Decision No. C23-0413

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 22A-0309EG

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF A NUMBER OF STRATEGIC ISSUES RELATING TO ITS ELECTRIC AND GAS DEMAND SIDE MANAGEMENT AND BENEFICIAL ELECTRIFICATION PLAN.

COMMISSION DECISION GRANTING APPLICATION WITH MODIFICATIONS, REQUIRING FILINGS, AND ISSUING CERTAIN DIRECTIVES TO GUIDE NEXT DSM PLAN FILING

Mailed Date:	June 22, 2023
Adopted Date:	May 11, 2023, May 17, 2023, and May 26, 2023

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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Application of Public Service Company of Colorado (Public Service or the Company) filed on July 1, 2022, which requests the Commission approve the proposals contained in the Company's Demand Side Management (DSM) and Beneficial Electric (BE) Strategic Issues application (Application).

2. Based on the record established in this Proceeding, we grant the Application with modifications and establish energy savings and budgets for 2022 through 2026.

3. The Commission also considers, and grants, the outstanding motions in this Proceeding, as discussed below.

B. Procedural History

4. On July 1, 2022, Public Service filed its Application and Direct Testimony requesting Commission approval of the proposals contained in the Company's DSM and BE strategic issues Application. Concurrent with its Application, Public Service filed a motion on July 1, 2022, requesting the Commission grant a waiver of the requirements in Rule 4754(g)(I) of the Commission's Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* (CCR) 723-4, associated with the structure of the incentive in the Company's natural gas DSM programs (Motion for Waiver).

5. By Decision No. C22-05315-I, issued September 6, 2022, the Commission set the Application for hearing and established the following parties to this Proceeding: Trial Staff of the Commission (Staff); the Office of the Utility Consumer Advocate (UCA); and the Colorado

Energy Office (CEO); City and County of Denver (Denver); the City of Boulder (Boulder); Climax Molybdenum Company (Climax); the Colorado Energy Consumers (CEC); Natural Resources Defense Council and Sierra Club (collectively, the Conservation Coalition); the Colorado Renewable Energy Society (CRES); the Energy Efficiency Business Coalition (EEBC); Energy Outreach Colorado (EOC); the Southwest Energy Efficiency Project (SWEEP); and Western Resource Advocates (WRA).

6. On or around November 1, 2022, Public Service filed Supplemental Direct Testimony, as directed by the Commission through Decision No. C22-0548-I.

7. On October 21, 2022, Public Service filed a Motion for Extraordinary Protection of Highly Confidential Information, which the Commission granted by Decision No. C22-0664-I, issued October 28, 2022.

8. On November 3, 2022, Public Service filed a Second Motion for Extraordinary Protection of Highly Confidential Information, which the Commission granted by Decision No. C22-0720-I, issued November 14, 2022.

9. On January 30, 2023, Boulder, the Conservation Coalition, SWEEP, and WRA (Stipulating Parties) filed a Stipulation stating that they have agreed to collectively support specific intervenor recommendations on the following five issues: (1) Beneficial Electrification Goals and Budget; (2) electric Demand Response (DR) goals; (3) budget flexibility for BE and electric energy efficiency; (4) incentives for gas water heaters and mixed-fuel Energy Star New Homes; and (5) Performance Incentive Mechanisms and income-qualified programs and benefits (Stipulation).

10. On February 1, 2023, the Commission held a remote public comment hearing. The Commission also received written public comment throughout the Proceeding from members of the public, Public Service customers, third-party providers of energy services, and community and business groups, which are part of the administrative record of this Proceeding.

11. On February 6, 2023, through February 9, 2023, the Commission convened an evidentiary hearing, during which parties had opportunity for cross examination and the Commissioners questioned certain witnesses. In addition, the Commission admitted Hearing Exhibit 1600 and all of the documents listed thereon into evidence. These documents consist of all of the pre-filed testimony and attachments in the Proceeding. In addition, during the course of the hearing, the following hearing exhibits were offered and admitted into the record: hearing exhibits 103 (Rev. 1); 112 (Rev. 1); 114 (Rev. 1); 113, Att. SWW-3 (Rev. 1); 115 (Rev. 1); 116 (Rev. 1); 116, Att. MRS-9 (Rev. 1); 1201 (Rev. 1); 1102 (Rev. 1); 402; 403; 140; 139; 1405; 1406; 1407; 1103; 302; 1106; 706; 144; 803; 1204; 1205; 1002; 1508; 1509; 705; 141; 702, Att. SR-17; 1408; 127; 128; 129; 130; 131; 1506; 1505; 118; 1507; and 142. Administrative notice was taken of hearing exhibits: 903; 405; 804; 709; and 142.

12. On March 10, 2023, Public Service, EEBC, Denver, CRES, SWEEP, Boulder, WRA, Conservation Coalition, CEC, UCA, EOC, Staff, CEO, and Climax, each filed a statement of position (SOP).

13. The Commission conducted live deliberations in this Proceeding on May 11, 2023, at a Commissioners' Deliberations Meeting, at the Commissioners' Weekly Meeting on May 17, 2023, and at a Commissioners' Deliberation Meeting on May 26, 2023, resulting in this Decision.

C. Background and Statutory Requirements

14. In the Application, Public Service explains that a DSM strategic issues proceeding is intended to address the Company's goals, budgets, policies, and procedures to inform future DSM plans. This Proceeding is the fifth in which the Commission, Public Service, and interested stakeholders examine the policies that will shape the Company's future DSM plan filings. Strategic issues proceedings establish higher-level policy parameters, such as program achievement goals, budgets, and cost-effectiveness frameworks, which guide subsequent plan proceedings. Although strategic issues proceedings occur less frequently, they provide a policy framework which allows programmatic matters to be considered without needing to repeatedly litigate methodological considerations.

15. Public Service implements electric and gas DSM programs pursuant to §§ 40-1-102, 40-3.2-103, 40-3.2-104, 40-3.2-105.5, 40-3.2-105.6, 40-3.2-106, and 40-3.2-107, C.R.S., and beneficial electrification programs pursuant to § 40-3.2-109, C.R.S. Historically, the Company has set electric DSM program goals through electric DSM strategic issues proceedings which cover approximately four-year intervals, with intervening DSM plan filings pursuant to § 40-3.2-104(2)(a), C.R.S.

16. For gas DSM, pursuant to § 40-3.2-103(1), C.R.S., commencing in 2022 and at least every four years, Public Service must file an application to open a gas DSM strategic issues proceeding to develop energy savings targets to be achieved by the utility, taking into account its potential for cost-effective DSM as well as statewide greenhouse gas emission goals. The statute directs the purpose of such proceedings will be to develop energy savings targets to be achieved by the gas utility, taking into account, its potential for cost-effective DSM as well as statewide greenhouse gas emissions reduction goals. The statute directs the Commission, as part of

approving the utility's application, to develop an estimated DSM budget commensurate with the natural gas savings targets, establish funding and cost-recovery mechanisms, and develop a financial bonus structure for DSM programs implemented by the gas utility.

17. Public Service notes that this strategic issues proceeding differs from prior matters because it also includes beneficial electrification. This is the Company's first BE strategic issues proceeding. Pursuant to § 40-3.2-109(6)(a), C.R.S., by April 1, 2024, and thereafter no less than every six years, each electric utility shall file an application for a BE strategic issues filing that proposes a 10-year BE target and objective criteria for measuring progress toward attainment of the target, which criteria may include the level of substitution of renewable sources for fossil fuel or the level of reduction in greenhouse gas emissions.

18. In addition to the inclusion of beneficial electrification in this strategic issues Application, the scope of this Application is greater than previous strategic issues proceedings because of increased emphasis on (1) reducing greenhouse gas emissions and (2) increased emphasis on access to programming for income-qualified (IQ) customers.

19. This increased emphasis on reduction of greenhouse gases is consistent with recent legislative changes, including additions to: (1) § 40-3.2-103, C.R.S., which now expressly require the Commission to consider Colorado's greenhouse gas reduction goals when reviewing a utility's proposed energy savings targets, added by House Bill (HB) 21-1238; (2) the addition of § 40-3.2-106, C.R.S., from HB 21-1238, which revises DSM program cost-effectiveness to include the social costs of carbon and methane and establishes values for each pollutant; and (3) the addition of § 40-3.2-107, C.R.S., also from HB 21-1238, which requires gas utilities, with Commission oversight, to consider the social cost of methane in planning and evaluating their DSM programs, sets that value to not less than $1,756 per short ton, and defines a discount rate

of 2.5 percent or less for program evaluation. Section 40-3.2-107, C.R.S., also requires the Commission, when calculating the cost of methane emissions, to obtain and apply the best available values for gas leakage during extraction, processing, transport, and delivery phases prior to consumption.

20. The increased emphasis on access to programming for IQ customers is also consistent with recent legislative changes. Section 40-3.2-103(3)(a)(II) – (IV), C.R.S., added by HB 21-1238, establishes minimum expenditure targets for income-qualified customers in gas utilities' DSM programs. The statute requires that at least 25 percent of overall residential gas DSM program expenditures be targeted at serving residential customers in income-qualified households.

21. Public Service states, at this point, a combined filing of gas DSM, electric DSM, and beneficial electrification, reduces the burden for parties, allows for a more holistic consideration of DSM, including issues that impact both the Company's natural gas and electric utility services, and is consistent with the allowance in recent Senate Bill (SB) 21-246, effective September 7, 2021, codified at § 40-3.2-109(6)(b), C.R.S., for combined BE and DSM strategic issues filings. Public Service states that, similar to previous strategic issues proceedings, this filing was designed to seek Commission re-examination and approval of the overall objectives and structure of Public Service's DSM initiatives to guide the Company in designing future DSM plans.

D. Energy and Demand Savings Goals and Budgets

1. Electric Energy Efficiency

22. Section 40-3.2-104(2)(a), C.R.S., directs the Commission to establish energy savings and peak demand reduction goals for Public Service and other investor-owned utilities,

taking into account the utility's cost-effective DSM potential, its need for electricity resources, benefits of DSM investments, and other factors determined by the Commission. Pursuant to § 40-3.2-104(2)(c), C.R.S., commencing January 1, 2019, the electric energy savings and peak demand reduction goals must be at least five percent of the utility's retail system peak demand, measured in megawatts, in the base year and at least five percent of the utility's retail energy sales, measured in megawatt-hours, using a 2018 base year.

a. Public Service Proposals

23. In its direct case, Public Service originally proposed goals of 415, 357, 317, and 289 gigawatt hours (GWh) for 2024, 2025, 2026, and 2027 respectively.[1] The Company argued that the reduced savings expectations (compared to the annual 500 GWh goal in place for 2019-2023) is justified because of the elimination of the Home Lighting Product program.[2] On rebuttal, the Company revised its savings goals to 450 GWh per year for years 2024-2026 with a corresponding $90 million per year budget, with no budget flexibility due to concerns regarding bill affordability.[3]

[1] Hrg. Ex. 102 (Mark Direct) at 36.

[2] Hrg. Ex. 102 (Mark Direct) at 19, 36.

[3] Hrg. Ex. 113 (Mark Rebuttal) at 3. Viewed on a unit-cost basis, Public Service's energy efficiency costs equate to $200/ MWh.

24. According to Public Service, the proposed declining goals and targets for electric energy efficiency are consistent with the results of the Company's 2022 Potential Study (Potential Study)[4] and are appropriate because the fundamental market factors that underlie electric and natural gas energy efficiency are diverging. Public Service argues that while the Company has historically been successful in achieving electric energy efficiency savings beyond the results of prior potential studies, with the increasing saturation of key end uses and the improved calibration in the Potential Study, it is not reasonable to assume that pattern will continue in the future.[5]

b. Intervenor Positions

25. Various intervenors proposed differing goals and budgets for electric energy efficiency.

26. UCA suggests the Commission maintain the Company's proposed original savings goals, but lower the budget considerably to budget caps of \$79.7 million for 2024, \$68.5 million for 2025, \$60.8 million for 2026 and \$55.5 million for 2027, with no budget flexibility.[6]

[4] Hrg. Ex. 102, Attachment NCM-1.
[5] Hrg. Ex. 102 (Mark Direct) at 19, 36.
[6] UCA SOP, p. 2. On a dollar per MWh basis, UCA's proposal translates to \$166 to \$157 per MWh.

UCA also argues that the Commission should continue to require Public Service to spend at least 25 percent on residential electric DSM throughout the years involved in this strategic issues proceeding. UCA notes this is consistent with the Commission's approval of the Company 2017 DSM strategic issues proceeding in Decision No. C18-0417, in Proceeding No. 17A-0462EG, and that § 40-3.2-104(4), C.R.S., requires the Commission to ensure that electric utilities "give due consideration to the impact of DSM programs on nonparticipants and low-income customers." UCA argues that its proposed budgets are appropriate because the Company has not provided evidence as to how it will make up reduction in lighting programs savings and also argues that the DSM budgets need to match the energy savings goals.[7]

27. CEC argues for a firm $90 million cap with no additional budget flexibility.[8]

28. Staff offers two budget options for the Commission to consider. Its first option includes a base budget of $78 million with ten percent budget flexibility. Staff's other option presented authorizes a $65 million base budget with a 20 percent flexibility value.[9] Staff suggests budget emphasis should be placed on gas DSM and beneficial electrification in anticipation of the 2023 Clean Heat Plan, and that its proposed options would free up $12 million and $25 million, respectively, on average per year. Staff argues that since Public Service is on track to meet its statutory electric DSM goals in 2022, electric energy efficiency goals and budgets do not need to be increased or remain at their current levels to meet the deadline established in § 40-3.2-104(2)(c), C.R.S., which requires by 2028 that a utility's energy savings

[7] UCA SOP, p. 5.

[8] CEC SOP, p. 3.

[9] Hrg. Ex. 900 (Soufiani Answer) at 44-46. On a dollar per MWh basis, Staff's first proposal translates to $143 per MWh and its second proposal translates to $160 per MWh.

and peak demand reduction goals are at least five percent of the utility's retail system peak demand (in MW), using a 2018 base year.[10]

29. CEO recommends the Commission adopt the Company's Rebuttal Testimony position of an annual net electric energy savings goal of 450 GWh for 2024-2026 with an annual budget of $98.7 million.[11]

30. Conservation Coalition generally argues for higher budgets and savings goals, requesting the Commission set a 455 GWh goal each year with a $98.9 million annual budget.[12] It also contends that this strategic issues proceeding is to set a spending *cap*, not a *budget* as is done in a plan proceeding, and that other parties misunderstand that distinction in this proceeding.[13] Conservation Coalition also claims its budget and savings proposals are rooted in quantitative rigor, stating that "each of the DSM and BE goals proposed by the Conservation Coalition is based on a study concluding that these goals are cost-effective: the electric and gas efficiency goals are based on cost-effectiveness analyses in the Guidehouse [Potential] study; the electric DR goals are based on cost-effectiveness analysis in the Brattle study; and the BE goals are based on the cost-effectiveness analysis in the CEO study."[14]

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[10] *Id*. at 29.

[11] CEO SOP, p. 17. On a dollar per MWh basis, CEO's proposal translates to $223 to $264 per MWh.

[12] Hrg. Ex. 701 (Grevatt Answer) at 32-34.

[13] Conservation Coalition SOP, p. 17. On a dollar per MWh basis, Conservation Coalition's proposal translates to $217 per MWh.

[14] Conservation Coalition SOP at p. 30 referring to Polis Letter (Hrg. Ex. 408), directing the Commission to: Maximize the use of federal funds to accelerate the transition to wind, solar, storage and other renewable resources that reduce fuel costs and lower exposure to volatile fuel markets.

31. SWEEP urges the Commission to approve Public Service's proposed electric energy efficiency goals and proposed budget of $92 million but with an added 20 percent budget flexibility.[15]

32. EEBC supports the Commission's rebuttal position of a 450 GWh goal for each year from 2024-2026 and argues that budget flexibility is key so the Commission should give the Company headroom of 20 percent flexibility to reach and exceed their proposed electric energy savings goals.[16]

33. Denver suggests that the Commission adopt Public Service's rebuttal electric energy efficiency goals of 450 GWh annually.[17]

c. Findings and Conclusions

34. We find that an annual electric energy savings goal of 440 GWh for years 2024 through 2026 strikes the best balance between maintaining continuity of the Company's DSM programs and managing the impact on ratepayers, both participants and non-participants. We find this level of energy savings goals reasonable in light of the phase-out of the Company's Home Lighting Program, which is currently a large and successful DSM effort. We also find that this goal strikes a reasonable balance between ensuring the continued success of the Company's DSM programs in reducing energy usage, in maintaining the continuity of programs for customers and program implementers, while still limiting non-participant rate impacts. While this has been expressed by the Commission as a series of annual goals with flat annual spending, nothing here should prevent the Company from presenting plans with some reasonable variation

[15] SWEEP SOP, pp. 11-12. On a dollar per MWh basis, SWEEP's proposal translates to $204 per MWh.
[16] EEBC SOP, p. 8. On a dollar per MWh basis, EEBC's proposal translates to $204 per MWh.
[17] Denver SOP, p. 12. On a dollar per MWh basis, Denver's proposal translates to $222 per MWh.

from year to year, achieving the annual goals established herein on an average basis over the SI period.

35. Regarding electric energy efficiency budgets, we will impose a spending cap of $78 million per year for 2024-2026, to achieve the 440 GWh in savings. We also find it appropriate to institute 20 percent budget flexibility. We note that the goals established above are tied to the base budget of $78 million established here. Instituting a 20 percent budget flexibility in this instance is appropriate due to the uncertainty inherent in the 2024 through 2026-time frame, including the effects of the Inflation Reduction Act (IRA), the phase-out of the residential lighting programs, and the implementation of the social cost of emissions in the cost-benefit analysis. We are mindful of the total impact of DSM expenditures and lost revenues on rates and find that this budget for electric energy efficiency works in concert with our other findings in this Decision on gas energy efficiency and beneficial electrification to establish a reasonable ratepayer impact overall. As with the savings goal, the Commission anticipates that the Company could present some variation in budget from year-to-year, while achieving the established budget limit here on an average basis over the course of the SI period.

36. We also agree with UCA that at least 25 percent of the electric DSM budget should be spent on residential customers, including low-income customers. A 25 percent guardrail is also consistent with the Commission's decision in the Company's most recent DSM strategic issues proceeding.[18]

[18] Decision No. C18-0417, in Proceeding No. 17A-0462EG.

37. On balance, this represents a unit cost of approximately $179 per MWh (of first-year energy savings), or alternatively, 5.6 GWh of first-year energy savings per million dollars of electric energy efficiency investment. We find that this unit basis is a reasonable pairing of achievable budgets and goals and is within a range represented by the positions put forth by parties in this proceeding.

2. Beneficial Electrification

38. Pursuant to § 40-3.2-109(2)(a), C.R.S., the Commission shall allow a utility to implement cost-effective beneficial electrification plans that support voluntary customer adoption of beneficial electrification measures. In approving the Company's BE goals, the Commission shall consider: (1) utility potential for cost-effective BE; (2) the state's greenhouse gas reduction targets; and (3) the potential for BE to reduce greenhouse gases.[19]

a. Public Service Proposals

39. In its direct case, Public Service proposed beneficial electrification budgets of $6-$14 million over the 2024through 2026-time frame to achieve savings of 157,000 – 482,000 dekatherms (Dth) per year. However, on rebuttal the Company proposed a goal of $7 million to reach a 200,000 Dth savings for 2024, a $17 million for a 465,000 Dth savings for 2025, and a $32 million budget for reaching an 840,000 Dth savings goal in 2026.[20]

[19] § 40-3.2-109(6)(a), C.R.S.

[20] Hrg. Ex. 113 (Mark Rebuttal) at 4. On a per unit basis, Public Service's proposal translates to $35 per Dth in 2024, S36.6 per Dth in 2025, and $38.1 per Dth in 2026.

