BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 25A-0044EG

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE MOUNTAIN ENERGY PROJECT AND ASSOCIATED CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN) FOR SUPPLEMENTAL SUPPLY.

HEARING EXHIBIT 601

ANSWER TESTIMONY AND ATTACHMENTS OF

KENJI TAKAHASHI ON BEHALF OF THE MOUNTAIN COMMUNITY COALITION

June 5, 2025

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, CURRENT EMPLOYER AND POSITION, AND BUSINESS ADDRESS.

A. My name is Kenji Takahashi. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric and gas industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q. PLEASE SUMMARIZE YOU WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. Since joining Synapse in 2004, I have worked on decarbonization planning, programs, and technologies across the energy sector, with a particular focus on the energy, economic, and environmental impacts of building decarbonization measures. These include energy efficiency, electrification, demand response, and other distributed energy resources.

Over the past 20 years, I have assessed the design, impact, and potential of energy efficiency, demand response, and distributed energy resources policies and programs in over 40 jurisdictions across North America for a variety of clients. These include environmental groups; municipal, state, and provincial governments; and federal agencies such as U.S. Environmental Protection Agency ("EPA") and U.S. Department of Energy. I also have extensive experience assessing the impacts of building decarbonization, with a particular focus on electrification. Recently, I led analyses of building decarbonization scenarios in Oregon and Minnesota, evaluating the potential impacts on emissions, health outcomes, and energy system investments. I have also provided expert testimony on the potential and design of building electrification programs, including proposals by Pepco and Baltimore Gas and Electric in Maryland (on behalf of the Maryland People's Counsel) and by New Mexico Gas Company (on behalf of the New Mexico Attorney General's Office). Further, I have co-authored several studies addressing the future of gas utility planning and non-pipeline alternatives ("NPA"). Notable examples include *A Framework for Long-Term Gas Utility Planning in Colorado*, prepared for the Colorado Energy Office ("CEO"), and *Gas Regulation for a Decarbonized New York*, prepared for the Natural Resources Defense Council.

I hold a Master's in Urban Affairs and Public Policy with a concentration in Energy and Environmental Policy from the Biden School of Public Policy and Administration at the University of Delaware. I also completed the Massachusetts Institute of Technology's online program "Sustainable Infrastructure Systems: Planning and Operations."

A copy of my current resume is attached as Attachment KT-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Mountain Community Coalition ("MCC"). The MCC is comprised of the Towns of Breckenridge, Frisco, Dillon, Silverthorne, Keystone, and Blue River, as well as Summit County Government.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION?

A. No.

Q. HAVE YOU TESTIFIED ON A SIMILAR TOPIC BEFORE A STATE OR PROVINCIAL COMMISSION IN OTHER JURISDICTIONS?

A. Yes. I have testified regarding building electrification, non-pipeline alternatives, energy efficiency, and demand response program assessments before the New Mexico Public Regulation Commission, the New Jersey Board of Public Utilities, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the Nova Scotia Utility and Review Board, and the Ontario Energy Board.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to review Public Service Company of Colorado's ("Public Service," "PSCo," or the "Company") Application for approval of the Mountain Energy Project ("MEP" or "Project") and to provide recommendations to the Public Utilities Commission of the State of Colorado ("Commission"). To this end, I reviewed the Company's Mountain Energy Project proposal to determine its reasonableness. This

testimony provides my key findings from this review and offers recommendations for improvement.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is structured as follows:

- Section 2: Key Findings and Recommendations
- Section 3: Overview of Public Service's Mountain Energy Project Filing
- Section 4: Assessment of Peak Demand and Supply Shortfall Forecasts
- Section 5: Assessment of Demand-Side Non-Pipeline Alternatives
- Section 6: Evaluation of Hybrid Portfolios
- Section 7: Review of Proposed Cost Recovery Mechanism
- Section 8: Review of NPA Implementation Plan

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR ANSWER TESTIMONY?

A. Yes, I am sponsoring attachment KT-1, which is my resume, as well as the following attachments:

- KT-2, Discovery Response MCC1-10
- KT-3, Discovery Response MCC1-4
- KT-4, Discovery Response MCC5-1
- KT-5, Discovery Response Attachment MCC1-5.A1
- KT-6, Discovery Response MCC7-3
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II. KEY FINDINGS AND RECOMMENDATIONS

Q. WHAT ARE YOUR PRIMARY FINDINGS REGARDING PUBLIC SERVICE'S FILINGS FOR THE MOUNTAIN ENERGY PROJECT?

A. My primary findings are as follows and are discussed more extensively below:

1. **PSCo overestimates peak gas demand by using unrealistic design temperatures and not properly accounting for policy impacts, local weather conditions, and equipment usage patterns**:

   a) PSCo significantly inflates peak gas demand forecasts for the Eastern Mountain Gas System by using an extreme design day temperature of -

39°F—far colder than heating, ventilation, and air conditioning ("HVAC") industry standards or building code requirements of -13°F used in MCC jurisdictions. This unrealistic assumption results in PSCo overstating forecasted peak demand by approximately 9 percent.

b) The Company's forecasts ignore recent local and state decarbonization policies, including Denver's Climate Action Plan and MCC jurisdictions' building decarbonization initiatives, which are expected to reduce upstream and local gas demand and reduce the supply shortfall to the Eastern Mountain Gas System. The Company also fails to fully incorporate the peak load impacts of its own Clean Heat Plan and demand-side management ("DSM")/Beneficial Electrification ("BE") programs.

c) PSCo assumes that all its regional gas systems peak at the same time, which likely inflates peak hour load and projected supply shortfalls by overlooking regional variation in weather and timing.

d) The Company's peak load forecasts rely on linear regressions between gas usage and temperature, which do not accurately represent buildings with snowmelt systems. These systems typically do not operate during extremely cold temperatures, resulting in a flatter usage curve than PSCo assumes for buildings with these systems.

2. **PSCo overstates supply shortfalls by relying on inflated load forecasts:**

Because the Company's peak demand forecasts are overstated, its projected

supply shortfalls in the Eastern Mountain Gas System are also overstated —likely by more than 50 percent. A more realistic assessment of design day temperatures and policy-driven demand reductions would result in a much smaller supply gap that the MEP needs to address.

3. **PSCo undervalues and underestimates demand-side NPA potential**: The Company's NPA potential study excludes upstream regions such as Denver and the Northern Gas Systems, omits viable NPA measures such as thermal energy networks, underestimates societal benefits, and assumes overly conservative envelope measure adoption rates. These limitations together result in a substantial underestimation of demand-side potential to meet system needs. PSCo is also overly optimistic about gas heating equipment adoption rates.

4. **PSCo misaligns its resource strategy by favoring supply-led solutions**: PSCo's proposed Hybrid Portfolio 2 emphasizes supply-side resources over demand-side measures and does not align with Colorado's decarbonization goals. It risks locking in long-term fossil fuel infrastructure. In contrast, a demand-led hybrid portfolio—when combined with updated peak load forecasts based on more realistic assumptions—could eliminate the supply shortfall by 2033 or earlier.

5. **PSCo proposes a reasonable system-wide cost recovery approach**: The Company's proposal to recover project costs through statewide DSM cost adjustment riders and base rates is appropriate. This method reflects the integrated

nature of the gas network and ensures that the costs are fairly shared across all customers.

6. **PSCo's NPA Implementation Plan lacks measure prioritization and transparency:** The NPA implementation plan does not prioritize electrification and building envelope measures, includes long-lived gas equipment that may delay the transition away from fossil fuels, overlooks cost-effective, low-cost efficiency actions, and lacks a plan for measurement and verification of program activities to evaluate implementation success.

Q. WHAT RECOMMENDATIONS DO YOU MAKE REGARDING PUBLIC SERVICE'S FILINGS FOR THE MOUNTAIN ENERGY PROJECT?

A. My recommendations regarding the Company's analysis and proposal are as follows:

1. **Revise Peak Load Forecasts**: Update the Company's peak load forecasts by:

   a) Using more appropriate design day temperatures—such as -13°F from MCC jurisdiction's building codes—that reflect realistic HVAC system sizing practices and performance limitations during extreme cold conditions.

   b) Incorporating the impacts of state and local decarbonization policies and programs, including the full effects of PSCo's Clean Heat Plan and DSM/BE Plan, across all relevant service territories.

c) Examining and accounting for gas usage patterns of buildings with snowmelt systems, which should reflect a more gradual increase in demand during extremely cold temperatures than in moderate temperatures, rather than assuming a continued linear relationship in those conditions.

2. **Reassess Upstream Supply Constraints**: Re-evaluate the assumed gas availability at the Marshall Compressor Station by accounting for potential upstream demand reductions in Denver and the Northern Gas System. This reassessment should fully reflect the impact of local and state decarbonization policies as well as more accurate design temperature assumptions and HVAC sizing practices in those regions. It should also reflect regional variation in weather conditions across the Company's gas systems, by using historical temperature data to estimate more realistic coincident peak hour loads, rather than assuming perfectly synchronized peak demand across all regions.

3. **Improve the NPA Potential Study**:

a) Expand the geographic scope to include gas savings potential in Denver and the Northern Gas Systems.

b) Incorporate several excluded technologies, in particular networked geothermal systems, building codes support, heat recovery ventilators/energy recovery ventilators, air-to-water heat pumps, as well as

cost-effective, low-cost measures such as low-flow shower heads, and hot water tank and pipe insulation.

c) Incorporate the full societal benefits of avoided air pollution and methane emissions.

d) Revise overly conservative assumptions about envelope measure adoption rates and overly inflated gas heating adoption rates.

e) Reassess the achievable potential estimates by making all the adjustments discussed above.

4. **Develop a Balanced NPA Portfolio prioritizing no-regrets actions**:

a) Create a revised hybrid solution that prioritizes demand-side measures, minimizes long-term reliance on liquified natural gas ("LNG") and compressed natural gas ("CNG") and ensures timely depreciation of supply-side assets to avoid future stranded costs.

b) Pursue no-regrets actions such as beneficial electrification and clean heat programs targeted to the Eastern Mountain system while evaluation of the size and type of supplemental supply resources continues.

5. **Support Equitable Cost Recovery**: Continue with a system-wide cost recovery approach, given the integrated nature of PSCo's gas systems and the broad benefits of the Mountain Energy Project for ratepayers across the state.

6. **Enhance NPA Implementation Planning**:

a) Prioritize electrification and envelope measures over new gas equipment, as such equipment could lock in long-term fossil fuel use.

b) Include cost-effective, low-cost measures such as low-flow showerheads and hot water tank insulation and pipe insulation.

c) Develop a detailed measurement and verification plan to assess annual progress at the measure level to inform future measure offerings and guide budget decisions for the next Implementation Plan.

III. OVERVIEW OF PUBLIC SERVICE'S MOUNTAIN ENERGY PROJECT FILING

Q. PLEASE BRIEFLY SUMMARIZE PUBLIC SERVICE'S MOUNTAIN ENERGY PROJECT.

A. Public Service is proposing the Mountain Energy Project to address what it identifies as supply constraints in its Eastern Mountain Gas System, which serves mountain communities such as Breckenridge, Keystone, and Grand Lake. According to the Company, recent customer growth combined with increased upstream gas demand has resulted in insufficient gas supply and pressure at the system's outer edges during peak winter conditions. The Company claims that these conditions create a risk of outages affecting thousands of customers during the coldest parts of the year and that action is needed to ensure reliable service through at least 2033. Instead of pursuing traditional large-scale gas infrastructure projects, which the Company's analysis found would be

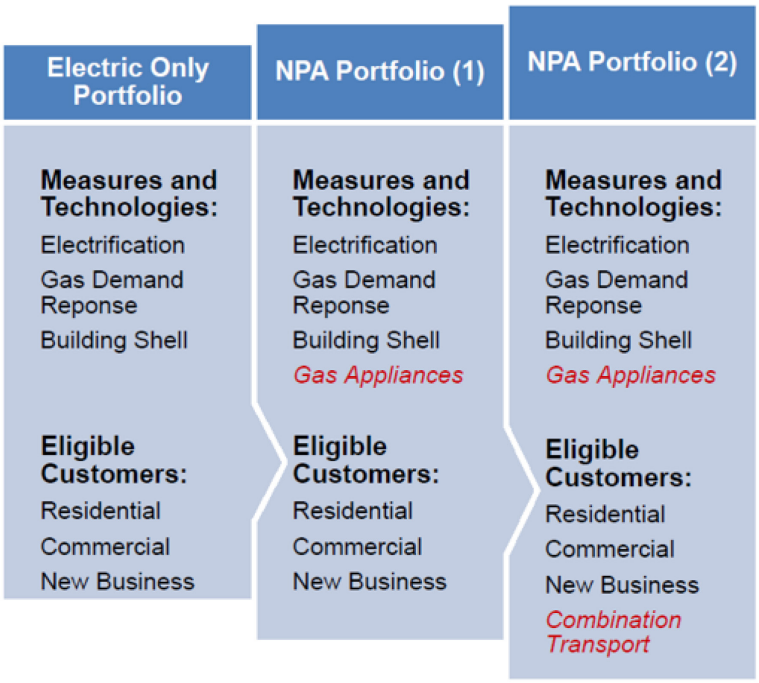
costlier and more difficult to construct, Public Service is proposing a hybrid solution, Hybrid Portfolio (2), which combines demand-side NPAs with supplemental supply solutions consisting of modular CNG and LNG facilities. The estimated cost of the proposed project is approximately $155 million. The Company asserts that this approach is more cost-effective and better aligned with Colorado's greenhouse gas reduction goals. The proposed hybrid portfolio includes energy efficiency, electrification, and gas demand response measures, as well as modular CNG and LNG facilities, which the Company believes can reduce peak demand and help avoid long-term fossil fuel investments.

Q. PLEASE BRIEFLY SUMMARIZE HOW PUBLIC SERVICE DEVELOPED ITS PROPOSED DEMAND-SIDE NPA PORTFOLIO.

A. Public Service developed its proposed demand-side NPA portfolio based on an NPA potential study commissioned by the Company and conducted by PA Consulting and its subcontractors (the "PA Team"). The study assessed the feasibility and peak demand reduction potential of various electrification, gas efficiency, and demand response measures in the Eastern Mountain Gas System. Using the results of this study, the PA Team developed and evaluated three demand-side NPA portfolios: the Electric Only Portfolio, NPA Portfolio (1), and NPA Portfolio (2), each varying in scope and measure inclusion, as shown in Figure 1. The Electric Only Portfolio includes electrification, gas demand response, and building shell measures for residential, commercial, and new business customers, but excludes gas appliance incentives. NPA Portfolio (1) adds gas appliance measures, while NPA Portfolio (2) further expands eligibility by also including combination transport customers who receive both gas and electric services from Public

Service. The Company ultimately selected NPA Portfolio (2) as the basis to develop two hybrid portfolios incorporating modular LNG and CNG facilities, one of which it selected as the foundation for the proposed Mountain Energy Project.

Figure 1. Development of NPA Portfolios by the PA Team



Source: Hearing Exhibit 102, Direct Testimony of Grace K. Jones at Figure GKJ-D-17.

