approved. The Company further

reiterates that beneficial electrification is an eligible DSM program.[121] Public Service characterizes the modifications suggested by the intervening parties to its proposed RDA mechanism as contrary to those legislative requirements.

263. In accordance with the RDA tariff sheets filed with Advice Letter No. 993, the RDA will be calculated as the difference between an authorized Baseline Revenue Per Customer (RPC) and an Actual RPC, multiplied by the number of customers to derive the Revenue Decoupling Amount for the previous year.

B. Positions of the Intervening Parties

264. Conservation Advocates support full revenue decoupling, contending that gas throughput will decline for many reasons including investment in DSM as well as electrification. For this reason, Conservation Advocates argue the Company should not have financial investment for increasing sales and full decoupling will render the Company indifferent to changes in sales, preventing Public Service from profiting should sales increase due to weather conditions. Conservation Advocates request that the Commission also adopt the three percent cap, but only in the case where Public Service under-collects its Baseline RPC. Conservation Advocates request that the Commission place no limit on bill decreases if there is over-collection. Additionally, Conservation Advocates recommend that all refunds should be made within the next year.

265. Conservation Advocates also propose a “k-factor” to be applied to the RPC associated with new customers, offsetting the incentive that a decoupling mechanism can create to increase customer base. Conservation Advocates argue that the customer growth incentive of decoupling could disincentivize electrification. Conservation Advocates propose a k-factor of 0.56.

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[121] Public Service SOP at p. 42.

266. Public Service objects to the k-factor because it implies that for new customers added to the Public Service system, the Company would only be allowed to recover 56 percent of the Commission Authorized RPC. In its SOP, Public Service argues that the General Assembly did not provide for different levels of revenue recovery for new and existing customers, however temporary. For this reason, Public Service argues that CA's proposed k-factor is contrary to HB 21-1238 and must be rejected.

267. Staff recommends the Commission approve partial decoupling, which is weather normalized. Staff argues that full decoupling inappropriately shifts weather-related risks of over- or under-recovery to ratepayers.

268. Staff also recommends an asymmetric soft cap, which limits surcharges on customer bills but does not limit refunds. Alternatively, Staff suggests asymmetrical carrying charges could be applied to RDA balances, with the WACC applied to balances owed ratepayers but no carrying charge on balances to be recovered by the Company. Staff argues that this asymmetric design will discourage Public Service from collecting and holding large balances that are owed to ratepayers and notes that the Commission has approved asymmetric carrying charges for other riders.

269. In its SOP, Public Service objects to Staff's proposed exclusion of weather from the decoupling mechanism, asserting that this would result in an RPC that does not match the level approved by the Commission in this rate case. Public Service argues that the Commission must adopt full decoupling to align with statue and ensure the Company will recover the approved RPC established in this proceeding, "no more and no less."[122]

[122] Public Service SOP at p. 43.

270. Public Service proposes to adjust the annual decoupling amounts for what is called a demand-side management related acknowledgement of lost revenues (DSM-ALR) that is in place during the year for which the decoupling adjustment is applied. The DSM-ALR relates to provisions in the Commission's Gas DSM rules, where a gas utility may include in its DSM bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission. Public Service explains that the DSM-ALR adjustment is needed for the proposed RDA because the DSM-ALR is intended to accomplish the same policy goal of removing disincentives for conservation. Public Service states that if the DSM-ALR were not subtracted from the annual decoupling amount the Company may be compensated twice for lost revenues associated with conservation

271. Staff suggests that the Commission instead enter a finding in this case that the Company is ineligible to recover DSM-ALR for rate classes with a decoupling mechanism.

272. Public Service concedes that Staff's recommendation to eliminate the DSM-ALR in 2023 results in mathematically the exact same financial impact but notes that the current DSM-ALR is specified in Rule 4754 of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4 and Staff did not request a waiver from this rule. Public Service concludes that because its mathematically the same and because it is not in violation of Commission rules, the Commission should adopt the Company's proposed treatment of the DSM-ALR in 2023 and beyond.

273. UCA recommends a partial RDA and a cap on surcharges but not refunds. According to UCA, the asymmetric caps are necessary to ensure the fullest possible benefit of gas decoupling for ratepayers. UCA objects to the soft cap because it could lead to excessive profits

for the Company when positive balances from over-collection expire. UCA argues that denying the soft cap will avoid disputes as to the expired balances.

C. Findings and Conclusions

274. We find that the Company's proposed RDA goes beyond the legislative directive to remove the disincentive to implementation of DSM programs.

275. The Commission is bound to give consistent, harmonious, and sensible effect to all of the parts of a statute, to the extent possible. Beginning with the first sentence, and with the context of the chapter in mind, the Commission is directed to "remove disincentives to the implementation of effective gas DSM programs through the adoption of a rate adjustment mechanism."[123] The statute further directs the Commission to adopt a rate adjustment mechanism that removes disincentives to DSM programs,[124] and that the proper approach to removing disincentives to DSM programs is through a revenue per customer mechanism that allows recovery "without regard to the quantity of natural gas actually sold by the gas utility after the date the rate took effect." This is what is commonly referred to as decoupling.

276. Section 40-3.2-103(5)(b)(I), C.R.S. does not state that *all* regulatory disincentives must be removed through the mechanism established. In fact, the statute dictates the specific regulatory disincentives that must be removed when applying the statute—*i.e.*, those related to the implementation of effective DSM programs.[125] Read in whole, § 40-3.2-103(5)(b)(I), C.R.S. requires the Commission to establish an RDA mechanism that removes regulatory disincentives to effective DSM implementation but does not require approval of an RDA mechanism that "captures

[123] § 40-3.2-103(5)(b)(I), C.R.S.
[124] *Id.*
[125] *Id*

all factors that could affect revenue per customer."[126] Put simply, the statute is focused on implementing a decoupling mechanism aimed at DSM implementation, not "full" decoupling.

277. Our reading of § 40-3.2-103(5)(b)(I), C.R.S. is consistent with our concurrent constitutional and statutory directives on ratemaking. When we look to Colorado's Public Utilities Law as a whole, we should read each provision in a consistent, harmonious, and sensible manner.[127] To understand this provision to require the Commission to only have the option of "full" decoupling would deprive the Commission of its fundamental and longstanding authority.[128] Read in the full context of Title 40, the Commission retains broad ratemaking authority to balance the utility's right to financial integrity with the consumers right to pay rates that accurately reflect the cost of service.[129] We do not read this subsection to strip the Commission of its authority to set reasonable and just rates. Therefore, to read § 40-3.2-103(5)(b)(I), C.R.S. harmoniously with the remainder of Title 40, the Commission undoubtedly retains discretion to implement what it deems is in the public interest and necessary to set just and reasonable rates.

278. HB 21-1238 specifically addresses a utility's implementation of DSM programs, and as such, does not require revenue decoupling applied broadly across the whole of the utility's customer base. Therefore, the RDA to be put into effect through the tariffs filed with Advice Letter No. 993 are to be applied to address revenue impacts solely attributed to DSM implementation. The RDA Rate shall be calculated using calculations of the revenue impacts

[126] *Id.*

[127] *AviComm v. Pub. Utils. Comm'n*, 955 P.2d 1023, 1031 (Colo. 1998), *Bd. of Cnty. Comm'rs (San Miguel) v. Colo. PUC*, 157 P.3d 1083, 1091 (Colo. 2007); *Gambler's Exp. Inc. v. Pub. Utilities Comm'n*, 868 P.2d 405, 410 (Colo. 1994).

[128] § 40-3-102, C.R.S. *See also* Colo. Const. Art. XXV.