40. The Company notes that beneficial electrification and energy efficiency efforts are overlapping subsets of DSM efforts, and that both can achieve fuel switching and a reduction in the amount of energy needed.[21] However, the Company expects that even as BE offerings evolve, some customers will initially adopt dual-fuel systems, particularly for existing homes.[22] It argues that beneficial electrification is not necessarily cost-effective for the Company, its ratepayers, or adopting customers and conducted an analysis of the revenue requirement and bill impacts of BE adoption scenarios across six home types and three infrastructure growth environments.[23] According to the Company's analysis, an electric-only scenario causes a higher total system cost than the dual-fuel BE or Conventional Home with EV Charger scenario.[24] For these reasons, Public Service argues that emission goals are most cost-effectively maintained with natural gas in the heating mix.[25]

b. Intervenor Positions

41. Various intervenors proposed differing goals and budgets for beneficial electrification.

42. The Stipulating Parties suggest a goal of 314,000 Dth in 2024, 779,000 Dth in 2025, and 1,446,000 Dth in 2026, with corresponding budgets of $12 million, $25 million, and $42 million, respectively.[26]

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[21] Hrg. Ex. 102 (Mark Direct) at 54.
[22] *Id*.
[23] *See* Hrg. Ex. 108 (Mark Supplemental Direct) at 7-50.
[24] *Id*.
[25] *Id*.
[26] Stipulation, p. 2. On a per unit basis, the Stipulation's proposal translates to $38.2 per Dth in 2024, $32.1 per Dth in 2025, and $29 per Dth in 2026.

43. Denver argues for even higher goals and budgets of 471,000 Dth supported by a $24 million budget in 2024, a 935,000 Dth goal supported by a $40 million budget for 2025, and a goal of 1,446,000 Dth supported by a $56 million budget in 2026.[27] Denver says that while its proposed values are higher than the Company's proposal, they are substantially lower than other states and Public Service's proposed annual budget is "effectively less than Denver's own investments in BE."[28] Denver also argues that the Commission should look at recent events related to natural gas rates and price volatility to support higher BE goals which should appeal to customers during and after periods of intermittent or sustained high natural gas prices.

44. Staff advocates for an additional BE budget that builds upon the allocations for BE it proposes under its options for electric energy efficiency described above. Specifically, Staff suggests a base goal of 299,000 Dth for 2024 (supported by a $9 million base budget), 451,000 Dth for 2025 (supported by a $13 million base budget), and 639,000 Dth for 2026 (supported by a $17 million base budget).[29] Staff argues against the Stipulation goals specifically because it states that the "Stipulation adds new ratepayer money on top of old money without any budget discipline,"[30] and notes that the Stipulation parties did not conduct any billing impact analysis of the budget proposals in the Stipulation.

45. EEBC supports the goals and budgets proposed by the Company and supports budget flexibility, particularly given the uncertainties around beneficial electrification, including

[27] Denver SOP, p. 5. On a per unit basis, Denver's proposal translates to $51 per Dth in 2024, and $42.8 per Dth in 2025, and $38.7 per Dth in 2026.

[28] Denver SOP, p. 3.

[29] Hrg. Ex. 900 (Soufiani Answer), pp. 7-8. On a per unit basis, Staff's proposal translates to $30.1 per Dth in 2024, and $28.2 per Dth in 2025, and $26.6 per Dth in 2026.

[30] Staff SOP, p. 10.

industry acceptance, so it states it makes sense to preserve the ability of the Company to work with parties to respond to changing market conditions [31]

46. CEO generally supports the Company's revised beneficial electrification budget and goal proposals, but suggests that the Commission provide flexibility in the BE budgets so that the Company can adapt to changes in circumstances, including the potential of higher levels of customer participation in the Company's programs, either as a result of the IRA or other factors.[32] CEO suggests it is likely that the High Efficiency Electric Home Rebate and the Home Energy Performance-Based, Whole Home Rebates program, both funded through the Inflation Reduction Act, which CEO will implement in Colorado after final federal approval, will increase customer adoption of BE measures.[33]

47. CEO also recommends that the Company's future BE and DSM strategic issues proceedings be better coordinated with its Electric Resource Plan (ERP) supply side effort.[34]

48. Conservation Coalition, a party to the Stipulation, supports the higher budget and goals set forth in the Stipulation and argues that the metrics are achievable because they are based off the CEO GDS potential study.[35] WRA, also a party to the Stipulation argues that the Commission should adopt the Stipulation budget and goals because it contends that data presented by the Company shows that exponential growth is not only possible but already happening.[36] WRA also contends that even under the Stipulation goals, the Company will still

[31] EEBC SOP, p. 16.
[32] CEO SOP at 16.
[33] CEO SOP, p.12.
[34] *Id*.
[35] Conservation Coalition SOP, p.16.
[36] Hrg. Ex. 1503 (Fickling Cross Answer) at 4.

fall short of the greenhouse gas emission savings needed by 2025 per the statutory clean heat targets, and is still substantially behind the programs in other states.

49. WRA also faults Public Service for its claims that the IRA's impact will be "relatively immaterial," and it did not account for the IRA in setting goals on a per-customer basis. WRA argues that the IRA and utility incentives present a unique opportunity to rapidly transform the BE market while it is young and that the infusion of federal funding plus a robust BE budget promises to accelerate near-term exponential BE growth with the best chance of a significant payoff.[37]

50. CEC argues for funding levels as proposed in Public Service's direct testimony with no additional budget flexibility. CEC contends the costs and benefits of BE are too uncertain to invest heavily at this juncture.[38]

51. On rebuttal, Public Service disputes that the Stipulation's higher BE goals are achievable and that even under the Company's rebuttal goals, BE participation would need to nearly triple again to achieve its 2024 goal.[39] The Company also cautions against relying on the 2020 CEO GDS Associates Study's "high electrification scenario" because it claims that CEO, the sponsor of the study, supports the Company's BE goals, and not the Stipulation goals based on the study. The Company also claims that SWEEP has provided no analysis of technology adoption that would be necessary to meet their higher proposed goals and no justification for why SWEEP supports a 2x greater goal for 2024, 2.5x greater goal or 2025, or a 3x greater goal for 2026 than proposed by the Company.[40]

[37] WRA SOP, p. 9-10.
[38] CEC SOP, p. 8.
[39] Hrg. Ex. 113 (Mark Rebuttal) at 53-54.
[40] Public Service SOP, p. 14.

c. Findings and Conclusions

52. We find that goals set by averaging the Stipulation's proposal and the Company's proposal for beneficial electrification is reasonable. We therefore find that a goal of 257,000 Dth in 2024, 622,000 Dth in 2025, and 1,143,000 Dth in 2026, with corresponding budgets of $9.5 million, $21 million, and $37 million, respectively, is reasonable and an appropriate level of beneficial electrification goals and spending to establish in this Proceeding. We believe that these goals strike the best balance between encouraging the Company to undertake an initial, ambitious effort into expanding BE offerings and managing any adverse impact on ratepayers, including both participants and non-participants. We find it reasonable to pursue beneficial electrification goals in excess of those put forth by the Company due to many of the positions put forth by intervenors indicating issues with the Company's cost effectiveness methodology, including shortcomings in the Company's beneficial electrification potential study, application of a social cost of methane considerably higher than that which the company put forth, and doubts about the thoroughness of the Company's evaluation of the system costs associated with different home heating types. Finally, we acknowledge the influx of funding through the implementation of the Inflation Reduction Act, is likely to drive increased participation rates above those contemplated in the company's potential study.

53. For many of the same reasons as in our prior decision on electric energy efficiency, we also find it appropriate to allow 20 percent budget flexibility. Instituting a 20 percent budget flexibility in this instance is appropriate due to the uncertainty inherent in the 2024 through 2026-time frame, including the effects of the IRA, the implementation of social cost of emissions in the cost-benefit analysis, and the fact that much of the data provided in this

record precedes the passing of the IRA. The uncertainty and potential for upward growth are amplified in the area of beneficial electrification since this is a new area of work for the utility and technological offerings and additional incentives are expected to change rapidly.

3. Gas Energy Efficiency

54. Section 40-3.2-103(2)(b), C.R.S., requires a utility's natural gas savings targets to reflect the maximum cost-effective and achievable natural gas savings potential of the utility.

a. Public Service Proposals

55. In its direct and rebuttal case, the Company proposes a gas energy efficiency budget of $21 million dollars per year to support a net Dth savings goal of 950,000 Dth in 2024, 1,000,000 Dth in 2025, and 1,050,000 Dth in 2026.[41] Public Service indicates these goals are based on the Potential Study provided by Guidehouse.[42] The Company advocates for 25 percent budget flexibility with an attendant presumption of prudence, pursuant to Rule 4753(k) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4.[43]

b. Intervenor Positions

56. Various intervenors proposed differing goals and budgets for electric energy efficiency.

[41] Public Service SOP, p. 8.
[42] Hrg. Ex. 102, Attachment NCM-1.
[43] Public Service SOP, p 10.

57. Staff recommends reducing the gas energy efficiency goals by 15 percent and adding these natural gas savings to the beneficial electrification goals; this would result in a gas energy efficiency goal of 807,500 Dth for 2024 and a gas energy efficiency goal of 935,000 for 2027.[44] Staff argues this is appropriate because more emphasis on beneficial electrification measures will be important to ensure that the Company's clean heat plan achieves emission reductions at the lowest cost to customers. Staff recommends a corresponding $21.0 million gas energy efficiency budget with a 25 percent flexibility.[45]

58. EEBC argues for a higher gas energy efficiency budget commensurate with the settlement proposed, and approved recently in Proceeding No. 22A-0315G.[46] EEBC urges the Commission to approve the Company's gas energy efficiency savings goals, but should also approve the higher budgeted amount in the process to ensure that the savings can be accomplished and the Company can adequately expand it programs to more IQ households.[47] In addition, EEBC states the Commission should approve 20 percent budget flexibility for gas energy efficiency programs.

59. UCA contends that the gas energy efficiency budget should be reduced to provide more funding for beneficial electrification without increasing overall costs to gas customers.[48] UCA suggests a reduction of gas energy efficiency budgets linearly until it reaches $12 million by 2030. UCA argues the Commission should adopt budgets of $21 million, $19.5 million, $18 million and $16.5 million for 2024 through 2027, respectively.[49] UCA urges the Commission

[44] Hrg. Ex. 900 (Soufiani Answer) at 51.
[45] *Id*. at 54.
[46] EEBC SOP, p. 10.
[47] *Id*.
[48] UCA SOP, p. 10.
[49] *Id*. at 10-11.

to strike a balance between maintaining continuity of the Company's gas DSM programs and managing the impact on ratepayers which it argues is struck with a 950,000 Dth for 2024, and approximate savings goals for 2025 through 2027 for 880,000, 815,000 and 750,000 Dth, respectively.[50] UCA also notes that consistent with § 40-3.2-103(3)(a)(II), C.R.S., the Commission must adopt a gas DSM expenditure budget that meets the requirement that "one of more of the gas DSM programs or measures, representing an aggregate total of at least 25 percent of overall residential gas DSM program expenditures, including expenditures serving income-qualified households, must be targeted to residential customers in income-qualified households."

60. SWEEP supports the Company's proposed budget and goals.[51] It argues that there is a role for gas energy efficiency efforts, particularly for weatherization and building shell measures, even as Colorado proceeds towards decarbonization of buildings by 2050, pursuant to the greenhouse gas Roadmap.[52]

61. WRA argues that a gas energy efficiency budget of $16 million and a 750,000 Dth savings goal is appropriate for 2024, and that the goals and budget should escalate to $18 million and 850,000 Dth by 2030.[53] WRA argues that eliminating incentives for market-rate residential and commercial gas spacing heating (except large commercial boilers) by December 31, 2027 (discussed further below below), will free up 20 percent of the gas energy efficiency budget for other uses, such as building envelope improvements.[54]

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[50] *Id*.
[51] SWEEP SOP, pp. 14-15.
[52] *Id*.
[53] WRA SOP, p. 14.
[54] *Id*. at 14-15.

c. Findings and Conclusions

62. We will impose a spending cap of $18 million each year for 2024-2026. We also find it appropriate to institute 25 percent budget flexibility consistent with Rule 4753(k) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4. Again, we believe these budget caps are appropriate due to the uncertainty inherent in the 2024 through 2026-time frame, including the effects of the IRA, the phase-out of certain gas incentive programs, and the implementation of social cost of emissions in the cost-benefit analysis. As highlighted earlier, we are also mindful of the total impact of DSM expenditures established in this Proceeding on ratepayers, including the cumulative impacts of the electric energy efficiency, gas energy efficiency, and beneficial electrification spending, and find that this budget constraint for gas energy efficiency works in concert with our other findings in this Decision to establish a reasonable ratepayer impact overall. As with the electric energy efficiency savings goals, the Commission has determined that this is a reasonable average for annual spending over the applicable SI period and the Company may provide reasonable proposals for varied spending from year-to-year.

63. We find that an annual gas energy savings goal of 814,000 Dth in 2024, 860,000 Dth in 2025, and 903,000 Dth in 2026, strikes the best balance between maintaining continuity of the Company's DSM programs and managing the impact on ratepayers, both participants and non-participants. These values represent the levels proposed by the Company at $21 million investment per year, modified to a lower $18 million budget per year.

E. DSM Potential Study

64. As part of its Application, the Company included a Potential Study created by Guidehouse. The Potential Study analyzed three scenarios: the reference scenario (*i.e.*, the "business-as-usual" scenario); the incentive optimized scenario (where the mTRC is removed but rebate levels are capped at the avoided cost value calculated by the mTRC); and the maximum achievable scenario (where rebate levels are equal to the incremental cost of efficient measures, the mTRC is removed, and marketing and market adoption factors are increased).[55] It indicated that its savings goals were developed using the Potential Study's incentive optimized scenario.

1. Proposals

65. ***GDS Associates Study.*** CEO also put forth a study called the GDS Associates Study which offers a high-level review of state-wide BE potential, and provided some useful guidance on how to utilize and understand potential studies.[56] Specifically, CEO's study explains that there is a larger bucket of BE that is feasible from a technical perspective, and then a smaller bucket of that technically possible BE that is economically feasible, and then yet a smaller bucket of "achievable potential" which is BE which is technically possible, economically feasible, and also can overcome market and adoption barriers. CEO does not recommend setting goals and budgets using the GDS Associates Study, but offers it as a resource in the record for the Commission and parties.

[55] Hrg. Ex. 108 (Mark Supplemental) at 30.
[56] Hrg. Ex. 1400 (GDS Study).

66. Several parties, including SWEEP and WRA, argue that the Commission should give little weight to the Guidehouse Potential Study presented by the Company. SWEEP points out several flaws in the study, and also notes that Public Service consistently achieves energy savings 25 to 50 percent higher than those predicted by Guidehouse in previous potential studies since 2016.[57] WRA points out several perceived issues, including that Guidehouse decided to not model air-source heat pumps to replace central air conditioners with back-up furnace set ups. Taken together, WRA argues, these assumptions lead to a pessimistic outlook for BE, showing low potential for residential space heating BE measures. WRA suggests the Potential Study be redone to: (1) incorporate commercial water heating measures into the BE Potential Study; (2) incorporate central and ductless heat pump measures with and without gas backup; (3) analyze all-electric new construction as a separate opportunity, taking into account potential upfront and operating cost savings from avoiding gas connections and fixed charges; and (4) recalculate the relative operating cost of gas and electric equipment given current rate structures, including higher gas rates and time-of-use electric rates. Gas rate assumptions should accurately reflect recent history, as well as reasonable expectations about the future.

67. Conservation Coalition argues that the study is not tailored enough to Public Service's service territory, and that key inputs do not align with data provided by Public Service through discovery, including that three "prominent Colorado HVAC distributors estimated that 70 percent to 80 percent of the add on/replacement residential market in Colorado is still installing baseline efficiency (80 percent AFUE) furnaces in 2022."[58] Conservation Coalition

[57] Hrg. Ex. 1000 (Brant Answer) at 4.
[58] Hrg. Ex. 701 (Grevatt Answer) at 44.

also questions the net-to-gross ratio used in the Potential Study to account for free ridership in program savings calculations.[59]

68. EEBC raises additional concerns about the Company's Potential Study, including that it excluded several available energy efficiency measures, and that it does not incorporate some of the energy efficiency measures or strategies that Public Service is successfully promoting within its DSM programs, including sealing HVAC ducts in buildings, attic fans for cooling homes, super-efficient new homes or commercial buildings that perform above Energy Star performance standards, and ground source heat pumps. In addition, EEBC contends that the study makes assumptions about rates of energy efficiency measure adoption and maximum levels of measure penetration, but those assumptions could be exceeded due to changing market conditions and other factors.[60] EEBC also contends that the Potential Study should recognize benefits that meters with Advanced Metering Infrastructure (AMI) can bring, including more insight into customer usage habits and the ability to enable more third-party energy service providers to better engage with customers and help them achieve energy savings and peak demand reduction.[61]

[59] *Id*. at 45.
[60] Hrg. Ex. 1101 (Geller Answer) at 40.
[61] *Id*. at 40-41.

2. Findings and Conclusions

69. The Commission sees substantial value in a reliable potential study both in guiding the strategic issues proceedings and for use in other proceedings moving forward, including electric resource planning, in which it is important to identify the most reliable estimates of potential for efficiency and beneficial electrification moving forward. We find that the parties have raised numerous helpful suggestions for improvement of the current Potential Study for future filings and have pointed out several valid flaws. A potential study should provide foundational information necessary for the Commission to better understand the broad market of both energy efficiency and beneficial electrification.

70. We find it appropriate to order the Company to develop a new or updated potential study prior to the Company's next strategic issues application filing. In developing this new or updated potential study, the Company shall work with stakeholders to address concerns raised here about the current Potential Study and provide an opportunity for stakeholders to have a voice in the development of a new study. We also order the Company to set the timeline for creating a new or updated study with the rebates and tax credits available under the IRA in mind, so that the data in the potential study considers the effects of the IRA on available technologies and cost estimates and remains accurate for as long as possible.

71. The new or updated potential study should project forward annual estimates of the following for the Company's electric and gas service territories:

a) The number of new homes and businesses to be built (including, separately, single family and multi-family units and appropriate commercial building distinctions), and the space and water heating appliances and fuels likely selected absent the Company's DSM and BE programs;

b) The number of major dwelling retrofits that would facilitate building envelope improvements and a metric of shell efficiency (if possible), absent the Company's DSM and BE programs;

c) The number and type/fuel of AC units, furnaces and boilers, water heaters, and stoves (*i.e.*, major energy appliances) that are being replaced on an annual basis and what is replacing them, again, absent the Company's DSM and BE programs. Together, items a-c describe the *Primary Addressable Market*;

d) The number and percentage (*i.e.*, adoption rates) of homes, retrofit building shells, and major appliances, as described as the Primary Addressable Market, that are projected to be impacted by the Company's DSM and BE programs at (a) current spending levels and program designs, and (b) optimized spending levels and program designs;

e) The unit and total cost, energy impact, emissions impact, and cost-effectiveness of the projected adoption rates as described in item d above;

f) The net-to-gross indices of various measures as assessed through at least two methods of analysis, potentially including: survey of Public Service-program participants; meter and/or billing analysis of program participants and non-participants; and adoption of measures in one or more proxy geographic areas that have no utility DSM or BE programs; and

g) Other analytic components, as necessary, to facilitate (i) the development of an appropriate DSM implementation path given the legislative and regulatory support for aggressive action; and (ii) the *post-hoc* evaluation of the Company's DSM implementation efforts necessary to support continual improvement of such.