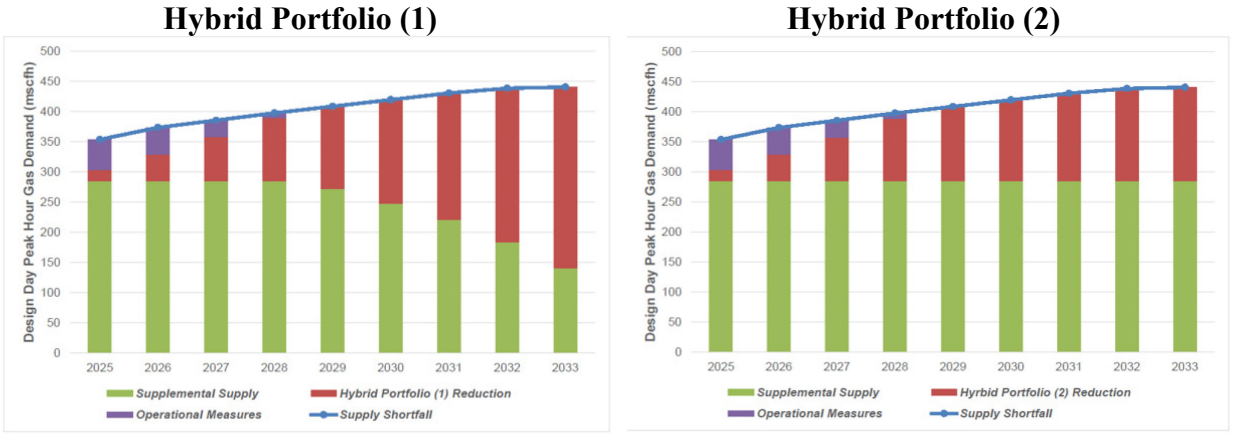
Q. PLEASE BRIEFLY SUMMARIZE THE TWO HYBRID PORTFOLIOS AND EXPLAIN WHICH DEMAND-SIDE PORTFOLIO THE COMPANY SELECTED TO DEVELOP THE FINAL HYBRID PORTFOLIO?

A. The Company refers to the two hybrid portfolios as Hybrid Portfolio (1) and Hybrid Portfolio (2). While both incorporate the same types of electrification, gas efficiency, and demand response measures, they differ in the scale and composition of the demand-side NPA measures and the projected volume of gas to be delivered from the proposed supplemental LNG and CNG facilities. Public Service developed Hybrid Portfolio (1)

and Hybrid Portfolio (2) separately for the Breckenridge, Keystone, and Grand Lake areas. Figure 2 below presents the Company's projections for Breckenridge under both scenarios, showing the expected volume of supplemental gas supply, peak hour demand reductions from demand-side NPA measures, and contributions from existing operational measures needed to address the projected supply shortfall.

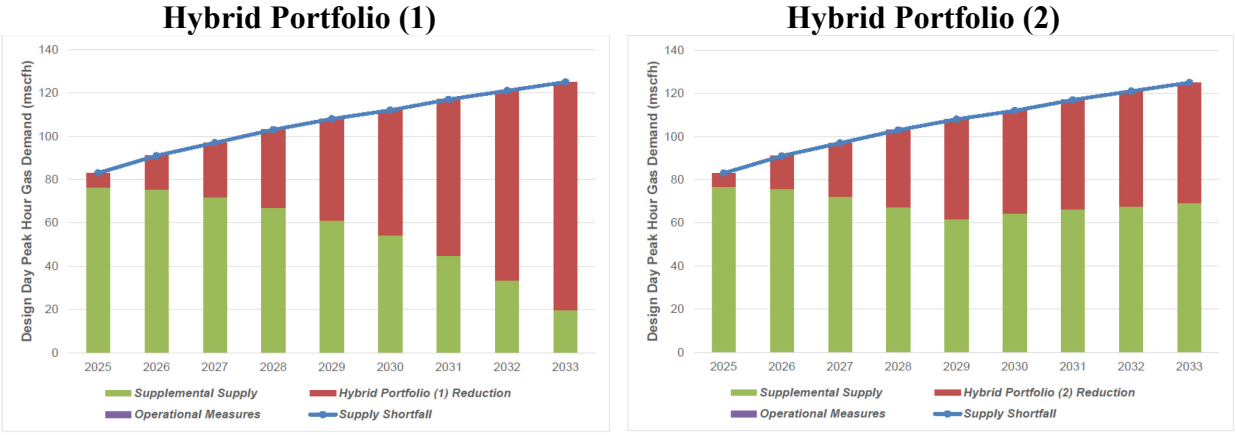
Public Service's analysis for Breckenridge (Figure 2 below) indicates that the demand-side NPA measures in Hybrid Portfolio (2) are projected to reduce peak hour gas demand by only about half as much as those in Hybrid Portfolio (1) and are not expected to reduce the need for the supplemental supply through 2033. The Company's analysis for Keystone (Figure 3 below) presents patterns similar to those for Breckenridge.

Figure 2. PSCo's projected supplemental supply and peak gas reductions to address supply shortfall under two hybrid portfolios in Breckenridge



Source: Hearing Exhibit 102, Direct Testimony of Grace K. Jones at Figure GKJ-D-31 and Figure GKJ-D-35.

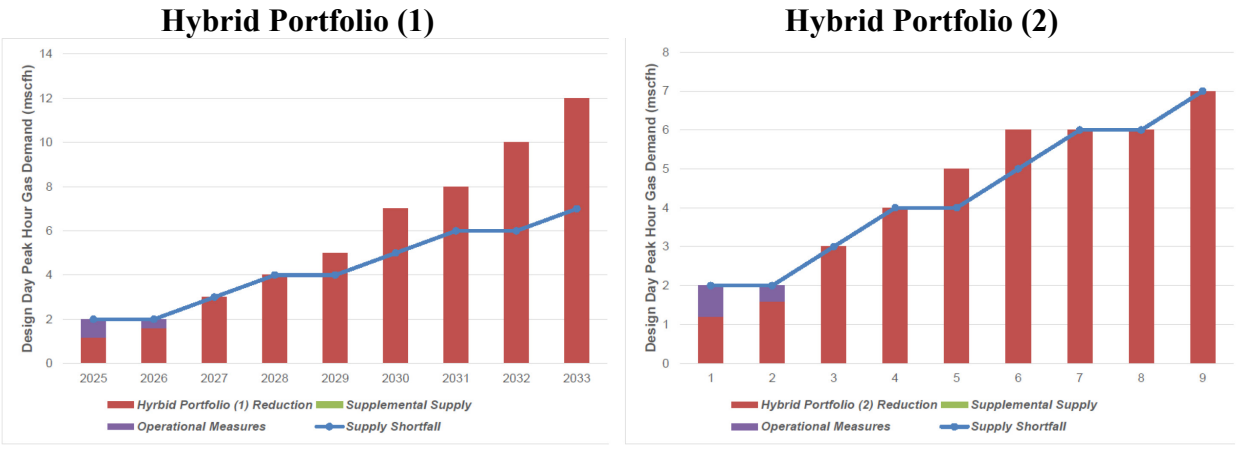
Figure 3. PSCo's projected supplemental supply and peak gas reductions to address supply shortfall under two hybrid portfolios in Keystone



Source: Hearing Exhibit 102, Direct Testimony of Grace K. Jones at Figure GKJ-D-32 and Figure GKJ-D-36.

In contrast, for Grand Lake, Public Service does not project any need for supplemental supply under either hybrid portfolio, as it identified sufficient demand-side NPA measures to fully address the projected supply shortfalls. The key difference between the scenarios lies in the scale of NPA measures. For Hybrid Portfolio (1), the amount of NPA exceeded the estimated supply shortfall, prompting the Company to reduce the NPA measures by more than 40 percent to align with the supply gap.

Figure 4. PSCo's projected supplemental supply and peak gas reductions to address supply shortfall under two hybrid portfolios in Grand Lake



Source: Hearing Exhibit 102, Direct Testimony of Grace K. Jones at Figure GKJ-D-33 and Figure GKJ-D-37.

Ultimately, the Company selected Hybrid Portfolio (2) across all regions as the basis for the Mountain Energy Project, citing its greater cost-effectiveness compared to Hybrid Portfolio (1). According to the Company's estimates, Hybrid Portfolio (1) would cost approximately $243 million, while Hybrid Portfolio (2) is projected to cost about $155 million.[1] Witness Jones provides a detailed breakdown of the cost for Hybrid Portfolio (2) as follows:

- NPA Portfolio - $48.7 million
- Electric Infrastructure to Support Electrification - $28 million
- Supplemental LNG Supply – Breckenridge - $55.8 million
- Supplemental CNG Supply – Keystone - $22.8 million[2]

Although Witness Jones does not provide a detailed cost breakdown for Hybrid Portfolio (1) in her testimony, she indicates that total utility costs—excluding the costs of

[1] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at Table GKJ-D-1.
[2] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 196:14-19.

supplemental supply facilities—amount to $164.8 million. The NPA potential study, however, provides a breakdown of these costs, identifying $133.6 million for NPA programs and $31 million for electric system upgrades.[3]

While both portfolios rely on the same types of measures and require similar supplemental gas infrastructure, the primary difference lies in the scale and cost of the NPA portfolio.

IV. ASSESSMENT OF EASTERN MOUNTAIN GAS SYSTEM SUPPLY SHORTFALLS

Q. ACCORDING TO PSCO, WHAT ARE THE SUPPLY SHORTFALLS IN THE EASTERN MOUNTAIN GAS SYSTEM?

A. PSCo forecasted design day peak hour demand and identified design day supply shortfalls in the Eastern Mountain Gas System beginning in 2022 and extending for at least 10 years. The Company modeled future design day demand over a 10-year horizon using historical usage data and projected customer count and large load capacity requests.[4] PSCo projected a 0.86 percent annual design day peak demand growth rate for residential and small commercial customers combined (0.97 percent for residential and -0.40 percent for small commercial).[5] The customer growth forecast, developed using regression modeling, accounts for some impacts related to market electrification and DSM/BE measures, however the Company did not include impacts from the more recent

[3] Hearing Exhibit 102, Attachment GKJ-2 at Table 5-4.
[4] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 42:9-12, 48:4-5.
[5] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 50:22–51:6.

2024–2026 Clean Heat Plan or 2024–2026 DSM/BE Plan in its forecast.[6] The Company compared its design day demand forecast to the available capacity on the system to calculate the supply shortfall. Based on this analysis, PSCo projected a design day shortfall of 447 mscfh in Breckenridge, 125 mscfh in Keystone, and 7 mscfh in Grand Lake with a total of 579 mscfh for the 2033-2034 heating season.[7]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S SUPPLY SHORTFALL ESTIMATE?

A. Yes. The Company did not provide adequate evidence to support its projections. In the absence of sufficient evidence, it appears that PSCo probably overstated the magnitude of the claimed supply shortfalls substantially. I base this concern on my finding that the Company's design day peak hour load forecasts are likely too high and that the Company has considerably underestimated the impact of public policy in the mountain region and in upstream systems. These factors suggest that the actual supply shortfalls are likely much smaller than the Company claims.

Q. HOW DID PUBLIC SERVICE OVERESTIMATE ITS DESIGN DAY PEAK HOUR LOAD FORECASTS?

A. PSCo's peak load forecasts for the Eastern Mountain System as well as for Denver and Northern Gas Systems appear overestimated due to two main reasons:

[6] Hearing Exhibit 601, Attachment KT-2, Discovery Response MCC1-10 (Apr. 22, 2025).
[7] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 106.

(a) PSCo estimated its load forecasts for the Eastern Mountain Gas System using an extremely cold design day temperature of -39°F. This temperature is not appropriate for estimating space heating demand for the region.

(b) PSCo's load forecasts overlook the impacts of state and local policies on gas demand and underestimate the effects of the Company's own programs.

A. Design Day Temperature

Q. HOW DID THE COMPANY ESTABLISH THE DESIGN DAY PEAK HOUR TEMPERATURE TO USE FOR ITS ANALYSIS?

A. The Company states that "[t]o calculate the Design Day temperature for the Eastern Mountain Gas System, the Company utilizes the daily minimum temperature data for Dillion 1 E, CO published by Northeast RCC CLIMOD 2. The Company does not track the coldest daily average temperature or weather data for the communities of Breckenridge, Keystone, and Grand Lake."[8]

Q. WHY IS THE COMPANY'S DESIGN DAY TEMPERATURE ASSUMPTION INAPPROPRIATE?

A. Public Service estimated design day peak hour peak load using an extremely cold design day temperature of -39°F. This temperature represents an unrealistic worst-case scenario and is far colder than the design day temperatures used by HVAC industry standards or MCC jurisdiction's building code requirement of -13°F.

[8] Hearing Exhibit 601, Attachment KT-3, Discovery Response to MCC1-4(f) (Apr. 22, 2025).

Q. COULD YOU PLEASE EXPLAIN HOW CONTRACTORS SIZE HEATING EQUIPMENT?

A. When HVAC contractors design and size heating systems, they do not use design temperatures defined by gas companies. Instead, HVAC contractors use design temperatures defined by (a) an HVAC installation manual called Manual J produced by the Air Conditioning Contractors of America Association, Inc. ("ACCA"),[9] (b) weather data published by the American Society of Heating, Refrigerating and Air-Conditioning Engineers ("ASHRAE"),[10] or (c) local building codes. Manual J and ASHRAE recommend the use of heating design temperatures at the 99th percentile (also called heating dry bulb at 99th percentile), representing weather conditions for which appropriately designed equipment will fully meet space heating loads for 99 percent of the hours in a typical year.[11] The EPA's ENERGY STAR program also recommends using the 99th percentile heating design temperature for accurate load calculations in residential HVAC design.[12]

Q. WHAT IS THE PURPOSE OF HEATING DESIGN TEMPERATURES FOR SPACE HEATING SYSTEMS USED BY HVAC CONTRACTORS?

A. The heating design temperature is used in system design to ensure that a building's heating system can maintain indoor comfort during nearly all cold weather conditions—

[9] Air Conditioning Contractors of America (ACCA), *Manual J Residential Load Calculation*, https://www.acca.org/standards/technical-manuals/manual-j.
[10] ASHRAE, *Climatic Design Conditions 2009/2013/2017/2021*, https://ashrae-meteo.info/v2.0/.
[11] Allison A. Bailes III, *Design Temperature vs. Degree Days* (2021), https://www.greenbuildingadvisor.com/article/design-temperature-vs-degree-days.
[12] U.S. Environmental Protection Agency, *ENERGY STAR Certified Homes Design Temperature Limit Reference Guide (2019 Edition)* at 1, https://www.energystar.gov/partner-resources/residential_new/working/hvac/hvac_designers/design_temp_limits.

without being oversized for rare, extreme lows. Designing to this temperature helps prevent performance and comfort issues associated with oversizing. For instance, oversized systems often cycle on and off frequently, resulting in inefficient operation, increased mechanical wear, and a shorter system lifespan. Oversized systems also make it harder to maintain stable indoor temperatures, often leading to hot and cold spots that reduce occupant comfort.

HVAC contractors can avoid oversizing by using heating design temperatures grounded in established industry standards, such as Manual J, ASHRAE, or local building codes. This practice strikes a balance between system capacity, occupant comfort, and the installation and operating costs of the system. By avoiding the added cost and energy consumption of sizing equipment for extremely rare cold events, this approach promotes both energy efficiency and reliable performance during typical winter conditions.