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

caused by customers participating in the Company's DSM programs. The RDA shall not be weather normalized when applied more narrowly to DSM impacts.

279. We recognize that decoupling for gas base rates has not been examined in Colorado through the lens of the drivers of utility investment and new customer connections. A potential unintended consequence of HB 21-1238 is that revenue decoupling may cause a utility to focus its financial growth on maintaining and adding customers, which, as shown by the record in this Proceeding, further drives capacity investments in the system. When those investments combine with efforts to reduce customer usage for emission reduction purposes, rates increase and rate design becomes more complicated, adding to the impacts from the RDA. For these reasons, we find Conservation Advocates' k-factor to be of interest but conclude at this time there is not enough detail in the record to ensure that the application of a k-factor would ensure that the Company could cover its marginal costs of providing service.

280. We therefore direct Public Service to modify the tariff sheets filed with Advice Letter No. 993 to implement the RDA in order to cause the Actual RPC to reflect the revenue per customer for customers participating in the Company's DSM programs and for the Revenue Decoupling Amount to be based on the current year number of customers participating in the Company's DSM programs. The Authorized RPC, or Baseline RPC, shall be calculated in accordance with the test year and COSS approved by the Commission in this Proceeding.

281. We adopt the "soft cap" for the RDA to address immediate rate impacts caused by revenue decoupling, but we agree with Staff that the cap should be applied asymmetrically. The RDA tariff sheets filed with Advice Letter No. 993 shall be modified as suggested by Staff to limit surcharges on customer bills but not limit refunds and to apply the WACC to balances owed ratepayers but no carrying charge on balances to be recovered by the Company.

282. Finally, we find that Public Service is ineligible to recover DSM-ALR for rate classes with a decoupling mechanism, consistent with the recommendations of Staff and Conservation Advocates.

IX. LINE EXTENSION POLICY

A. Public Service Direct Testimony

283. In its Direct Testimony filed in this Proceeding, Public Service responds to the Commission's directive in Decision No. C21-0715 in Proceeding No. 21A-0071G that approved the PSIA Settlement to present an evaluation of the Company's line extension policy, including appropriate construction cost allowances, to fully assess whether existing customers subsidize, or bear the risk of stranded costs associated with, new customer attachments.

284. Public Service notes that the Company's current policy, the Distribution Extension Policy set forth in part in the tariff sheets filed with Advice Letter No. 993, has been in place since October 2019, after receiving stakeholder input pursuant to a Commission statewide proceeding opened as directed by SB 17-271[130] and after concluding a Company-specific review of line extension polies in Proceeding No. 18AL-0862G. The resulting Distribution Extension Policy included several changes, including the number and type of agreements, standardized costs, and a pre-set credit applicable to off-site distribution main credits.

285. In this Proceeding, Public Service proposes increases to its construction allowances for service laterals and distribution mains contending the increases are necessary due to the increase in capital investment presented in the CTY, including more than $1 billion of PSIA rate base being added to rate base. The Company applied an Average Embedded Cost (AEC)

[130] As directed by SB 17-271 the Commission opened Proceeding No. 18M-0082EG (the 2018 Combined Line Extension Policy Proceeding) to receive comments from investor-owned electric and gas utilities and other stakeholders.

calculation method, which divides the entire gross value in rate base for each type by the number of relevant customers and determined and calculated average investment of $582 for residential service laterals, up from $383 per lateral, and $985 for residential distribution mains, up from $331 per distribution main, for new construction allowances.[131]

286. Public Service maintains that new customers will not be subsidized by existing rate payers through the implementation of its gas line extension policy, because the annual revenue requirement for a new customer is $215, but the annual revenue received from the customer is $381.[132]

B. Public Service Supplemental Direct Testimony

287. Upon initial review of Public Service's Direct Testimony regarding its line extension policy, the Commission directed Public Service to file Supplemental Direct Testimony.[133] Specifically, the Commission directed the Company to provide the following additional information:

> An analysis of whether the non-commodity, non-overhead applicable revenues arising from system growth offsets the annual carrying costs on the investment [since the last gas rate case based on a] 30-year depreciation [schedule]. The analysis should explicitly identify the number of new customers expected as a direct result of the investment, as well as the Company's assumptions for the average usage and demand per customer and any annual growth or decline in the per customer gas usage assumed as part of the Company's analysis.

[131] Other increases in proposed construction allowances are summarized in Table SWW-D-13, Hrg. Exh. 123 Wishart Direct at p. 68.

[132] Hrg. Exh. 123 Wishart Direct at p. 68, Table SWW-D-14.

[133] Commission Decision Nos. C22-0232-I and C22-0275-I issued April 15, 2022 and May 4, 2022, respectively.

288. Public Service was also directed to update its 15-year model to include 2020 and 2021 actuals and have the capability to evaluate increasing natural gas commodity costs starting at $3.90/Dth and alternative depreciation settings.

289. In its Supplemental Direct Testimony, filed on May 13, 2022, Public Service presented an analysis indicating that the Company invested $394.3 million over the October 2019 through June 2022 period to hook up new customers, including $254.4 million directly attributable to new business, and an additional $139.9 million to increase upstream capacity to serve those customers, referred to as reliability.[134] Public Service explains the $139.9 reliability investment can serve an additional 64,500 customers added after 2022. When current and future customers are contemplated, they will produce a total revenue of $47.4 million, which will increase over time.

C. Positions of the Intervening Parties

290. Staff agrees with the Company that new customers should receive a construction allowance that reflects payment toward the cost of the line extension the customer will make through future gas bills, so that the customer is not paying for the equipment twice.[135]

291. Staff also contends a construction allowance is appropriate because the infrastructure in question will be entirely owned and maintained by the utility, the utility's ratepayers should bear some portion of the costs of utility-owned assets.[136]

292. Staff offers three options. First, the Commission could reject the Company's proposed increase and leave the current construction allowances in place. Second, the Commission could direct Public Service to recalculate the allowances according to the AEC method, but the

[134] Hrg. Exh. 129 Wishart Supplemental Direct at p. 15, Table SWW-SD-1.
[135] Hrg. Exh. 602 Haglund Answer at p. 15:5-7.
[136] Hrg. Exh. 602 Haglund Answer at p. 16:15-19.

calculations would be based on net embedded plant rather than gross embedded plant as done by Public Service in its Direct Testimony. According to Staff, this should cause roughly a 29 percent reduction in proposed allowances. Third, the Commission could require new customers to cover the upfront costs of new meters and regulators. Staff explains that the Company currently pays for 100 percent of these investments necessary to provide service to new customers.

293. Staff also suggests the Commission require updates to the Public Service's standardized construction costs values used for determining payments from new customers (or the developers of their new facilities) for connecting to the Company's system. Staff supports a standardized construction cost approach adopted previously. However, Staff objects to Public Service decision not to file updates for those standardized costs in this Proceeding. Accordingly, Staff recommends that the Commission require, in this Proceeding, that Public Service update those standardized cost estimates to reflect more current values. Staff maintains that if actual costs rise over time, but the standardized cost used by the Company remains fixed, ratepayers will cover a greater and greater portion of the actual costs. That result would further lead to a systematic under-collection of construction costs from line extension applicants and a corresponding over-payment by ratepayers."[137]

294. Staff further recommends the elimination of the 28 percent off-site distribution main extension credit.[138] In its Answer Testimony, Staff explains that the off-site distribution main extension credit is an up-front credit a new customer receives that reduces the cost of an off-site main extension by 28 percent and that a new customer may receive an off-site credit in addition to a construction allowance. Staff explained that it opposed the credit when Public Service updated

[137] Hrg. Exh. 602 Haglund Answer at p. 35:11-17.
[138] Staff SOP at p. 38.