72. Regarding Conservation Coalition's concerns regarding the net-to-gross ratio utilized in the Potential Study presented by Public Service, we agree that the net-to-gross ratio utilized by the Company should be supported by the Company in its upcoming 2024 DSM plan. The Company's assumption of a 100 percent net-to-gross ratio is not supported given the scale of other potential incentives and initiatives, which raise significant concerns about the accuracy of that value. Going into the next strategic issues proceeding, the Company should present a well-reasoned value to use for a net-to-gross ratio as part of its new or amended potential study.

F. Cost-Benefit Analysis Considerations

73. Pursuant to § 40-2-102(5)(a), C.R.S., "cost-effective", with reference to a gas or electric DSM program, a BE program, or any measure related to either a DSM or BE program, means having a benefit-cost ratio greater than one. For many years, Colorado has utilized a modified total resource cost test (mTRC) to determine the cost effectiveness through a cost-benefit analysis. A program, measure, or portfolio is considered cost-effective if it is expected to deliver lifetime benefits that exceed its costs on a net-present-value basis.[62] The mTRC test, which includes a measure's incremental costs, the utility program costs, the impact of the measure on the energy system (including both commodity costs and utility system costs), and an estimate of externality costs. Externality costs are account for by using the social costs of emissions as well as an estimate of non-energy benefits or "NEBs."

74. As part of its Application, Public Service put forth several proposals related to considerations of the cost-benefit analysis framework utilized to determine DSM program offerings, including a new "proxy plant" method for calculating avoided energy costs. Other intervenors raised several other potential changes to the cost-benefit analysis framework, including proposals related to avoided energy costs, avoided capacity costs, behind the meter leakage and emission calculations, NEBs, and the discount rate.

1. Proxy Plant Methodology

(a) Proposals

75. In its Application, Public Service explains that the historical method for determining avoided electric costs consisted of four components: (1) an assumption of generation

[62] Hrg. Ex. 102 (Mark Direct) at 86.

capacity avoidance; (2) a combination of transmission and distribution avoidance; (3) an hourly stream of marginal electric energy cost estimates; and (4) an hourly stream of electric system emissions intensities.[63] However, the Company states that changes in the electric generation system, including the switch from mainly dispatchable gas-fired generation plans to non-dispatchable renewable generation, require updating the Company's methodology for calculating avoided electric energy costs.

76. The Company proposes that a proxy plant method be applied to complement the historical approach; the proxy plant method identifies the change in future generation build and electric energy delivered given the change in hourly total system load from energy efficiency and beneficial electrification.[64] The proxy plant method considers wind and solar plants and would apply to electric efficiency and beneficial electrification calculations.[65]

77. Public Service asserts that this new methodology will better capture the impacts of solar and wind generation than its historical approach, because (1) solar and wind output is independent of load changes, so their energy cost and emissions impacts are accurately captured by their annual energy impacts rather than hourly marginal energy and emissions impacts, and (2) historically, marginal energy costs are based on fuel costs of the marginal generating plant, but solar and wind have no fuel costs, and so the costs of these resources that are built to serve increased load on the system are not captured.

78. UCA, WRA, SWEEP, and CRES all oppose adoption of the proxy plant method at this time.

[63] *Id.* at 17.
[64] *Id.* at 19-20.
[65] *Id*. at 21.

79. UCA recommends that the Commission instead order that the avoided energy costs and emissions be based on the projects selected in the Phase II competitive solicitation in the ERP proceeding. UCA recommends further that the timing of ERP and DSM strategic issues proceedings should also be adjusted so that the DSM strategic issues filings occur when the ERP Phase II data are available. UCA argues that the Company should be required to file updated avoided costs 60 days after the 120-day report, and that these costs should be used in the DSM plans to be developed from this strategic issues Proceeding.

80. WRA states that despite the significance and novelty of this approach and its requests for transparency, no technical conference has been held and parties still have questions about the proposed methodology. WRA argues that a technical conference is needed to address parties' questions, vet potential shortcomings, and examine how the approach could be improved. WRA states that Public Service characterizes the methodology as a "conceptual discussion at this point" that can be fully litigated later based on actual data, modeling and portfolios.[66] Given the significance of the proposed change in methodology, WRA contends that the Commission must defer a decision, and instead require the Company to file (1) avoided costs using both methods in its next DSM-BE Plan filing, along with executable workpapers; (2) outputs, such as confidential hourly marginal energy prices and emission rates and load shapes from both approaches; and (3)conduct a technical conference after the plan application is filed and in advance of answer testimony. WRA contends that the Commission lacks "substantial evidence" under the requisite evidentiary standard to approve the change in methodology proposed by the Company.[67]

[66] WRA SOP, p. 26, citing Hearing Transcript at 148:3-149:22, 156:10-12, 166:1-167:20 (Feb. 8, 2023).
[67] WRA SOP, p. 26.

81. SWEEP recommends that the Commission order Public Service to provide parties with greater transparency regarding the proxy plant method. SWEEP does not object to the general approach of the method, but states that the Company did not provide sufficient data in this proceeding for parties to fully understand the method and how it compares to the traditional method. SWEEP recommends that the Commission direct Company to present results of both methodologies in its next DSM and BE plan proceeding. SWEEP also supports WRA proposal that the Company convene a technical workshop to more fully explain the method.[68]

82. CRES agrees with WRA and SWEEP on the need for the Company to host a stakeholder process to explain and justify its proposed proxy plant method. CRES places specific emphasis on the importance of using long-run marginal emissions rates for BE and DSM, rather than the short-run emission rates it contends the Company has used in its assessment of emission reductions.[69] The degree to which the proxy plant method reflects long-run marginal emission rates remains unclear.

83. Public Service asks that the Commission approve its proposed proxy plant method. It notes that in its rebuttal testimony, the Company provided a detailed description of the methodology and notes that SWEEP agrees that the concept is sound. The Company states that it is willing to host a technical workshop on the method to support its next DSM and BE Plan after direct case is filed but "sufficiently in advance of due date for intervenor answer testimony.[70]

[68] SWEEP SOP, pp. 27-28.
[69] CRES SOP, pp. 11-13.
[70] Public Service SOP, p. 34.

b. Findings and Conclusions

84. We find it is premature to approve the Company's proposed proxy plant method for calculating avoided electric energy costs at this time. As the parties note, the methodology is complex, and the Company has yet to sufficiently explain it or answer party questions. We direct the Company to submit a detailed description of the methodology accompanied by workpapers demonstrating the application of both its historical and proposed proxy plant methodologies in conjunction with its next DSM plan Application. We also order the Company to host a technical conference on the proxy plant methodology well in advance of the Answer Testimony due date in its next DSM plan proceeding. We further order the Company (for its next DSM plan applications) to continue to present costs using the historical methodology at least until the Commission approves the new proxy plant methodology.

2. ERP-selected Projects in Avoided Energy and Emission Calculations

c. Proposal

85. UCA proposes that avoided electric capacity costs should be based not on estimated combustion turbine (CT) costs from Phase I of an ERP proceeding, but on the "lowest cost bid received but not selected" in Phase II. UCA argues that it is not reasonable to use estimated costs when actual costs are available, especially when the evidence demonstrates a significant difference between actual and estimated costs.[71] UCA requests that the Commission adopt its recommendation and the process the Company recommends in its rebuttal case, that it uses an EnCompass model run based on the costs included in the most recently completed ERP Phase II proceeding for a 50 MW capacity increase.

[71] UCA SOP, pp. 19-20.

86. Public Service does not address this point in its SOP, but in its rebuttal case indicated that the Company agrees with this idea in principle, but that it is unclear what the "first project not selected" would represent. The Company proposed to use EnCompass to identify the capacity resource that would have been selected from bids in the most recently completed Phase II ERP proceeding, had load been 50 MW higher than modeled. The resource identified by this model run would form the avoided capacity cost.

d. Findings and Conclusions

87. We agree with UCA that the avoided costs and emission rates used in both the proxy plant and the historical method should be derived by modeling the Company's system inclusive of resources selected in Phase II of the most recent preceding ERP proceeding. The Company has not articulated a reason why generic assumptions should be used rather than actual bid characteristics. Accordingly, we direct the Company to calculate avoided electric capacity costs based on marginal resource from last ERP as identified by an EnCompass run with an incremental 50 MW load.

3. Modeling Provisions

(a) Proposals

88. In addition to the concerns WRA expresses regarding the Company's proposed proxy plant method, it recommends that the Company be directed to continue to provide certain data regarding its DSM modeling that it agreed to provide as part of the settlement of its previous strategic issues proceeding,[72] including confidential hourly marginal prices and emissions rates used to determine the avoided energy value of DSM plans, as well as hourly marginal prices,

[72] Proceeding No. 17A-0462EG, Settlement Agreement p. 11.

average hourly prices, emissions data, and load net of renewables, and curtailment data presented on a daily and monthly basis.[73]

89. Neither the Company nor any other party responded to WRA's recommendation.

e. Findings and Conclusions

90. We find it appropriate to continue the existing practice of requiring Public Service to provide to the Parties the modelling data described by WRA and as listed on page 11 of the settlement agreement approved in Proceeding No. 17A-0462EG.

4. Calculation of Avoided Energy Costs

a. Proposals

91. Avoided capacity and energy costs are the main components of the direct energy benefits of DSM. When determining cost-effectiveness of DSM, avoided capacity and energy costs are combined with certain non-energy benefits and the sum is compared to the direct and indirect costs of the programs. Section 40-1-102(5)(a), C.R.S., defines cost effectiveness and lists the utility's "avoided generation, transmission, distribution, capacity, and energy costs" as some of the benefits of DSM.

92. The Company states that it currently uses PLEXOS modeling for purposes of calculating Public Service's avoided cost of energy associated with DSM programs, but will now shift to the use of EnCompass modeling software because it is the same modeling software used in its ERP and related proceedings.[74] The Company also discusses changes to the cost-benefit analysis for avoided energy costs, including applying a marginal hourly avoided energy cost

[73] Hrg. Ex. 1500 (Farnsworth Answer) at 28-29.
[74] Hrg. Ex. 106 (Landrum Direct) at 9.

(derived from EnCompass modeling forecasts) and establishing an estimated marginal hourly avoided emission rate. The Company uses outputs from EnCompass to calculate avoided costs, the marginal energy price, marginal emission rate, and system generation mix.[75]

93. The Company is not proposing to set the actual avoided costs for use in future DSM plans, but proposes to establish the methodology that will be used in future DSM plans to set actual avoided costs.[76]

94. WRA contends that the Company's approach may produce negative avoided costs during hours where the marginal resource is curtailed renewable energy and argues that electric efficiency programs should not be penalized due to curtailment of renewable energy, since under current designs, these programs cannot shift load or adjust usage according to renewable curtailment. WRA argues that the Commission should require the avoided cost calculation to exclude any values less than zero, noting that this is the approach the Commission adopted in approving the settlement in the 2017 strategic issues proceeding (*See* Decision No. C18-0417).[77]

95. In rebuttal testimony, Public Service agrees with WRA that its historical method for determining marginal energy price did not capture avoided baseload generation, but contends that the Company's proposed proxy plant method does capture that avoided cost in that it accounts for baseload generation not built due to the impacts of its energy efficiency programs. Public Service states that the Company will adopt WRA's recommendation to exclude negative avoided cost during periods when renewable generation is curtailed.[78]

[75] *Id*. at 11.
[76] *Id*. at 16.
[77] Hrg. Ex. 1500 (Farnsworth Answer) at 18-21.
[78] Hrg. Ex. 117 (Landrum Rebuttal) at 7-9.

b. Findings and Conclusions

96. We agree that it is reasonable to exclude negative prices from the avoided costs when renewable generation is curtailed, particularly in light of the agreement between the proposing party, WRA, and the Company. We therefore order the Company to adopt WRA's recommendation to exclude negative avoided cost during periods when renewable generation is curtailed.

5. Upstream and Behind the Meter Methane Leakage

97. Pursuant to § 40-3.2-106, C.R.S., a utility shall consider the social cost of carbon dioxide emissions and the social cost of methane emissions when determining the cost, benefit, or net present value of any plan or proposal submitted in several proceedings, including beneficial electrification and DSM proceedings.

98. For gas DSM programs, when calculating the cost of methane emissions related to DSM cost-effectiveness, the Commission shall obtain and apply the best available values for natural gas leakage during the extraction, processing, transportation, and delivery of natural gas by the gas public utility as well as leakage from piping or other equipment on customer premises. § 40-3.2-107(2)(b), C.R.S.

99. With regard to cost-effectiveness analysis of beneficial electrification programs § 40-3.2-109(3)(a)(II), C.R.S., specifies that the social costs of carbon dioxide and methane emissions, including the avoided carbon dioxide emissions from the direct combustion of fossil fuel in appliances or industrial equipment that is replaced with electricity and the avoided upstream emissions of methane from the production and delivery of fossil fuel to the appliance or equipment be accounted for.

a. Proposals

100. WRA, Conservation Coalition, and CRES all criticize the Company's failure to account for both behind-the-meter and upstream methane leakage in its cost-effectiveness analysis. These parties contend generally that the leakage rate of zero percent that the Company inherently ascribes to leakage downstream of the customer meter and upstream of the Company's distribution system is inaccurate, and that incorporating realistic values for this leakage would likely alter the cost-effectiveness of measures and programs, and might suggest budget priorities that differ from those the Company presents in this Proceeding.

101. Conservation Coalition further criticizes the Company's use of what it terms as an "extremely low" 0.2089 percent methane leakage rate for its distribution system, which Conservation Coalition claims is a factor of 10 to 20 times below the leakage rates commonly estimated in scientific studies. Conservation Coalition cites several recent peer-reviewed studies estimating leakage in distribution systems at between 2.2 percent and 4.7 percent, and references the U.S Environmental Protection Agency's (EPA) use of a factor of 1.4 percent leakage in its 2015 greenhouse gas inventory. Conservation Coalition argues that the low leakage rate the Company uses results in inaccurate avoided methane costs, which in turn leads to inaccurate analysis of the cost-effectiveness of BE measures. Conservation Coalition contends that applying more realistic leakage values would substantially increase the cost-effectiveness of BE measures.[79]

[79] Hrg. Ex. 702 (Reeves Answer) at 28-30.

102. WRA argues that the Commission should require the Company to account for behind-the-meter and upstream methane emissions. Specifically, WRA recommends, based on EPA's approach and peer-reviewed studies, the following methane leakage rates: 649 g methane/year for gas stoves; 1,400 g methane/year for gas storage water heaters; and 2,390 g methane/year for tankless gas water heaters. WRA disputes the Company contention that these leakage rates are novel by noting that the EPA has been accounting for these emissions since 2022 in its national greenhouse gas inventory, that the California Air Resources Board includes it in its emissions inventory, and that the California Public Utilities Commission accounts for leakage when evaluating energy efficiency and demand response cost effectiveness. In answer testimony, WRA suggests that if the Commission does not adopt the methane leakage values WRA recommends, it could solicit additional information from parties regarding data sources and methodology as part of a miscellaneous docket or informational workshop.[80]

103. CRES makes several arguments regarding methane leakage in its SOP. First, it notes that § 40-3.2-107(2)(b), C.R.S., requires the Commission to "obtain and apply the best available values for natural gas leakage during the extraction, processing, transportation, and delivery of natural gas by the gas public utility as well as leakage from piping or other equipment on customer premises." CRES further criticizes the Company's estimate of leakage from its own distribution system, citing the documentation presented in Conservation Coalition's answer testimony that demonstrates leakage rates of two percent to nine percent. CRES recommends that the Commission direct the Company to show what their current and future projected electric

[80] Hrg. Ex. 1501 (Fickling Answer) at 43.

and gas DSM program products would score on the mTRC tests utilizing a range of leakage rates, including much higher than 0.2 percent.[81]

104. The Company responds to these assertions by stating that these are novel issues and that the Commission has not provided prior guidance on how to approach these potentially complicated methodologies. It notes that the Commission declined to require consideration of behind-the-meter methane leakage in Decision No. C22-0760 in Proceeding 21R-0449G because the Air Pollution Control Division's (APCD) clean heat workbook did not provide reliable information on accounting for behind-the-meter leakage, and contends that the Commission should continue to defer to the APCD on this matter.

b. Findings and Conclusions

105. The Company has provided little support for the methane leakage rate it applied in its mTRC analyses and has provided no justification for ignoring methane leakage upstream or downstream of its distribution system. As the parties have argued, the implausibly low value proposed by the Company results in avoided costs (particularly for beneficial electrification and gas DSM) that are artificially low, producing inaccurate conclusions in the Company's mTRC analyses of energy efficiency and BE measures and programs. The scale of the impact of methane emissions that were excluded is significant, given the greenhouse gas impacts of methane emissions and the resulting social cost. For this reason, we order the Company, consistent with § 40-3.2-106, C.R.S. and § 40-3.2-107, C.R.S., to consider emissions from leakage within its distribution system as well as behind the meter emissions and upstream emissions when calculating the cost-effectiveness for DSM measures, including beneficial electrification, moving forward.

[81] CRES SOP, p. 17.

106. Conservation Coalition, WRA, and CRES present credible evidence suggesting that the Company's estimate of leakage within its distribution system is likely well above the 0.2 percent assumption presented by Public Service, and that the inherent assumptions of zero upstream and downstream leakage are invalid. Accordingly, we direct the Company to apply the comparatively conservative assumption of 2.2 percent[82] total gas leakage from production through consumption in the mTRC calculations for its gas energy efficiency and BE programs in its next DSM plan application.

107. At this time, we see no need to open an additional proceeding to analyze leakage rate data. This is an evolving issue which other entities, including the EPA and the Colorado Air Quality Control Commission's (AQCC) are currently studying. Throughout Proceeding No. 21R-0449G, the Commission repeatedly expressed interest in having the most holistic greenhouse gas accounting available and continuing to pursue this issue with the most accurate information available at the time. In this circumstance, statute indicates that the accounting should be holistic, including upstream and downstream leakage, and other parties have provided considerably more credible estimates on this record that the Company's, as it relates to those impacts.[83] We expect that methane leakage values in cost-effectiveness analyses will evolve over time as utilities and parties provide updated information and encourage them to provide detailed information in the next DSM plan application, as well as subsequent proceedings, to allow the Commission to refine the accuracy of the estimates used.

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[82] This leakage values were developed by the National Energy Technology Laboratory, and is included in the record in Hrg. Ex. 702 (Reeves Answer), Attachment SR-12.

[83] *See* § 40-3.2-107(2)(b), C.R.S.: For gas DSM programs, when calculating the cost of methane emissions related to DSM cost-effectiveness, the Commission shall obtain and apply the best available values for natural gas leakage during the extraction, processing, transportation, and delivery of natural gas by the gas public utility as well as leakage from piping or other equipment on customer premises.

6. Discount Rate

f. Proposals

108. Public Service has historically used its weighted average cost of capital (WACC) as the discount rate for cost-benefit analysis calculations for its DSM programs. Currently, the Company's WACC is approximately 6.54 precent for electric and 6.42 percent for gas.[84]

109. Staff notes that in Proceeding No. 21A-0166E, the most recent Black Hills Colorado Electric, LLC DSM proceeding, the Commission approved use of a two percent discount rate for DSM cost-effectiveness analysis rather than the Company's WACC, but specified that the WACC still be used to determine present values of Company investments in Transmission and Distribution (T&D) to determine avoided T&D costs. Staff proposes that 2.5 percent be used in this case to reflect recent federal interest rate increases. Staff states that "a lower discount rate places greater value on future benefits from actions taken today to meet the State's energy/climate goals and therefore better complements the State's goals compared to a higher discount rate."[85] In response to Company argument that it's inconsistent to use different discount rates for DSM and avoided T&D, Staff notes that these two investments are funded from different sources—DSM investments are paid entirely with ratepayer dollars, whereas T&D are funded by shareholders and so should be discounted at the WACC. If the Commission does not require use of 2.5 percent, it should require two calculations: one using 2.5 percent and one using the WACC.