Q. WHAT ARE THE HVAC DESIGN TEMPERATURES FOR THE EASTERN MOUNTAIN AREA?

A. The design temperature for 99th percentile at Copper Mountain—the closest weather station to Breckenridge in ASHRAE's weather database—is -1.6°F.[13] On the other hand, the building codes adopted by MCC jurisdictions, including Breckenridge and Keystone in Summit County,[14] require contractors to use a colder temperature of -13°F as the

[13] ASHRAE, *Climatic Design Conditions 2009/2013/2017/2021*, *2021 (IP) Design temperature at Copper Mountain, CO (WMO: 722061)*, https://ashrae-meteo.info/v2.0/.
[14] Silverthorne, Frisco, Dillon, and Blue River adopted Summit County building codes by reference with local amendments.

design temperature for heating systems.[15] These recommended design temperatures for HVAC system designs are 26 to nearly 38 degrees warmer than PSCo's assumed design temperature of -39°F.

It is also notable that the ASHRAE weather database provides more extreme temperature data based on various statistical metrics for some weather stations. For example, the database indicates that the 1-in-50-year low temperature at Leadville Lake County Airport weather station in Lake County (which has a slightly colder 99th percentile design temperature than Breckenridge) is approximately -29°F. Table 1 below lists the 1-in-50-year low temperature statistics for other weather stations in four nearby mountain areas, along with 1-in-20 years temperatures and 99th percentile design temperatures. 1-in-50-year low temperatures for these weather stations are above -30°F, except for one weather station in Grand County. However, the 99th percentile design temperature for this station is approximately 10 degrees colder than the design temperature at Copper Mountain in Summit County (likely due to inversions). These weather statistics indicate that PSCo's design temperature represents an unrealistic worst-case scenario that is not useful for estimating peak loads from space heating systems in the Eastern Mountain Gas System.

[15] Town of Breckenridge, *Building Codes* at Table R301.2(1), https://breckenridge.town.codes/Code/8-1-5; Summit County, *Building Codes* at Table R301.2(1), https://cms3.revize.com/revize/summitcoco/Documents/Services/Community%20Development/Building%20Inspection/Energy/2018%20ICC%20Amendments%20Combined%20Resolutions%20May%2011,%202021_20210514172703436 7.pdf.

Table 1. ASHRAE space heating temperature statistics (°F)

Weather station	County	99% design temperature	1-in-20 years	1-in-50 years
Aspen Pitkin County AP	Aspen	0.6	-21.2	-24.8
Eagle County Regional	Eagle	0.6	-24.2	-28.6
Copper Mountain	Summit	-1.6	n/a	n/a
Leadville Lake County AP	Lake	-3.0	-25.5	-29.0
McElroy AFLD	Grand	-11.2	-32.7	-34.9

Source: ASHRAE Climatic Design Conditions 2009/2013/2017/2021, https://ashrae-meteo.info/v2.0/.

Q. HOW DOES A HEATING SYSTEM DESIGNED USING AN APPROPRIATE HEATING DESIGN TEMPERATURE PERFORM AND CONSUME ENERGY DURING RARE, EXTREME COLD WEATHER EVENTS?

A. A heating system may not be able to fully maintain the indoor temperature setpoint (e.g., 70°F) during extreme cold conditions, but it will still provide substantial heating and help prevent indoor temperatures from dropping too low. From an energy consumption perspective, this means that space heating systems have a practical limit on peak energy use around the heating design temperature. Beyond this point, energy consumption does not continue to increase linearly as outdoor temperatures drop further, because the system is already operating at or near full capacity. This means that even if PSCo's gas pipeline system is designed to meet demand at -39°F, this has limited relevance for space heating systems because HVAC contractors typically size heating systems using substantially warmer temperatures.

Q. DOES PSCO'S PEAK LOAD FORECAST METHODOLOGY TAKE INTO ACCOUNT THIS EFFECT?

A. No.

Q. HOW DOES PSCO ESTIMATE PEAK LOAD AND ACCOUNT FOR OUTDOOR TEMPERATURE DATA IN ITS FORECAST METHODOLOGY?

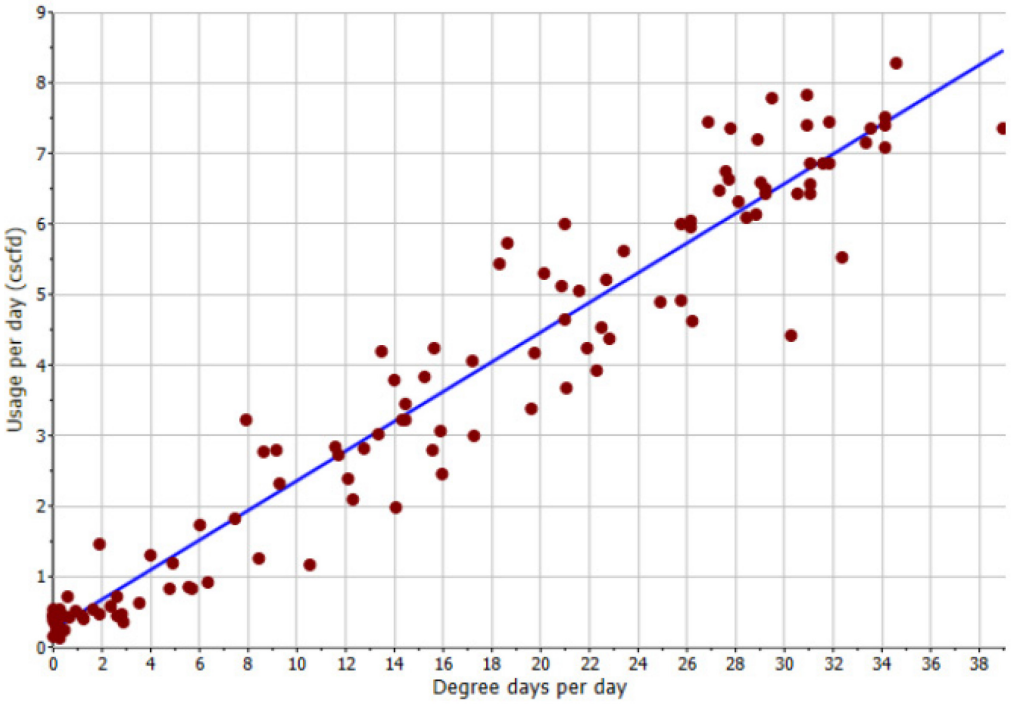
A. The Company uses its proprietary software called the Synergi Gas® Customer Management Module ("CMM") to estimate peak hour gas demand for each premise in the NPA area. As explained in Witness Grace K. Jones' supplemental direct testimony, CMM first estimates peak day gas usage per premise as follows:

> This proprietary software utilizes an algorithm to analyze monthly customer data, meter read data, and weather data to determine the peak day coefficients for the base and heat components of demand. Specifically, the CMM performs a *linear regression analysis* for each individual premise, correlating metered gas usage with total Heating Degree Days ("HDD") for each monthly billing period. This analysis establishes both the base demand and the heating coefficient for each premise.[16]

In her supplemental testimony, Witness Jones presented a graphic of the linear regression line for a residential premise, labeled as Figure GKJ-SD-2. This graph is presented below.

[16] Hearing Exhibit 107, Supplemental Direct Testimony of Grace K. Jones at 24:13-18 (emphasis added).

Figure 5. Representative Residential Premise Gas Demand Curve based on PSCo's Design Day Load Analysis in CMM



CMM then applies a peak hour factor of 1/18 to design day gas demand to estimate peak hour gas usage for each premise.[17] This methodology clearly indicates that the Company's design day peak hour load calculations fail to account for the capacity limits of space heating systems installed in buildings as it assumes that space heating demand continue increasing linearly as outdoor temperatures drop, all the way down to the Company's assumed minimum of -39°F—an assumption that does not reflect the practical operating limits of most heating systems. Notably, in her supplemental

[17] *Id.* at 25:7-8. In its response to MCC5-1, Public Service provides the following statement about the 1/18 factor: "While the Company does not have hourly or daily metering capabilities for individual firm residential customers, there are several metering points across the Company's system that do, such as supply receipt points and operational meters for odorization. The Company uses this data as a proxy to determine the 1/18th peak hour factor for customer daily load profiles." Hearing Exhibit 601, Attachment KT-4, Discovery Response MCC5-1 (May 22, 2025).

testimony, Witness Jones provides the following statement about onsite equipment sizing:

> CMM does not include limitations based on on-site equipment sizing or other factors. Notably, the Company does not have access to individual premise level appliance data, such that imposing a limitation based on on-site equipment sizing would require guesswork and therefore would not be reliable.[18]

Q. DOES IMPOSING A LIMITATION BASED ON ON-SITE EQUIPMENT SIZING NECESSARILY INVOLVE GUESSWORK, OR CAN IT BE DONE USING ESTABLISHED INDUSTRY STANDARDS?

A. While the Company may not have access to detailed, premise-level appliance data, this does not preclude the use of credible, standardized methods to estimate peak hour gas load at a regional level. As noted above, well-established industry practices—such as those defined by ASHRAE, Manual J, and local building codes—provide standard heating design temperatures and equipment sizing assumptions. These standards are widely used by HVAC professionals to size heating systems appropriately based on outdoor design conditions. By applying these standardized inputs, it is entirely reasonable to estimate average equipment sizes and the corresponding peak gas usage per premise. This approach is not guesswork; it is a recognized engineering method grounded in empirical climate data and building science.

[18] Hearing Exhibit 107, Supplemental Direct Testimony of Grace K. Jones at 26:6-9.

Q. WHAT IMPACT WOULD USING INDUSTRY-STANDARD DESIGN DAY TEMPERATURES HAVE ON THE COMPANY'S ESTIMATES OF PEAK GAS LOAD?

A. As noted above, the heating design temperature at Copper Mountain (the nearest weather station to Breckenridge) is -1.6°F according to ASHRAE's weather database.[19] In contrast, building codes in MCC jurisdictions —applicable to new construction—require the use of -13°F as the design temperature. This lower temperature corresponds to approximately 17 percent greater heating system capacity compared to the ASHRAE-based value, assuming buildings start to use space heating when outdoor temperatures are below 65°F. Local jurisdictions do not specify the design temperature for heating system replacements in existing buildings. However, to take a conservative approach and to follow the local practice, I will estimate the impact of -13°F as the HVAC design temperature on peak hour gas load.

Using the design temperature in building codes adopted by MCC jurisdictions of -13°F, I estimate that PSCo overestimates space-heating-related peak load by 25 percent. Assuming that buildings require heating when outdoor temperatures fall below 65°F, a design temperature of -13°F implies heating must support an indoor-outdoor temperature difference of 78 degrees (65°F – (-13°F) = 78°F). In contrast, using the Company's assumed design temperature of -39°F results in a requirement of 104 degrees (65°F – (-

[19] ASHRAE, *Climate Design Conditions 2009/2013/2017/2021*, *2021 (IP) Design temperature at Copper Mountain, CO (WMO: 722061)*, https://ashrae-meteo.info/v2.0/

39°F) = 104°F). This results in a 25 percent higher heating load than what would be expected using the design practices typical in Breckenridge and other MCC jurisdictions.

Notably, some contractors may oversize heating systems even beyond the level defined by the design temperature in MCC jurisdiction codes. Contractors may do so when the exact heating equipment size to match calculated loads is not available or if they want an additional safety margin. To account for this effect, I increase the heating peak demand by 20 percent, assuming a capacity oversize factor of 20 percent. This adjustment raises the supported indoor-outdoor temperature difference to approximately 94 degrees, which is about 10 percent lower than the heating load assumed by PSCo (which would sustain 104 degrees). In other words, PSCo overestimates heating load by approximately 10 percent based on this load adjustment.

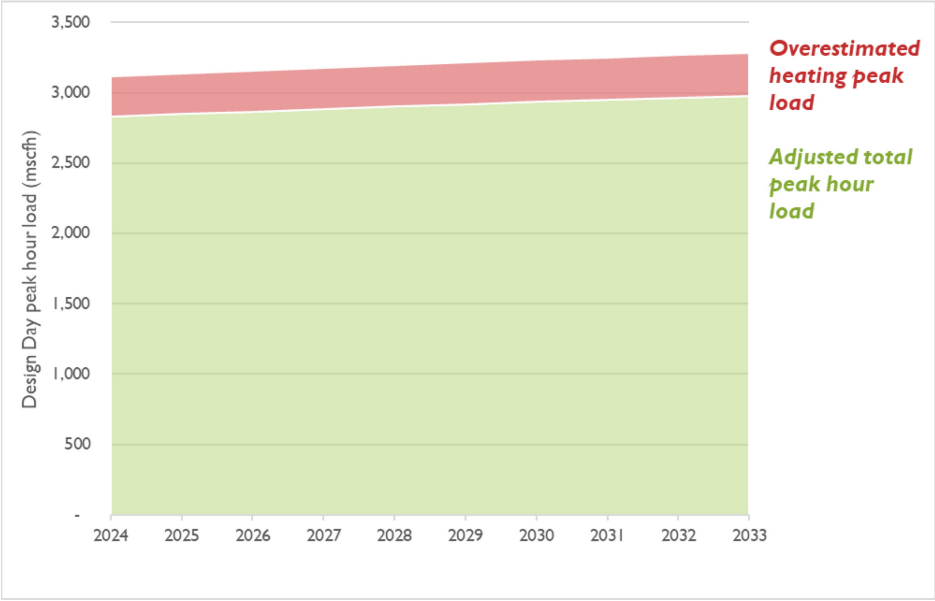
Q. HOW WOULD CORRECTING FOR HVAC SYSTEM DESIGN IMPACT PSCO'S DESIGN DAY PEAK HOUR LOAD FORECASTS?

A. PSCo does not provide design day peak hour load forecasts separately for Breckenridge, Keystone, and Grand Lake within the Eastern Mountain Gas System, even though it does provide supply shortfall estimates for those locations separately. Instead, PSCo reports design day peak hour load forecasts only for the Eastern Mountain Gas System as a whole. [20] PSCo estimates that the current design day peak hour load in the Eastern Mountain Gas System is approximately 3,100 mscfh[21] (excluding interruptible customers) and projects that this load will increase to about 3,280 mscfh (excluding

[20] Hearing Exhibit 601, Attachment KT-5, Discovery Response Attachment MCC1-5.A1 (Apr. 22, 2025).
[21] Mscfh stands for thousand standard cubic feet per hour.

interruptible customers) by the 2033/2034 winter season.[22] I applied the 10 percent load overestimation factor that I discussed above to the space heating load portion of PSCo's load forecast and revised the overall peak load forecast accordingly. I estimated the share of space heating load based on the data provided in Witness Jones' direct testimony, which ranges from 84 percent for gas transport customers to 98 percent for residential customers.[23] The resulting design day peak hour load forecasts are approximately 9.2 percent lower than PSCo's estimates, ranging from 2,830 mscfh in the first year to 2,980 mscfh by 2033/2034 (See Figure 6 below). In other words, PSCo appears to overestimate its peak hour load forecasts by roughly 286 mscfh to 300 mscfh.

Figure 6. Analysis of peak hour load overestimation in the Eastern Mountain Gas System based on design temperature adjustments



[22] Hearing Exhibit 601, Attachment KT-5, Discovery Response Attachment MCC1-5.A1 (Apr. 22, 2025).
[23] Hearing Exhibit 102, Attachment GKJ-2 at Table 4-2.