its line extension policy most recently, arguing that while the fixed credit amount created administrative efficiencies and reduced uncertainty for Public Service and for property developers, it did so by shifting costs and risk onto ratepayers, because new customers and property developers would receive the credit regardless of whether subsequent connections to the extension ever occurred. Staff argues that the off-site credit creates a subsidy for new gas customers and should thus be eliminated. Although the Commission rejected Staff's position in the earlier proceeding, it explains that it brought forward its position on the credit again because the Commission explicitly requested a full assessment of the policy in this Proceeding.[139]

295. Conservation Advocates recommend the elimination of construction allowances for new service lines, meters, and on-site distribution for several reasons. They argue that the elimination of construction allowances would send more accurate economic signals to new customers. The elimination of the allowances is consistent with the Company's efforts to meet 2030 and 2050 decarbonization goals. Conservation Advocates further assert that "a sizable portion of gas infrastructure will no longer be used and useful in 2050.[140]

296. Public Service responds that modifications to construction allowances are not an appropriate strategy to prioritize electrification and represent discriminatory ratemaking, contending it would be fairer to provide incentives for electrification of new construction rather than to penalize customers who choose new gas service. The Company also notes that its Beneficial Electrification Plan filed on July 1, 2022 in Proceeding No. 22A-0309EG includes aggressive electrification goals and significant beneficial electrification incentives.[141]

[139] Hrg. Exh. 602 Haglund Answer at pp. 24-31.
[140] Hrg. Exh. 1200 Fickling Answer at pp. 25-26 and pp. 82-83.
[141] Hrg Exh. 149 Wishart Rebuttal at p. 49:13-20.

297. In its SOP, responding primarily to Staff, Public Service argues that the Commission should not revisit its approach to off-site distribution credits, which was analyzed prior to the adoption of the existing line extension policy. The Company also states that it is open to updating standardized costs based on 2021 data through a compliance filing at the end of this Proceeding.[142]

D. Findings and Conclusions

298. We are unpersuaded by Public Service's argument that new customers subsidize existing customers and find that the issue is more complex than is demonstrated by the Company's analysis. For instance, we question the assumption that all new customers are permanent. The assumptions made in the record in this Proceeding only hold if customers do not electrify, either in part or in whole. The Company also failed to properly account for the large capital costs associated with meeting new customer growth in terms of increases in broader system-wide and sub-regional peak design day demands. Finally, some portion of the investments in system and shared corporate services appear to result directly from new customer growth.[143] We thus question the presumption that it is correct to continue with system investment driven by customer additions simply on the basis of what has historically been done to provide service to new and existing customers. We further note that income-qualified customers are less likely to benefit from line extensions, creating an equity problem. Public Service and the intervening parties must consider what is reasonable given the shifts in the natural gas environment in the coming years.

299. Based on this assessment of the evidence presented in this Proceeding, we decline to authorize an increase in construction allowances as proposed by Public Service. The record

[142] Public Service SOP, pp. 47-48.

[143] Hearing Transcript, August 24, 2022 at p. 61: 1-8.

does not support an increase. Public Service shall not modify the values of the construction allowances set forth on the tariff sheets filed with Advice Letter No. 993 and shall continue to implement the existing allowances as recommended by Staff for effect November 1, 2022.

300. We find good cause to move to the alternative method for calculating construction allowances also recommended by Staff. However, in the event new construction values based on this modified method are to be implemented in the future, the record supports a transition period for such a change given the nature of the property development and the certainty we seek to preserve for builders. Therefore, we direct Public Service to update the calculation of AEC to be based on net embedded plant for each type of asset as suggested by Staff rather than the gross embedded plant for potential effect beginning no earlier than November 1, 2023. This calculation shall use the cost values included in the HTY. However, we cap the construction allowance at current values as we do for effect November 1, 2022. In other words, if the recalculated construction allowances to be set forth on updated tariff sheets filed with Advice Letter No. 993 are greater than current allowances, no change in the construction allowances will occur for effect November 1, 2023.

301. Regardless of whether construction allowances change for effect November 1, 2023, we require that the Company's line extension policy cause for 50 percent of the costs of new meters and regulators to be paid by the new customers or the developers of the customers new homes and businesses beginning on that date.

302. With respect to the off-site distribution credit, we direct Public Service to cease the payment of the credit for effect November 1, 2022. We are persuaded by Staff's arguments set forth in Answer Testimony that the credit serves as an unsupported subsidy to new customers and builders.

303. We also order Public Service to update the standardized construction costs contained in the Company's gas tariff reflect current costs. We appreciate that standardized construction costs add certainty and administrative efficiency to the benefit of both builders and the Company, however they place the burden of increased construction costs on ratepayers, rather than the new customers due to the failure to keep pace with actual costs. We agree with Staff that regular updates to such costs are necessary and in the public interest and appreciate that Public Service agreed to file revised tariff sheets to update these costs for effect November 1, 2022. We are further persuaded that it is necessary to continue to update these tariff sheets through an annual advice letter filing, based on the previous year's data.

304. The steps for complying with these directives regarding the Company's line extension policy are explained in detail below.

X. QUALITY OF SERVICE PLAN (QSP)

305. In its Direct Testimony, Public Service explains that the Quality of Service Plan (QSP) for its gas utility operations quantitatively measures, on an annual basis, the Company's performance in delivering service to its customers according to performance targets for Damage Prevention, Emergency Response, and Grade 2 Leak Repairs. Public Service also explains that its current QSP was approved by the Commission through Decision No. R19-0565, as modified by Decision No. C19-0728, in Proceeding No. 18A-0918G.

306. The minimum performance baselines in the QSP are as follows:

> Damage Prevention: Damages must not exceed 2.02 damages per 1,000 locates.
>
> Emergency Response: Public Service must respond to at least 76.1 percent of emergency calls within 60 minutes.
>
> Grade 2 Leak Repair Time: Average repair time must not exceed 63.3 days.

307. Public Service files an annual report on the previous year's performance. If Public Service does not meet each QSP performance baseline each year the QSP is in effect, it incurs a financial penalty that accrues in a regulatory liability to be credited to customers in the next phase gas rate case. Public Service shows in the Direct Testimony of Lauren Gilliland that Public Service has exceeded all QSP performance baselines in 2019 and 2020.[144]

308. Public Service seeks authority in this Proceeding to extend the current QSP through December 31, 2024. The Company argues that the current QSP metrics are appropriately focused on the objective of delivering quality gas service to customers while aligning with the Commission's mission to ensure safety, reliability, and adequate gas service. Public Service also suggests that continuing under the current QSP through the end of 2024 promotes regulatory efficiency. The Company states that, as a consequence of recent environmental legislation in Colorado, any effort to rework the QSP at this time is premature, particularly since the existing QSP metrics are working.

309. Staff disagrees and proposes several modifications to the Company's QSP. Staff witness Adam Gribb recommends that the goal for Damage Prevention be tightened from 2.02 damages per 1,000 locates to 1.32 damages per 1,000 locates. He suggests that the Emergency Response target be raised from 76.1 percent of more calls within 60 minutes to 95 percent of calls. He further recommends that Grade 3 Leaks repairs be added with the Grade 2 Leak repairs with a common standard not to exceed 1 day.

310. Mr. Gribb further suggests that the Commission require Public Service to add to the QSP an annual leak repair metric to address some 11,000 "active leaks," with tiered penalties for

[144] Hrg. Exh. 107 Gilliland Direct at p. 40.

failure to repair less than 3,000 leaks per year. He also suggests that the Commission require the Company to add both a monthly metric and an annual metric for lost and unaccounted for gas. In terms of financial penalties, he states that, for most metrics, an increase from $250,000 to $360,000 is warranted.