[84] Hrg. Ex. 900 (Soufiani Answer) at 84.
[85] Staff SOP, p. 16.

110. SWEEP makes many of the same arguments. It notes that the selection of the discount rate significantly affects the outcome of cost-effectiveness tests since implementation costs are short term, but benefits are longer term. It contends that use of the WACC as the discount rate is inappropriate because it undervalues the long-term benefits and cost savings of DSM and because it reflects shareholder cost of capital for utility investments. But it is customers, not shareholders, who pay for DSM via the Demand Side Management Cost Adjustment (DSMCA). Like Staff, SWEEP notes that the Commission recognized this in Proceeding No. 21A-0166E. SWEEP also references HB 21-1238, which directed utilities to use a customer focused discount rate for gas DSM, and notes that Company witness Nick Mark stated that Public Service has no objection to this. SWEEP contends that the Commission should explicitly order Company to use a single 2.5 percent discount rate in evaluating the cost-effectiveness of electric and gas energy efficiency and BE programs.

111. While it does not oppose the use of a lower discount rate in cost-effectiveness evaluation, Public Service contends that a single discount rate should be used, rather than one for discounting future benefits and another (the WACC) to be used in the calculation of the present value of avoided utility investments, as advocated by Staff. The Company is open to the use of 2.5 percent discount rate, but contends any rate that is adopted should be used consistently. It argues that there should not be multiple discount rates in the same cost effectiveness calculation. The Company also notes that the current gas DSM rules contemplated use of WACC which will need to be addressed if the Commission wishes to require use of a 2.5 percent rate.

g. Findings and Conclusions

112. Regarding the use of multiple discount rates within a given cost-effectiveness analysis as advocated by Staff and SWEEP, we note that while this practice may be

unconventional in financial analysis,[86] the Legislature has explicitly directed the Commission to consider using multiple discount rates within a single analysis, at least in application to the evaluation of gas DSM programs. Section 40-3.2-107(2)(b), C.R.S. directs the Commission to "use the same discount rate as that used to develop the federal social cost of methane, as set forth in the addendum to the technical support document" to set the cost of methane emissions for DSM programs. However, paragraph (2)(c) of the same statute instructs the Commission to "discount other future cost streams into the net present value analysis of any resource portfolio in the gas DSM program planning process using a discount rate that the commission deems relevant to the parties responsible for financing or paying these future costs." To the degree that there is a divergence between the discount rate used in developing the social cost of methane and the rate the Commission deems relevant to the parties responsible for paying future costs, the statute contemplates the use of at least two discount rates within the analysis.

[86] Pursuant to § 40-3.2-107(2)(b), C.R.S., since 2021, the Company must use the discount rate from the federal technical support document to discount social costs of emissions. Here, where the Company uses WACC as a general discount rate for cost-effectiveness, it is already using two discount rates within the same analysis (*i.e.*, WACC and the SCE discount rate established by statute).

113. However, we find no evidence on the record in this Proceeding regarding what specific discount rate would be relevant to customers responsible for financing DSM. Staff and SWEEP contend such a customer-focused discount rate is approximately 2.5 percent but provide no surveys or other evidence that Public Service customers actually apply such a low discount rate to their investment decisions or are comfortable with the fact that a significant portion of the suggested return would be via environmental benefits which may not have direct monetary value to each ratepayer. The Commission notes that the discount rate for certain Public Service customers may, in fact, be much higher than the suggested 2.5 percent level or even the Company's WACC, as evidenced by the generally low adoption rate of energy efficient technologies without utility incentives or of rooftop solar energy unless the economic payback is a short time frame. We also note the Company's WACC represents, in essence, a mix of stocks and corporate bond returns that a household may reasonably seek in an investment portfolio. In absence of any specific evidence on this issue, the Commission declines to adopt a specific "customer-focused" discount rate at this time. Finally, we are concerned that systematically applying a too-low discount rate may result in higher near-term non-participant and IQ customer rate impacts as additional dollars are spent today to achieve benefits far out into the future.

114. Nonetheless, we find it sensible to review and consider program and portfolio cost-effectiveness using what we will term a "societal discount rate" of 2.5 percent. As several parties have argued, a societal discount rate provides a longer-term perspective by placing more weight on the value of future benefits of DSM programs, and such a design is generally consistent with recently passed statute including SB 19-236, HB 19-1261, SB 21-246, HB 21-1324, HB 22-1381, SB 23-016, and HB 23-1281.

115. We find good cause to resolve this discrepancy by directing Public Service to conduct and present two cost-effectiveness analyses in future DSM plan applications.[87] The first will utilize the Company's WACC to discount all future costs and benefits of DSM, with the exception of the social costs of methane emissions which must, by § 40-3.2-107(2)(b), C.R.S., be discounted at the rate used in the addendum to the technical support document for methane emissions and the social cost of carbon emissions which must, by § 40-3.2-106, C.R.S., be discounted at 2.5 percent or less. The second analysis will discount relevant customer-focused costs and benefits at a 2.5 percent rate and continue to utilize the Company's WACC as the discount rate for Company-related or infrastructure investments.

116. To the extent the various discount rate scenarios suggest conflicting cost-effectiveness determinations in the plan proceeding, the Commission requires the Company to indicate its preferred path forward, and to generally allow stakeholder comment at that time. The Commission will further review the legislative requirements and economic merits in the plan proceeding.

7. Non-energy Benefit Adders

h. Proposals

117. Pursuant to § 40-1-102(5)(a), C.R.S., when determining the cost-effectiveness of a program or measure related to DSM or BE programs, the Commission can consider other costs or benefits it determines relevant. A non-energy benefit adder increases the value of the measured benefits of a DSM measure or program to account for difficult or impossible to

[87] To the extent that completing this analysis required the Company to use a discount rate different than that prescribed by Rule 4751(e) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4, which defines discount rate at the utility's after-tax weighted average cost of capital, we find good cause to waive this provision to ensure the Company can perform the discount rate analysis required by this decision.

quantify benefits of DSM and BE efforts. The inclusion of the social cost of emissions is in addition to the NEB adders in the cost-benefit analysis.

118. The Company proposes to continue to use the NEBs approved in the prior strategic issues filing. Specifically, these are: 50 percent non-energy benefits "adder" to low-income measures and products and a 20 percent adder to all other measures and products.

119. EOC notes that the Commission's decision in Proceeding No. 21A-0166E (the most recent electric DSM plan Proceeding for Black Hills Colorado Electric, LLC) agreed with Black Hills that, due to the incorporation of the social cost of carbon (SCC) and social cost of methane (SCM) in the mTRC calculations, NEB adders should be returned to 25 percent (for IQ programs) and ten percent (all other programs). EOC also states that the settlement in the Company's 2023 DSM/BE Plan (Proceeding No. 22A-0315EG) utilizes the same 50 percent NEBs adder it has used since 2018. EOC states that if the NEBs adders are reduced as they were in Black Hill's case, many measures and projects may not pass cost-effectiveness screening. While EOC notes that Public Service has not raised the NEBs adders as an issue in this Proceeding, it seeks clarification from the Commission that the 50 percent NEBs adder will continue to be applied to IQ products and measures in future DSM and BE plans.

i. Findings and Conclusions

120. The inclusion of the SCC, and subsequently the SCM, in the mTRC analysis monetizes the previously unquantified value of future climate change damage due to carbon dioxide and methane emissions avoided due to DSM. The inclusion of the SCC alone adds over $163 million to the projected benefits of the Company's 2023 DSM program, representing fully 32 percent of program lifetime benefits exclusive of the (approximately

$54.7 million) NEBs adder. For these reasons, we agree that the NEB adders should be some amount lower than the 50 percent adder for IQ programs and 20 percent for all others.

121. However, we find the record in this Proceeding does not provide us with adequate support to set specific NEB adder values at this time. We direct the Company to raise this issue in its next DSM plan filing where we intend to request that the parties work together to further explore this issue.

8. Inflation Reduction Act (IRA) Impact

122. For many years, Colorado has utilized a mTRC to determine the cost effectiveness through a cost-benefit analysis, pursuant to § 40-2-102(5)(a), C.R.S., and previous Commission decisions.

123. Public Service suggests the tax credits and rebates offered under the IRA do not change underlying technical potential under the mTRC test used in Colorado. Colorado is expected to receive funding averaging between $11.8-$15.2 million for nine years. Guidehouse calculated a one percent change in electric consumption and three percent change in gas consumption (10-year cumulative). Public Service contends the IRA funding cannot substitute for utility funding because they are administered by different entities and may have different goals or appliance requirements. Public Service also requests the Commission assume a 100 percent net-to-gross ratio (*i.e.*, no free-ridership) because attribution is too difficult to calculate.

124. UCA contends the IRA will likely lead to direct funding for Public Service's service territory in the $7-$9 million range, and that tax credits and deductions will roughly double those values. Accordingly, UCA argues the Commission should establish a conservative IRA budget impact of $14 million, and reduce Public Service's proposed DSM/BE budget commensurately. UCA contends their recommendation is consistent with Governor Polis' direction to "[e]nsure Colorado is taking full advantage of federal funding by enabling utilities to pursue and implement projects and programs that leverage competitive federal funding to expand customer facing programs to reduce energy consumption and costs,"[88] UCA also suggests the IRA impact be split about $3 million for BE to $11 million for EE, and that the Commission consider budget reductions in light of the funds available through the IRA.

125. In light of the generous tax credits and rebates now available under the IRA, the Commission considered whether it was appropriate to adjust the mTRC test to consider the impacts of this new source of funding on the cost-effectiveness of DSM and BE efforts.

[88] UCA SOP, p. 13 (citing Hrg. Ex.408 at 4).

126. However, because the mTRC test measures the economic potential of a measure on a societal basis, and not on a participant cost level, we agree with Public Service[89] that further modifications to the mTRC in light of the IRA may not be appropriate at this moment. Because the mTRC treats incentives to the customer, regardless of the source, as simple income transfers that do not alter the underlying cost of a measure, the company argues that the cost at a societal level is unchanged. We question whether this is an appropriate assumption when applied to federal incentives, however, we are still interested in the effects that the IRA will have on DSM, and particularly BE, adoption. While the societal cost as a whole would not be impacted, it is highly likely that more localized costs, like those to individual customers and the utility system level, could be significantly altered due to an influx of federal incentives. For this reason, we order the Company in its next DSM plan filing to conduct and present the "utility test" for its programs in its DSM plan. While this data will be presented primarily for informational purposes, we see value in seeing multiple perspectives on cost-effectiveness and would welcome feedback from the Company and other stakeholders on how to consider these perspectives in the next plan filing. In the next DSM plan filing, we would also like to be made aware if there are any measures that did not meet the cost-effectiveness threshold which would have met that threshold had the IRA incentives been included in the calculation.

127. While we agree with UCA that the IRA will result in additional public funds in Public Service's territory, we decline to reduce Public Service's proposed DSM/BE budget on a commensurate basis. We agree that there is substantial uncertainty about how the IRA will affect DSM spending and participation, but do not on this record, find a need to adjust budgets or goals exclusively as a result of the IRA funding potential.

[89] Hrg. Ex. 108 (Mark Supplemental Direct) at 75-76.

1. Equity Considerations

128. In its Application, Public Service included several proposals related to efforts it seeks to make involving disproportionately impacted (DI) communities and income-qualified customers. Additionally, several proposals and recommendations presented by intervenors address equity-related issues related to the Company's strategic issues Application.

129. According to Senate Bill 21-272, and as enacted in § 40-2-108(3)(d)(II), C.R.S., a "disproportionately impacted community" means a community that is in a census block group where the proportion of households (1) that are low income is greater than 40 percent; (2) that identify as minority is greater than 40 percent; or (3) that are housing cost-burdened is greater than 40 percent; or (4) is a community deemed by the State to have a history of environmental racism or to have multiple stressors and lack of public participation that "affect health and the environment and contribute to persistent disparities." The Commission has not yet further defined DI Communities, though it has related ongoing efforts in Proceeding No. 22M-0171ALL.

a. Tiered Offerings

j. Proposals

130. In its Application, the Company proposed expanding access to the Company's income-eligible programs to all residents living in disproportionately impacted communities.[90] Public Service stated that this expansion would be appropriate because simplifying the qualification process based on location recognizes that poverty is often concentrated in specific

[90] Hrg. Ex. 102 (Mark Direct) at 83.

areas, and that the income-verification process can be time-consuming and burdensome for participants.[91]

131. In its answer testimony, EOC proposes a tiered approach for access to income-eligible programs.[92] EOC notes that while using EnviroScreen, 43.2 percent of the Company's service territory is located in DI communities,[93] there is substantially more need than there are available resources.[94] In light of this disparity, EOC argues that a tiered structure of benefits balances priorities and access to scarce resources. EOC proposes a four-tier approach, with the greatest needs receiving the most intensive energy services in Tier 1, down to customers living in DI Communities who provide no income verification receiving lower cost programs and benefits. Eligibility for Tiers 1 and 2 would be limited to customers verifying household income levels at or below 80 percent Area Median Income (AMI), 60 percent State Median Income (SMI), or 200 percent Federal Poverty Level (FPL), with these customers receiving at least the current level of access to whole home weatherization measures. Eligibility for Tier 3 would be limited to customers who self-attested these same income levels, without providing proof or documentation of income to a third party.[95] SWEEP, CEO, Denver, and Boulder each expressed support for EOC's proposal.[96]

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[91] *Id*.
[92] EOC SOP, pp. 6-7.
[93] Hrg. Ex. 110 (Schoenheider Direct) at 24.
[94] Hrg. Ex. 110, Attachment MRS-4 at 1 (Summary Tab).
[95] EOC SOP, pp. 7-9.
[96] Hrg. Ex 1001 (Brant Cross Answer) at 23; Hrg. Ex. 602 (Keleher Cross Answer) at 6; Hrg. Ex. 1403 (Durkay Cross Answer) at 4.

132. After receiving feedback from other parties, Public Service expressed support for the Commission ordering a tiered structure for programming eligibility modeled off EOC's proposal.[97] The Company states it will work with stakeholders to define the details of the tiered structure for program eligibility and propose a refined approach in its next DSM and BE plan filing.[98]

133. In its SOP, EOC states that it appreciates the Company's acceptance of a tiered approach, but is concerned that the vague request to direct development of a tiered methodology with stakeholders in the next plan filing will increase controversy and costs for parties, and is likely to create uncertainty and delay around the IQ Program.[99] EOC also proposes several guiding principles it suggests the Commission adopt, if it does not choose to adopt the tiered approach.[100] EOC argues that the Commission should order that the budget dedicated to serving IQ customers in the 2023 plan be the minimum budget for IQ customers (tiers 1 and 2) in future program years.[101]

b. Findings and Conclusions

134. EOC's tiered approach and tier definitions provide a reasonable starting point for incorporating DI communities into income-qualified program offerings by the Company. We request that the Company work further with stakeholders to refine the eligibility requirements and program offerings for DI communities into IQ programs with the EOC's tier proposal as the

[97] Public Service SOP, pp. 28-29.
[98] Hrg. Ex. 116 (Schoenheider Rebuttal) at 38-41; Public Service SOP, p. 29.
[99] EOC SOP, pp. 10-11.
[100] *Id.*
[101] Hrg. Ex. 1201 (Ilderton Answer) at 13.

starting point. The results of this stakeholder engagement should be presented in the next DSM or BE application proceeding.

135. Finally, we agree with EOC that DSM spending targeted to non-IQ residents of DI communities should not detract from program funds available to the IQ community. We therefore direct the Company to develop budgets for non-IQ offerings in DI communities that are incremental to the IQ budget. The budget for the 2023 IQ program shall serve as the budget floor for that community going forward.

2. Census Block Data

(1) Proposals

136. Public Service proposes using EnviroScreen to identify DI communities within its service territory in order to expand access to income-eligible programs to DI communities.

137. Boulder expresses concern that the EnviroScreen mapping tool the Company uses to identify DI communities is an insufficient indicator of need. Boulder identifies a census block in the Interlocken area of Broomfield that EnviroScreen identifies as a DI community, but Boulder notes that in this block, only 21.5 percent of households are considered low-income and only 21.3 percent are people of color.[102] Boulder also points to shortcomings in the accuracy of the information in census blocks and disparity within census blocks, such as when manufactured housing communities across the borders of census blocks.

138. Boulder acknowledges that EnviroScreen can be used for initial identification of target communities, but recommends that only those census blocks where at least 40 percent of households are low income and/or people of color be designated as DI for DSM analysis and

[102] Hrg. Ex. 801 (Elam Answer) at 9-11; Boulder SOP, p. 9.

programming. Boulder also recommends creating a process where communities can "self-identify" to receive a DI designation.[103]

139. Public Service addresses Boulder's concerns and agrees that EnviroScreen is not free from any concerns, but argues that until the Commission adopts or directs a different methodology, use of EnviroScreen for identification of DI Communities is reasonable and consistent with the public interest.

(2) Findings and Conclusions

140. The Commission currently has an ongoing docket to identify disproportionately impacted communities in Proceeding No. 23M-0171ALL. Because of this and other ongoing efforts, we find it premature to rule here regarding the Company's proposal to identify DI communities using census block data through the use of EnviroScreen and Boulder's proposal to limit DI communities identified to only those census blocks where at least 40 percent of households are low income or identify as a minority. As parties have correctly stated, Proceeding No. 22M-0171ALL is currently active and gathering information to allow the Commission to initiate a rulemaking on this topic and to make decisions about, for example, the long-term use of EnviroScreen and the pathways by which communities may self-identify as disproportionately impacted.

c. Cost-effectiveness of IQ Programs

k. Proposals

141. EOC requests that the Commission order the Company not to reject projects or measures proposed in custom Multifamily Weatherization (MFW) and Nonprofit Energy

[103] *Id.*

Efficiency Project (NEEP) programs applications if their mTRC score is lower than one. EOC states that it recognizes the importance of safeguarding ratepayer funds and thus strives to pursue and undertake projects or implement measures that will support a higher mTRC for the IQ program, but argues that there are ample environmental, societal, and moral reasons to undertake certain projects and measures—often the most needed ones for the most vulnerable customers-which will readily score an mTRC greater than 1.[104] EOC does not offer recommended modifications to cost-effectiveness testing for IQ programs, but in its answer testimony, EOC recommended that the Commission order the Company to hold stakeholder meetings and develop in conjunction with stakeholders a revamped project approval system for IQ customers by the filing of the next DSM plan.[105]

142. Public Service does not directly address EOC's proposals but states in its rebuttal testimony that it encourages EOC to continue participating in these meetings and states that without a specific proposal, it is difficult to provide a specific response to changes to the mTRC test.[106]

[104] EOC SOP, pp. 18-19.
[105] *Id*. at pp. 22-23.
[106] Hrg. Ex. 116 (Schoenheider Rebuttal) at 38.

l. Findings and Conclusions

143. The record in this Proceeding indicates that there is substantially more need than can be served by the Company's annual IQ DSM budget and that there is a vast gap between need and what the Company is able to provide in any given year. This being the case, it makes most sense to use limited IQ funds where they will provide the most benefit, as measured by the mTRC, rather than completely ignoring cost-effectiveness and potentially undertaking projects with costs that greatly exceed their benefits. Accordingly, we reject EOC's request here and reinforce the important role that the mTRC and other tests play in allocating scarce program resources. We direct the Company to require an mTRC greater than 1.0 at the project level, even if individual measures proposed for the project have an mTRC below 1.0. This should allow for a reasonable bundling of measures within a project, so long as the project, as a whole, achieves the required mTRC, which should promote prioritization to minimize cost impacts to other ratepayers as we continue to increase levels of support to IQ customers. Recognizing that many of the IRA incentives are targeted at IQ customers with enhanced levels of incentives, we would also like to be made aware if we are missing any opportunities to take advantage of these incentives for IQ customers simply because the mTRC cost effectiveness test does not consider those federal investments in its calculation.

d. Budget for IQ DSM Programs

m. Proposals

144. Conservation Coalition advocates that program benefits should accrue to IQ customers in proportion to their representation in the total population of households that the Company serves. Conservation Coalition calculates that 22 percent of Public Service's electric

accounts and 28 percent of its gas accounts are income-qualified customers. Accordingly, it recommends that the Company's goals be set such that 22 percent of electric savings and 28 percent of savings from both gas energy efficiency and BE accrue to IQ households.[107]

145. CEO states that it supports Conservation Coalition's proposal.[108]

146. UCA recommends that the Commission require the Company to allocate a minimum of 25 percent of total electric DSM expenditures on the residential sector, but makes no specific recommendation regarding electric DSM expenditures on IQ customers. With regard to gas DSM, UCA notes that § 40-3.2-103(3)(a)(II), C.R.S. requires that "one or more of the gas DSM programs or measures, representing an aggregate total of at least 25 percent of overall residential gas DSM program expenditures, including expenditures serving income-qualified households, must be targeted to residential customers in income-qualified households."[109]

147. In its SOP, Public Service commits to (1) spend at least 20 percent of total BE funding to support IQ/DI communities; (2) allocate 25 percent of overall residential spending on gas DSM to target IQ customers (as required by statute); (3) spend at least 25 percent of electric energy efficiency budget to support residential customers; and (4) allocate 25 percent of overall residential spending on electric DSM to target IQ customers.[110]

[107] Hrg. Ex. 701 (Grevatt Answer Rev. 1) at 94-101.
[108] CEO SOP, p. 11
[109] UCA SOP, p. 7.
[110] Public Service SOP, p. 30.

b. Findings and Conclusions

148. The Commission approves the spending guardrails that the Company outlines in its SOP, including that it will (1) spend at least 20 percent of total BE funding to support IQ/DI communities; (2) allocate 25 percent of overall residential spending on gas DSM to target IQ customers (as required by statute); (3) spend at least 25 percent of electric energy efficiency budget to support residential customers; and (4) allocate 25 percent of overall residential spending on electric DSM to target IQ customers. We agree with Public Service and intervenors that these guardrails promote benefits to both IQ/DI customers and residential customers.