Q. HOW WOULD PUBLIC SERVICE'S SUPPLY SHORTFALL ESTIMATES CHANGE IF THIS HEATING LOAD ADJUSTMENTS WERE APPLIED?

A. Table 2 below presents PSCo's estimated supply shortfalls in the Eastern Mountain Gas System alongside my adjusted estimates. Based on a more appropriate design day temperature, I estimate that the supply shortfalls would be reduced to between 34 percent and 48 percent of PSCo's original estimates—ranging from approximately 150 mscfh in 2025 to 280 mscfh in 2033.

Table 2. Analysis of the potential supply shortfall changes based on design temperature adjustments

	PSCo's supply shortfall estimates (mscfh)	Peak load overestimated based on design temperature adjustment (mscfh)	Adjusted supply shortfalls (mscfh)	Adjusted supply shortfalls (% of the original estimates)
2025	439	288	151	34%
2026	467	290	177	38%
2027	486	292	194	40%
2028	505	294	211	42%
2029	521	296	225	43%
2030	537	297	240	45%
2031	554	299	255	46%
2032	566	301	265	47%
2033	579	302	277	48%

Source: Hearing Exhibit 102, Direct Testimony of Grace K. Jones at Figure GKJ-D-11.

Q. WHAT IMPACT DOES A MUCH SMALLER SUPPLY GAP HAVE ON THE POTENTIAL FOR DEMAND-SIDE NPAS TO CLOSE THE GAP?

A. I estimated the remaining supply shortfalls under the Electric Only Portfolio scenario and Hybrid Portfolio (1) scenario. Table 3 shows the results of this analysis for the Electric

Only Portfolio. Under this scenario, projected peak load reductions under begin at 11 percent of the adjusted supply shortfalls in 2025 and increase to 98 percent by 2033. By 2033, the remaining shortfall in 2033 is just 5 mscfh. Notably, the Electric Only Portfolio does not include any gas savings potential from electrification measures implemented by transport customers. This suggests that, if expanded to include transport customers, the Electric Only Portfolio could mitigate the entire supply shortfalls by 2033 while requiring much smaller supplemental supply facilities before 2033.

Table 3. Potential changes to the remaining supply shortfalls under Electric Only Portfolio scenario

	Adjusted supply shortfalls (mscfh)	Electric Only Portfolio		
		NPA peak hour load reductions (mscfh)	Remaining supply shortfalls (mscfh)	NPA peak hour load reduction (%)
2025	151	16	135	11%
2026	177	39	138	22%
2027	194	59	135	30%
2028	211	88	123	42%
2029	225	116	109	52%
2030	240	146	94	61%
2031	255	181	74	71%
2032	265	224	41	84%
2033	277	272	5	98%

Table 4 presents the results of my analysis of supply shortfalls under Hybrid Portfolio (1). I selected Hybrid Portfolio (1) for this analysis instead of Hybrid Portfolio (2) because the former is led by demand-side actions while the latter is supply-driven and sized to reflect indefinite use of supplemental facilities. The purpose of this analysis is to demonstrate that demand-side NPAs could potentially eliminate the need for

supplemental supply facilities by 2033 or earlier. As shown in Table 4, NPA measures under Hybrid Portfolio (1) could close the supply gas as early as 2031.

Table 4. Potential changes to the remaining supply shortfalls under Hybridge Portfolio (1) scenario

	Adjusted supply shortfalls (mschf)	NPA peak hour load reductions (mschf)	Hybrid Portfolio (1) Adjusted supply shortfalls + NPA (mschf)	NPA peak hour load reduction (%)
2025	151	25	125	17%
2026	177	59	118	33%
2027	194	93	101	48%
2028	211	140	71	66%
2029	225	183	42	81%
2030	240	233	7	97%
2031	255	284	-29	111%
2032	265	345	-79	130%
2033	277	413	-136	149%

Q. IS PSCO OVERESTIMATING PEAK HOUR DEMAND IN OTHER RELEVANT PORTIONS OF ITS SERVICE TERRITORY AS WELL?

A. I do not have sufficient information to evaluate whether PSCo is also overestimating design day demand in other locations. However, if the Company is overestimating demand in the Denver and Northern Gas Systems, that overestimate could be impacting the Company's calculations of available gas for the Eastern Mountain Gas System because Witness Jones states: "[f]or the Eastern Mountain Gas System, the Marshall Compressor station is the primar[y] source of gas supply which feeds gas from the Company's Denver and Northern Colorado gas systems."[24] Witness Jones also states that

[24] Hearing Exhibit 102. Direct Testimony of Grace K. Jones at 35:1-3.

"[t]he gas feed into the Marshall Compressor Station is downstream of the Company's Denver and northern Colorado gas systems. As a result, on Design Day, the gas supply into the Marshall Compressor Station needed to fully supply the Eastern Mountain Gas System is affected by past and ongoing increases in upstream customer demand."[25] This suggests that if demand upstream of the Marshall Compressor Station were lower than projected (due to overestimates of design day load), more gas may be available for the Eastern Mountain Gas System. Finally, PSCo states that there are hardware limitations at and downstream of the Marshall Compressor Station that would limit the availability of gas to the Eastern Mountain Gas System even if more gas were available at the compressor.[26] However, PSCo has not presented any evaluation of those limits in this case, nor has it indicated whether a hybrid solution that mitigated some of those limits (combined with greater gas supply from upstream) could mitigate some or all of the issues in the Eastern Mountain Gas System.

Q. ARE THERE ANY OTHER ISSUES WITH PUBLIC SERVICE'S LOAD FORECASTING APPROACH THAT COULD LEAD TO OVERESTIMATION OF DESIGN DAY PEAK HOUR LOAD FORECASTS OR UNDERESTIMATION OF AVAILABLE GAS?

A. Yes. I have two additional concerns with the Company's forecasting methodology. First, the Company assumes all jurisdictions within its service territory across the state experience peak hour conditions at the same time when estimating design day peak hour loads and potential supply shortfalls. Second, the Company's use of linear regressions

[25] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 35:12-16.
[26] Hearing Exhibit 601, Attachment KT-6, Discovery Response MCC7-3(a) (May 30, 2025).

based on daily gas usage and heating degree days does not adequately account for how snowmelt systems operate during periods of extreme cold.

Q. PLEASE EXPAND ON YOUR POINT ABOUT THE TIMING OF PEAK HOUR CONDITIONS ACROSS DIFFERENT JURISDICTIONS.

A. In its response to SWEEP's data request, Public Service provides the following statement:

> [T]he Company assumes that the Northern, Denver, Eastern Mountain, Southern Mountain, and Western Mountain Gas Systems reach their Design Day peak hour demand at the same time. The basis of this assumption is that due to the geographic proximity of these systems, Design Day temperatures may occur concurrently.[27]

This assumption is overly conservative and could contribute to an overestimation of peak hour load and potential supply shortfalls. Although these systems are relatively close in proximity, it is uncertain whether all regions experience their coldest temperatures during the same hours. Assuming perfect coincidence in Design Day conditions across such a large and topographically diverse service territory likely overlooks spatial and temporal variations in weather and gas usage patterns. This could result in inflated peak hour demand estimates and unnecessary investment in supply-side infrastructure. A more appropriate approach would model peak hour demand separately for each system using region-specific temperature data and historical load patterns, and then estimate the

[27] Hearing Exhibit 601, Attachment KT-7, Discovery Response SWEEP1-2(f) (May 21, 2025).

highest coincident peak hour load across the service territory. This is an approach commonly used in electric transmission system planning.

Q. PLEASE EXPAND ON YOUR POINT ABOUT SNOWMELT SYSTEMS.

A. Snowmelt systems are generally not recommended for operation during extremely cold conditions because melting snow becomes more difficult and the resulting water may quickly refreeze, creating safety hazards. Recognizing this, Breckenridge's building code requires all snowmelt systems to have automated controls that limit operation to times when moisture is present and outdoor air temperatures are between 20°F and 40°F, with slab temperature sensors providing additional control.[28] This means that gas usage for buildings with snowmelt systems does not increase as steeply when temperatures fall below 20°F. For such buildings, the slope of the gas usage curve becomes gentler under extremely cold conditions—rather than continuing to rise at the same rate as assumed in the Company's regression model. As a result, the Company's methodology may overstate peak day and peak hour gas usage for buildings with snowmelt systems during periods of extreme cold.

[28] Town of Breckenridge, *Building Code* § 8-1-9: Amendments to the International Energy Conservation Code, Section C410.2 – Snowmelt Systems, https://breckenridge.town.codes/Code/8-1-9.

B. Policy Impacts

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT COULD REDUCE SUPPLY SHORTFALLS EVEN FURTHER?

A. Yes. As I mentioned above, Public Service's peak load forecasts are not fully accounting for the impacts of state and local policies. Such policies are climate policies by local governments in the Eastern Mountain Gas System, Denver, and communities in the Northern Gas systems, as well as the Company's own 2024–2026 Clean Heat Plan and DSM/BE programs.[29]

Q. WHY ARE DENVER'S CLIMATE POLICIES RELEVANT TO THE SUPPLY SHORTFALLS IN THE EASTERN MOUNTAIN GAS SYSTEM?

A. PSCo's supply forecast does not account for changes in load in Denver. The Company assumes a fixed amount of gas will be available at the Marshall Compressor Station.[30] It also states that it evaluated options to upgrade the ability of the gas system in Denver to transport gas from interstate pipelines to the Marshall Compressor Station, and determined that these options were not feasible.[31] However, the Company does not address the potential for reductions in demand in Denver to make room on existing pipelines to carry more gas to the Marshall Compressor Station. As mentioned above, Witness Jones states that the amount of gas available at that station is affected by past and ongoing increases in upstream customer demand;[32] it therefore should also be true that

[29] *See infra* n.42.
[30] Hearing Exhibit 601, Attachment KT-8, Discovery Response MCC1-5 (g-i) (Apr. 22, 2025).
[31] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 70:10–71:2.
[32] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 35:13-16.

the amount of available gas can be increased by future reductions in upstream customer demand.

Q. PLEASE DESCRIBE DECARBONIZATION POLICIES IN DENVER AND OTHER COMMUNITIES UPSTREAM OF THE EASTERN MOUNTAIN GAS SYSTEM.

A. Many cities and counties in Colorado have their own decarbonization policies outside of the state's net-zero emissions goal by 2050.[33] The cities of Denver and Boulder are part of the Northern Gas System and are located upstream of the Marshall Compressor station. Their energy policies directly impact the supply shortfall in the Eastern Mountain Gas System.

Denver's 80x50 Climate Action Plan lays out sector-specific targets and strategies for reducing emissions 80 percent by 2050, relative to 2005 levels. The Climate Action Plan includes a 30 percent energy use reduction target in commercial buildings by 2030 and a 20 percent reduction in residential single-family homes by 2035.[34] The City of Boulder's Climate Action Plan commits the city to reducing emissions 70 percent from 2018 levels by 2030 and reach net-zero emissions by 2035.[35] Boulder has already eliminated natural

[33] Hearing Exhibit 600, Answer Testimony of Jessica Burley at 10-13.
[34] City and County of Denver, *80x50 Climate Action Plan*, at 2-3 (2018) https://www.denvergov.org/content/dam/denvergov/Portals/771/documents/EQ/80x50/DDPHE_80x50_ClimateActionPlan.pdf.
[35] City of Boulder, *Update on Climate Action Plan*, at 2 (June 8, 2021), https://bouldercolorado.gov/media/3302/download?inline=.

gas from new residential construction[36] and has a target to eliminate operational emissions for all existing buildings by 2040.[37]

Q. PLEASE DESCRIBE DECARBONIZATION POLICIES IN BRECKENRIDGE AND OTHER COMMUNITIES IN THE EASTERN MOUNTAIN GAS SYSTEM.

A. As discussed in testimony of Jessica Burley on behalf of the Mountain Community Coalition, many communities within the Eastern Mountain System have their own decarbonization targets. The Summit Community Climate Action Plan ("CAP") has a goal of 50 percent emissions reductions by 2030 and 80 percent reductions by 2050.[38] The CAP also establishes a building-sector goal to reduce building energy usage 21 percent by 2030 and 36 percent by 2050.[39] Breckenridge, Frisco, Dillon, Silverthorne, and Summit County Government have formally adopted the same GHG reduction targets.[40]

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[36] *Id.* at 45.
[37] *Id.* at 16.
[38] Summit Climate Action Collaborative, *Summit Community Climate Action Plan: Strategies for a Sustainable Future* at 6 (2018), available at: https://cms3.revize.com/revize/summitcoco/Documents/Services/Sustainability/Summit%20Community%20Climate%20Action%20Plan.pdf.
[39] *Id.* at 7.
[40] Town of Breckenridge, *Sustainable Breck Plan*, at 25 (2022), https://plan.sustainablebreck.com/wp-content/uploads/SustainableBreck-Plan.pdf; Town of Frisco, *An Energy Action Plan for Town of Frisco*, at 2 (2022),https://library.municode.com/co/frisco/munidocs/munidocs?nodeId=6ba6139fe71e7; Town of Dillon, *An Energy Action Plan for Dillon*, at 11 (2024), https://xcelenergycommunities.com/sites/xcelenergycommunities.com/files/document/pdf/Partners%20in%20Energy%20-%20Dillon%20Energy%20Action%20Plan%20Final.pdf; Town of Silverthorne, *Sustainability Strategic Plan: Final*, at 43-47, 58 (2024), https://www.silverthorne.org/home/showpublisheddocument/1675/638604561918670000.

Q. HOW WERE DECARBONIZATION POLICIES OVERLOOKED IN THE COMPANY'S LOAD FORECASTS?

A. The Company did not account for the impacts of decarbonization policies upstream of the Eastern Mountain System. Instead, the Company assumes capacity at the Marshall Compressor Station that is supplying gas to the Eastern Mountain System will remain at current levels throughout the project period.[41]

Q. PLEASE EXPLAIN HOW THE COMPANY UNDERESTIMATED THE IMPACTS OF ITS DSM/BE PROGRAMS AND THE CLEAN HEAT PLAN.

A. PSCo included impacts from the Company's 2023 Biennial Plan Goals and Proposed Strategic Issues Goals and market electrification trends in its load forecast;[42] however, it did not incorporate the 2024–2026 DSM/BE plan, filed in December 2023, or the 2024–2027 Clean Heat Plan, filed in August 2023.[43] By failing to account for the recent DMS/BE and Clean Heat Plan programs, the Company overestimates its MEP load forecast.

C. Recommendation

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S DESIGN DAY PEAK HOUR LOAD AND SUPPLY SHORTFALL FORECASTS?

A. I recommend that Public Service re-analyze and revise its design hour peak load and supply shortfall forecasts by: (a) using a realistic design temperature—such as the value

[41] Hearing Exhibit 601, Attachment KT-8, Discovery Response MCC1-5 (g-i) (Apr. 22, 2025).
[42] Hearing Exhibit 601, Attachment KT-9, Discovery Response MCC1-9 (a) (Apr. 22, 2025).
[43] Hearing Exhibit 601, Attachment KT-2, Discovery Response MCC1-10 (Apr. 22, 2025).

specified in building codes adopted by MCC jurisdictions—that better reflects actual HVAC contractor installation practices; and (b) accounting for the impacts of state and local policies on gas demand, as well as addressing the Company's underestimation of the effects of its own programs.