311. Public Service objects to Staff's proposed changes to the QSP. With regard to Staff's proposed change to Grade 2 Leak Repair, for example, Public Service contends that Staff's proposals are not attainable without additional investment and represent a significant departure from federal regulations. The Company also rejects the metrics associated with lost and unaccounted for gas, arguing that they do not correlate with leaks or emission rates and suffer from several other shortcomings. Public Service adds that Staff does not explain how these metrics could be achieved or at what cost. The Company further contends that Staff's proposed increased penalty amounts are arbitrary and lacking support.

312. In its Rebuttal Testimony, Public Service proposed to tighten the performance thresholds for its three existing QSP measures. For Damage Prevention, damages must not exceed 1.47 damages per 1,000 locates. For Emergency Response, Public Service must respond to at least 95 percent of emergency calls within 60 minutes, and for Grade 2 Leak Repair Time, the average repair time must not exceed 52 days, based on three-year average times.

313. In its SOP, Staff repeats its concerns about how Public Service tracks leaks across its utility system. Staff stands behind the conclusions and recommendations of Mr. Gribb and is silent on the modifications to the QSP proposed by Public Service in its Rebuttal Testimony.

314. We will not adopt Staff's proposed changes to the QSP, although we share many of Staff concerns regarding system leaks. We instead agree with Public Service that a more comprehensive review of the QSP for the Company's gas operations will be necessary as a result

of the implementation of the environmental legislation recently enacted in Colorado. New and revised QSP metrics will likely be adopted in the furtherance of greenhouse gas emission reductions and new gas planning procedures even while performance measures related to safety and service quality will also remain important. A more complete redevelopment of the QSP in the near future is necessary to align gas utility expenditures with the priorities of these various efforts.

315. We will authorize Public Service to continue its existing QSP measures with the same penalty levels as currently in place through December 31, 2024. There will be no additional measures added to the QSP at this time. However, we find that the tightening of existing performance thresholds for Damage Prevention, Emergency Response, and Grade 2 Leak Repair Time as offered by the Company in its Rebuttal Testimony is reasonable and will serve to address, at least in part, some of the concerns raised by Staff regarding leaks and safety. Therefore, Public Service shall modify the tariff pages filed with Advice Letter No. 993-Gas to update the QSP to reflect the new, more stringent metrics offered in the Company's Rebuttal Testimony.

XI. TRANSPORTATION AND INTERRUPTIBLE SERVICE TARIFFS

316. Public Service seeks to make several significant modifications to the Company's tariff sheets that govern transportation and interruptible sales service. Advice Letter No. 993-Gas includes these tariffs sheets.

317. Public Service witness Susan Bailey presents the Company's proposed tariff changes, including modifications to the Gas Sales Service General Terms and Conditions as related to Schedule IG for interruptible sales, and the Gas Transportation Terms and Conditions and standard transportation form agreements for both firm and interruptible transportation service. Ms. Baily provides testimony in support of many of these proposed changes. Ms. Baily explains that many of these tariff sheets were modified recently in the Company's 2019 Gas Rate Case in

Proceeding No. 19AL-0309G. She further explained the stakeholder process that occurred after that case. Public Service witness Joni Zich provides testimony related to proposed tariff revisions concerning receipt points, delivery point hourly flow quantities, and gas quality provisions from hazardous waste landfills.

A. In-Path Primary Receipt Points

318. Public Service proposes to require Shippers to name in-path Primary Receipt Points (PRPs) to be used on days when the system is "constrained." Public Service states that there were four such days in the last year.[145] Public Service explains that by requiring a Shipper to deliver gas to in in-path PRP, the Shipper's gas can physically flow to the customer's delivery point on a "constrained day" and the Shipper would not be able to cause Public Service to buy or sell gas to facilitate situations where the Shipper "buy[s] gas from a location that does not flow to the delivery point."

319. Public Service contends that the requirement for in-path PRPs will allow it to better plan for system capacity, especially on "constrained days" and avoid capital investment in additional infrastructure that would be necessary if Shippers are allowed to continue using secondary receipt points.[146] In its SOP, Public Service concludes that "as growth continues, [the Company] is always seeking ways to avoid unnecessary capacity investments that can be avoided by relatively straightforward Shipper actions on a limited number of days each year."[147]

[145] Public Service SOP at p. 36.
[146] Hrg. Exh. 106 Zich Direct at p. 101.
[147] Public Service SOP at p. 37.

320. Public Service explains that Shippers must currently identify PRPs in any event. Public Service also emphasizes that the in-path PRP would only be required on "constrained days" and asserts that most Shippers have already voluntarily identified in-path PRPs.

321. For the definition of the Primary Receipt Point, Public Service modifies the tariff as follows:

> Primary Receipt Point(s) – In-Path Receipt Point(s) specified in the Firm Gas Transportation Service Agreement or amendments thereto as Primary Receipt Point(s) where Receiving Party is entitled to firm gas on Transporter's System under either Firm Gas Transportation Service or the On-Peak Demand Quantity Option under Interruptible Gas Transportation Service on Transporter's System. A Receipt Point is In-Path when it does not utilize displacement to serve Receiving Party(ies), and the Transporter has determined that gas will flow between the Receipt Point and Delivery Point to serve the Receiving Party(ies) during capacity constraints on the System. Transporter may direct Shipper to Primary Receipt Point(s) when system conditions warrant.

322. Later in the Transportation Terms and Conditions, Public Service adds the following:

> All applications, agreements, and amendments for Firm Transportation Service must contain Primary Receipt Point(s). In addition to all other remedies available under the Gas tariff, Transporter may direct Shipper to such Primary Receipt Point(s) when system conditions warrant and charge Shipper an Unauthorized Overrun Penalty per Dth used at Secondary Receipt Point(s) for failure to comply. An Unauthorized Overrun Penalty may also be imposed under the additional circumstances provided in the definition of Unauthorized Overrun Penalty in the Gas Transportation Terms and Conditions.

323. WoodRiver, a shipper that provides gas commodity to transportation customers on Public Service's system and that is a party in this Proceeding, objects to the in-path PRP requirement, arguing that it is ambiguous as to what a "constrained day" is and what receipt points are considered in-path. WoodRiver asserts that Public Service has not defined the conditions which constitute a constrained day and has not sufficiently developed how a constrained day will be

noticed to Shippers.[148] WoodRiver further states that there are questions regarding the receipt point zones that Public Service created based on its assessment of the operational and hydraulic limitations within its system and on the specific receipt points that are considered "in path" based on that modeling. WoodRiver claims that Public Service does not know whether there is availability at any of its listed receipt points and concludes that if some of the newly required receipts points are unavailable, a shipper may have to discontinue service to existing customers.[149] Overall, WoodRiver maintains the in-path primary receipt point proposal is unnecessary, unjust, and unreasonable because it has not been sufficiently developed and creates uncertainties and burdens for Shippers and transportation customers.[150]

324. Similar to WoodRiver, Tiger, another shipper and intervening party, contends the Company has provided little guidance as to what constitutes "in-path." Tiger also faults the map of zones provided by the Company as ambiguous. Tiger further argues that the tariff is unclear as to when the Company could order a Shipper to an in-path Primary Receipt Point and how that order would be executed.[151] Tiger likewise concludes that the in-path concept is arbitrary and lacks transparency.[152]

325. Tiger further argues that changing the definition of a Primary Receipt Point to include in-path is contrary to which requires the company to take into account displacement gas when determining capacity. Additionally, by advancing the in-path requirement, Tiger alleges that

[148] WoodRiver SOP at p. 10.
[149] WoodRiver SOP at p. 11.
[150] WoodRiver SOP at p. 12.
[151] Tiger SOP at pp. 12-15.
[152] Hrg. Exh. 1000 Thomson Answer at p. 7:1-11

Public Service can favor its own gas supply customers over those of Shippers, violating Rule 4208 of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4.