149. We also see merit in Conservation Coalition's proposal that spending on IQ programs should accrue to IQ customers in proportion to their representation in the total population of households that the Company serves, However, understanding the costs and ratepayer impact overall, we decline to order this as a binding budget target at this time. We agree with Conservation Coalition that programs should be designed with this in mind and that the Company should show progress in its next filing demonstrating showing that it is moving closer to the proportional spending advocated by Conservation Coalition.

5. Point of Sale Rebates for IQ Customers

(1) Proposals

150. EOC advocates for the establishment of point-of-sale rebates for certain efficient equipment for income-qualified customers. EOC argues that point-of-sale rebates simplify the transaction and lower barriers to participation, and that non-IQ customers have enjoyed such rebates in past DSM plans. EOC recommends that the Commission order the Company to begin offering point-of-sale rebates to customers participating in the IQ program (both IQ and

customers living in DI Communities). EOC contends that such rebates would help customers with low and moderately low incomes offset the high initial costs of high efficiency electric and natural gas equipment, insulation, air sealing, and other traditional weatherization measures.[111]

151. EOC notes that the IRA provides funding for IQ point-of-sale programs in the High Efficiency Electric Home Rebate program to be implemented by state energy offices. It argues that there is therefore a substantial opportunity to "stack" funding from the IRA with utility incentives, as well as potentially On-Bill Financing, to enable IQ customers to afford high efficiency electrification. EOC recommends that income-verified customers could be issued an activation code to be used at the point of sale. It also suggests that a geographic identifier with account or premise number could be used to unlock savings for DI community customers. Rather than wait for the CEO to finalize its process, EOC recommends that the Company be required to launch a pilot in its next BE/DSM plan, with input from CEO and other stakeholders, which utilizes these or other processes to enable point-of-sale rebates for IQ customers, as well as potentially DI community customers.[112]

152. Although the Company did not address this issue in its SOP, it did provide conceptual support for EOC's general proposal in testimony. However, Public Service notes while it is generally agreeable to further considering revised rebates, especially in light of additional federal funding opportunities, it cautions against having two separate programs (*i.e.*, one implemented by the Company and another by CEO).[113]

[111] EOC SOP, p. 15-16.
[112] Hearing Transcript at 69-71 (Feb. 8, 2023).
[113] Hrg. Ex. 116 (Schoenheider Rebuttal) at 44-46.

b. Findings and Conclusions

153. We direct the Company to work with EOC and other interested parties to investigate the possibility of providing point-of-sale rebates tailored to IQ customers and DI communities, and to include in its next DSM plan application either a plan to roll out such rebates in conjunction with or in advance of the CEO IQ point-of-sale rebate program, or a description of why it has concluded that such rebates would be ill-advised at this time. We recognize the value of point-of-sale rebates for IQ customers in improving access to valuable programs but hesitate at this time to order the Company to implement a program that could end up overlapping or duplicating CEO's efforts, without proper coordination.

6. Health and Safety Budget

(1) Proposals

154. In its Application, the Company states that it added an income qualified program spend for "health and safety" measures to its portfolio in the 2019-2020 DSM plan. This spending is intended to mitigate health and safety concerns that had previously prevented completion of energy efficiency projects in the homes of income qualified customers.[114]

[114] Hrg. Ex. 105 (Schoenheider Direct) at 23-24.

Public Service does not request the Commission set a health and safety spending limit in this Proceeding, it has previously been set at $275,000, but states it instead intends to propose specific spending amounts in subsequent DSM plans. Here, the Company requests that the scope of permissible health and safety projects expand to allow for the following: removal/mitigation of vermiculite and asbestos; electrical repair or upgrade to enable efficient equipment, including: knob and tube wiring, panel upgrades, repair damaged wiring, outlets, junction boxes; HVAC repair such as chimney liners, flue, gas valve, sensor repairs; Mold, moisture-related mitigation (including structural repair like foundation, roofing, walls, windows, doors repair and replacement); radon mitigation; addressing plumbing leaks and sewer problems, including clogs; remedying access issues due to inaccessible crawl spaces; integrated pest management (insect/vermin remediation and blocking); and remediation of excessive clutter and hoarding.[115]

155. EOC strongly supports the Company's proposal to increase the scope of permissible health and safety projects and states that EOC regularly experiences pre-weatherization hazards including, for example, addressing leaks in the roof that would prevent attic insulation, spliced electrical wiring that prevents adding insulation to spaces, vermiculite insulation, asbestos on the heating ducts and in the heating appliance, and improper venting of combustion appliances.[116] EOC also asks the Commission to approve that an incremental budget equivalent to 15 percent of the overall IQ program budget be spent on pre-electrification measures, instead of a set amount as previously established. EOC argues a

[115] *Id*. at 24.
[116] EOC SOP, p. 13.

larger budget is appropriate because of the proposed expansion of permissible efforts, and because the $275,000 budget has previously been completely spent in 2020, 2021, and 2022.[117]

b. Findings and Conclusions

156. We are aware that health and safety issues must sometimes be addressed before energy improvements can safely be implemented and agree that it is appropriate to fund remediation of such issues where they would otherwise preclude responsibly moving forward with an energy-related improvement. However, we find it difficult to understand how some of the issues the Company proposes to address in expanding the scope of health and safety spending, such as remediation of excessive clutter and hoarding, are necessary to enable saving energy, which should be the primary goal of the IQ program, or why the proposed remediation should be conducted at ratepayer expense. We therefore direct the Company to limit health and safety spending to address only those issues that, in the reasonable opinion of a building professional, would make it impossible to complete the energy efficiency project under consideration in a manner that preserves the safety or health of the occupants. In situations where the cost of a health and safety remediation rises to a considerable fraction of the budget proposed for the energy project, we encourage the Company to consider whether, given the extreme disparity between the need for IQ services and the annual budget available to address that need, it might be best to deny efficiency services at the residence in question in favor of other residences also requiring assistance where completion of efficiency work does not pose health and safety concerns.

[117] EOC SOP, p. 14.

H. On Bill Financing

(2) Proposals

157. Public Service states that consistent with the settlement in Proceeding No. 20A-0287EG, the Company engaged with stakeholders on several occasions in 2021 and 2022 to evaluate the potential for an on-bill financing (OBF) offering. The Company supports on-bill financing generally, and is requesting approval to present a program in its next DSM and BE plan. As part of that approval, the Company seeks clarity on the funding source and the interest rate. The Company principally recommends use of the DSMCA for funding, as it allows for a low interest rate set at the customer deposit rate. Should the Commission direct the Company itself to fund the program, the applicable interest would be the Company's WACC.[118]

158. In this Proceeding, the Company requests guidance on the funding source and interest rate, but states that it will continue to work in partnership with stakeholders to further define the on-bill financing offerings, and particularly regarding income-qualified customers.

159. Staff does not support the use of the DSMCA to fund an OBF program unless program eligibility is limited to income-qualified ratepayers. If the program were to be made available to all ratepayers, as Public Service proposes, it would have the effect of forcing lower income ratepayers (including renters) to provide the financing for higher income property owners to make investments that increase the value of their properties. Limiting the eligibility of a DSMCA-funded program to income-qualified ratepayers would have the dual benefit of (1) mitigating this potential forced transfer from lower income to relatively affluent ratepayers and (2) focusing the program on the group of ratepayers who stand to benefit the most from such

[118] Hrg. Ex. 105 (Schoenheider Direct) at 37.

a program, as the high upfront cost of energy efficiency and BE investments is likely to pose a more significant barrier to these ratepayers and they are less likely to have access to low-interest financing.[119]

160. CEO supports OBF, and it requests that: (1) OBF also expand to support renewable energy installations installed in combination with DSM or BE measures; and (2) the Company allow participants to choose how applicable rebates are provided, such as through traditional processes or credited against outstanding balances. In its SOP, CEO explains that its support for utility-led OBF also derives from a 2020 report commissioned by CEO identifying market barriers and policy recommendations for BE. While CEO supports the Commission conducting a thorough consideration of funding sources that can be capitalized for an OBF program, CEO cautions the Commission against relying on CEO's ability to fund this capitalization.[120]

161. EOC supports OBF, stating in its SOP that OBF theoretically offers customers opportunities to obtain highly efficient appliances and equipment they might not otherwise be able to afford. It suggests program design elements to assist income-qualified customers, including low-interest rates, metrics other than credit scores, and measure support for appliances other than just high-efficiency heating systems. EOC advocates for inclusion of point-of-sale rebates as an option in the program. EOC also recommends customer safeguards to ensure energy assistance funding goes only to the usage charge and that disconnections are avoided at all costs.[121]

[119] Hrg Ex. 902 (Haglund Answer) at 25; Staff SOP, p. 21.
[120] CEO SOP, pp. 28-29.
[121] EOC SOP, p. 20.

162. Boulder supports the development of an OBF program. It clarifies that its support of OBF is focused on strategies, and specifically tariff based products, which do not assign debt to a customer. It contends that even at a low rate, taking on debt is a barrier to customer participation, particularly for low-to-moderate income customers. For an OBF product to advance equity within the DSM portfolio, Boulder argues, any assignment of debt must vest at the meter, not the customer. Boulder suggests that given the additional revenue the Company will enjoy due to BE, it is reasonable for Company shareholders to "invest in this new line of business." While it states that it does not oppose using the DSMCA as the initial financing source, it expresses concern that growth in an OBF program would put funding for DSM and BE in competition funding for OBF. It recommends that the Commission direct Public Service to explore other low-cost financing sources, such as net income from the Company's residential natural gas business.[122]

163. Denver is supportive of the program. It also requests: (1) a study on how financing products may be used to lower interest rates; (2) development of consumer protections; and (3) a limitation on offerings for only those that do not promote gas infrastructure or gas appliances.[123]

164. SWEEP is supportive of the OBF program, and it asserts that the Company must develop in a future filing adequate customer protections. SWEEP notes the Company's agreement with the need for such safeguards and willingness to work with stakeholders to develop them for proposal in the next DSM and BE plan filing.[124]

[122] Boulder SOP, pp. 5-7.
[123] Denver SOP, p. 13.
[124] SWEEP SOP, p. 28.

165. On rebuttal, Public Service opposes the notion that OBF should not be available for appliances that use natural gas, for the same reasons it opposes the termination of incentives for those appliances. It contends that OBF should be open to major appliances and permanent upgrades that are otherwise eligible for participation in the DSM portfolio. However, Public Service states it will work with interested stakeholders through its DSM Roundtable quarterly meetings to continue to assess and develop the safeguards. Through discussions with stakeholders, the Company is hopeful that a robust set of safeguards can be developed and agreed to, limiting the need for litigation on the matter in the plan filing.[125] With regard to using OBF to fund the installation of renewable energy projects, the Company questions whether the DSMCA would be the appropriate funding vehicle, or whether the Renewable Energy Standard Adjustment might be more appropriate. It recommends that CEO continue to explore this with the Company in future DSM Roundtable discussions. Public Service notes that Commission guidance that it is appropriate for the Company to continue working on this program along with the fundamental concepts proposed in this Proceeding will assist program creation and will address the detailed elements in the next DSM and BE plan.

[125] Hrg. Ex. 116 (Schoenheider Rebuttal) at 31-35.

(3) Findings and Conclusions

166. We find that on-bill financing is likely a cost-effective way to reduce barriers to participation in the Company's DSM programs, especially among IQ customers who may lack the resources to make costly upfront efficiency investments, and that it better aligns a participant's costs of participating with the savings that are thereby achieved. We are therefore supportive of the Company's efforts to engage with the parties to develop an OBF proposal for the next DSM plan application. The following paragraphs provide guidance on our preferences for the development of this proposal.

167. We share the concern Staff raises that if OBF is made available to all ratepayers and collected through the DSMCA, that IQ customers could be subsidizing non-IQ customers. We are also concerned that if OBF is available to all customers, the demand for financing could strain the DSM budget and put OBF in competition with the funding available for DSM implementation. Much will depend upon the source or sources of capitalization for on-bill financing or on-bill repayment (OBR) (if a third-party source of capitalization is used), and what interest rate is embedded in the financing terms. While on-bill financing or repayment would ideally be available to all ratepayers, we encourage the Company and the parties to prioritize availability of this financing for IQ customers first, and to evaluate whether it can be offered to non-IQ customers, and at what appropriate interest rate necessary to avoid these potential pitfalls.

168. In its testimony, the Company discusses only two potential sources for capitalization: ratepayer funds financed through the DSMCA at the customer deposit rate (currently 1.69 percent) or shareholder funds, which would be financed at the Company's

WACC. We note that these are not the only two potential sources for financing customer investments in energy efficiency. Private sources of capitalization may be readily available and used as they are in other states. Public funding may then be paired with private capital to expand access to funds as there are state, federal, and private sources of funding that could be tapped for this purpose potentially reduce financing costs and reduce qualification thresholds that exclude portions of the population by using those public funds to reduce risk to the lender. We encourage the Company and parties to explore these alternative sources of financing comprehensively.

169. We will express our preference here that if OBF or OBR is offered, the financing rate for IQ and DI customers should be zero or very low, whereas the financing rate for non-IQ customers should be higher, but in no event higher than the Company's WACC.

170. Elsewhere in this Decision we provide direction on phasing out incentives for high-efficiency gas appliances in favor of electrification. We would request that the OBF and OBR policies should align with the direction provided on phasing out incentives and no measure should be incentivized through OBF or OBR for which the Commission has determined rebates should be discontinued, especially given the phase-out of several areas related to gas-fired equipment.

171. Finally, we have concerns about OBF being made available for financing investments in renewable energy unless there is a third-party source of capitalization. Although the RESA may be a more appropriate vehicle than the DSMCA to finance ratepayer investments in renewable energy, we may explore this issue in a future proceeding, as appropriate.

I. Demand Response

1. Electric Demand Response Goals

a. Company Proposal

172. Public Service requests that the Commission approve the Company's electric DR goals as consistent with the Commission's prior directive, party input, and the public interest. The Company notes that its existing DR portfolio "is among the largest in the U.S."[126] However, the Company recognizes the need to add more DR and move towards a structure that focuses on winter peaking, which is necessary due to the expected impact of electrification. The Company thus proposes for the first time both summer and winter DR goals. The Company states it is committing to the increased DR goals to mitigate the need for additional capacity resources.

173. The Company differentiates its demand response into dispatchable and non-dispatchable (*e.g.*, a high efficiency AC unit) resources. Dispatchable resources fall into three categories: (1) Direct Load Control (*e.g.*, Saver's Switch); (2) Interruptible Tariffs (*e.g.*, ISOC tariff); and (3) Other DR offerings such as Critical Peak Pricing (CPP), an EV-specific CPP (EV-CPP), Peak Day Partners (PDP), and Peak Partners Reward (PPR). The Company offers one residential and five commercial programs.[127]

174. Overall, the Company proposes on rebuttal a 593 MW goal for summer 2024 and a 281 MW goal for winter 2024; a 618 MW goal for summer 2025 and a 301 MW goal for winter 2025; and a 652 MW goal for summer 2026 and a 334 MW goal for winter 2026 but that the budgets should be set in the next DSM plan proceeding.[128]

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[126] Public Service SOP, p. 17.
[127] Hrg. Ex. 104 (Bruers Direct) at 12.
[128] Public Service SOP, p. 17.

b. Party Positions

175. WRA contends Public Service's overall DR portfolio impact of roughly ten percent of summer peak load lags behind its counterparts at Alabama Power and Duke Energy Florida whose DR portfolios equal 15.5 percent and 14.2 percent of summer peak loads, respectively. WRA argues that Public Service should be required to procure 786 MW, or 10.9 percent, by 2027. WRA recommends the Company implement new demand response programs, including residential battery storage leasing pilot, including an income-qualified component; a residential peak time rebate pilot leveraging alerts based on load disaggregation; approaches to multifamily demand management; and third-party bid demand response programs, particularly focused on nonresidential customers.[129]

176. The Stipulation offers the following summer and winter DR goals as its proposal: for 2024, 538 MW in summer and 272 MW in winter; for 2025, 686 MW in summer and 340 MW in winter; and for 2026, 720 MW in summer and 373 MW in winter.[130]

[129] Hrg. Ex. 1502 (Valentine Answer) at 39.
[130] Stipulation, p. 3.

177. Staff contends the Company's proposed DR goals lag behind the assumed levels in the ERP decision. Staff, however, agrees with the Company that only dispatchable DR is the proper focus of developing DR goals and targets (thus, excluding residential and commercial TOU rates), but that TOU-related reductions should be recognized in future ERP cases. Staff argues the advanced meters could be leveraged to accomplish winter DR savings the distributed intelligence, although the Potential Study "suggests that DI will contribute nothing to the Company's DR programs through 2030." Staff also suggests there is potential value in "a V2G program" even through the Potential Study suggests otherwise. Staff suggests the Commission direct Public Service to model DR as a supply-side resource in its next ERP proceeding.[131]

178. UCA contends the DR portfolio should be expanded to included savings the Company already identified that too much of the DR budget is spent on administration, that DR programs should cover all days of the week (not just non-holiday weekdays), and that a pilot third-party aggregation program should be reconstituted. A prior third-party aggregation program successfully procured 20 MW but was terminated by the Company and redeveloped as the Peak Partner Rewards program, but the program provides only 12.12 MW, well below the 48 MW target for the program.

[131] Staff SOP, pp. 17-18.