I also recommend that Public Service revise its design day peak hour load forecasting and supply shortfall forecasting methodology to account for two key factors: (a) the gas usage patterns of buildings with snowmelt systems, which should reflect a more gradual increase in demand during extremely cold conditions rather than assuming a continued linear relationship below 20°F; and (b) regional variation in weather conditions across its gas systems, by using historical temperature data to develop more realistic estimates of coincident peak hour demand rather than assuming full simultaneity across all regions.

If Public Service is also using an unrealistically low design temperature for the Denver and Northern Gas Systems, I further recommend that it revise those assumptions and re-estimate the amount of gas available at the Marshall Compressor Station during peak conditions.

V. ASSESSMENT OF DEMAND-SIDE NPA POTENTIAL ESTIMATES

Q. WHAT ARE YOUR CONCERNS ABOUT PUBLIC SERVICE'S NPA POTENTIAL ESTIMATES?

A. As noted in the overview section, Public Service engaged a group of consultants—including PA Consulting, Apex Analytics, and Jacobs Engineering Group (collectively referred to as the PA Team)—to evaluate the natural gas savings potential from demand-

side NPA measures. My review of this NPA potential study indicates that the NPA potential study is not comprehensive and contains several flaws that result in an underestimation of both the scale and benefits of the NPA potential. Such flaws are as follows:

a) The NPA potential study did not include any gas savings potential in Denver and the Northern Gas Systems.
b) The technical potential analysis relied on an overly restrictive screening process which excluded several NPA measures that it should have included.
c) The economic potential analysis underestimated societal benefits.
d) The achievable potential analysis assumed unrealistically low adoption rates for electrification measures—particularly air-source and ground-source heat pumps.

A. Technical Potential

Q. DOES THE NPA POTENTIAL STUDY INCLUDE SAVINGS POTENTIAL IN REGIONS OUTSIDE OF THE EASTERN MOUNTAIN GAS SYSTEM.

A. No. The NPA potential study only focuses on gas saving measures in the Eastern Mountain Gas System and does not include potential gas savings in other regions.

Q. WHY IS IT ALSO IMPORTANT TO ASSESS GAS SAVINGS MEASURES IN DENVER AND THE NORTHERN GAS SYSTEMS?

A. As discussed in the previous section regarding the impact of policies in Denver and the communities served by the Northern Gas Systems, these areas are located upstream of the Marshall Compressor Station serving the Eastern Mountain Gas System. If gas demand in

these upstream areas can be reduced, it could free up additional supply for the Eastern Mountain Gas System. Therefore, it is important to evaluate the gas savings potential in Denver and other Northern Gas System communities.

Q. PLEASE SUMMARIZE THE PA TEAM'S ANALYSIS OF THE NPA TECHNICAL POTENTIAL.

A. To develop NPA portfolios, the PA Team first estimated technical potential of NPA measures for the Eastern Mountain Gas System. According to the NPA potential study, technical potential is defined as "*the theoretical maximum amount of energy use that could be displaced*, disregarding all non-engineering constraints such as cost effectiveness and the willingness of end users to adopt the [energy efficiency] measures."[44] The PA Team assembled a list of more than 70 potential NPA measures and technologies using sources such as the Company's Technical Reference Manual and a national survey of NPA options.[45] The PA Team then assessed whether to include each measure or technology using a qualitative screening process based on the following criteria: (a) whether the measure had measurable impact on peak hour gas demand; (b) the relative magnitude of peak hour/peak day gas demand impact on a scale of 1–5; and (c) five additional qualitative criteria as follows: (1) commercial availability of measure; (2) customer acceptance of solution; (3) availability of contractors; (4) ease of

[44] Hearing Exhibit 102, Attachment GKJ-2 at 64.
[45] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 100: 3-6.

implementation; and (5) greenhouse gas impacts.[46] This screening process resulted in a total of 33 NPA measures and technologies that were included in the study.

The PA Team then developed gas savings estimates using the Company's Technical Reference Manual ("TRM") for its DSM programs and calibrated to consumption and peak data for the mountain region.[47] The PA Team states in the potential study that "[t]his screening was intended to streamline the overall analysis by excluding measures expected to have minimal impact on potential."[48]

Table 5, below, provides total technical potential estimates by sector and end use. It is notable that the PA Team used the NPA measure with the highest gas savings to estimate technical potential for each measure type (e.g., space heating equipment). Thus, from a technical potential perspective, efficient gas equipment that can save very small amounts of gas relative to heat pumps has no gas savings potential.

[46] Hearing Exhibit 102, Attachment GKJ-2 at 24.
[47] Hearing Exhibit 102, Attachment GKJ-2 at 24.
[48] Hearing Exhibit 102, Attachment GKJ-2 at 27.

Table 5. NPA technical potential by measure category and sector in 2033 (mscfh)

Sector	Measure Category	Breckenridge	Keystone	Grand Lake	Total
Residential	Electrification	1,149.6	399.8	58.7	1,608.1
Residential	Building Shell	267.8	93.1	13.6	374.5
Residential	Demand Response	38.2	13.1	2.1	53.4
Residential	Behavior	5.7	2.0	0.3	8.0
Residential	Whole Building	4.5	1.6	0.2	6.3
Residential	Water Saving	0.3	0.1	0.0	0.4
Residential	Gas Equipment	0.0	0.0	0.0	0.0
Residential	Gas Equipment Tune Up	0.0	0.0	0.0	0.0
Residential	Thermostat Retrofit	0.0	0.0	0.0	0.0
Residential	**Subtotal**	**1,466.0**	**509.6**	**74.9**	**2,050.5**
Commercial	Electrification	552.8	189.7	6.3	748.8
Commercial	Building Shell	277.1	94.9	3.1	375.1
Commercial	Demand Response	23.2	7.6	0.3	31.1
Commercial	Gas Equipment	0.0	0.0	0.0	0.0
Commercial	**Subtotal**	**853.0**	**292.2**	**9.8**	**1,155.0**
Total		**2,319.0**	**801.8**	**84.7**	**3,205.5**

Source: Hearing Exhibit 102, Attachment GKJ-2 at Table 4-19 and Table 4-20.

Q. WHAT ARE THE MAJOR ISSUES WITH THE TECHNICAL POTENTIAL APPROACH?

A. The NPA potential study employed an overly restrictive measure screening process that excluded numerous measures without adequate consideration or supporting evidence. This approach is inconsistent with the definition of *technical potential*, which refers to "the theoretical maximum amount of energy use that could be displaced, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the [energy efficiency] measures."[49] Some of the excluded measures that I consider

[49] Hearing Exhibit 102, Attachment GKJ-2 at 24.

important, applicable, and available in the region—and therefore should have been included—are as follows:

a) Thermal energy networks
b) Building code support program
c) Heat recovery ventilators/energy recovery ventilators
d) Low-cost measures such as low-flow showerheads and water heater tank insulation and pipe insulation

Finally, the NPA potential study did not analyze air-to-water heat pumps or even acknowledge them as a potential NPA measure to replace gas boilers.

Q. PLEASE EXPLAIN WHY THE COMPANY SHOULD INCLUDE THERMAL ENERGY NETWORKS?

A. The Company did not include thermal energy networks (which the potential study refers to as "Ground Source Network Loop") in its NPA potential estimate, despite the significant potential for gas savings from this technology. The Company cited "low market availability" as the reason for exclusion, which it defines as "a measure that lacks commercial enterprises selling or installing the measure in the mountain area."[50] However, this rationale does not justify excluding the technology, as thermal energy networks are already commercially viable, and qualified contractors capable of designing and installing such systems are available in the region. There are a few notable thermal energy network projects in and around the mountain area that demonstrate the feasibility and applicability of this technology include:

[50] Hearing Exhibit 601, Attachment KT-10, Discovery Response MCC2-6(c) (May 9, 2025).

- **Colorado Mesa University project**: Colorado Mesa University ("CMU") operates a geothermal thermal energy network which provides heating and cooling to over 1.2 million square feet across 16 buildings—serving approximately 90 percent of the campus's energy needs.[51] The system consists of 450 boreholes drilled 500 feet deep and a 2.5-mile central loop, and it uses features such as the campus swimming pool and irrigation systems as heat sinks. According to estimates by the U.S. Department of Energy, the system reduces CMU's carbon emissions by nearly 18,000 metric tons annually and results in about $1.5 million in energy cost savings each year.[52] Notably, Public Service commissioned a study analyzing the performance of CMU's networked geothermal system, which reported a coefficient of performance ("COP") of 8.9 during the 2022–2023 heating season—significantly higher than that of conventional heat pump systems.[53]
- **Breckenridge pilot**: Breckenridge has been actively working with a private firm to design and install a thermal energy network and was recently selected as one of Colorado's gas planning pilot communities under House Bill 24-1370 to develop thermal network projects. This selection was made jointly by the CEO and Public Service.[54]
- **Denver pilot**: Denver is advancing two district thermal energy pilot projects as part of its clean energy and sustainability goals. In the Sun Valley neighborhood, the Denver Housing Authority is implementing a four-pipe system that combines ground-source geothermal, solar, and biomass energy to

[51] U.S. Department of Energy, *Geothermal Heat Pump Case Study: Colorado Mesa University* (2024), https://www.energy.gov/eere/geothermal/geothermal-heat-pump-case-study-colorado-mesa-university; Colorado Mesa University, *Geo-Grid System*, https://www.coloradomesa.edu/sustainability/initiatives/geo-grid.html.
[52] U.S. Department of Energy, *Geothermal Heat Pump Case Study: Colorado Mesa University* (2024), https://www.energy.gov/eere/geothermal/geothermal-heat-pump-case-study-colorado-mesa-university.
[53] Xcel Energy, *Evaluating a Community Ground Source Heat Pump System at Colorado Mesa University* (2023), https://www.coloradomesa.edu/sustainability/documents/cmu-cgshp-summary-2023.09.06.pdf.
[54] Proceeding No. 25D-0183G, *Petition of Public Service Company of Colorado and the Colorado Energy Office for Approval of Selected Gas Planning Pilot Communities and Submittal of Proposed Partnership Agreement* (Apr. 30, 2025).

serve new affordable housing and community buildings.[55] In downtown Denver, the city received nearly $5 million in April 2025 through Colorado's Geothermal Energy Tax Credit Offering to develop a multisource thermal system using a shared water loop to heat and cool approximately 5.5 million square feet of municipal buildings.[56]

The Company also states that planning, siting, and constructing thermal energy networks would take too long to implement, referencing the thermal energy network project implemented by Eversource in Framingham, Massachusetts which took six years to complete.[57] This should not be the reason to reject this technology in the potential study and from the Mountain Energy Project. First, the timeline of the Mountain Energy Project is longer than 6 years. In addition, it likely would not take PSCo as long to implement thermal energy network systems given that the Framingham project faced supply chain delays due to the COVID-19 pandemic.[58] Moreover, PSCo could apply lessons learned from the Framingham project and other projects (such as the thermal energy network installation at Colorado Mesa University) to expedite the process.

[55] U.S. Environmental Protection Agency, *Denver Sun Valley Neighborhood-South Platte River Urban Waters Partnership and Making a Visible Difference in Communities 2011-2021*, at 3 (2022), https://www.epa.gov/system/files/documents/2022-04/sun-valley-10-year-summary-2-24-22.pdf.
[56] Colorado Governor's Office. 2025. *Polis Administration Awards $14.4 Million to Support Nation-Leading Efforts in Geothermal Heating*, (April 3, 2025), https://www.colorado.gov/governor/news/polis-administration-awards-144-million-support-nation-leading-efforts-geothermal-heating.
[57] Hearing Exhibit 601, Attachment KT-11, Discovery Response MCC2-8(a) (May 9, 2025).
[58] NSTAR Gas Company d/b/a Eversource Energy, *Geothermal Demonstration Project Status Report for 2024 PBR Compliance*, Docket D.P.U. 24-GSEP-06 (Oct. 31, 2024), https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//iibceihj?oErR2IGpEvzCkNmqazPiVGFJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMlNqhcSkxPf0qUr1gASPKrYE1qejvebf677PtCVStUdHoHpEGELGLGjR+ZpYgt

Q. PLEASE EXPLAIN WHICH OTHER MEASURES THE TECHNICAL POTENTIAL ESTIMATE SHOULD INCLUDE AND WHY.

A. In addition, the following technologies missing from the technical potential estimate are worth examining:

- **Building codes support:** The PA Team excluded this measure, stating that this program is "Out of Program Scope."[59] However, in its response to MCC's data request, Public Service indicated that "[t]he Company currently supports updated codes and standards to facilitate savings at statewide level through its Residential and Business New Construction programs."[60] In the same response, the Company also cited uncertainty about future building codes and the slow pace of code development as reasons for exclusion. However, states and local governments typically adopt new model building codes developed by the International Code Council and ASHRAE.[61] Further, the slow development process is not a sufficient justification for exclusion, given that the NPA potential study covers a 9-year timeframe from 2025 to 2033.[62]
- **Heat recovery ventilators/energy recovery ventilators**: The PA Team considered this measure for commercial buildings but excluded it due to "Low Impacts."[63] For residential buildings, the PA Team did not include heat recovery ventilators or energy recovery ventilators, stating that these systems are not applicable to existing buildings without ventilation and that, in new construction, they "[do] not save gas during times of high outdoor-air

[59] Hearing Exhibit 102, Attachment GKJ-2 at Table 4-7.
[60] Hearing Exhibit 601, Attachment KT-12, Discovery Response MCC2-7(d) (May 9, 2025).
[61] U.S. DOE, *Commercial and Residential Building Energy Codes*, https://www.energycodes.gov/commercial-and-residential-building-energy-codes.
[62] Note that California's investor-owned utilities have been operating robust building codes and standards support programs for many years and assess the potential of such a program. Their energy efficiency potential studies often find a substantial amount of energy savings potential from codes and standards support programs. *See* C&S Savings section of Guidehouse Inc., *2023 Energy Efficiency Potential and Goals Study* (2023), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2023-potential-goals-study/final-2023-group-e-pg-study-report.pdf.
[63] Hearing Exhibit 102, Attachment GKJ-2 at Table 4-8.

infiltration, which aligns with natural gas usage peak times."[64] However, the PA Team did not provide any evidence to substantiate these claims. In reality, heat recovery ventilators and energy recovery ventilators are highly cost-effective technologies capable of recovering up to 80–90 percent of heating energy.[65] Moreover, top-performing models can maintain high efficiency even under extremely cold conditions.[66]

- **Cost-effective, low-impact, and low-cost measures:** The PA Team excluded low-cost measures such as low-flow showerheads and water heater tank insulation and pipe insulation, due to "Minimal Peak Hour Savings."[67] However, these measures are easy to implement and often highly cost-effective.[68] They can help consumers reduce natural gas use and lower their gas bills, while also improving the overall cost-effectiveness of the NPA portfolio. Notably, these measures can be installed as part of home energy audits with little-to-no additional installation cost. Given these benefits, such measures should be included in both the NPA potential analysis and the program offerings under the Mountain Energy Project. The Company's approach appears overly narrow, as it places too much emphasis on peak load reduction and excludes these measures without adequately considering their cost-effectiveness and potential for customer bill savings.
- **Air-to-water heat pumps ("AWHPs"):** The omissions of this emerging technology is a notable gap in the NPA study. Gas boilers are a common gas

[64] Hearing Exhibit 601, Attachment KT-13, Discovery Response MCC2-5(b) (May 9, 2025).
[65] For example, Eversource in Massachusetts estimates benefit cost ratios ranging from 6 to as high as 14 for HRVs. *See* the "Calcs" tab for Eversource Energy (NSTAR Gas) BC Model for the 2025-2027 Three-Year Energy Efficiency Plan, https://ma-eeac.org/wp-content/uploads/D.P.U.-24-141-Exh.-Eversource-Energy-5-EGMA-BC-Model.xlsx; Massachusetts Energy Efficiency Advisory Council, *Plans and Updates*, https://ma-eeac.org/plans-updates/.
[66] For example, Panasonic's Intelli-Balance 100 ERV maintains 56 percent efficiency at -13°F. Panasonic, *Intelli-Balance 100 Energy Recovery Ventilator*, https://ftp.panasonic.com/ventilationfan/intellibalance/intellibalance100_sellsheet.pdf.
[67] Hearing Exhibit 102, Attachment GKJ-2 at Table 4-7.
[68] For example, Eversource in Massachusetts estimates that benefit cost ratios ranging from 34 to 125 for low-flow showerheads. See the "Calcs" tab for Eversource Energy (NSTAR Gas) BC Model for the 2025-2027 Three-Year Energy Efficiency Plan, https://ma-eeac.org/wp-content/uploads/D.P.U.-24-141-Exh.-Eversource-Energy-5-EGMA-BC-Model.xlsx.

heating system in the Eastern Mountain region. While cold climate air-source heat pumps ("ccASHPs") analyzed by the PA Team can be viable alternatives,[69] many customers may prefer to retain their radiant in-floor heating systems, which are not compatible with ccASHPs. AWHPs, by contrast, can supply hot water for radiant systems and therefore warrant consideration. In addition, AWHPs—particularly when paired with thermal storage—are increasingly recognized for their ability to significantly reduce electric peak heating loads by shifting energy consumption to off-peak hours.[70]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PA TEAM'S TECHNICAL POTENTIAL ESTIMATE?