326. Tiger further argues that the in-path requirement requires transportation customers to cede their current capacity rights at a Primary Receipt Point to the advantage of the Company's own customers. Additionally, gas supply costs for transportation customers will increase because they will be required to source gas from specific points in their zone. Tiger also asserts that the change will endanger service to certain areas of the state, such as the Vail Valley.[153]

327. While Tiger objects to the in-path receipt point requirement, it provides certain requests for the situation where the Commission accepts the Company's proposed changes to its Transportation Terms and Conditions:[154] (1) the change should not go into effect until April 2023 so that Shippers can adjust their contracts; (2) the Company should not be allowed to change any Primary Receipt point to in-path if the customer has used the receipt point for more than two years; (3) the Company should be required to provide a list of all customers and potential in-path Primary Receipt Points within 30 days of a Final Decision and must accommodate the needs of Shippers and their customers; (4) going forward, a Shipper's Primary Receipt Point for an existing customer cannot be changed unless the customer's capacity increases by more than 20 percent; and (5) all in-path receipt points must be posted on the Company's electronic bulletin board (EBB) site and cannot be changed without 30-days' notice.

328. UET, a third shipper that is a party in this Proceeding, refutes Public Service's argument that the in-path primary receipt point requirement is in the public interest, contending the Company provides no evidence to support its position. UET notes the Company admits it has

[153] Tiger SOP at p. 14.

[154] Hrg. Exh. 1000 Thomson Answer at pp. 14:19-15:12.

no calculations indicating increased costs resulting from Shippers using their current Primary Receipt Points, and the Company provides no forecasts showing cost savings or investment deferrals. UET contends the in-path proposal is contrary to the public interest because it will increase costs for transportation customers and will require transportation customers to give up their contractual rights to capacity at their current Primary Receipt Points.[155]

329. We agree with WoodRiver and Tiger that there are significant unanswered questions concerning the in-path PRP proposal. First, Public Service needs to better define a "constrained day" for both operational and planning purposes. Shippers and the Commission must have a better understanding of the specific problem the Company is attempting to solve with this proposal. Second, the Company must better define and identify "receipt zones" and the associated in-path PRPs. The Company's system may comprise distinct areas within which gas can flow from a receipt point to a delivery point without displacement, and there are also likely certain configurations of the system that prevent the gas from physically flowing across zones as suggested by the Company's proposal for in-path PRPs. However, the requirement for in-path PRPs appears to be too undeveloped to be properly administered as proposed in this case.

330. Because Public Service's proposal could unnecessarily burden shippers and transportation customers when implemented as proposed in this Proceeding, we reject the in-path PRP requirement. Safety and system economics nevertheless remain paramount considerations of the Commission. In this instance, Public Service has not shown it lacks the means to safely operate its system without the proposed in-path PRPs, and, as pointed out by Tiger, the Company has not provided a robust economic justification for avoided investment, either.

[155] UET SOP at pp. 6-7.

331. Accordingly, the definition of Primary Receipt Point(s) in the tariff shall read:

> Primary Receipt Point(s)–- Receipt Point(s) specified in the Firm Gas Transportation Service Agreement or amendments thereto as Primary Receipt Point(s) where Receiving Party is entitled to firm gas on Transporter's System under either Firm Gas Transportation Service or the On-Peak Demand Quantity Option under Interruptible Gas Transportation Service on Transporter's System.

332. As discussed below, Public Service remains authorized to assess an Unauthorized Overrun Penalty in the event that a Shipper fails to comply with an order by Public Service to a Primary Receipt Point and continue to use Secondary Receipt Point(s).

B. Unauthorized Overrun Penalty

333. Public Service proposes an increase to the unauthorized overrun penalty in the gas transportation and interruptible sales schedules to encourage compliance with Operational Flow Orders (OFOs), curtailment orders, and direction to primary receipt points.

334. In the Gas Transportation Terms and Conditions, Public Service proposes to expand the definition of the "Unauthorized Overrun Penalty" to include:

> Unauthorized Overrun Penalty – An amount charged (i) to a Shipper in the event a Shipper's deliveries exceed an OFO Tolerance Level; (ii) to a Shipper receiving Firm Transportation Service or the On Peak Demand Quantity Option under Interruptible Transportation Service that fails to comply with an order by Transporter directing the Shipper to a Primary Receipt Point and such Shipper continues to use Secondary Receipt Point(s); or (iii) ~~and~~ to an Interruptible Transportation Shipper transporting Gas above its On Peak Demand Quantity in the event of an Interruption. Transporter will provide Shipper notice of the applicable Unauthorize Overrun Penalty.

335. In its SOP, Public Service explains that the Unauthorized Overrun Penalty is designed to incentivize proper action (*i.e.*, move to a primary receipt point, respond to an Operational Flow Order, or interrupt), so the marketer does not engage in arbitrage to the detriment of all other customers. Thus, in a related change to the tariff, Public Service modifies the terms for issuing OFOs as follows:

> Transporter shall have the right to issue OFOs that require Shipper action to alleviate conditions that threaten or could threaten the safe operation or integrity of Transporter's System or to maintain operations required to provide efficient and reliable firm gas service. In addition, Transporter may call an OFO at any time during the Gas Day, if the OFO is directed at a Shipper or limited number of Shippers within an Operational Area.

336. Public Service also seeks to increase the unauthorized overrun penalty in include the market price of gas per CIG Rockies Index plus the current penalty of $25/Dth in the Firm Gas Transportation Tariff (Schedule TFS), as follows:

> Unauthorized Overrun Penalty, per Dth:
>
> Maximum Rate, per Dth: $25.00 plus the market price of gas per the CIG Rockies Index as published by Gas Daily.
>
> Minimum Rate, per Dth………………. 2.7167

337. Public Service contends that the increased penalties provide the necessary financial incentive for Shippers and interruptible sales customers to comply with curtailment orders called to ensure adequate pipeline capacity for safe and reliable service.[156]

338. Tiger objects to Public Service's proposed changes to the unauthorized overrun penalty, arguing that the change is excessive and unnecessary. Tiger contends that there would be no maximum that could be charged[157] and that the Company would be able to call an OFO at any time, for any reason.[158] Tiger also argues that there is no evidence that the current Unauthorized Overrun Penalty provides inadequate incentive and that current rate design accounts for costs associated with the Unauthorized Overrun Penalty.[159] Tiger also voices concern that Public

[156] Hrg. Exh. 108 Bailey Direct at p. 29:3-13.
[157] Hrg. Exh. 1000 Thomson Answer at p. 16:20-22.
[158] Hrg. Exh. 1000 Thomson Answer at p. 17:1-5.
[159] Tiger SOP at p. 24.

Service does not have a process for assessing a penalty for failure to use a Primary Receipt Point during an OFO and contends that the tariff does not include a provision for such a process.[160]

339. Tiger further argues that the Company's Gas Transportation System (GTS) which pulls information from the Company's SCADA and sends the data to Shippers about two days later, lacks accuracy and immediacy[161] and therefore cannot be relied upon by shippers to balance their deliveries. Tiger faults the GTS as the reason the Company increasingly calls OFOs and curtailments and asks the Commission to deny increases in the Unauthorized Overrun Penalty until Shippers are assured of receiving accurate and timely information regarding their customers' volumetric usage.[162]

340. Echoing Tiger, UET characterizes as unfair and unreasonable the imposition of the Unauthorized Overrun Penalty and potential termination for failure to use in-path Primary Receipt Points, contending the data supplied by GTS is not accurate and compliance with the in-path requirement would be extremely difficult.