179. EEBC recommended both that the Company solicit proposals for DR programs and that it prioritize use of the new AMI meters.

c. Findings and Conclusions

180. For 2024, we adopt the Company's proposed 2024 goals of 593 MW for summer 2024 and 281 MW for winter 2024 which was widely supported by the parties. We find this a reasonable near-term goal for the Company in light of the need to expand both the DR capacity available and the use and number of programs available. For 2025 and 2026, we find an average of the Stipulation and the Company's proposal to strike a reasonable balance between ensuring the Company strives for ambitious DR offerings, while acknowledging that the Company has substantial work ahead of it to expand DR offerings. This works out to an additional 35 MW for each summer and winter compared to the goals presented by the Company—for 2025, the DR summer goal is 628 MW and the winter goal is 301 MW, for 2026, the summer goal is 663 MW and the winter goal is 321 MW.[132] Regarding the utilization of AMI meters, we are disappointed that the Company seems uncertain as to how to maximize value of the AMI to both the customer and the utility given that ratepayers have invested hundreds of millions of dollars into these technologies. We request that the Company quickly develop a suite of, not just pilots, but full, scalable, programs that clearly show this investment is cost-effective and takes advantage of the expanded technology opportunities presented by AMI in order to more fully optimize the use of grid infrastructure.

[132] For future filings, we expect the Company to present, at minimum, gross numbers for goals and budgets. While expression of goals and budgets incrementally also has value, the Company should always at least provide presentation of figures on a gross basis.

181. Additionally, we wanted to express a need for consistency in the future related to how demand response goals are communicated. It is confusing and difficult to follow progress across proceedings when some goals are communicated as gross values and others only as incremental values. This mix of methods has the potential to cause significant inconsistencies in interpreting current expectations. The Company and parties should focus on consistent metrics and communications utilizing gross values so that confusion is avoided in the future, especially as we consider an enhanced focus on demand response and specific performance incentives.

2. Gas Demand Response Goals

182. Public Service explains that like electric demand management, gas demand management (GDM) is an effort to engage with customers and influence them to make decisions that will contribute to lower peak demand on the Company's natural gas system. By reducing peak demand or by slowing growth, GDM can save costs for customers and support system reliability.

183. Public Service states that GDM is an emerging area of DSM and there are few established programs focused on it nationally that could serve as models for potential achievement. Given the newness of the field, Public Service argues it is not appropriate to establish specific goals at this time, but rather the Company will continue to develop and test various proposals to determine what is effective. Once the Company and stakeholders have established a better understanding of what can be achieved, the Company can propose specific goals in a future strategic issues filing.[133]

[133] Public Service SOP, p. 20.

184. In its direct case, the Company proposed a new methodology to estimate the value of natural gas capacity in its efforts to support DSM programs at Targeted Demand Areas in order to avoid or defer capacity investments through the implementation of DSM and BE measures. It proposed a new methodology to support the benefits of capacity avoidance in future years. The Company has historically applied a gas capacity value that assumes one percent of savings occur on peak. Moving forward, the Company proposes to compliment that value with a new methodology that is time and location based. It reflects time through a metric based on dekatherms per hour on a peak day.

185. The Company does not support the Commission establishing natural gas DR goals based on peak capacity reduction or peak day volumetric reduction in this Proceeding. It claims any such goal would be arbitrary because there is no baseline of information upon which to determine realistically achievable potential. It proposes exploring gas demand response further in its upcoming gas infrastructure plan filing, which it will make pursuant to Commission Rule 4552 of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4.

186. UCA recommended the Company establish a new metric to capture the avoided capacity cost, representing the avoidance of adding pipeline capacity. The UCA did not propose a specific calculation or input, but instead generally sought the development of this metric to assist in gas demand response program development, as well as to address underestimates of gas DSM, gas DR, and electric BE.

187. At this juncture, the Commission declines to adopt gas DR goals because the Proceeding record does not have sufficient information to establish goals at this time. We support the general idea behind the Company's proposal to utilize a new methodology that identifies capacity constrained portions of the system and targets DSM efforts in those areas

given the potential for significant cost savings by strategically deferring or avoiding a system capacity need. However, the proposed methodology from the company for Targeted Demand Areas is not appealing to the Commission in its current form, because it could produce enhanced benefits to the Company without actually resulting in savings to ratepayers through avoidance of any project expenditures or any consideration of gas demand response, more specifically. A more geographically-focused approach, designed to help us better understand the potential for targeting demand response, is of significant interest to the Commission, perhaps utilizing some of the information provided by the Company about the potential value of demand reductions in areas with capacity constraints. The Commission expects to explore directing the Company to issue RFPs to evaluate the ability of third parties to provide these services in a miscellaneous docket following the conclusion of this Proceeding.

188. We explicitly recognize that the Company should not have a gas DR goal of zero as these investments can limit future gas system capital costs and, over time, greater experience can lead to more effective program design, which we would like to see occurring sooner rather than later. Given that the purpose of this proceeding is to be strategic in identifying where DSM programs should be headed over the next several years, it is important to recognize that the Commission sees gas DR as a crucial area to begin exploring in earnest and development of such capabilities at scale is expected over the strategic plan period. Further, we find that the Company's existing gas DR pilot has, to date, failed to produce meaningful results and exhibited several major flaws in design and execution, despite a reasonably sized investment. More disturbingly, after over two years of implementation, the Company has put forth no concrete ideas on program changes or new or different concepts, despite explicit prompting from the

Commission in various forums, including in a request for supplemental direct testimony on this issue.

3. Demand Response Potential Study and ERP Alignment

(1) Proposals

189. The Company presents goals for demand response that were "informed by" the DR Potential Study conducted by the Brattle Group.[134] That study developed DR potential for 2030, based on the need for alignment with the Company's ongoing ERP and clean energy plan *(*see Proceeding No. 21A-0141E). The Company explains the study incorporated market trends in customer adoption of foundational technologies such as control systems, behind-the-meter batteries, and electric vehicles.[135]

190. Several parties raise concerns regarding the Company's DR Potential Study.

191. The Conservation Coalition offered some critiques of the study and expressed some confusion regarding the methodology used to determine goals. Among the critiques is that the study wrongly focused on DR potential in the year 2030, and that "the Company has admitted that it did not develop its 2024-2027 DR goals in the same manner that Brattle developed its 2030 goals, *i.e.*, by estimating the cost-effective, achievable potential for individual DR programs."[136]

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[134] Hrg. Ex. 102, Attachment NCM-2.
[135] Hrg. Ex. 115 (Bruers Rebuttal, Rev. 1) at 8.
[136] Hrg. Ex. 702 (Reeves Answer) at 48.

Conservation Coalition argues that the study is flawed because it did not consider a suite of additional DR programs for residential customers including: time-of-use and EV managed charging, smart or grid-interactive water heating, peak-time rebates, behind-the-meter storage, and behavioral demand response. Conservation Coalition raises issues with the Company's AC Rewards program, noting that the program only allows three thermostat brands as eligible for enrollment: Ecobee, Honeywell, and Emerson thermostats and that it is limited to only single-family homes with central air conditioning. It states that "[e]xpanding eligibility to include more thermostat brands, such as Google Nest, will be more inclusive of a diverse market, increase market potential, and increase scale and magnitude of the Company's smart thermostat DLC demand response capability." Because the Company considered only single-family homes with central AC and thermostats from those three manufacturers, the study shows an eligibility rate of only 40 percent of residential customers, and no potential savings relevant to residential winter load requirements. The Conservation Coalition recommends that the Commission order the Company to provide a revised DR study.

192. Several parties highlight the importance of alignment between the Company's SI and ERP filings.[137] In particular, Conservation Coalition advocates that the relationship between the two is "critical" and "failing to account for cost-effective [energy efficiency] and DR resources in supply-side planning and procurement" can lead to over-procuring supply-side resources (which can result in unnecessary ratepayer costs and emissions), as well as the risk of over-rewarding the Company for DSM achievements that fail to reduce supply-side resource acquisition because the ERP does not account for them.[138]

[137] Hrg Ex. 701 (Grevatt Answer) at 18; Hrg. Ex. 400 (Neil Cross Answer) at 31; WRA SOP at26-27.
[138] *Id*. at 18-20.

Similarly, WRA advocates that the Commission should order Public Service to update its DR potential study before filing its next ERP and extend the DSM forecast for the next SI plan to include targets that cover through the end of the next resource acquisition period.[139] WRA also argues that the Company should develop generic DR resources for its next ERP.[140] Staff argues the Commission should direct Public Service to model demand response as a supply-side resource in Phase I of its next ERP proceeding, expected to be the Just Transition Plan filed in 2024.[141] Staff notes that the Tri-State Generation and Transmission recently modeled DR in its Phase I ERP proceeding, and that if the Commission wishes to consider the impact of DR in Phase I, the only alternative to modeling competitive DR as a generic resource is the approach the Commission took in Public Service's recent Phase I proceeding: to order the Company to model DR as a simple load reduction.[142]

c. Findings and Conclusions

193. We find that the Company's DR study provides some insights into the DR market potential, but that additional information should be included to make the study more useful. We require the Company to amend or complete a new study in time for use in the Company's next ERP and strategic issues filings with additional information included, including:

a) A comprehensive look of other programs throughout the country and an updated baseline capturing other programs already developed but not considered in the baseline in the current study;

b) Total and DR-participating number of customers with central AC or ASHPs;

c) Total and DR-participating number of customers with smart thermostats;

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139 WRA SOP, pp. 26-27.

140 *Id*.

141 Staff SOP, p. 19.

142 *Id*. at 20.

d) Total and DR-participating number of customers with higher-voltage (*i.e.*, Level II) EV chargers; and

e) Total and DR-participating number of industrial customers.

194. A new or amended study should also assess key new technologies and their potential, including battery storage and previously approved investments in new demand response capabilities, like DRMS. We are also request that the DR study provide a more holistic look at load reduction strategies measurements and strategies, not be limited to just demand response, but also including demand management, demand flexibility and other strategies. In exploring the broader environment of demand management and demand flexibility opportunities, the study should identify the different use cases, from intraday balancing to handling of the top dozen or so annual peaking events to emergency reliability-related demand response needs. It should identify the types of programs and designs most suitable for each use case and the potential and relative economics associated with each. This more holistic review is of interest to the Commission to understand how to utilize and incentivize demand management, in all of its forms, to optimize use of grid infrastructure to maximize value and minimize costs for ratepayers. We also note that the parties brought up several other helpful changes or considerations for a new potential study in this Proceeding. We encourage the Company to work with stakeholders before amending or completing a new demand response study to incorporate these considerations.

195. We also agree with the parties who advocate for better alignment on DR presentation in the Company's SI and ERP proceedings. We agree with Staff that we need to learn how to better account for DR within an ERP by trying and learning from that exercise. We are also further convinced on the feasibility of modeling DR based on the recent filings by Tri-State Generation and Transmission in its ERP. We therefore order the Company to use best

estimates of DR as a generic resource for Phase I in the Just Transition Plan anticipated in 2024 and take bids in Phase 2 of the just transition plan to facilitate the refinement of modeling values for the Company's next ERP filing (anticipated in 2026). We find that this will allow the Commission to better assess how to use DR as not only a peaking resource but also as a grid optimization and flexibility resource, which could ideally lead to savings in both expenses and emissions.

4. On-Site Emissions

a. Proposals

196. WRA argues participants in demand response programs, including ISOC, PPR, and PDP, may use on-site diesel or natural gas generation during demand response curtailment events, and if so, there could be a resulting increase in greenhouse gas emissions.[143] WRA recommends the Commission issue a series of directives to the Company, including requiring that it conduct an "inventory" of fossil fuel generation assets used "in its DR programs"; requiring new DR program participants to refrain from using fossil fuel resources during DR event; prohibiting current or future DR program participants from responding to economic events with fossil fuel resources; restricting the use of on-site capacity from existing DR customers to only capacity or contingency events; requiring the Company to estimate and report emissions from on-site generation during DR events; and providing annual reporting to the Commission regarding compliance with EPA regulations for emergency generation.[144]

[143] Hrg. Ex. 1502 (Valentine Answer) at 11-12 29-32.
[144] *Id.*

197. Boulder agrees the Commission should require reporting from the Company regarding emissions resulting from behind-the meter generation during demand response events. Boulder also recommends an increased emphasis on aligning loads with available zero-emissions capacity, particularly during the latter two years covered by this strategic issues Proceeding.[145]

198. SWEEP also expresses concern regarding greenhouse gas emissions and other pollutants from backup generators and recommended that the Company collect data regarding the use of such generators.[146]

199. Public Service contends it does not currently track or monitor those emissions, and has no statutory obligation to do so. The Company raises concerns, including: the Company has over 220,000 voluntary DR participants; the Commission should comprehend AQCC's current and proposed regulations on the issue as their oversight overlaps in this area; and such restrictions could lead to less participation in the Company's DR programs.

b. Findings and Conclusions

200. We decline to adopt the proposals requested by WRA at this time. While we share the concerns raised by WRA, primarily that DR efforts should not inadvertently raise emissions, we find that many of these issues would be better addressed by the AQCC before the Commission further considers the issue. We direct Commission advisors to consult with AQCC or the Air Pollution Control Division to discuss progress regarding tracking of onsite emissions and identify if this issue should be raised again within proceedings before this Commission.

[145] Hrg. Ex. 801(Elam Answer) at 18-19.
[146] Hrg. Ex. 1000 (Brant Answer, Rev. 1) at 61-62.

5. Demand Response Pilots and Other Calls for Competition

(1) Party Recommendations

201. CEO suggested the Commission require the Company to facilitate third-party demand aggregation to create a "virtual power plant," or VPP. CEO notes that Governor Polis, in a recent policy letter, calls upon the Commission to "[i]nvestigate the role of virtual power plants for resilience and cost-effective coordination of demand-side resources that may allow lower dispatch of natural gas power plants."[147] CEO recommends that the Company engage stakeholders in developing and assessing VPP solicitations, that VPP bids are responsive to real utility needs, and that such VPP solicitations feed an "iterative cycle" that informs and influences the ERP and DSM processes.[148] CEO also notes that recently-passed legislation, HB 22-1362, facilitates neighborhood-scale electrification through several initiatives, and contends BE adoption and investment in DI communities are broad goals of the Colorado legislature and the Governor, as indicated in numerous legislative and non-legislative documents.[149]

202. Several other parties recommended greater use of competitive processes. Conservation Coalition recommends "that the Company solicit bids from vendors for procuring demand response resources, providing a pathway for aggregators to offer proposals for unique strategies and products that could provide deeper savings potential of the non-residential segment."

203. UCA suggests if the Company is unwilling to expand and effectively implement demand response, this area should be open to private entities. UCA proposes the addition of a

[147] CEO SOP, p. 30, citing Hrg. Ex. 408 at 5.
[148] CEO SOP, p. 30.
[149] CEO SOP, pp.11-16.

pilot to determine the private sector's ability to deliver a demand response product in the form of third-party demand aggregation.

204. EEBC recommends the Commission direct the Company to prioritize the use of its Advanced Metering Infrastructure for DR applications and also conduct RFPs to solicit proposals for additional DR programs starting in 2024.

205. EOC suggests the Commission require the Company develop a pilot program in its next DSM/BE Plan to incentivize high-efficiency electrification in new construction of multifamily affordable housing buildings. EOC suggests such a pilot program would best be run by a third-party implementer that is knowledgeable in applicable energy and green jurisdictional codes, CHFA program requirements, housing tax credit compliance, and state certifications requirements.

206. The Company notes that quarterly DSM Roundtables facilitate stakeholder input, and contends specific proposals are best addressed through plan dockets with more up-to-date market information.[150] The Company also notes that the settlement of the 2023 DSM and BE plan, which was the Commission recently approved with modifications in Proceeding No. 22A-0315EG, provides for a DR RFP which can address Commission interest in such, as raised at hearing.

b. Findings and Conclusions

207. The Commission agrees with CEO and others who have argued that the Colorado legislature has passed several statutes that prioritize BE adoption, and seek to limit gas and electric infrastructure investment, and reduce greenhouse gas emissions. It is incumbent upon the Commission to implement these goals as opportunities arise, as well as to direct efforts to

[150] Public Service SOP, p.35.

maximize the value of ratepayer-funded investments made in utility infrastructure. The Company argued specific proposals should be conveyed and supported in plan proceedings.

We find that, given the legislative guidance and lackluster performance in some of these areas by the Company thus far, it is not appropriate to wait until upcoming plan applications to assess various concepts related to third-party provision of gas DR services, VPPs, and other innovations that may be available from the private sector. Accordingly, the Commission intends to open in the near future a miscellaneous docket to further explore these issues and garner stakeholder input on reasonable parameters for Company-issued RFPs.

208. The Commission also agrees with EOC that more competition should be brought into the multi-family program to incentivize high-efficiency affordable new construction. We require the Company to develop such an activity as part of its next DSM plan application and to work with stakeholders, if possible, to facilitate the cost-effective delivery of such.

J. Program Design

1. Baselines for Energy Savings Calculations

209. The Company proposes numerous baseline protocols to calculate savings from energy efficiency and BE implementation.[151]

210. These proposals are uncontested by any party.

[151] Hrg. Ex. 102 (Mark Direct) at 59-64, as modified on rebuttal, Hrg. Ex. 113 (Mark Rebuttal) at 72.

211. We find these uncontested baseline protocols to be reasonable and will allow the Company to incorporate these protocols into its calculations of savings from energy efficiency and BE implementation.

2. Allocation of Beneficial Electrification Budget

(1) Proposals

212. As part of its Application, the Company proposes a new methodology for allocating BE costs and determining its benefits. Specifically, Public Service proposed a methodology for analyzing and apportioning the costs and benefits of measures that cut across multiple DSM/BE categories.[152]

213. The Company explains there are essentially three options: (1) allocate all BE costs to gas customers, as is currently the case; (2) assign all BE costs to electric customers; or (3) establish a method to allocate a portion of costs to gas customers and a portion to electric customers.[153] The Company contends the current approach ignores electric system impacts of BE and may also raise equity concerns with having one group of gas customers pay for another group to dramatically reduce their usage or to leave the system entirely. Thus, the Company proposes to allocate the cost of BE programs to both its natural gas and electric customers using the following approach:

a) Costs for measures and programs that do not directly affect energy consumption (such as circuit panel upgrades) will be allocated entirely to the electric utility (through the E-DSMCA);

b) Costs to support all-electric new construction will also be allocated to the electric business;

[152] Hrg. Ex. 102 (Mark Direct) at 8690; Hrg. Ex. 102, Attachment NCM-3.
[153] Hrg. Ex. 102 (Mark Direct) at 56-58.

c) Costs to electrify end-uses currently met with fossil fuels other than natural gas (such as propane furnaces or gasoline lawnmowers) will be allocated entirely to the E-DSMCA; and

d) Costs for measures and programs that seek to electrify existing natural gas end-uses will be allocated 50/50 to the electric and natural gas utilities.

214. The Company contends that its proposal for allocation of BE costs and benefits are not contested, and both EEBC and SWEEP generally stated support for the approaches.[154]

b. Findings and Conclusions

215. We find the Company's proposal reasonable and adopt it for the use in this strategic issues proceeding as it attempts to fairly balance the interests of both gas and electric customers. While we approve this general framework for allocation of BE costs and benefits, we find this approach to be most applicable to the Company's dual electric and gas customers. We note that we expect future proceedings to explore further how to handle customers for which Public Service supplies only gas or electric service.

3. Measure Incentives

(1) Company's Position

216. In Public Service's direct case, the Company argues that programs that encourage the installation of efficient gas appliances are still important despite the benefits of beneficial electrification. Public Service refers to the top forty measures identified in the Potential Study, and notes that approximately one third of the total identified results from the installation of efficient gas appliances.

[154] Public Service SOP, p. 16.