A. I strongly recommend that Public Service and the PA Team assess the technical, economic, and achievable potential of thermal energy network technologies and include them in all NPA portfolios for consideration for the Mountain Energy Project. I also recommend that Public Service and the PA Team consider exploring the potential of the following measures: building codes support; heat recovery ventilators and energy recovery ventilators for residential and commercial buildings; air-to-water heat pumps; and cost-effective, low-cost measures such as low-flow showerheads and water heater tank and pipe insulation.

[69] According to Attachment MCC2-6.A1, this is the only heat pump technology that the NPA potential study analyzed for residential buildings. Hearing Exhibit 601, Attachment KT-14, Discovery Response Attachment MCC2-6.A1(May 9, 2025).

[70] The CalNEXT study, *Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage*, assessed the performance of AWHP systems paired with thermal energy storage in single-family homes in California. The study estimated winter peak load reductions ranging from 17 percent to 82 percent across different test sites. CalNEXT, *Technical Evaluation of Air-to-Water Heat Pumps with Thermal Storage* (Nov. 22, 2024), https://calnext.com/wp-content/uploads/2024/12/ET22SWE0050_Technical-Evaluation-of-Air-to-Water-Heat-Pumps-with-Thermal-Storage_Final-Report.pdf.

B. Economic Potential

Q. PLEASE DESCRIBE HOW THE PA TEAM ESTIMATED THE NPA ECONOMIC POTENTIAL.

A. The PA Team did not conduct a formal analysis of the economic potential of NPA measures and did not provide corresponding economic potential estimates in the study, [71] although the PA Team did mention it "assessed the potential of each NPA measure/technology in three categories" including economic potential.[72] Instead, the PA Team examined the cost-effectiveness of each measure that was included in the technical potential estimate, using an Expanded Ratepayer Impact Measure ("ERIM") test to screen out extremely high-cost measures.[73]

The ERIM test incorporates the value of carbon reductions, in addition to the costs and benefits included in the standard Ratepayer Impact Measure ("RIM") test, which reflects the perspective of non-participating ratepayers. These costs and benefits include avoided costs for both the gas and electric system, program overhead, incentives, and lost revenue.[74]

Using the ERIM test, the PA Team calculated the net cost of each measure to construct a supply curve ranking measures by cost per MSCFH of gas reduction. Measures were

[71] Hearing Exhibit 601, Attachment KT-15, Discovery Response MCC2-10(a) (May 9, 2025).
[72] Hearing Exhibit 102, Attachment GKJ-2 at. 64.
[73] Hearing Exhibit 601, Attachment KT-15, Discovery Response MCC2-10(a) (May 9, 2025); Hearing Exhibit 102, Attachment GKJ-2 at 67.
[74] Hearing Exhibit 102, Attachment GKJ-2 at 66; Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 176:12-15. According to Witness Jones, "a traditional [RIM] test reflects the cost-benefit perspective of non-participating customers, while the ERIM adds in the same expanded set of social benefits present in the EMTRC, to the extent they apply to non-participants (e.g. emissions benefits)." Hearing Exhibit 102, Attachment GKJ-7 at 6.

screened out if they had exceptionally high ERIM costs or required incentives greater than $100,000 per MSCFH-year. The team noted that the excluded high-cost measures represented less than 2 percent of the total technical potential.[75]

Notably, this screening did not include the avoided cost of a traditional gas infrastructure project. This is likely because, in a later step of the PA Team's potential study, the PA Team compares the total net costs of a few NPA portfolios to the costs of a traditional gas infrastructure project. A standard methodology for estimating economic potential typically includes all relevant costs and benefits, including the avoided cost of traditional utility infrastructure, and assesses the cost-effectiveness of each measure. Measures that meet a defined threshold, often a benefit-cost ratio of 1.0 or slightly lower, are then used to calculate the total economic potential estimate.[76] However, the PA Team's economic potential analysis did not follow this standard practice.

Q. ARE THERE ANY MAJOR ISSUES WITH THE PA TEAM'S COST-EFFECTIVENESS SCREENING?

A. Yes. While the PA Team incorporated various important benefits and costs in its economic screening, it did not fully account for the benefits of avoided emissions in particular: (a) avoided air pollution and (b) avoided methane leaks.

[75] Hearing Exhibit 102, Attachment GKJ-2 at 67.
[76] Guidehouse and Synapse Energy Economics, *Massachusetts Energy Efficiency and Demand Response Potential Study for 2025-2027* at 28 (2024), https://ma-eeac.org/wp-content/uploads/2024-02-28-2025-2027-MA-PS-Final-Report-wAppx-Unitil.pdf; Guidehouse, *2023 Energy Efficiency Potential and Goals Study* a 12 and 35 (2023), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2023-potential-goals-study/final-2023-group-e-pg-study-report.pdf.

Q. PLEASE EXPLAIN HOW THE NPA POTENTIAL STUDY TREATED THE BENEFITS OF AVOIDED AIR POLLUTION.

A. The PA Team did not quantify the benefits of avoided air pollution associated with natural gas heating systems and categorizes this benefit as INQ which means "Included, Not Quantified."[77] This designation indicates that the PA Team included this benefit qualitatively but did not quantify the benefits "because the impact is de minimis or there is lack of defensible methods for quantification."[78] However, this benefit can be estimated using publicly available tools such as U.S. Environmental Protection Agency's CO-Benefits Risk Assessment ("COBRA") tool.[79] Further, many studies have found that the health and environmental benefits from avoided air pollution are substantial.

Q. CAN YOU DESCRIBE THE COBRA TOOL?

A. The COBRA tool is a screening-level model that estimates the health and economic benefits of reducing emissions of key outdoor air pollutants, such as fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). COBRA models how changes in these emissions affect ambient air quality and quantifies the resulting impacts on public health, including premature deaths, asthma attacks, hospital visits, and lost workdays. The tool then assigns economic values to these health outcomes to estimate the total societal benefits of pollution reduction measures. COBRA is particularly useful for evaluating the co-benefits of clean energy policies, such as heating electrification, by

[77] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 175:15-16.
[78] *Id.*
[79] EPA, *CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)*, https://cobra.epa.gov/.

allowing users to compare scenarios and visualize impacts at the county level across the United States.

Q. ARE YOU AWARE OF ANY STUDIES THAT QUANTIFY THE AVOIDED AIR POLLUTION RESULTING FROM THE ELECTRIFICATION OF GAS HEATING? IF SO, PLEASE DESCRIBE SUCH STUDIES.

A. Rewiring America's 2024 report *Breathe Easy* quantifies the significant health and economic benefits of electrifying U.S. households by replacing fossil-fuel-based appliances with efficient electric alternatives such as heat pumps.[80] The study estimates that heating electrification could prevent approximately 3,400 premature deaths, 1,300 hospital admissions, 220,000 asthma attacks, and 670,000 missed workdays each year—amounting to an estimated $40 billion in annual health-related savings.[81] It also projects an annual reduction of more than 300,000 tons of $PM_{2.5}$ and its precursors, equivalent to removing 40 million gasoline-powered cars from the road.[82]

Notably, the report finds that replacing a gas furnace with a heat pump yields an average annual health benefit of $367 per household, primarily due to reduced emissions of $PM_{2.5}$ and its precursors (e.g., nitrogen oxides).[83] These findings highlight electrification as not only a climate solution but also a powerful strategy to improve public health and household economics.

[80] Rewiring America, *Breathe Easy - Household electrification as a public health intervention to improve outdoor air quality* at 2 (2024), https://a-us.storyblok.com/f/1021068/x/3c121cf7ec/breathe-easy-health-benefits-from-electrification.pdf.
[81] *Id.*
[82] *Id.*
[83] *Id.* at 12.

To estimate these benefits, the study used the COBRA tool to quantify outcomes such as asthma cases and lost workdays, and employed an open-source air quality model, the Intervention Model for Air Pollution ("InMAP") to simulate changes in ambient $PM_{2.5}$ concentrations resulting from residential electrification.

Q. PLEASE EXPLAIN HOW THE NPA POTENTIAL STUDY ASSESSED THE BENEFITS OF AVOIDED METHANE LEAKAGE AND HOW THE STUDY CAN IMPROVE ITS METHODOLOGY?

A. The PA Team quantified the benefits of avoided methane leakage by estimating the reduction in gas throughput from implementing NPA measures. The potential study assumed a leakage rate of 2.2 percent and quantified the avoided costs of the leakage using the social cost of methane from the federal Interagency Working Group ("IWG")'s Technical Support Document on the Social Cost of Greenhouse Gases.[84] Notably, Public Service states that IWG's analysis assumes a 100-year global warming potential for methane.[85]

However, this 100-year timeframe is not appropriate from a climate policy perspective. Most local and state greenhouse gas emissions reduction targets—including Colorado's goal of net-zero emissions by 2050—fall within a much shorter planning horizon. Moreover, the warming impact of methane over shorter timeframes is significantly greater. According to the Intergovernmental Panel on Climate Change, methane's global warming potential over a 20-year timeframe is approximately 80, compared to 30 over a

[84] Hearing Exhibit 102, Attachment GKJ-7 at 20-21.
[85] Hearing Exhibit 601, Attachment KT-16, Discovery Response MCC2-44(b) (May 5, 2025).

100-year timeframe.[86] As a result, using the more relevant 20-year global warming potential would increase the estimated benefits of avoided methane leakage by more than 2.5 times.

Q. WHAT IS THE IMPLICATION OF INCORPORATING THESE MISSED OR UNDERREPRESENTED SOCIAL BENEFITS ON NPA POTENTIAL ESTIMATES?

A. Incorporating the full benefits of avoided air pollution and methane leakage would increase the value of all NPA measures—but value would increase significantly more for heating electrification than for new efficient gas heating equipment. As noted in the Overview section, the Company ultimately examined two hybrid portfolios and selected Hybrid Portfolio (2) over Hybrid Portfolio (1), citing greater cost-effectiveness. However, Hybrid Portfolio (1) includes roughly twice as many NPA measures and a higher share of electrification. Therefore, accounting for the omitted social benefits would enhance the overall benefits of Hybrid Portfolio (1) more than Hybrid Portfolio (2).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PA TEAM'S ESTIMATE?

A. I recommend that Public Service and the PA Team quantify and incorporate the avoided costs of reduced air pollution associated with NPA measures. I also recommend revising the assumed global warming potential of methane by using a 20-year timeframe instead

[86] Intergovernmental Panel on Climate Change (IPCC), *Climate Change 2021: The Physical Science Basis*, Chapter 7: The Earth's Energy Budget, Climate Feedbacks and Climate Sensitivity at Table 7.15 (2021), https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter07.pdf.

of a 100-year timeframe and recalculating the benefits of avoided methane emissions from NPA measures accordingly

C. Achievable Potential

Q. PLEASE DESCRIBE HOW THE PA TEAM ESTIMATED THE NPA ACHIEVABLE POTENTIAL.

A. The achievable potential is a subset of the economic potential that considers expected customer adoption of measures, market barriers, and budget caps. The PA team developed an adoption curve for each measure based on a customer survey and estimated achievable potential estimates. Adoption curves show anticipated customer adoption starting at the current market penetration of a technology and ultimately reaching the percentage of customers who said they would adopt the technology if the incremental cost were $0.[87] Adoption projections for each measure assume customers receive 100 percent incentives. As noted in the Overview section, the PA team and the Company used the achievable potential estimates to develop two NPA portfolios. Based on the results of these portfolios, they then developed the Hybrid 1 and Hybrid 2 portfolios and Implementation Plan.

Q. WHAT ARE YOUR CONCERNS ABOUT THE COMPANY'S ACHIEVABLE POTENTIAL METHODOLOGY?

A. I am concerned that the Company overestimated projections for new gas heating systems. In fact, the projection is substantially higher than the number of new gas heating systems

[87] Hearing Exhibit 601, Attachment KT-17, Discovery Response SC2-1(b) (May 22, 2025).

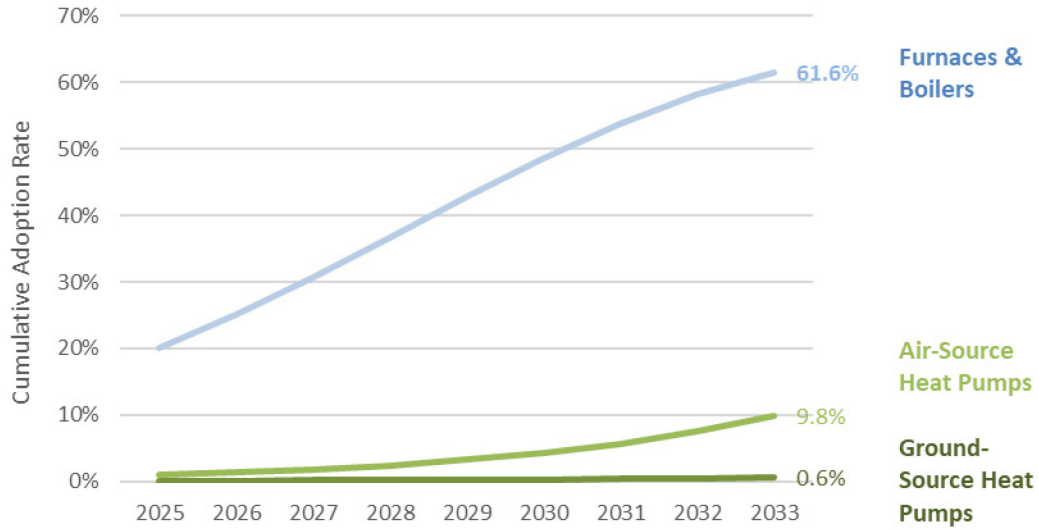
recently installed in the Eastern Mountain region under the Company's DSM/BE program.

I am also concerned that the Company's projections for building envelope measures are overly conservative in its achievable potential estimates. The projected adoption rates—particularly for attic insulation and air sealing—are lower than the levels historically achieved in the Eastern Mountain Gas System. With enhanced rebates and a more comprehensive program support structure, the Company could achieve significantly higher adoption of these measures.

Q. WHAT ADOPTION RATES DID THE COMPANY ASSUME FOR HEAT PUMPS AND GAS MEASURES IN THE ACHIEVABLE POTENTIAL STUDY?

A. The Company assumed a much higher adoption rate for furnaces and boilers than for air-source and ground-source heat pumps. As shown in Figure 7 below, PSCo projected a 61.6 percent cumulative adoption rate for furnaces and boilers by 2033, but only a 9.8 percent adoption rate for air-source heat pumps, and less than a 1 percent adoption rate for ground-source heat pumps.

Figure 7. PSCo cumulative measure adoption curve



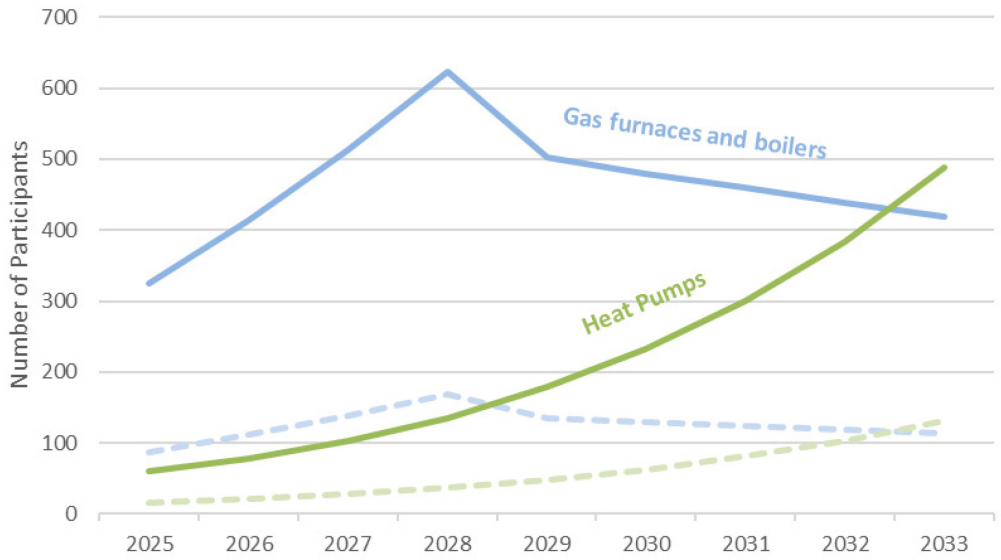
Source: Hearing Exhibit 601, Attachment KT-18, Discovery Response Attachment SC2-1.A1_FINAL (May 22, 2025).

Q. WHAT ARE THE ANNUAL PROJECTED INSTALLATIONS OF HEAT PUMPS AND GAS HEATING SYSTEMS IN THE ACHIEVABLE POTENTIAL ANALYSIS?

A. Reflecting the adoption rates discussed above, PSCo's achievable potential study projects greater deployment of gas space heating systems —including furnaces and boilers—than of electric heat pumps (including air-source and ground-source heat pumps, heat pump water heaters, and whole building electrification). Figure 8 shows the projected annual measure counts for the entire Eastern Mountain Gas System and for Breckenridge. Between 2025 and 2033, the achievable potential projects the cumulative adoption of nearly 4,200 furnaces and boilers cumulatively throughout the Eastern Mountain Gas System, including 1,100 in Breckenridge. In contrast, it projects the adoption of about

2,000 heat pumps cumulatively throughout the region, with roughly 500 in Breckenridge.[88]

Figure 8. Annual measure adoption assumptions for residential customers in the Eastern Mountain Gas System and Breckenridge



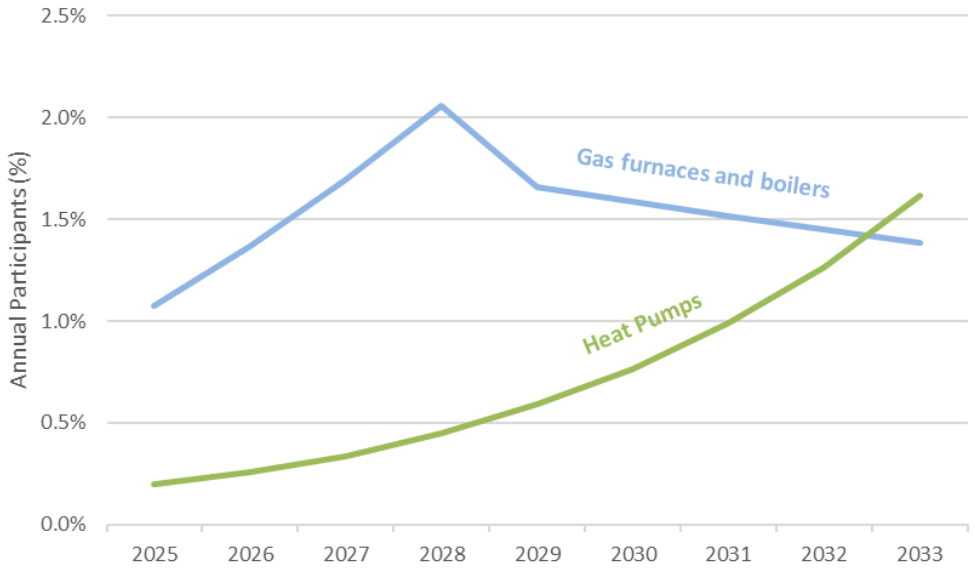
Note: Dotted lines reflect values for Breckenridge.
Source: Hearing Exhibit 601, Attachment KT-19, Discovery Response Attachment MCC2-12.A1 (May 9, 2025).

I converted these annual measure adoption counts to annual adoption rates as a percentage of the total residential customers in the Eastern Mountain Gas System (Figure 9 below).[89] Heat pump adoption rates remain below 0.5 percent until 2029, and ultimately reach 1.6 percent of residential customers in 2033. Gas furnace and boiler

[88] Hearing Exhibit 601, Attachment KT-19, Discovery Response Attachment MCC2-12.A1 (May 9, 2025).
[89] Based on the customer counts provided in Hearing Exhibit 102, Attachment GKJ-2 at Table 4-3.

adoption rates are 4 to 5 times as large as heat pump adoption rates for the first four years of the MEP, and then eventually approach a 1:1 ratio.

Figure 9. PSCo annual residential adoption rate in the Eastern Mountain Gas System



Source: Hearing Exhibit 601, Attachment KT-19, Discovery Response Attachment MCC2-12.A1 (May 9, 2025); Hearing Exhibit 102, Attachment GKJ-2at 21-22.

Q. HOW DO THESE ADOPTION RATES COMPARE WITH HISTORICAL MEASURE UPTAKES IN THE EASTERN MOUNTAIN GAS SYSTEM?

A. Public Service has provided historical participation data for heat pumps, building envelope measures, and gas heating systems.[90] Table 6 below compares these historical participation counts with the Company's projected levels. While the projected adoption of heat pumps increases more than fourfold from 2024 to 2028, this growth appears directionally appropriate given recent policy momentum and market trends. However, the

[90] Hearing Exhibit 601, Attachment KT-20, Discovery Response MCC8-4 (June 2, 2025).

projections for new gas heating systems are substantially overstated. The Company forecasts a jump from 69 installations in 2024 to 325 in 2025—more than triple the actual installation counts in the previous year—and a continued increase to 623 by 2028, nearly a tenfold rise from 2024 levels. This trajectory is difficult to reconcile with regional decarbonization goals and historical participation trends. Additionally, the projected participation for building envelope measures in the early years—66 in 2025 and 84 in 2026—falls below the historical counts achieved in 2022 (98) and 2024 (100). This indicates that the Company is underestimating the achievable potential for these cost-effective efficiency measures.

Table 6. Historical and projected NPA measure participation counts by measure

	Historical			Projection - Achievable Potential			
	2022	2023	2024	2025	2026	2027	2028
Gas heating systems	36	59	69	325	413	514	623
Heat pumps	6	11	32	61	78	102	136
Envelope measures	98	77	100	66	84	105	132

Source: Hearing Exhibit 601, Attachment KT-20, Attachment MCC8-4 (June 2, 2025); Hearing Exhibit 601, Attachment KT-19, Attachment MCC2-12.A1 (May 9, 202)

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ACHIEVABLE POTENTIAL ESTIMATE?

A. I recommend the PA Team and the Company revise the achievable potential estimates by (a) updating their overly conservative assumptions for envelope measure adoption to better reflect historical participation levels and the higher adoption rates achievable through comprehensive program strategies and enhanced incentives, and (b) reducing the

projected adoption rates for gas heating systems to align more closely with historical participation levels and regional decarbonization goals.

VI. EVALUATION OF HYBRID PORTFOLIOS

Q. WHAT WAS PSCO'S APPROACH TO MEETING ITS FULL ESTIMATED SUPPLY SHORTFALL?

A. As I indicated in the Overview section, PSCo's modeling indicated that its demand-side measures could not scale to the full size of the supply shortfall it identified in the Keystone and Breckenridge locations within the timeframe of the analysis. It then identified distributed supply solutions, using LNG and CNG, which could fill the remaining gap. Combining demand-side with supply-side solution results in what PSCo refers to as "hybrid" portfolios. As discussed above, PSCo developed two hybrid portfolios: one that maximized use of demand-side resources (Hybrid Portfolio 1), and one that maximized use of supply-side resources (Hybrid Portfolio 2). I will refer to approaches that start with demand-side resources and only add supply-side resources as needed as "demand-led" approaches, and approaches that start with supply-side resources and only add demand-side resources as needed as "supply-led" approaches. Hybrid Portfolio 1 uses a demand-led approach and Hybrid Portfolio 2 uses a supply-led approach.

Q. WHAT APPROACH DOES PSCO RECOMMEND AND REQUEST THAT THE COMMISSION APPROVE?

A. PSCo recommends Hybrid Portfolio 2, which would be a supply-led solution, and requests that the Commission approve implementation steps for that portfolio.

Q. WHAT ADVANTAGES DOES A DEMAND-LED APPROACH HAVE OVER A SUPPLY-LED APPROACH?

A. I highlight three notable advantages:

- A demand-led approach is consistent with and amplifies the policy direction for decarbonization through electrification that has been adapted and espoused by the State of Colorado and by the MCC and Denver.
- Costs incurred to meet electrification policy objectives also help a demand-led NPA be successful, reducing the net cost of the NPA.
- A demand-led approach creates flexibility and optionality value for supply-side resources, which can be repurposed as demand-side solutions reduce the need for their use.

Q. WHAT ADVANTAGES DOES A SUPPLY-LED APPROACH HAVE OVER A DEMAND-LED APPROACH?

A. I highlight two advantages:

- A supply-led approach can be less expensive over the analysis period, depending on how the costs are calculated and which costs are included.
- Supply-side resources can be more assured to be successfully deployed by a date certain.

Q. COULD YOU ELABORATE FURTHER ON THE ADVANTAGES OF A DEMAND-LED APPROACH FOR POLICY CONSISTENCY AND AMPLIFICATION?

A. Colorado and MCC jurisdictions directly impacted by this project have policies for decarbonization through electrification or other measures. I detailed these policies earlier in my testimony. A demand-led approach to meeting the capacity gap (particularly when it emphasizes full electrification measures) would align program designs and messages for customers across the Company's various programs (that is beneficial electrification, clean heat, and NPA programs). Installing gas supply assets in communities committed to electrification, and proposing to use them for 20 years with no plans to ramp down or transition away for their use, would send a message that the utility's (and regulators') commitment to achieving state and local policy goals is weaker than would be sent by a demand-led approach.

Q. COULD YOU ELABORATE ON THE ADVANTAGES OF A DEMAND-LED APPROACH FOR REDUCING NET COSTS OF POLICY AND NPA OBJECTIVES?

A. When a given action, such as home electrification, achieves both NPA and policy objectives, this is an efficient use of capital. Colorado is committed to reducing emissions cost-effectively through electrification, so most or all customers who electrify as part of the NPA would also be contributing to meeting state policy goals. Focusing clean heat and beneficial electrification efforts in a geographic area that also delivers NPA savings is an efficient use of ratepayer funds. The net cost of the demand-led NPA is lower than it would be if these actions were additional to what would happen anyway. A supply-led

approach with less electrification fails to capture this synergistic value while paying full cost for supply-side resources. Gas efficiency measures may have a role in a demand-led approach, but these costs are likely to be incremental while electrification costs may not be.

Q. COULD YOU ELABORATE ON THE ADVANTAGES OF A DEMAND-LED APPROACH RESULTING FROM FLEXIBILITY OF SUPPLY-SIDE RESOURCES?

A. PSCo is proposing to use modular equipment for LNG and CNG supply in Breckenridge and Keystone. Company witnesses Jones and Roberts each testify that this modular nature allows the assets to be redeployed in other locations or sold when they are no longer needed.[91] This flexibility only provides value to the Company's gas system and ratepayers in the event that the net capacity supply gap (after accounting for demand-side measures) falls over time. A supply-led approach which limits demand-side actions to the minimum required and keeps supplemental supply fully utilized does not provide this benefit.

[91] *See* Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 88 ("if the supplemental supply shortfall is mitigated such that the facility can be downsized, the supplemental supply equipment can be utilized somewhere else on the Company's bulk natural gas system or sold off to interested buyers"); Hearing Exhibit 105, Direct Testimony of Laura L Roberts at 27 ("If the supply shortfall in Breckenridge is mitigated such that the proposed operating LNG equipment is no longer needed, it can be mobilized and relocated on a temporary basis to provide capacity support for planned project work, winter mitigation strategies at other locations, or other emergency situations.") and at 59 ("If the supply shortfall in Keystone is mitigated such that the proposed operating CNG equipment is no longer needed, it can be mobilized and relocated on a temporary basis to provide capacity support for planned project work, winter mitigation strategies at other locations, or other emergency situations").

Q. COULD YOU ELABORATE ON THE ADVANTAGES OF A SUPPLY-LED APPROACH WITH RESPECT TO OVERALL COST?

A. The Company's comparison of the costs of Hybrid Portfolio 1 (demand-led) and Hybrid Portfolio 2 (supply-led) shows the supply-led option with lower cost. This indicates that a supply-led approach can be lower cost, using the cost methodology and the cost categories chosen by the Company. This result will not be universally true and may depend on what costs are included in the calculation (such as how electrification costs are included, given that they may be required in any case to meet policy objectives).

Q. COULD YOU ELABORATE ON THE ADVANTAGES OF A SUPPLY-LED APPROACH WITH RESPECT TO CERTAINTY AND SPEED?

A. Demand-led approaches depend on customers participating in programs to adopt new equipment in their buildings. While there is extensive history supporting the achievability of this resource, it does depend on unregulated actors and market conditions in a way that supply-led solutions do not. Supply-led solutions can also address the full required gap at once, without waiting for customer uptake. This can be particularly important in a situation such as in Breckenridge and Keystone (assuming the Company's own design day criteria, which I earlier explained is inappropriate), where the utility's analysis indicates that it allowed a substantial capacity gap to develop before acting to address the gap.

Q. IS THERE ANY PARTICULAR DISADVANTAGE OF HYBRID PORTFOLIO 2 THAT INFORMS YOUR THINKING REGARDING THE RIGHT PATH FORWARD?

A. Yes. Hybrid Portfolio (2) as described by the Company is a pure supply-led NPA in that demand-side measures are only used to keep gas peak demand flat at the level that can be met with supply-side measures. The Company would depreciate CNG and LNG assets over an expected useful life of 20 years.[92] The Company has not evaluated the need for or use of these assets after the end of its 10-year planning horizon for Hybrid Portfolio (2).[93] As Hybrid Portfolio (1) shows, it could take more than 10 years to reduce demand to a level that enables retirement of the supplemental assets —based on the Company's design day criteria, and potentially a shorter period if adjusted for lower demand assumptions. By contrast, Hybrid Portfolio (2), which limits demand-side intervention to lower peak demand would risk creating a situation in which its ratepayers find themselves in 20 years faced with a remaining capacity gap that can only be met by replacing or extending the life of the supply-side assets. This would be shortsighted.

Q. WHAT DO YOU RECOMMEND THE COMPANY DO, IN LIGHT OF YOUR ANALYSIS OF THE ADVANTAGES AND DISADVANTAGES OF DEMAND-LED AND SUPPLY-LED APPROACHES, AND YOUR CONCERNS ABOUT THE SIZE OF THE CAPACITY GAP?

A. I recommend that the Company revise its analysis and submit a revised proposal that draws on the best of demand-led and supply-led approaches and incorporates a revised

[92] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 131:18-20.
[93] Hearing Exhibit 601, Attachment KT-21, Discovery Response MCC2-28 (May 5, 2025).

supply gap based on my earlier testimony. In the event that the Company does not do this as part of its analysis in this docket, I recommend the Commission require it to conduct such analysis prior to approving any expenditure or cost recovery on the Mountain Energy Project. Specifically, as discussed above, I recommend the following steps:

a) Develop a revised peak hour forecast that reflects a lower peak hour demand corresponding to a more detailed evaluation of building gas demand during peak conditions. As detailed earlier in my testimony, for example, a 9 percent reduction in peak demand resulting from better accounting for gas heating system capacity would result in a reduction in the supply gap in the Eastern Mountain Gas System by more than a factor of two.
b) Incorporate the expected baseline impact of state, utility, and local policies and programs into the projection of peak gas demand, and thus the size and trajectory of the capacity gaps. This includes impact of building codes and new construction market shifts toward all-electric construction that limit gas demand growth. Further, impact from potential targeting of these programs to the highest-impact areas for NPA performance should be incorporated here or at the NPA design stage, while ensuring that all program impacts are counted once and only once.
c) Incorporate into available capacity the potential for additional gas supply at the Marshall Compressor Station, due to reductions in gas demand in the Denver and Northern Gas System area resulting from policy in those areas. PSCo should also include additional actions in those areas among the potential NPA measures.
d) Develop an NPA portfolio to meet the remaining capacity gap(s) that balances demand-side and supply-side options, with the goal of minimizing overall project cost (incremental to costs incurred to meet policy objectives), while accounting for the need to avoid a supply gap at the end of the useful life of the supplemental supply-side assets. This may include deploying the supplemental supply for a shorter period of time, reducing the amount of supplemental supply needed, and/or include using CNG in Breckenridge instead of LNG, among other

outcomes. If the required capacity is smaller, the supplemental supply may be needed for less time, which may shift the appropriate balance between utility ownership and leasing of the supplemental supply facilities and infrastructure. Conduct cost evaluation including the cost of capital and taxes paid by the Company for capital investments. Use utilization-based depreciation to ensure that the supply assets are fully depreciated by the time they are no longer needed, and depreciation costs fall as the assets are needed less over time. (The Company should be responsible for any remaining undepreciated value at the time the assets are no longer used and useful.) If supplemental supply assets can be repositioned from the project for use in other projects, include an estimate of the value of that flexibility in portfolio evaluation.

I recognize that conducting revised analysis of this sort may require additional time in this proceeding, which may put implementation of a final plan by next winter at risk. If full evaluation of NPA design and supplemental capacity needs will take time past critical decision-points for the winter of 2025–26, the Company should minimize capital expenditure for that winter and maintain optionality for the final NPA portfolio. It should, however, pursue no-regrets actions such as beneficial electrification and clean heat programs targeted to the Eastern Mountain system while evaluation of the size and type of supplemental supply resources continues.

VII. REVIEW OF NPA COST RECOVERY MECHANISM

Q. HOW HAS THE COMPANY PROPOSED TO RECOVER THE COST OF THE PROPOSED MOUNTAIN ENERGY PROJECT?

A. PSCo is proposing to recover the 2025–2027 NPA Portfolio costs of the Mountain Energy Project through the electric and gas DSM cost adjustment riders ("DSMCA-E"

and "DSMCA-G").[94] The Company is proposing to recover LNG and CNG costs primarily through base rates, and electric infrastructure costs through GMAC.[95] The Company proposes to fund this project through another existing funding pool called Vertical 2 for the Clean Heat Plan and is requesting to convert leftover budget from the Clean Heat Plan's Vertical 1 funding pool into Vertical 2 for this purpose.[96] The Company is requesting to apply the amortization and weighted average cost of capital previously approved for Vertical 2 budgets.[97]

Q. HAS THE COMPANY PROPOSED TO RECOVER THE COST OF THE PROJECT ONLY FROM RATEPAYERS IN THE EASTERN MOUNTAIN GAS SYSTEM?

A. No. By recovering costs through the DSMCA-E and DSMCA-G riders, the Clean Heat Plan's cost recovery mechanism, and base rates, these costs will be recovered from all ratepayers implicated by each method.

Q. DO YOU THINK THE COMPANY'S PROPOSED APPROACH IS REASONABLE?

A. Yes, for the following reasons:

a) The Eastern, Western, Southern, and Northern Gas Systems are all interconnected, and therefore the supply constraint in the Eastern Mountain Gas System is impacted by the demand in other regions, particularly Denver and the Northern Gas System.[98]

[94] Hearing Exhibit 101, Direct Testimony of Ryan A. Matley at 6-7.
[95] Hearing Exhibit 101, Direct Testimony of Ryan A. Matley at 39.
[96] Hearing Exhibit 101, Direct Testimony of Ryan A. Matley at 42-43.
[97] *Id.*
[98] Hearing Exhibit 102, Direct Testimony of Grace K. Jones at 34:11–35:3.

Since all the regions are interconnected, and demand on each section has implications for the others, it is reasonable that the cost of the Mountain Energy Project be recovered by all ratepayers. Moreover, the potential avoided gas system costs of implementing the Mountain Energy Project (i.e. pipeline reinforcement) benefit all ratepayers.

b) Reduced gas demand and greenhouse gas emissions in the Eastern Mountain Gas System will contribute to achieving the Company's and the state's clean heat and decarbonization goals—the benefits of which accrue to all ratepayers and residents of Colorado.

c) The lessons learned from implementing the Mountain Energy Plan will benefit other regions in PSCo's service territory by reducing the amount of time for planning, development, and implementation for future NPA projects. The lessons learned from this project will reduce costs for future decarbonization and NPA projects in other areas of PSCo's territory.

VIII. REVIEW OF NPA PROGRAM IMPLEMENTATION PLAN

Q. PLEASE DESCRIBE THE ROLE OF THE IMPLEMENTATION PLAN WITHIN THE MOUNTAIN ENERGY PROJECT.

A. The NPA Implementation Plan describes the Company's plans for implementing NPA measures across the Eastern Mountain Gas System in line with the Hybrid 2 portfolio for 2025 through 2027. The Implementation Plan provides information about the Company's budget allocation, expected gas savings, and forecasted participation for each of the proposed measures, as well as program outreach strategies.[99]

[99] Hearing Exhibit 103, Attachment KRK-2 at 4.

Q. HOW MUCH IS THE COMPANY BUDGETING FOR ELECTRIC AND GAS NPA MEASURES?

A. The Company is proposing a $21.5 million budget for residential and commercial NPA implementation, including incentive costs and administrative/marketing costs (Table 7). Gas measures account for 35 percent of the proposed budget (including 3 percent for demand response), beneficial electrification accounts for 47 percent, and the remaining 17 percent of the budget is for marketing and administrative costs. The Company projects that this portfolio will result in approximately 154,000 mscf of annual gas savings for residential and commercial customers between 2025 and 2027. Of these savings, 32 percent are expected to come from gas equipment measures (such as high-efficiency furnaces and boilers), while 33 percent are attributed to beneficial electrification.[100]

[100] Hearing Exhibit 601, Attachment KT-22, Discovery Response MCC3-9 (May 9, 2025).

Table 7. NPA Implementation Plan proposed budget 2025–2027

Measure Type		2025	2026	2027	Total
Gas	Energy efficiency – non-equipment	$629,764	$710,549	$865,585	$2,205,898
	Energy efficiency – home energy reports	$20,788	$21,230	$21,648	$63,666
	Energy efficiency – equipment	$1,239,636	$1,586,831	$1,992,868	$4,819,335
	Demand response	$36,950	$269,590	$417,240	$723,780
	Subtotal	$1,927,138	$2,588,200	$3,297,341	$7,812,679
Electric	Beneficial electrification	$2,567,932	$3,315,363	$4,277,369	$10,160,664
	Subtotal	$2,567,932	$3,315,363	$4,277,369	$10,160,664
Both	Marketing and administration	$1,078,401	$1,258,134	$1,258,134	$3,594,669
Both	**Total**	$5,575,496	$7,163,723	$8,834,871	$21,574,090

Source: Hearing Exhibit 103, Attachment KRK-2; Hearing Exhibit 601, Attachment KT-23, Discovery Response MCC3-2(a) (May 9, 2025); Hearing Exhibit 601, Attachment KT-24, Discovery Response MCC3-4(a) (May 9, 2025).

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S NPA PROGRAM IMPLEMENTATION PLAN?

A. Yes. I have three main concerns with NPA Implementation Plan. First, PSCo's budget for gas measures ('Energy Efficiency – Equipment') is overly generous. Providing incentives for gas equipment locks customers into the gas system for another 20 years, or the lifetime of the equipment. This does not align with state and local decarbonization goals, which prioritize transitioning away from fossil fuel heating to electric alternatives.

Second, the Implementation Plan omits cost-effective, low-cost measures such as low-flow showerheads and water heater tank and pipe insulation, as these were excluded from the NPA potential estimate. As discussed in the NPA technical potential section, these measures are easy to install, often highly cost-effective, and can be deployed during

home energy audits at little-to-no cost. They help reduce natural gas use and lower customer gas bills, while also enhancing the overall cost-effectiveness of the NPA portfolio. Given these benefits, the Company should include such measures in the NPA program implementation plan for the Mountain Energy Project.

Third, the Implementation Plan does not include a plan for measurement and verification of program activities to evaluate implementation success.[101] This is problematic, especially for a first-of-its-kind NPA project like this one, because the Company will have no way of understanding the level of demand reductions resulting from specific measures, barriers to customer participation, cost-effectiveness, and other important metrics. It is important for the Company to have a robust measurement and verification plan to evaluate the success of each measure type and inform future iterations of the Implementation Plan.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S NPA IMPLEMENTATION PLAN?

A. I have the following recommendations on the NPA Implementation Plan:

- PSCo should prioritize incentives for electrification and building envelope measures over new gas equipment. This can be achieved by reallocating some or all of its Energy Efficiency – Equipment budget (currently supporting gas equipment) to the Beneficial Electrification funding pool.

[101] Hearing Exhibit 601, Attachments KT-25, Discovery Response MCC3-7(a) (May 9, 2025).

- The Implementation Plan should include cost-effective, low-cost measures such as low-flow showerheads, hot water tank insulation and hot water pipe insulation.
- PSCo should develop a detailed measurement and verification plan to assess annual progress at the measure level. The Company should use this plan to inform future measure offerings and guide budget decisions for the next Implementation Plan.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations regarding the Company's analysis and proposal are as follows:

1. **Revise Peak Load Forecasts**: Update the Company's peak load forecasts by:

   a) Using more appropriate design day temperatures—such as -13°F from MCC jurisdiction's building codes—that reflect realistic HVAC system sizing practices and performance limitations during extreme cold conditions.

   b) Incorporating the impacts of state and local decarbonization policies and programs, including the full effects of PSCo's Clean Heat Plan and DSM/BE Plan, across all relevant service territories.

   c) Examining and accounting for gas usage patterns of buildings with snowmelt systems, which should reflect a more gradual increase in demand during extremely cold temperatures than in moderate temperatures, rather than assuming a continued linear relationship in those conditions.

2. **Reassess Upstream Supply Constraints**: Re-evaluate the assumed gas availability at the Marshall Compressor Station by accounting for potential upstream demand reductions in Denver and the Northern Gas System. This reassessment should fully reflect the impact of local and state decarbonization policies as well as more accurate design temperature assumptions and HVAC sizing practices in those regions. It should also reflect regional variation in weather conditions across the Company's gas systems, by using historical temperature data to estimate more realistic coincident peak hour loads, rather than assuming perfectly synchronized peak demand across all regions.

3. **Improve the NPA Potential Study**:

   a) Expand the geographic scope to include gas savings potential in Denver and the Northern Gas Systems.

   b) Incorporate several excluded technologies, in particular networked geothermal systems, building codes support, heat recovery ventilators/energy recovery ventilators, air-to-water heat pumps, as well as cost-effective, low-cost measures such as low-flow shower heads, and hot water tank and pipe insulation.

   c) Incorporate the full societal benefits of avoided air pollution and methane emissions.

d) Revise overly conservative assumptions about envelope measure adoption rates and overly inflated gas heating adoption rates

e) Reassess the achievable potential estimates by making all the adjustments discussed above.

3. **Develop a Balanced NPA Portfolio prioritizing no-regrets actions**:

a) Create a revised hybrid solution that prioritizes demand-side measures, minimizes long-term reliance on LNG and CNG and ensures timely depreciation of supply-side assets to avoid future stranded costs.

b) Pursue no-regrets actions such as beneficial electrification and clean heat programs targeted to the Eastern Mountain system while evaluation of the size and type of supplemental supply resources continues.

4. **Support Equitable Cost Recovery**: Continue with a system-wide cost recovery approach, given the integrated nature of PSCo's gas systems and the broad benefits of the Mountain Energy Project for ratepayers across the state.

5. **Enhance NPA Implementation Planning**:

a) Prioritize electrification and envelope measures over new gas equipment, as such equipment could lock in long-term fossil fuel use.

b) Include cost-effective, low-cost measures such as low-flow showerheads and hot water tank insulation and pipe insulation.

c) Develop a detailed measurement and verification plan to assess annual progress at the measure level to inform future measure offerings and guide budget decisions for the next Implementation Plan.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.