341. We approve Public Service's proposed definition of the "Unauthorized Overrun Penalty." It is reasonable for Public Service to require deliveries to Primary Receipt Points when an OFO has been called. The penalty serves to cause Shippers to use Primary Receipt Points instead of Secondary Receipt Point(s) to alleviate conditions that threaten or could threaten the safe operation or integrity of Public Service's system.

342. However, we reject Public Service's proposed modification to the definition of an OFO. The proposed provisions "to maintain operations required to provide efficient and reliable

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[160] Hrg. Exh. 1000 Thomson Answer at p. 17: 13-19.
[161] Tiger SOP at p. 6.
[162] Tiger SOP at p. 23.

firm gas service" are insufficiently defined. The OFO is important for ensuring system safety and reliability. If an OFO is supposed to also address circumstances when system economics require more controls over Shippers, a far more robust economic analysis is necessary to support such a proposal. Tiger has presented evidence that such a robust economic analysis is lacking in the record in this proceeding.

343. We approve Public Service's tariff schedule setting the maximum Unauthorized Overrun Penalty amount equal to $25.00 per dekatherm plus the market price of gas per the CIG Rockies Index as published by Gas Daily. Such a penalty will serve as a proper financial incentive for Shippers and interruptible sales customers to comply with curtailment orders called to ensure adequate pipeline capacity for safe and reliable service.

344. Certain advocacy of the shippers in this Proceeding raises concerns about potential shortcomings of the Company's GTS (Quorum). However, we have insufficient information to determine the validity of these allegations and to effectively address the specific issues they raise for shippers. If a formal examination by the Commission is warranted regarding the GTS, a shipper should file a petition for the Commission to open an investigation. The petition filing would elicit responses from Public Service and, if an investigation is opened, the examination of the GTS would allow a full review process that includes Public Service, Staff, and other interested parties.

C. 1/24th Rule

345. Currently, Shippers must cause gas to be tendered at receipt points at a constant hourly flow rate throughout the day, equal to a flow rate of 1/24 of the daily scheduled quantity. However, the Company proposes to modify its tariff so that if a shipper's flow is inconsistent, the Company can restrict receipt or delivery quantities. Additionally, if the maximum hourly flow rate is above the 1/24 requirement, the Shipper could be required to pay for system reinforcements to

provide firm service consistent with the Company's Distribution Extension Policy or the Company might implement flow control equipment at the shipper's expense.[163]

346. Tiger objects to the 1/24 requirement as not in the public interest and asserting that the Company provides no evidence to support the change. Tiger notes that Shippers do not control the rate that gas is tendered over the system, thus the rule would unfairly punish them for circumstances beyond their control. Additionally, few customers use gas at a consistent rate. Tiger also argues that the requirement would be prejudicial to transportation customers because it would not necessarily be imposed on the Company's gas sales customers.[164]

347. UET also objects to the 1/24 requirement because the Company provides no evidence to support the proposed change and because the change would be unfair and unreasonable because Shippers do not receive hourly usage information, nor can they control the speed at which the system accepts gas.

348. WoodRiver also objects to the Company's 1/24 rule to delivery points, contending that it is unfair to end-use customers and infeasible to administer because customers don't consume gas at a constant rate.[165] Although the 1/24th Rule is intended to address capacity concerns, WoodRiver argues that the Company has not shown how the rule relates to capacity or addresses issues of capacity constraints and notes that only transportation customers would be subject to the 1/24th rule. WoodRiver argues the Company is proposing discriminatory regulation by creating a rule that applies to transportation customers but not the Company's sales customers.[166]

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[163] Tariff sheets T-27 and 28, Hrg. Exh. 108 Att. SLB-1.

[164] Tiger SOP at p. 30.

[165] Hrg. Exh. 1300 Krattenmaker Answer at p. 16:8-12.

[166] WoodRiver SOP at pp. 8-10.

349. In response to WoodRiver, Public Service clarifies that the rule does not require a precise flow rate for each hour but requires Shippers to establish proper contractual Maximum Daily Quantities, to use nomination cycles and telemetry to track customer consumption, and to respond if capacity is not available to support excessive hourly flows. The Company also contends the requirement supports appropriate hydraulic modeling and minimizes the need for capacity projects.[167]

350. We share the Shipper's concerns that the proposed 1/24th rule is not feasible to administer and enforce. Public Service should develop another approach to ensure that Shippers establish proper contractual Maximum Daily Quantities and make necessary adjustments within the available nomination cycles. The intervening shippers are correct that it is not shippers but their suppliers who cause gas deliveries throughout the day. We also agree with WoodRiver that Public Service has not shown how the proposed rule relates to capacity or addresses issues of capacity constraints.

D. Shipper Gas Nominations and Balancing

351. Public Service proposed no changes to the provisions in its Transportation Terms and Conditions governing the monthly cashout of over-deliveries and under-deliveries of gas by Shippers. In the event of Imbalances less than or greater than 5 percent at the end of any month, the Company will correct the imbalance to zero percent by purchasing from or selling to the Shipper, as applicable, the amount of gas necessary to bring the Imbalance to zero percent. Gas sold to the Shipper to make up under-deliveries will be charged at 125 percent of an index price and purchases of over-deliveries will be bought at 75 percent of the index. Public Service notes

[167] Public Service SOP at p. 40.

that the five percent tolerance was part to the 2019 Gas Rate Case and was approved by the Commission.

352. A M Gas raises objections to these cashout policies even though they are not proposed to be modified by the Company in this proceeding. At a high level, AM Gas states that while it is appropriate for the Company to encourage a Shipper to be as accurate as possible, the cashout terms "are too severe given the uncertainties involved. A M Gas contends that the difference between the Company's cost for gas and the cashout price means the cashout price is a penalty."

353. If the Commission agrees with the Company on this point, A M Gas requests the Commission require a cashout only for imbalances that are outside the five percent tolerance band or allow the entire balance to be cashed out at 25 percent above Public Service's estimated cost based on based on index pricing.

354. Public Service objects to this proposal, stating that it would simply relieve Shippers from their responsibility to understand and appropriately manage their customers and usage. Public also notes the GCA rate is specifically tied to the five percent balancing tolerance. [168]

355. We deny the requests of A M Gas regarding the monthly cashout, as we do not want to disrupt the move to a five percent tolerance band established in the 2019 Gas Rate Case. We are also persuaded by Public Service's explanation that shippers now pay a GCA rate that is specifically tied to this five percent balancing tolerance, and that the higher price for over-supplied and lower price for under-supplied marketer gas specifically encourages shipper balancing, which avoids the Company having to purchase or sell gas to make up for a shippers' imbalance.

[168] Public Service SOP at p. 40.

E. Security and Deposits

356. Public Service proposes to evaluate an existing shippers' continued creditworthiness and require additional security as it deems appropriate, apply security against unpaid shipper bills after 60 days, and remove the cash deposit requirement for receiving parties that execute their own transportation service agreements with Public Service.

357. A M Gas objects to this tariff modification as arbitrary and unfairly penalizing marketers in determining financial risk and refunds of security deposits. A M Gas contends there is no risk difference between sales customers and marketers. A M Gas further refutes Public Service's arguments that a shipper's lack of a physical business addresses and the shipper's aggregation of customers should factor into its risk evaluation. A M Gas contrasts the tariff's security requirement for shippers, that includes review of financial statements, senior unsecured debt, and credit ratings, with that for commercial sales customers, which requires just an Experian credit score evaluation.