217. The Company anticipates that most customers in the future will install systems where natural gas heating is retained as a peak or backup resource for premises that are primarily electrified. These heating and cooling configurations are referred to as dual-fuel systems. Dual-fuel systems considerably reduce natural gas consumption, but also preserve a customer's ability to use natural gas during the coldest periods. Despite the Company's anticipation of dual-fuel adoption, Public Service clarified that customers wishing to fully electrify can do so, and the Company will have supportive programming to incentivize all-electric adoption.[155]

218. The Company further argues that many low-efficiency gas options are available, they are prevalent in the market, and they are the default choice for most customers. Full electrification of these end uses may not be practical for many customers, nor may it be the way to achieve the greatest reduction in greenhouse gas emissions given a fixed budget. According to the Company, it is therefore important to continue to promote efficient gas appliances to customers which will permit the Company to provide bill savings, reduced throughput, reduced peak demand, and reduced greenhouse gas emissions.

a. Proposals

219. The Stipulation recommends that by January 1, 2024, the Company phase out incentives for market-rate residential gas water heaters.[156] The Stipulation also calls for the Company to end ENERGY STAR New Home (ENNH) Incentives for mixed-fuel homes starting January 1, 2024.[157]

[155] Hrg. Ex. 113 (Mark Rebuttal) at 5.
[156] Stipulation, p. 3.
[157] Stipulation, p. 3.

220. The Company strongly opposes the Stipulation's call to end from ESNH any new home that is not all electric. The Company states that in 2021, only four homes were built all electric through ESNH, with that amount only growing to eight in 2022, representing only 0.1 percent of ESNH homes. Public Service argues that it is critical that ESNH ensures that the homes participating (roughly 7,000 such homes) continue to be built above applicable code, with better building shells, so that they will require less heating demands, no matter the source of heating.[158]

221. Denver advocates for a phase-out of market-rate furnaces.[159] Denver also proposes a multi-year transition plan and recommends that new construction programs, including commercial, should be limited to all-electric buildings, as supported by a robust educational and marketing efforts.[160]

222. Conservation Coalition supports the Company continuing to offer a gas energy efficiency program, but recommends the Company transition ENERGY STAR homes to an all-electric program beginning in 2024, to end incentives for residential gas water heating in 2024, to phase out incentives for residential gas combustion heating equipment so they are not offered after December 31, 2026, and to phase out commercial gas heating and water heating incentives for applications where residentially sized equipment is used by December 31, 2026.[161]

223. SWEEP offered support for dual-fuel systems with some caveats. SWEEP pointed to its analysis that it is not currently cost effective to fully electrify an existing home that heats with a natural gas furnace. In addition, gas furnaces can serve as back-up heating options

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[158] Public Service SOP, p. 8.
[159] Hrg. Ex. 801 (Elam Answer) at 19.
[160] Hrg. Ex. 600 (Keleher Answer) at 14-16.
[161] Hrg. Ex. 701 (Grevatt Answer) at 9.

to customers who also have a heat pump. These hybrid heating systems are cost-effective options for customers in the short-term. SWEEP argues that the Company should no longer provide new construction customers natural gas energy efficiency measures that use natural gas unless gas is used as a back-up fuel. SWEEP also recommends ending incentives for residential gas water heating, beginning in 2024, and phasing out natural gas space heating incentives in existing buildings between 2024-2027, but only "once the market is able to support this change.[162] WRA agrees with SWEEP, and suggests the Commission eliminate market-rate incentives for gas water heating and mixed-fuel ESNH homes starting on January 1, 2024.

224. WRA also argues that starting on January 1, 2024, the Commission also should transition the Energy Star New Homes program to electric-only. New construction provides the lowest-hanging fruit for electrification and, as Public Service admits, retrofits generally are more expensive than all-electric new homes. It claims several analyses for the Denver area show that all-electric new homes offer ratepayers notable savings over mixed-fuel new homes, including thousands of dollars in upfront costs. All-electric new homes avoid costly gas and utility hookup charges, internal and external gas pipe costs, and gas fixed charges on bills.

225. Several parties (Conservation Coalition, Denver, and Boulder) recommend Public Service phase out incentives for air conditioner rebates. On rebuttal, Public Service states that it is proposing a phase out of air conditioner rebates that takes place through the end of 2027.[163] Public Service proposes to phase out from the ESNH program rebates for natural gas heating and

[162] Hrg. Ex. 1000 (Brant Answer, Rev. 2) at 1-42.
[163] Public Service SOP, p. 8.

water heating equipment by the end of 2024, including both residential and business new construction.[164]

c. Findings and Conclusions

226. The Commission notes that a material portion of customers with gas-fired space heating appliances may already utilize high efficiency units in their homes and businesses, since they have been widely available for at least 15 years, meeting or exceeding the typical life cycle of many residential heating units. The Commission finds it appropriate to assume those customers would likely replace their heating appliances with another high efficiency unit, even without utility incentives. Further, we have a good cause to believe the heat pump market will evolve rapidly over the next several years, including the manufacture, distribution, and installation segments of the market. We similarly expect customer comprehension and comfort with the technology to rapidly improve due to the availability of IRA incentives and other factors facilitating market adoption. Accordingly, the Commission finds it necessary to restrict DSM incentives for high efficiency gas-fired space heating equipment to only customers replacing lower efficiency units for the market rate, retrofit portion of Public Service's DSM activity starting January 1, 2024, and for all incentives for gas heating appliances in this market segment to end by January 1, 2027. Otherwise, we risk incentivizing behavior that would have occurred without incentives and over-counting savings and benefits by assuming lower efficiency units were being removed, even in situations where that is not the case, and no savings were actually caused by the Company's rebate.

227. Gas water heating incentives for the retrofit, market rate market segment shall terminate by January 1, 2025. With the federal minimum efficiency standards increasing shortly,

[164] *Id.*

and widely available alternatives, we find it reasonable to phase-out incentives for gas water heaters in the retrofit market beginning January 1, 2025

228. The Commission finds the arguments persuasive to terminate incentives designed to spur efficient residential air conditioning and commercial rooftop units in the retrofit, market rate segment of the market by January 1, 2024.

229. With respect to the new construction, market-rate segment of Public Service's customer base, we find the record in this Proceeding clearly indicates that the cost of electrification from the start is far more cost-effective than retrofitting gas equipment with electrification technologies at a later date. Facially, it seems inconsistent and counter-productive given the full view of policy goals to continue to give any rebates for gas-fired or traditional AC equipment in new construction. Accordingly, we find that by January 1, 2024, no incentives should be provided for residential-type gas-fired space heating, water heating, or air conditioning equipment for the new construction market.

230. Regarding gas-fired water heating equipment, we agree with the Stipulating Parties to end incentives for new construction, market-rate residential water heaters by January 1, 2024.

231. With respect to the Energy Star New Homes program, the Commission agrees with WRA and others that the program should fully encourage BE technologies as soon as reasonably possible. Related to the prior point, since the record in this proceeding clearly indicates that new construction represents the "low hanging fruit" for electrification, with customers facing considerable costs to electrify at a later date, it makes little sense to continue incentivizing programs with gas-fired space or water heating equipment in new construction. We also recognize that there may be housing developments underway that reasonably expected to

participate in the ESNH program, and that a one-year phase-out is appropriate. Accordingly, we require that the ESNH program support only all-electric housing by June 30, 2024. We also support Denver's suggestion of development in the future of an all-electric program for low-income housing, particularly as it would further support the benefits of the energy transition for IQ customers and take advantage of the IRA incentives targeted at this market.

232. More broadly, based on the evidence presented in this proceeding, the Commission believes it may be appropriate to sunset all incentives related to new gas-fired equipment by the end of the period covered by this strategic plan.

233. With respect to incentive continuation among the IQ/DI communities, the Commission recognizes there are multiple challenges to modifying or terminating program design, including but not limited to: low property ownership rates, "split incentives" between landlords and tenants (where landlords purchase appliances, but tenants pay the energy bills), and insufficient capital for upfront investment. The Commission also notes the need, by the IQ community, for DSM services is far larger than can be reasonably provided in any given year. The Commission further believes that grouping IQ/DI communities together would only exacerbate this shortage of DSM services. Accordingly, we find it necessary to distinguish between the IQ and DI communities for the purposes of setting specific program design parameters. At this juncture, we will not require the modification of rebate design, or termination of rebates, as described above for the IQ community. Instead, we require the Company to develop a proposal, working in concert with stakeholders to this proceeding, to address the IQ community in a manner that is generally consistent with the Commission's desire to phase out incentives for gas heating, water heating, and air conditioning, but in a manner that facilitates the least discontinuity for the IQ community, to the extent reasonably possible. We

further support Denver's suggestion that the Company put forth a program in its next plan filing for an all-electric new construction program specifically for affordable housing.

K. Performance Incentive Mechanisms

(1) Company Proposals

234. In its direct case, Public Service proposed five performance incentive mechanisms (PIMs) to address: (1) electric energy efficiency; (2) gas energy efficiency; (3) BE; (4) Portfolio-wide carbon emissions; and (5) DR.[165] Public Service suggests that its request for PIMs is consistent with Colorado statute (§ 40-3.2-104(5), C.R.S.), which states that the Commission to shall allow an opportunity for a utility's investments in cost-effective DSM programs to be more profitable to the utility than any other utility investment that is not already subject to special incentives. The Company proposed its PIM start at 50 percent of its goals being achieved. The Company also proposed a $30 million "soft" cap, after which any incentive would be shared with the State's Low Income Energy Assistance Program, or LEAP, and a $8 million cap for the DR program alone.[166]

235. The Company explains that it was awarded $23.7 million in total incentives, including the electric disincentive offset, and acknowledgement of lost gas revenues in 2021.[167] The BE program, and any requested PIM, is new overall, and DR was not incentivized in the past.

236. As explained in its rebuttal case, in response to party feedback, Public Service proposed revised PIM proposals. Notably, the Company withdraws its proposal for a portfolio-

[165] Hrg. Ex. 103 (Wishart Direct) at 23-24.
[166] *Id*. at 26-27.
[167] *Id*. at 48.

wide carbon incentive.[168] Instead of a stand-alone carbon incentive, the Company seeks to align its incentives with reducing greenhouse gas emissions by including the value of the social cost of emissions (SCE) in the calculation of net benefits. It also proposes to lower the share of net economic benefits payable to the Company in recognition of the fact that inclusion of the SCE greatly increases the total attributable benefits of DSM activities, as calculated per the mTRC test. The Company also revises its proposed maximum total PIM to a hard cap of $35 million without the LEAP-sharing mechanism.[169] Public Service notes that the $35 million potential incentive represents only 0.7 percent of total annual electric and gas revenues of $5.1 billion.

237. Public Service's revised electric energy efficiency PIM proposal would allow the Company to begin earning at 70 percent of the Company's 450 GWh goal; is based on a share of net benefits (including the social costs of emissions or SCE); starts at three percent of such benefits and increases by one percent for every five percent of goal achieved; and is capped at 14 percent of net benefits or 125 percent of the savings goal.[170] The Company contends the opportunities for electric energy efficiency, in particular due to higher federal standards and overall market adoption of residential lighting measures.

[168] Hrg. Ex. 114 (Wishart Rebuttal) at 6.
[169] Hrg Ex 114 (Wishart Rebuttal) at 39.
[170] *Id*. at 7.

238. The Company notes that SCE represent 60 percent of the total value of net economic benefit, and suggests that if SCE are removed from the net benefits calculation, it should be awarded a PIM that starts at eight percent of net economic benefits and increases three percent for every five percent of incremental savings achieved. The Company suggests such modifications can be assessed via an executable spreadsheet.[171]

239. The Company is not proposing to continue its current electric Disincentive Offset, which currently awards the Company up to $3 million from lost revenue from DSM efforts. The Disincentive Offset, combined with the electric energy efficiency PIM was subject to a broader $18 million cap.

240. The Company proposes a gas energy efficiency PIM similar to the electric energy efficiency PIM: it would allow the Company to begin earning upon achieving 70 percent of the annual goal, is based on a share of net benefits (including SCE), starts at five percent of such benefits and increases by one percent for every five percent of goal, and is capped at 14 percent of benefits or 125 percent of goal.[172]

241. The Company proposes a BE incentive at a set unit value $15 per Dth saved, starting at 50 percent of the Company's proposed goal, and capped at 125 percent of its goal. The Company contends the BE PIM is necessary because the Company's decoupling mechanism prevents the Company from benefiting from the additional revenue associated the increased

[171] Hrg. Ex. 114, Att. SWW-3.
[172] *Id*. at 7.

electric residential sales resulting from BE.[173] Without the PIM, the Company contends that it will lack financial incentives necessary to motivate it toward aggressive action.[174]

242. The Company proposes to retain the Acknowledgement of Lost Revenue (ALR) mechanism that is specifically provided for in Rule 4754(g)(I) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4, and given the outcome in Proceeding No. 22AL-0046G.[175] The Company proposes an ALR value of $3.08 per Dth saved via both the gas energy efficiency and BE programs.

243. The DR PIM is designed to incentivize both the dispatch of all DR capacity and the incremental procurement of additional capacity under the DR suite of programs. The DR incentive will have two prongs: (1) a dispatch incentive of fifty cents per each kWh of DR load reduction annually above a baseline of 5,000,000 kWh; and (2) a $120 per kW incentive for incremental annual increases in DR capacity procured via the Company's suite of DR programs. Public Service proposes the combined DR incentive have a standalone hard cap of $10 million.[176]

[173] Hearing Transcript at 118-119 (Feb. 9, 2023).
[174] Hearing Transcript at 70:19-21 (Feb. 9, 2023).
[175] Hrg. Ex. 114 (Wishart Rebuttal) at 21-22.
[176] Hrg. Ex. 114 (Wishart Rebuttal) at 31, 33-34.

c. Party Responses

244. UCA suggests the Commission set the electric and gas energy efficiency incentive recovery to begin at 80 percent, and end at 130 percent, of the established goals.[177] The electric energy efficiency PIM should start at eight percent and 7.5 percent of electric energy efficiency and gas energy efficiency net benefits, respectively, without consideration of SCEs or further escalation, according to the UCA. UCA notes the Commission has not historically adopted either the SCC or SCM in incentives awarded, and that the Commission has specifically referred to the exclusion of non-energy benefits in approving a Public Service settlement of a prior strategic issues proceeding.[178] UCA recommends the Commission reject the proposed BE PIM, or lower it to $2.50 per Dth which would result in approximately 20 percent of the 2027 net economic benefit going to Public Service; instead, a $15 per Dth incentive as proposed by Public Service would result in a $4 million incentive, well larger than the net economic benefit predicted for 2026 or 2027, and represents an oversized percentage of the BE budget. UCA recommends the Commission reject the DR PIM on grounds that Public Service's proposal rewards the Company for activities it already does or should do without an incentive. UCA cautions that the DR PIM dispatch component will incent Public Service to call excessive DR events. UCA suggests the Commission set a hard cap as the sum of the individual PIMs, or alternatively set a hard cap of $20 million.

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[177] UCA SOP, p, 7.

[178] UCA SOP at p. 29, citing Decision No. C18-0417, in Proceeding No. 17A-0462EG, Att. A at ¶ 17.

245. Staff also suggests starting points at 80 percent of goals. Staff notes that the Commission has already approved in Proceeding No. 21A-0141E a stakeholder process for an emissions reduction PIM for the Company's electric operations.[179] Staff recommends the Commission approve that process be allowed to develop an appropriate emission reduction PIM, and that including emissions in the DSM-specific PIMs is not only duplicative but misguided in that it would reward the Company for unverified and unmeasured emissions as well as double count those emission reductions. Regarding the DR PIM, Staff argued for a two-tier structure to incentivize both increased capacity and load reductions during DR events.[180] Staff-proposed Tier 1 would incentivize DR capacity, starting at five percent of the associated net economic benefits at 100 percent of the goals, and escalating at a ten percent rate, up to 200 percent of the goal. Staff calculates the Company's five percent share would result in a $818k payment based on 2021 DR achievements. Tier 2 would be a $/kWh incentive for all DR energy dispatched above the 5 million kWh, consistent with Public Service's direct case proposal.

246. CEO supports the Company's $15 per Dth BE incentive, but suggests it start at 80 percent of annual goals, not 50 percent as proposed by the Company, and notes that BE already provides a natural incentive with its corresponding increase in electric sales. Electric and gas incentives should also start at 80 percent of goals, according to CEO, who notes that this threshold is consistent with prior practice and argues that a lower starting point may reduce the Company's motivation or result in a too-generous incentive relative to performance.[181]

[179] Staff SOP, p. 6.
[180] Staff SOP, pp. 13-14.
[181] CEO SOP, pp. 18, 24.

CEO recommends that the goals of any electric DR PIM be to incentivize the Company to deploy DR that directly offsets the need for future fossil-fuel peaker plant generation units, as identified by the Commission, and align the Company's motivations to dispatch DR resources with customer and system benefits.[182] CEO proposes several distinct steps to incentivize incremental DR capacity resources, including: (1) resource identification, submitted via specific tranches or technologies; (2) a three-year qualification period to verify the capacity contribution; and (3) incentive collection on the qualified resources over the resources' remaining lifetime without any return on the unrecovered portion of incentive.[183]

247. CEC argues the Commission should exclude the SCE in its electric and gas energy efficiency PIMs, fix Public Service's share of net benefit to create a truly linear incentive, and ensure that ratepayers pay no more in incentives than necessary to incent impactful utility behavior.[184] CEC argues that historically, the energy efficiency PIM has not included, or needed, consideration of SCE, that SCE is already reflected in program selection, and that including the SCE will inflate the incentives without a comparable decrease in utility or ratepayer costs. CEC argues the electric and gas energy efficiency PIM designs unreasonably carves for the Company's benefit an increasing share of incremental benefits due to its non-linear design, or at least to grow Public Service's share of benefits at a slower rate, and submitted a modified version of a Public Service spreadsheet to contend the Company would retain nearly all incremental customer bill savings if achievement neared roughly 120 percent of the pre-established goals. CEC suggests the BE PIM starting point at 50 percent of the goal violates Colorado law by

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[182] CEO SOP, pp. 19-20.
[183] Hrg. Ex. 1404 (Weingarten Cross-Answer) at 14-17.
[184] CEC SOP, p. 8.

awarding the Company for underperformance. CEC suggests an overall cap of 20 percent of program expenditure or $27 million, whichever is less.[185]

248. Climax argues Public Service's proposed DR PIM should be rejected because it will discourage potential customers to join the ISOC program and may even cause existing subscribers to consider withdrawing from ISOC participation.[186] Climax suggests the energy, or dispatch, component of the proposed DR PIM would incentivize Public Service to call DR events unnecessarily to earn incentives, and not for demand control reasons. Climax also argues the capacity PIM is unnecessary as the Company has operated the ISOC program for over 20-years with no special monetary incentives, and only the values of reliability, operating reserves, and net economic benefits being sufficient.[187]

249. Conservation Coalition suggests an additional threshold on the PIM aimed at ensuring the Company prioritizes income-qualified customers across its suite of energy-efficiency, demand response, and BE programs. Conservation Coalition proposes the Company must meet 80 percent of its IQ/DI benefits target in order to receive a PIM for that DSM program area. The Stipulating Parties agreed with Conservation Coalition, and adopted the 80 percent IQ/DI threshold as a stipulated position.[188] The Stipulating Parties suggested that the target for any program area should be set based on the percentage of IQ customers among the total customers served by the Company for that fuel type (gas or electricity); specifically, that no less than 22 percent of residential benefits associated with electric energy efficiency and DR

[185] CEC SOP, pp. 8-9.
[186] Climax SOP, p.1.
[187] Climax SOP, p. 2.
[188] Stipulation, p. 4.

programs be apportioned to IQ customers, and no less than 28 percent of residential benefits for gas energy efficiency and BE programs be apportioned to IQ customers.

250. EOC disagrees with the Conservation Coalition and the Stipulating Parties, and suggests there are complex logistics involved in creating such an "Equity PIM" given that the IQ program benefits from multiple outside funding sources other than the Company.[189] EOC contends the Company should not receive an incentive based on funding from EOC, CEO or other sources. EOC also raises concerns that placing an IQ benefit target at the center of the utility's PIM potentially alters IQ-focused programs into profit-motivated endeavors. EOC suggests the record in this Proceeding does not support adoption of an Equity PIM, but that it would appreciate the opportunity to work with the Company and other stakeholders to design a mechanism that considers the complexities involved.

251. Denver supports Conservation Coalition's proposal but recognizes, given the early stages of the implementation of SB 21-272, it may be premature for the Commission to tie the Company's PIM to IQ for five years. Denver encourages the Commission, however, "to continue to explore PIMs that will robustly increase benefits for income-qualified customers and disproportionately impacted communities, particularly as the Commission continues its equity-related efforts."[190]

[189] EOC SOP, p. 27.
[190] Denver SOP, p.12.

d. Findings and Conclusions

252. Overall, we support the continued provision of financial mechanisms to incent the Company to implement an array of DSM programs for the purpose of maximizing net economic and other benefits to ratepayers, in the context of the concerns about non-participant rate impacts discussed above. We also find that each of the Company's four DSM programs (electric energy efficiency, gas energy efficiency, BE, and DR) can play a role in that broad goal through: the reduction of greenhouse gas emissions; the reduction of capital investments necessary to serve peak system requirements; the reduction of fuel and other energy expenses; or some combination of the above. Accordingly, we deny various party arguments to broadly reject PIMs to support each of the Company's BE and DR programs. We find well-designed financial incentives can and should reward the Company for providing DSM services that maximize net economic benefit as cost-effectively as reasonably possible, and incentivizing both BE and DR programs is consistent with that overall goal.

(1) Electric Energy Efficiency PIM Design

253. With respect to the electric energy efficiency PIM, we agree with Staff, UCA, and other parties who suggest that an appropriate starting point is 80 percent of the goals, not 70 percent as proposed by the Company. Although the Company is losing a significant percentage of its residential savings represented by its Home Lighting Program, the Company has repeatedly been able to meet 80 percent of goals and earn a bonus and efficient and technologically advanced offerings continue to evolve, making their limited reason to be pessimistic about the Company's ability to achieve the established goals. The Commission finds

that setting the starting point at 80 percent is consistent with past practice and will incent the Company to seek out innovative and effective marketing and delivery mechanisms.

254. We also find the electric energy efficiency PIM should not include the value of avoided emissions via the SCE. While we agree with the Company that there may be merit in having a consistent approach between the assessment of program cost-effectiveness (where SCE are included) and any financial incentive, we find more compelling arguments by Staff and others that emissions should be assessed across Company activities in a holistic manner, and that there is an ongoing stakeholder process to do so, established via the Company's ERP application submitted as Proceeding No. 21A-0141E. This will avoid the potential to double-incentivize the same activity or outcome and set a bigger picture goal upon which multiple programs can be on equal footing. We also agree with Staff that the Commission should incentivize actual emission reductions, when possible, rather than projected emission reductions. Accordingly, the Commission denies the Company's request to include SCE in the PIM calculation. With respect to the compensation factor and its escalation, the Company requested that, if SCE was excluded from the PIM calculation, it be allowed to receive eight percent of the net economic benefits once it achieved the starting point, escalating three percent for each five percent of additional achievement relative to the goals. CEC argued for a flat, or linear, share of net economic benefit, or risk too great a share of incremental customer savings going to the Company via a higher PIM. EEBC supported the Company's escalation factor, contending it will spur the Company to implement its programs aggressively, and facilitate greater savings and benefits. The Commission finds that an escalating compensation factor is reasonably appropriate, but that the Company's specific request does not adequately protect ratepayers. We set the compensation

factor at eight percent, escalating at 0.5 percent for every five percent of achievement, terminating at 125 percent.

255. SWEEP and the other Stipulating Parties suggested the Commission require a separate IQ/DI threshold to attain the electric energy efficiency PIM. The Company responded that while it is adopting specific budget reservations for IQ customers and remains open to further discussion with stakeholders, the Commission should not set minimum IQ/DI achievements before it can earn any PIM. EOC raised important real-world complexities with an IQ/DI threshold, including the fact that funds for IQ projects often come from CEO or EOC itself, and may inappropriately reward the Company or send mixed economic signals. The Commission agrees with these concerns. While fulfillment of the IQ/DI goals is important and fully embraced by the Commission, we believe there are too many evolving program parameters and complexities to require a specific threshold for a PIM at this juncture. We ask the Company to report on this issue and work with EOC and other stakeholders in its upcoming DSM plan and subsequent proceedings to find the appropriate financial tools to align Company interests, as well as the needs of the IQ community and the entities who serve them.

(2) Gas Energy Efficiency PIM Design

256. With respect to the Gas energy efficiency PIM, for the reasons referenced in the discussion of the electric energy efficiency PIM, above, we find it necessary to reject the inclusion of SCE in the PIM calculation. Although the stakeholder process initiated in the Company's ERP proceeding relates only to emissions from electric generation technologies, as Staff points out, the Company will be similarly evaluating system-wide emissions due to its gas operations as part of its upcoming Clean Heat Plan, due later this year. We find that filing is the appropriate venue to evaluate, and potentially incentivize, overall emission reductions associated

with the transmission, distribution, and combustion of gas by the Company's gas customers. While DSM programs play an important role in emission reductions associated with certain customers (*i.e.*, its DSM participants), the Company is statutorily required to reduce emissions for *all* customers based on a 2015 baseline, and any incentive should be tied to those broader goals and avoid a situation where multiple incentives could overlap for the same activity or outcome.

257. Also, as with its electric energy efficiency PIM, the Company requests to set the gas energy efficiency PIM compensation factor at a higher level, specifically eight percent of net economic benefits, if the Commission rejects the inclusion of SCE in the PIM calculation. We agree that the starting point should be higher but find an eight percent starting level results in too high a PIM for the Company relative to direct program investment and customer rate impacts. The Commission finds that setting the Company's starting share at six percent of net economic benefits appropriately balances the need for financial inducement with our concerns over non-participant rate impacts.

258. With respect to the escalation factor of the Company's share, as with the electric energy efficiency PIM, the Company requested a three percent bump for every five percent increase in the percentage of the target achieved. We believe the Company's proposal provides too much of the incremental benefit to the Company and would set the escalation value to 0.5 percent for each five percent increase in achievement. We also cap the incentive at 125 percent of the goals.

259. Changes to the rules governing gas DSM programs in Proceeding No. 21R-0449G removed some specificity about some of the factors utilized in determining a gas DSM bonus, including the energy factor. These were largely removed to allow each utility to have an

appropriate bonus structure evaluated within their DSM SI proceeding. This record did not include discussion from parties on the virtues of some of the specific mechanisms that had been used in the gas DSM PIM structure. In this case, the Commission wants to express interest in seeing parties engage in the next DSM SI proceeding on the optimal PIM structure, which may include some of those former concepts, like a mechanism to incentivize as cost effective results as possible.

260. The Commission further denies requests by the Stipulating Parties to require a specific IQ/DI threshold on achievements of the Gas energy efficiency program.

(3) Beneficial Electrification PIM Design

261. With respect to the BE PIM, the Company requests in its Rebuttal Testimony a flat $15 per Dth once it reaches a target of 50 percent of its goal. The Company argued that its BE program is brand new, and its ability to achieve the goals highly uncertain. Numerous parties contend 50 percent is too low a starting point, and that the IRA will be providing complementary inducements to electrify end-use appliances, which will only assist the Company's overall BE program. The Commission agrees that the IRA is likely to provide significant support for BE measure adoption, especially as public awareness, and comprehension of the array of benefits under the IRA and Company programs improves over time. Accordingly, the Commission approves an escalating starting point over the three-year strategic issues period of: 50 percent in 2024, 60 percent in 2025, and 70 percent in 2026.

262. The Company provides little backing for the proposed $15 per Dth incentive value other than it produces an incentive of roughly $4 million which the Company asserts represents a sufficient inducement to implement the BE program. Public Service argues the Commission should approve a volumetric value, rather than a share of net economic benefits,

because it does not project positive net economic benefits until 2026, and the Company should not wait until then to be incentivized to implement BE programs. UCA argues the Commission should implement a share-of-net-economic-benefits design, or greatly reduce the unit value to $2.50 per Dth. The Commission views beneficial electrification as an important area to incentivize performance to ensure the Company's goals align with state policy goals around electrification, especially at a pivotal time with the development of technological options and influx of federal incentives. However, given the lack of baseline information to understand the proper metric for an incentive and the significant alterations the Commission has ordered to some of the underlying cost effectiveness assumptions that had been presented by the Company, this is a difficult area in which to set an initial incentive. For the near term, the Commission agrees with the Company that a volumetric approach is appropriate in this evolving context, but with UCA that $15 per Dth represents too high a benefit for Public Service. Applying the Company's model, such a price could result in a PIM of $19.1 million by 2026, based on the Commission's modified goals for the BE program. Instead, we find a unit value at $7.50 per Dth saved through the BE program, with the PIM starting points discussed above, will provide sufficient incentive to the Company to implement its BE program robustly. We cap this incentive at 125 percent of the annual goal. We also find that the Company's flat volumetric approach lacks a key benefit found in the electric and gas energy efficiency PIMs: to motivate the Company to achieve a higher percentage of its goals. The energy efficiency PIMs accomplish this task by escalating the percentage of net benefits attributable to the Company. The Commission finds it necessary to adopt a similar approach for BE, and requires Public Service to design its PIM so that $7.50 per Dth is the value provided to the Company based on the median value between the annual starting share and 125 percent of the annual goal, as described above.

For every five percent change in achievement, the PIM value shall increase (for higher achievement) or decrease (for lower achievement) by 0.5 percent.

263. The Commission also notes that, as explained by the Company, roughly 27 percent of its electricity customers are not also the Company's electric customers, and vice versa. We find that the Company may only benefit financially from certain customers adopting BE technologies (*i.e*., those served by other gas companies or those that heat with propane). In contrast, the Company may experience mixed financial signals from BE investments by customers who take both electric and gas service. Likewise, the Company may be negatively impacted financially from BE investments by customers who take gas but not electric service from the Company. The Commission recognizes the record in the instant Proceeding does not adequately address this issue and requires no immediate modification. However, we require the Company to consider these diverse outcomes when proposing future modifications to its BE PIM, and to work with relevant stakeholders to account for how the multiple customer use cases could impact the basis upon which to provide Public Service financial incentives to pursue these programs.

(1) Demand Response PIM

264. The Company proposed, via its rebuttal case, a two-tiered PIM for its DR program, including: (1) a dispatch incentive of $0.50 per kWh for all kWh greater than five million dispatched in a calendar year, and (2) a capacity incentive of $120 per kW for all incremental kW added to its DR portfolio suite. Climax argues that the Commission should not approve the Company's proposed Demand Response PIM because it will discourage expansion

of the ISOC Program and may even cause some subscribers to question continuing in the ISOC Program.[191]

265. It argues that a PIM is unnecessary and would increase Public Service's revenue in return for no value. Staff and CEO suggested the DR PIM be tied to net economic benefits, and proposed specific constructs to facilitate that. Staff's proposal tied the net economic benefit to the value reported by the Company in its annual DSM report; CEO tied the net economic benefit to a three-year confirmation process for all identified tranches of DR capacity and a long-term incentive payout schedule. UCA raised concerns that the Company's flat $0.50/kWh dispatch incentive would simply motivate Public Service to over-utilize its DR programs, or to dispatch the programs at times of low value, low attrition rates, or both.

266. The Commission agrees in principle with Staff and CEO that the DR PIM should be tied to a calculation of net economic benefits. We also agree in principle with UCA, that the incentive should not encourage the Company to over-utilize the programs in a way that could not produce valuable results or create a disincentive for customers to participate. We also agree with the concept embedded in CEO's proposal that any capacity-related component should be contingent on confirmed MW. However, we find CEO's three-year confirmation process overly complicated and potentially ineffective. We further find that the current record in this Proceeding does not support a thorough calculation of net economic benefits, either for the dispatch of DR resources or the provision of any incremental capacity procured via the Company's suite of DR programs. Finally, we note that the Company's various DR programs may provide a diverse range of capacity values due to seasonality, potential frequency of use, and other attributes which may require a more specific valuation, if possible. Accordingly, we

[191] Climax SOP, p. 2.

require the Company to re-assess its DR PIM proposal, and to propose to the Commission through its upcoming DSM plan application a revised DR PIM tied to: (a) net economic benefits with specific justification for how benefits were determined, and (b) unique program capacity and callability attributes of each DR platform within the Company's DR portfolio. The PIM should be based, at least in part, in the Company's ability to reliably demonstrate that it can control the amount of load being counted, but strike a balance in doing so that does not dissuade participation from customers and is appropriate for the type of program being offered.

(2) Overall Cap and Miscellaneous Items

267. The Company requested an overall PIM cap at $35 million and a DR-specific PIM cap of $10 million. The Commission notes that, through this order, Public Service is required to re-submit DR budgets and DR PIMs as discussed above. Accordingly, at this time, the Commission will define a PIM cap for the electric energy efficiency, gas energy efficiency, and BE programs only. Based on Commission modeling of each PIM design, using the Company-developed tools provided in this Proceeding, the Commission finds that an appropriate PIM cap for the combined electric energy efficiency, gas energy efficiency, and BE programs to be: $18 million for 2024, $22 million for 2025, and $25 million for 2026.

268. With respect to Acknowledgement of Lost Revenues, or ALR, the Company has requested continuation of this mechanism to recover fixed costs associated with provision of gas service. No party objected to the Company's request. The Commission approves continuation of ALR for savings attributable to gas energy efficiency savings.

L. Other Issues

1. ISOC Miscellaneous Docket

269. For many years, Public Service has offered the interruptible service option credit (ISOC) program which provides the Company an avenue to interrupt customers on the electric system who voluntarily participate in the program for economic or reliability purposes.

270. Staff argues that ISOC is due for a comprehensive evaluation and potential refresh to help ensure the program's benefits match its costs.[192] Staff states that an evaluation of the program is necessary because the Company has dramatically reduced the frequency of its ISOC interruption events in recent years while events from other demand response programs have increased. Staff also argues that Public Service has never exceeded and rarely has come close to any customer total cap of interruption event hours in past years Staff states that the customers and associated capacity enrolled in the program have not grown materially in recent years and that the ISOC Program was designed prior to the Company offering other demand response programs that have become more popular with customers.[193]

271. Staff suggests the Commission open a miscellaneous proceeding that includes: (1) a report summarizing the components, methodologies, and results of the Company's evaluation of the ISOC program; (2) a forecast of the number of ISOC interruption events the Company plans to dispatch during the years of the DSM strategic issues filing; (3) a proposal to increase ISOC customer enrollment; (4) a proposal to increase ISOC system net benefits; and (5) a

[192] Staff SOP, p. 21.
[193] Staff SOP, pp. 20-24.

narrative detailing how the Company plans to use ISOC in relation to its (a) suite of other demand response programs; (b) demand side planning; and (c) ERP.[194]

272. Public Service opposes Staff's request for the establishment of a new miscellaneous proceeding to reconsider the ISOC program. Public Service argues that Staff had every opportunity to use this Proceeding to identify potential changes to ISOC, but it failed to identify any. Public Service also identifies the stakeholder process approved in Proceeding No. 21A-0192EG and the stakeholder engaged to address economic interruption considerations can be used to address ISOC and as such there is demonstrated need for a duplicative ISOC review process as requested by Staff.[195]

273. In response to Staff's concerns, Climax urges the Commission to continue to support the ISOC Program because it provides valuable reliability, operating reserves, and economic benefits by avoiding the cost of additional capacity during times of system stress.[196]

274. The Commission declines to open a miscellaneous proceeding to re-evaluate the ISOC program at this time. There are several other ongoing and future dockets in which the ISOC program could be re-evaluated if intervenors have concerns or ideas for improvement. Also, the Commission has directed the Company to more thoroughly explore the use cases and potential for the full variety of demand management opportunities available, of which review of the ISOC program, including growth potential and any concepts for design improvements, should be a component in the next DR potential study.

[194] Staff SOP, p. 26.
[195] Public Service SOP, 22.
[196] Climax SOP, p. 1.

2. Cost Recovery

275. Public Service requests Commission approval to defer the transcript, hearing, and legal counsel costs for this matter in an interest free regulatory asset for presentation in a future cost recovery proceeding.[197] Public Service commits to presenting the actual expenses at the time of the future cost recovery filing.

276. The Commission approves the deferral of the transcript, hearing, and legal counsel costs for this matter in an interest free regulatory asset for presentation in a future cost recovery proceeding and expressly defers ruling on the appropriateness of recovering these costs until they are properly raised in Public Service's next rate case.

3. Other Proposals

277. Public Service sets forth two other proposals that it states are uncontested. First, it proposes to end the participation analysis required by Decision No. C14-0731, issued in Proceeding No. 13A-0686EG, on July 1, 2014, because it states the requirement is burdensome and the resulting data has not been used by the Commission or stakeholders. Public Service also proposes to remove the maximum life of 20 years used when calculating average lifetimes for energy savings measures. Going forward, Public Service proposes to instead use actual estimated lifetimes. It states this change will not impact estimated lifetimes for most measures, but will allow for a more accurate consideration of the lifetime of building shell measures.[198]

[197] Hrg. Ex. 101 (Ihle Direct) at 51-52.
[198] Public Service SOP, p. 35.

278. We find it appropriate to allow the Company to use actual estimated lifetimes instead of an automatic 20-year lifetime moving forward. However, we decline to end the participation analysis required by Decision No. C14-0731. We find that this information, which requires the Company to present an analysis of DSM participation, potentially useful to future proceedings and helping the Commission to better understand non-participant rate impacts.

4. Timing of Future Strategic Issues Filings

279. In the Company's original Application, the Company requested that the Commission establish goals and budgets in this Proceeding through year 2027. However, on rebuttal, the Company requested that the Commission approve budgets and goals through 2026 only.

280. The Commission agrees that establishing the goals and budgets discussed above through 2026 in this Proceeding is appropriate.

281. We also agree with the Company's proposal to file its next strategic issues plan filing in 2025 to better align these proceedings with the Company's next ERP. We therefore order the Company to file its next strategic issues in 2025.

5. Rule Waiver of 4754(g)(I)

282. Concurrent with its Application, Public Service filed a motion requesting the Commission grant a waiver from Rule 4754(g)(I) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4, which dictates a specific formulation for natural gas DSM incentives and was eliminated through the recently completed rulemaking taking place in Proceeding No. 21R-0449G. The Company seeks a waiver of the then-effective Rule 4754(g)(I) to implement its natural gas energy efficiency incentive proposal.

283. Pursuant to Rule 1003(a) of the Commission's Rules of Practice and Procedure, 4 CCR 723-1, we find good cause to waive Rule 4754(g)(I) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4, because the rule provision is no longer found in the Commission's Gas Rules, and because waiving this rule provision allows for implementation of the incentives discussed above.

II. ORDER

A. It Is Ordered That:

1. The Application of Public Service Company of Colorado (Public Service) filed on July 1, 2022, which requests the Commission approve the proposals contained in the Company's Demand Side Management (DSM) and Beneficial Electric (BE) Strategic Issues application, is granted with modifications, consistent with the discussion above.

2. The Motion for Variance of Rules 4754(g)(I) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4, filed by Public Service on July 1, 2022, is granted.

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

4. This Decision is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING MAY 11, 2023, May 17, 2023, and May 26, 2023.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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MEGAN M. GILMAN

ATTEST: A TRUE COPY

TOM PLANT

Commissioners

Rebecca E. White,
Director