358. A M Gas contends that, at a minimum, all customers should be provided the same security refund provisions, noting that commercial customers' deposits are refunded after 12 months but marketers are not offered deposit refunds.[169]

359. WoodRiver agrees that security requirements should be reevaluated based on actual level of risk presented by an individual Shipper. WoodRiver maintains that this evaluation should be transparent, but WoodRiver states that Public Service does not provide guidance on how it determines security amounts. Because of this, WoodRiver contends the proposed tariff for security requirements could lead to unjust and discriminatory results. WoodRiver requests the Commission

[169] A M Gas SOP at p. 4.

require Public Service to include explicit recognition that security requirements shall be lowered when a Shipper's risk decreases.

360. Public Service clarifies that in calculating the security, the Company looks at the entire potential exposure to reduce risk to the Company or its other customers and explains that Gas Transportation charges might include unauthorized overrun penalties and future penalties.[170] The Company rejects the arguments made by A M Gas, stating that marketers don't bear the same risk as an end-user Receiving Party because the Company can shut off gas to a Receiving Party because the Receiving Party has a physical location, but cannot do the same with a shipper.[171]

361. We authorize Public Service to make the proposed tariff changes related to security and deposits. We find that the proposed modifications are warranted given prevailing high and more volatile natural gas costs. The modified language to the tariff sheets enhances the language being replaced and the degree of change—in terms of tariff language but perhaps not in terms of monetary amounts due to high gas commodity costs—is not as material as A M Gas suggests. However, we agree with WoodRiver that Public Service must disclose how specifically it intends to conduct its analysis of credit and risk and how that analysis will relate to the establishment of security requirements. We therefore direct Public Service, in its next base rate proceeding, to set forth further details in its Transportation Terms and Conditions how specifically it intends to conduct its analysis of credit and risk and how that analysis will relate to the establishment of security requirements, per the recommendations of WoodRiver.

362. While we authorize Public Service to make the proposed tariff changes related to security and deposits, we also direct Public Service to add a provision to that same section of its

[170] Hrg. Exh. 138 Duggirala Rebuttal at p. 13:5-11.
[171] Hrg. Exh. 138 Duggirala Rebuttal at pp. 9:19-10:10

Transportation Terms and Conditions to permit the reevaluation of security requirements upon the request of a shipper seeking a reduction in such requirements based on a reasonable showing of a material reduction in the shipper's risk to the Company. We agree with WoodRiver about the potential for reductions in security requirements based on reduced risk posed by Shippers in good standing.

F. Access to Customer Records

363. A M Gas requests that the Commission order Public Service to make an option to Shippers to access billing information in the agency agreement signed by transportation customers, contending marketers should have access to billing information at the election of their customers. A M Gas notes the Company has agreed to discuss this option further with Shippers, but also states the Company would not agree to include such on option on its forms as a result of this proceeding. A M Gas states that "a marketer needs as much information as possible to serve its customers."

364. We decline to direct Public Service to make such an option available on any form at this time. As stated above, if there are problems with the GTS (Quorom) and A M Gas or another shipper concludes that a formal examination of the GTS by the Commission is warranted, it should file a petition for the Commission to open an investigation.

G. Terms of Service for Interruptible Customers

365. Public Service proposes changes to its gas tariff that will allow it to call interruptions when the Company determines such are warranted by emergency circumstances, including economic circumstances, conduct curtailment demonstration tests, and move interruptible Receiving Parties and Schedule IG customers to firm service if they fail to meet interruptible service requirements.[172]

[172] Hrg. Exh. 108 Bailey Rebuttal at p. 30:1-7.

366. Staff is generally supportive of Public Service's proposals regarding the terms for service for interruptible customers. However, Staff requests the Commission require Public Service to establish guidelines for choosing the priority of interruptions and increase communications prior to interruptions and to submit a report in its next gas rate case explaining how the changes improved compliance with interruptible services. The report could address the types of communications taking place with interruptible customers, feedback from interruptible customers, results from curtailment demonstration tests, the number of customers being moved to firm service, and annual interruptible sales and revenues.

367. UCA states in its SOP that the Company's proposed changes to the tariffs for interruptible customers are critical for patching the vulnerabilities in the Company's system exposed by Winter Storm Uri. These changes are critical for preserving the safety of the gas system and to protect residential and small commercial ratepayers from unintended liability for the actions of marketers and shipper-customers. UCA further observes that fierce opposition to the Company's proposed tariff changes by certain Shippers "demonstrates the importance to marketers' business models of preserving the ability to deliver gas when and where it is most profitable, *not* when and where it is needed for delivery to end users and to maintain the integrity of the system."[173]

368. However, UCA further recommends requiring moving an interruptible customer to firm rates for any failure to curtail when required to do so and a one-strike rule for failures during a Curtailment Demonstration Test. UCA further calls for a penalty of 24 months of demand charges be assessed of Interruptible customers who do not curtail, in addition to moving the

[173] UCA SOP at p. 40.

customer to a firm schedule.[174] In its SOP, UCA states that a "blatant disregard for safety must end."[175] UCA concludes that failure or refusal of customers to be interrupted "created a threat to public safety" during Winter Storm Uri, and the Commission should prevent that threat from materializing in the future.[176]

369. Public Service expresses concern with UCA's proposals because some shippers might not be able to curtail if their back-up systems fail unexpectedly. Additionally, Public Service states that moving these shippers to firm service would require system capacity, which necessitates a case-by-case evaluation because the current system is modeled only on firm customers.

370. WoodRiver agrees generally that interruptible customers should be required to pass an annual demonstration that they can curtail but contends that such demonstrations are unreasonable for certain customers who do not operate in the winter, when curtailments would be most likely to occur, or customers who can curtail by ceasing to operate. WoodRiver contends that for the latter, shutting down as part of a demonstration test would be burdensome. WoodRiver states that during Winter Storm Uri, these types of customers curtailed when requested. Customers who interrupt by not operating should be able to certify this by not operating rather than completing the actual test.[177]

371. The Company rejects WoodRiver's (and Tiger's) arguments, stating that the changes are necessary in light of the experience during Storm Uri in February 2021 when a number of customers declined to interrupt. Public Service emphasizes its obligation to manage the system overall and the proposed changes to the interruptible tariffs are in the public interest.

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[174] Hrg. Exh. 304 Neil Answer at pp. 11:1-12:14.
[175] UCA SOP at p. 41.
[176] *Id*.
[177] WoodRiver SOP at pp. 4-5.

372. Annual certification by a customer of its ability to curtail by not operating does not replace the assurances offered by an actual test. We therefore approve Public Service's proposed changes to its tariff related to interruptible service.

373. We also agree with WoodRiver that the Company must exercise reasonability and common sense in conducting testing. However, we find that an actual test is a necessary step to ensure customers are willing and able to interrupt when required despite WoodRiver's contention that an actual test is unnecessary in certain instances. We note that while annual testing is necessary, it is not unreasonable to conduct such testing outside of the peak demand season when the specific circumstances of the customer's usage indicate there is generally no usage to interrupt during such periods.

XII. OTHER REQUESTS

A. Customer-Owned Yard Lines (COYLs)

374. In its SOP, Public Service explains that the Company's current plan to address customer-owned yard lines (COYLs) was established by the settlement approved in the 2020 Gas Rate Case. The Company agreed to identify COYLs in its service territory as part of the three-year leak survey rotation established in that settlement. After the first year of survey (2020), the Company had identified approximately 2,750 COYLs and provided proper notice and information to customers.

375. Staff recommends that the Commission require Public Service to address leaks associated with COYLs and farm taps in that leak survey program, contending that this additional work could be done at minimal cost to ratepayers.[178]

[178] Hrg. Exh. 604C Ramos Answer at p. 102:10-19.

376. Public Service asks the Commission to reject Staff's suggestion, requesting to be allowed to complete its current three-year leak survey and its COYL identification cycle before providing a full proposal, with cost estimates and support, on how best to address COYLs including leaks associated with COYLs. The Company states it will continue its annual updates and participate in any associated rulemaking.

377. Public Service states that it has not fully identified or quantified the COYLs in its service territory. The Company argues that, given that it has not yet identified or quantified the number of COYLs in its service territory and has not identified the total capital and O&M costs of replacement, and that the question whether maintaining a COYL if replacement were not permitted by the customer or Commission remains unanswered, the Company proposes to complete the current three-year leak survey and COYL identification cycle before further advancing its COYL proposal.

378. We agree with Public Service that it should complete its current leak survey and decline to modify that survey per Staff's suggestion regarding COYLs and farm taps. Public Service shall continue to prepare to act on the COYLs in its service area in accordance with forthcoming proposals and Commission rules.

B. Gas Storage Inventory Costs

379. Staff objects to Public Service earning its WACC on natural gas held as inventory in storage, the Gas Storage Inventory Cost (GSIC). Staff contends gas storage inventory is a demonstrably temporary, volatile short-term asset and the carrying charge on such inventories should be a short-term financing rate instead of the Company's WACC.[179] Staff rejects as irrelevant Public Service's contention that it funds its operations with a mix of internally generated

[179] Staff SOP at p. 25.

funds, short- and long-term financing, noting that the Commission has segregated certain regulatory asset for individual financing treatment. Staff also challenges Public Service's argument that FERC accounting rules require gas storage costs as a rate base asset and notes that FERC rules do not address what is included in rate base.

380. In support of its position that the GSIC should earn a WACC return Public Service cites to Decision No. C13-1568 in Proceeding No. 12AL-1268G, in which the Commission allowed the GSIC to be treated consistent with other assets in determining a return and acknowledged that different types of financing are used to cover storage gas costs.

381. We agree with Staff that the return on gas storage inventories should be at the cost of short-term debt, not at the WACC, given the temporary and volatile nature of the asset. The Commission has significantly modified its approach to setting returns on items included in a utility's rate base since the 2012 gas rate case cited by the Company.

C. Bill Redesign Costs

382. The settlement in Public Services 2021 electric rate case, Proceeding No. 21AL-0317E, requires Public Service to undertake a redesign of its customers' bills. In this Proceeding, Public Service states that it is unclear what the required bill redesign will entail but contends that if the redesign includes all operating companies, the gas utility should bear its allocated costs.[180]

383. Staff opposes the Company's proposal, because the proposed bill redesign is part of an electric rate proceeding for electric utility service and the settlement in that case did not contemplate the inclusion of bills for gas utility service. Staff further contends that gas bills are

[180] Public Service SOP at p. 32.

less complex than electric bills, so the redesign proposals contemplated in the previous rate case do not apply.

384. We agree with Staff's arguments and deny inclusion of bill redesign costs in this Proceeding.

D. Requests of the Parties Not Discussed by the Commission

385. Public Service requests approvals of several items that were not addressed by any intervening party. These uncontested requests of the Company are deemed approved.

386. All contested requests of the parties not discussed by the Commission in this Decision, including requests of Public Service contested by one or more of the intervening parties, are denied. All uncontested requests put forward by intervening parties not discussed by the Commission in this Decision are also denied.

XIII. CONCLUSION

387. We have carefully reviewed the extensive evidentiary record in this Proceeding, mindful of the public comments submitted in writing and offered orally at a public comment hearing on August 18, 2022.

388. Based on this review of the extensive evidentiary record, our consideration of the SOPs filed by Public Service and the intervening parties, and our deliberations, we establish new rates to recover the Company's expenses and provide the Company a reasonable opportunity to earn a fair rate-of-return. Consistent with the discussion above, we are establishing just and reasonable base rates in this Proceeding, not adopting the individual components of the COSS, the CCOSS, and the calculated revenue requirement presented by the Company and modified by this Decision.

389. The new rates, terms, and conditions of service filed by Public Service with Advice Letter No. 993-Gas as modified by this Decision are just, reasonable, and non-discriminatory.

390. The rates, terms, and conditions for service not specifically discussed in this Decision are just and reasonable and are approved as well. (For example, Public Service is authorized to update the Schedule of Charges for Rendering Service on Sheet Nos. 12 and 12A.)

391. We permanently suspend the tariff sheets filed with Advice Letter No. 993-Gas and cause an effective implementation date of November 1, 2022 for the new rates, terms, and conditions for service established by this Decision. In lieu of the rates and other tariff changes originally proposed in the tariff sheets filed with Advice Letter No. 993-Gas, Public Service shall make a compliance advice letter and tariff filing on not less than two business days' notice to place the new rates, terms, and conditions for service into effect on November 1, 2022.

392. The tariffs filed by Public Service with Advice Letter No. 993-Gas on January 24, 2022, will be permanently suspended, and will not become effective.

XIV. COMPLIANCE PROCEDURES

393. 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.

394. For the rates, terms, and conditions approved for effect November 1, 2022, 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 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. 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.

395. Consistent with the discussion above, Public Service shall include in its tariff filing for rates, terms, and conditions for effect November 1, 2022 updates to the tariff sheets for its line extension policy that set forth updated construction amounts for effect November 1, 2022. While the construction allowances set forth on the tariff sheets for the Company's line extension policy shall not be modified as proposed by Public Service in this proceeding, the Company shall modify the tariff sheets to eliminate the off-site distribution credit for effect November 1, 2022.

396. On not less than two business days' notice, Public Service shall file certain compliance tariff sheets addressing its line extension policy to further modify its line extension policy, as required by this Decision, for effect November 1, 2023. Consistent with the discussion above, Public Service shall determine whether updated construction allowances calculated according to the method proposed by Staff in this Proceeding, involving the use of net instead of gross average embedded costs based on the data underlying the selected HTY, results in lower construction allowance amounts relative to the amounts continued for effect on November 1, 2022 by this Decision. The updated net embedded cost amounts for the construction allowances will be allowed to replace those that will take effect on November 1, 2022 only if they are lower than those continued for effect on November 1, 2022. Regardless of whether any of the construction allowances change, the updated line extension policy for effect on November 1, 2023 shall require customers eligible to receive the construction allowance to bear 50 percent of the costs of the meters and regulators required to serve the customer, consistent with the discussion above.

397. The advice letter and tariff sheets for the modified line extension policy for effect November 1, 2023 shall be filed as a new advice letter proceeding 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. 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.

XV. ORDER

A. The Commission Orders That:

1. The effective date of the tariff sheets filed by Public Service Company of Colorado (Public Service) on January 24, 2022 with Advice Letter No. 993-Gas is permanently suspended and shall not be further amended.

2. The tariff sheets filed with Advice Letter No. 993-Gas are permanently suspended and shall not be further amended.

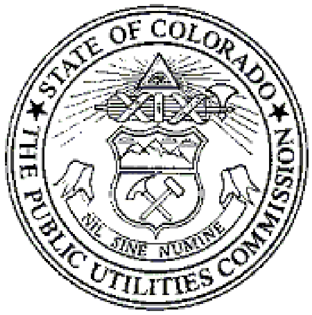
3. In accordance with the discussion above, Public Service shall file advice letter compliance filings to modify the tariff sheets in Colorado PUC No. 8 consistent with the findings, conclusions, and directives in this Decision.

4. 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.

5. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS AND WEEKLY MEETINGS
September 28 and 30, 2022 and October 5 and 19, 2022.**

(S E A L)



ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners