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CHRIS BURDIN
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0314
IDAHO BAR NO. 9810

Street Address for Express Mail:
11331 W CHINDEN BLVD, BLDG8, SUITE 201-A
BOISE, IDAHO 83714

Attorney for the Commission Staff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF INTERMOUNTAIN GAS COMPANY'S 2023 INTEGRATED RESOURCE PLAN	**CASE NO. INT-G-23-07** **COMMENTS OF THE COMMISSION STAFF**

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission, by and through its Attorney of record, Chris Burdin, Deputy Attorney General, submits the following comments.

BACKGROUND

On December 28, 2023, Intermountain Gas Company ("Company") filed its 2023 Integrated Resource Plan ("2023 IRP") with the Idaho Public Utilities Commission ("Commission"). The Company requests that the Commission issue an order acknowledging the Company's 2023 IRP. The Company files an IRP every two years to describe its plans to meet its customers' future natural gas needs. The IRP must discuss the subjects required by several Commission Orders[1] and Section 303(b)(3) of the Public Utility Regulatory Policies Act

[1] *See* Order Nos. 25342, 27024, 27098, 32855, 33314 and 33997.

("PURPA"), 15 U.S.C. § 3202. The Commission reviews the IRP to ensure that it discusses these subjects and represents a diligent effort by the Company to plan for the anticipated supply and demand for natural gas.

The 2023-2028 IRP

In the 2023-2028 IRP, the Company explains that it regularly forecasts demand of its growing customer base and determines how to best meet the load requirements brought on by this demand. 2023 IRP at 2-3. The Company's IRP represents a snapshot in time of the Company's ongoing planning process; it describes the anticipated conditions over a five-year planning horizon, the anticipated resource selections, and the process for making resource decisions. *Id*. at 1.

The Company sells natural gas to two major markets: the residential/commercial market and the large volume market. *Id.* at 2. In 2020, roughly 50% of throughput on the Company's system was related to large volume sales and transportation. *Id.* Currently, the Company serves approximately 412,500 customers. *Id.* at 1.

The Company calculated peak-day delivery under base, low growth, and high growth scenarios against current available natural gas delivery system capacity to project the magnitude and timing of delivery deficits on a regional and a total Company perspective.

STAFF ANALYSIS

Staff examined the Company's 2023 IRP to determine whether it meets the Commission requirements and orders, and adequately plans its future resources to meet demand from 2023 through 2028. Staff believes that the Company's 2023 IRP satisfies Commission requirements and is reasonable. Staff recommends the Commission:

1. Acknowledge the Company's 2023 IRP;
2. Order the Company to work with Staff to implement IRP reporting that includes system enhancement information in future IRPs, within six months of a Commission order;
3. Order the Company to work with Staff to develop reports to the Commission of capacity enhancement projects that include in-service dates and project costs, within six months of a Commission order; and

4. Establish the practice of authorizing the Company's Demand Side Management ("DSM") avoided costs as part of IRP filings and authorize the DSM avoided costs associated with this filing.

Demand Forecast

The Company's demand forecast is used to determine the timing and capacity of new plant additions. The demand forecast is an important driver of expenditures that will eventually be included in the Company's rates. Staff reviewed the Company's methodology for estimating future demand and believes it is adequate.

The Company's demand forecast is based on three separate components: 1) a prediction of the number of customers; 2) a forecast of weather sensitive customers' response to temperatures; and 3) an estimate of the weather customers may experience. *Id.* at 11. The Company also includes contracted maximum deliveries to industrial customers in its demand forecast.

The Company forecasted changes in its peak-day loads due to customer growth under its low, base case, and high growth economic scenarios. The Company forecasted total residential, commercial, and industrial peak-day loads to increase each year for five years by an average of 1.84% (low growth), 2.56% (base case), and 3.22% (high growth). *Id.* at 114.

The Company identified deficits on both a total system perspective and within its Areas of Interest ("AOI"). *Id.* at 5. For each potential deficit, timing and magnitude were identified. The Company evaluated and compared potential capacity improvement alternatives for each identified capacity deficit in its optimization model. The Company calculated and compared the NPV cost, the amount of capacity, and capacity gain for each potential capacity improvement, which are described in greater detail in the *Deficits and AOI Summaries* sections below.

Deficits and AOI Summaries

Over the 2023-2028 IRP planning period, the Company projected delivery capacity deficits within each AOI and within other areas of its territory: 1) Canyon County AOI, 2) State Street Lateral, 3) Central Ada County AOI, 4) Sun Valley Lateral, and 5) Idaho Falls Lateral. *Id.* at 98 – 110. In this IRP, the Company provided capacity analysis, identified when deficits will occur, and described enhancements to resolve identified deficits. Staff reviewed the Company's method for determining the design day, and the resulting peak-delivery requirements under various growth assumptions and believes the Company's analysis is reasonable.

For each of the five AOIs, Staff noted that there were differences between the year the Company said it needs a project and when the corresponding Load Demand Curve ("LDC") shows a capacity deficit. The Company clarified that projects must typically be started in a year that precedes the forecasted deficit year, because projects often take more than one year to complete. Response to Production Request No. 27. Therefore, the IRP often states that a project is needed in a year that precedes the actual deficit.

Staff commends the Company for the improvements it has made in this section of the IRP. As the information in this section is so foundational to subsequent capital prudence reviews, Staff encourages the Company to include additional information for capacity enhancements that are (1) budgeted to begin *after* the IRP, (2) status updates for *ongoing* capacity enhancements that are budgeted to start *during* the IRP year, and (3) the in-service date and final cost information for *completed* capacity enhancements between the previous IRP and the current one. Staff recommends that the Commission order the Company and Staff to work together to implement an IRP reporting methodology to include additional information on enhancement selections within future IRPs, within six months of a Commission order. Staff believes that this additional information will assist tracking capacity enhancements through future IRPs.

A summary of the capacity enhancements within each AOI included in the 2023 IRP and any of Staff's specific conclusions are provided below.

Canyon County Area

The Canyon County AOI serves core market customers in Canyon County. The LDC analysis shows an AOI deficit occurring in 2024. In the 2021 IRP, the Company considered three alternatives to meet growth predictions, and selected "Ustick Phase III". The Company stated that "Ustick Phase III was chosen in 2021 as <u>the largest capacity increasing alternative</u>." 2023 IRP at 100 (emphasis added).

To better understand the Company's justification for selecting the Ustick Phase III alternative, Staff asked the Company to provide its business case analysis. The Company explained that "Cost is a consideration in the alternative analysis but <u>is not the deciding factor</u>."

Response to Production Request No. 28 (emphasis added). Staff is concerned that this enhancement may not have been the least-cost least-risk alternative.

State Street Lateral

The State Street Lateral serves core market customers in the Star, Eagle, Meridian, and northwest Boise areas. The LDC analysis shows the first AOI deficit occurring in 2028. In the 2021 IRP, the Company considered two alternatives and selected the "State Street Phase II Uprate" as the lowest cost alternative. 2023 IRP at 102. The Company stated that it budgeted the State Street Phase II Uprate for 2024 at an estimated cost of $902,000. *Id.* at 103. Staff accepts the Company's assertion. However, for future IRPs, Staff requests that the Company present each alternative with updated costs to confirm the preferred alternative is still lowest cost.

The Company also clarified that the State Street Phase II Uprate project will require an additional project, the "State Penn Gate Uprate," and the Company explained why this project was the only alternative. The Company estimated the "State Penn Gate Uprate" project will cost $2,730,000 and targeted it for construction in 2026. *Id.* Staff accepts the Company's explanation of why no alternatives could be considered for this project.

Central Ada County

The Central Ada County AOI serves core market customers in Ada County between Chinden Boulevard and Victory Road, north to south, and east of Black Cat Road. The LDC analysis shows the first AOI deficit occurring in 2025, with the infrastructure chokepoint being the distribution piping immediately downstream from the Meridian Gate. In the 2021 IRP, the Company considered three alternatives, and selected the "12-inch South Boise Loop" project because it was "the lowest cost option with the most capacity gained." *Id*. at 104. The Company believes the project will eliminate any capacity deficit until beyond 2028.

The Company estimates the 12-inch South Boise Loop project will be online in fall of 2024 and its total cost will be $17,900,000. The project consists of three major sub-projects: The completed 12-inch Cloverdale project, the installed Kuna Gate project, and the almost completed Victory and Cloverdale Regulator project.

Staff appreciates the Company's update of this ongoing project and encourages the Company to document the final costs and in-service dates for the three sub-projects in the next IRP.

Sun Valley Lateral

The Sun Valley Lateral ("SVL") serves core market customers in Blaine and Lincoln counties. The SVL is a 68-mile long, 8-inch high-pressure pipeline, with a compressor station located near the city of Jerome, Idaho. Most of the demand on this lateral is furthest from its source. The LDC analysis shows the first AOI deficit occurring in 2024, with the infrastructure chokepoint having insufficient pressure at the north end of the line, in the Ketchum area. *Id*. at 106.

The Company considered alternatives in the 2019 IRP and again in the 2021 IRP, both times concluding that the Shoshone Compressor Station was the least-cost least-risk solution. The project was completed in time for the 2023-2024 winter season and its estimated cost was $6,700,000. The Company believes the project will eliminate any capacity deficit beyond 2028. Staff appreciates the Company's update of this ongoing project and encourages the Company to document the final cost and in-service date in the next IRP.

Idaho Falls Lateral

The Idaho Falls Lateral serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties. It originates south of Pocatello and extends north approximately 100 miles to Saint Anthony. The LDC analysis shows the first AOI deficit occurring in 2027, with the infrastructure chokepoint being at the end of the line at Saint Anthony.

The Company considered two alternatives in the 2021 IRP and chose the Blackfoot Compressor Station as the least-cost option while providing the largest capacity to the lateral. *Id*. at 108. The Company expects the project to come online in 2024, estimates its cost will be $20,000,000, and that the project will satisfy predicted growth through 2028. Staff appreciates the Company's update of this ongoing project and encourages the Company to document the final cost and in-service date in the next IRP.

Other AOI Capacity Projects

The Company described two gate upgrades needed to support core growth, but fall outside of the defined AOIs. The gates that serve Payette and New Plymouth are approaching their physical capacity limit, requiring the Company to enlarge the undersized piping and components. The Company estimates the Payette Gate Upgrade will cost $3,490,000 and the New Plymouth Gate Upgrade will cost $2,760,000.

Staff accepts the Company's explanation of why no alternatives are possible for these projects but will ask for evidence that the physical capacity limits have been reached when the Company requests a determination of prudence. Staff also encourages the Company to document the final cost and in-service dates for each gate project in the next IRP.

Five Year Plan

One of the requirements of a natural gas IRP is for the Company to include integration of the demand forecast and resource evaluations into a short term (e.g., two-year) and long-range (at least a five-year) plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers. As illustrated in Table No. 10 of the Company's 2023 IRP, two enhancements are detailed within the next two years; the Idaho Falls lateral compressor in 2024 and the State Street Uprate in 2025. The Company provided the following table to summarize its five-year plan. *Id.* at 111.

Table 10: Five-Year Planning and Timing of Capacity Enhancements Selected

AOI →	Ada County		State Street Lateral		Canyon County		Sun Valley Lateral		Idaho Falls Lateral	
Year↓	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected	Capacity (th/day)	Capacity Enhancement Selected
2023	870,000	12-inch S Boise Loop	820,000	None	1,390,000	12-inch Ustick Phase III	247,500	Shoshone Compressor Station	904,000	None
2024	870,000	None	820,000	None	1,390,000	None	247,500	None	1,093,000	IFL Compressor Station
2025	870,000	None	950,000	State Street Uprate	1,390,000	None	247,500	None	1,093,000	None
2026	870,000	None	950,000	State Penn Gate Upgrade	1,390,000	None	247,500	None	10,930,000	None
2027	870,000	None	950,000	None	1,390,000	None	247,500	None	10,930,000	None
2028	870,000	None	950,000	None	1,390,000	None	247,500	None	1,093,000	None

The Company will review its five-year plan deficits and alternatives considered for capacity enhancement in development of the 2025 IRP. The Company will modify its plan as needed to meet demand predictions and ensure safe, reliable service to its customers. Staff will continue to review the capacity enhancements selected in the Company's future IRPs.

Supply Options

The Company's service territory is located between the Western Canadian Sedimentary Basin ("WCSB") located in Alberta and British Columbia and the Rockies region located in Wyoming, Colorado, and Utah. A bi-directional interstate pipeline operated by Northwest Pipeline runs through the Company's territory and enables purchases from both regions. The WCSB supplies approximately 79% of the Company's natural gas. *Id.* at 41.

The Company utilizes natural gas storage as a capacity resource. Currently, the Company has storage capacity in four facilities. Two of the facilities, one at Jackson Prairie and the other at Plymouth, Washington, are operated by Northwest Pipeline. A third facility, the Dominion Energy storage field ("Clay Basin"), is located near the Utah and Wyoming border. The fourth storage facility, the Company-owned LNG facility, located in Nampa, Idaho, is described in greater detail below.

Nampa LNG Facility

The Nampa LNG plant is primarily used to supplement gas supply onto the Company's distribution system. The plant is capable of storing up to 600 million cubic feet of LNG. The plant can re-gasify approximately 60 million cubic feet per day and inject the gas into the Company's Canyon County and Ada County distribution systems when needed.

During off-peak months, the Nampa LNG facility obtains pressurized natural gas from the Canyon County lateral, liquifies it, and then stores it in a large steel storage tank with a capacity equivalent to 600 million standard cubic feet of gas (about 600,000 Dth). The liquified gas is withdrawn to supply the Company's non-utility customers; and during winter months, liquified natural gas is trucked from the Nampa LNG facility to the Company's gasification facilities along the Idaho Falls Lateral. Natural gas liquification is an energy intensive process and using liquified natural gas to meet demand for purposes beyond needle peaking events can be costly.

However, gas trucked from the Nampa facility to the Company's degasification facilities along the Idaho Falls lateral is essential for meeting that lateral's needle peak demand.

Purchasing Options

As part of the IRP, the Company creates a base, high, and low natural gas price forecast based on pricing forecasts sourced from Wood Mackenzie, EIA, S&P Global, NYMEX Henry Hub, and Northwest Power and Conservation Council. 2023 IRP at 50. The Company states that it utilizes a proprietary model to select a monthly base price projection for purchase points for the AECO, Rockies and Sumas markets. The forecasts for these can be shown in Chart 1 (Figure 26) below. The Company uses this type of analysis, along with input from its Gas Oversight Committee, to hedge a portion of its gas supply portfolio at fixed priced forward physicals.

<u>Chart 1. Company Natural Gas Price Forecast</u>

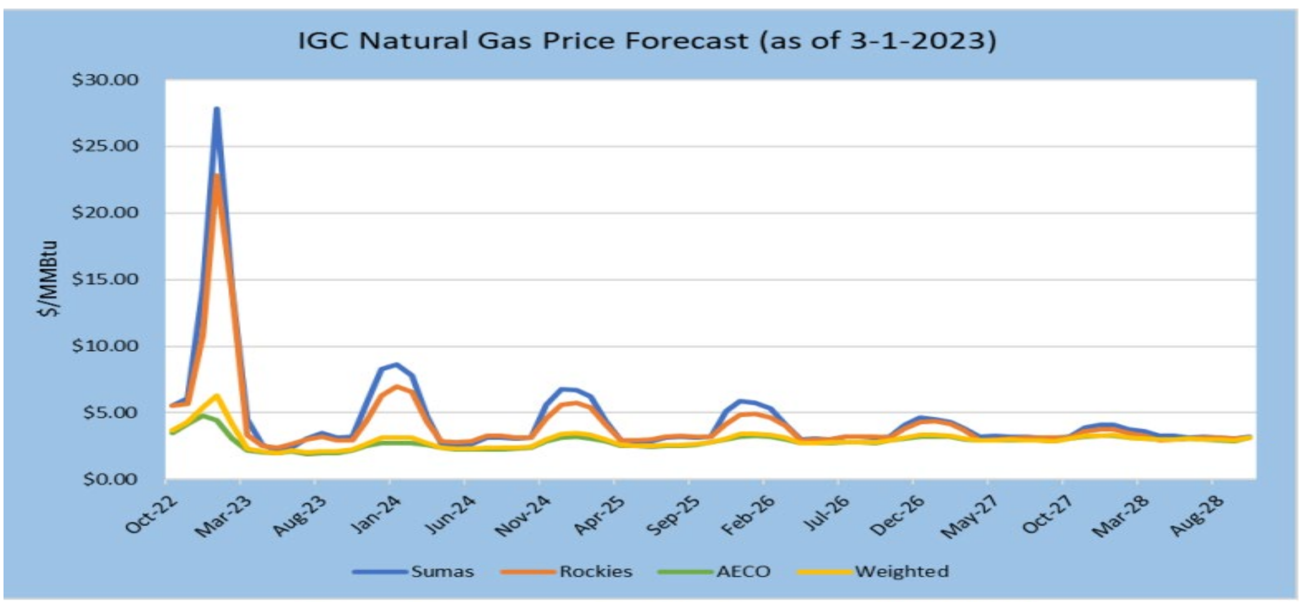

Figure 26: Intermountain Price Forecast as of 03/1/2023

DSM Opportunities

Conservation Potential Assessment

In the 2023 IRP, the Company contracted with Guidehouse ("Evaluator") to conduct the 2023 Conservation Potential Assessment ("CPA") to estimate the DSM therm savings for the forecast horizon, which is included as Exhibit No. 4. In Order No. 35663, the Commission approved the Company's proposal to base DSM program planning on the most recently filed IRP.

Because of this change, Staff has placed additional scrutiny on the CPA forecast used to inform future DSM offerings. Staff is concerned that the Company used over-stated therm savings data to calibrate its models, thus overstating the forecasted energy savings potential.

The CPA explains that models for future Energy Efficiency ("EE") offerings were calibrated using historic data from the Company's 2021 EE Annual Report. CPA at 18. When the 2021 EE Annual Report was filed in Case No. INT-G-22-03, Staff disagreed with the estimates that the Company used to report savings for the Whole Home and Furnace programs. In that report, the Company used an estimated Furnace rebate savings of 86 therms per furnace sourced from the Company's 2019 CPA and provided an internal evaluation ("Internal Evaluation") which was used to support the use of the CPA estimate over the more recent 2020 Impact Evaluation. For the Whole Home Tier I and II rebates, the Company used estimates of 161 therms/unit and 128 therms/unit respectively. These estimates were the result of a simulation analysis provided as part of the Company's 2020 Evaluation Measurement and Verification ("EM&V") impact evaluation.[2] The 2020 EM&V included a statistically rigorous analysis based on the measurable savings of customer bills ("Billing Analysis") and an alternative analysis that estimated savings using Home Energy Rating System models for each project compared to a reference model that reflected Idaho building code requirements ("Simulation Analysis").

Since the 2020 EM&V was published in Case No. INT-G-20-06, Staff has consistently stated its concern over the use of the estimates provided by Simulation Analysis instead of Billing Analysis to report program savings. Additionally, in Case No. INT-G-22-03, Staff commented that the Company's Internal Evaluation was flawed by excluding a significant portion of the program's rebates and that the therm savings should have been lower. In Order No. 35663, the Commission directed the Company to use the Billing Analysis to evaluate the performance of the Furnace and Whole Home measures and comported with previous orders to immediately and continuously monitor, evaluate, and update its EE program incentives with the best available data. The results of the Billing Analysis estimate savings of 56 therms/unit for the Furnace measure using a matched control group analysis and 29 therms/unit using a pre-post analysis. For the Whole Home rebate, the Billing Analysis estimates savings of 58 therms/unit using a matched control group analysis.

[2] Case No. INT-G-20-06 Supplement to Application for details on the Simulation Analysis and Billing Analysis.

For the purpose of calibrating its models for these measures, the Evaluator used the result from the Company's Internal Evaluation of 81 therms/unit for the Furnace measure. Response to Production Request No. 24. For the Whole Home Tier I and Tier II measure, the Simulation Analysis results of 161 therms/unit and 128 therms/unit were used. Response to Production Request No. 33. By using therm savings estimates that are higher than what is supported by the Billing Analysis to calibrate its models, Staff believes that the Company has overstated the savings potential of these measures.

Further, for measures with no historic data, the model was calibrated using historical data from existing measures that shared a similar end use. Response to Production Request No. 25. Staff believes the inputs for the Furnace and Whole Home measures are overstated; therefore, any measure calibrated to these inputs is likely also overstated. Staff cautions the Company on planning any program changes to the Whole Home or Furnace measures based on the results of this CPA or planning new measures that are calibrated using the same end uses as the Furnace and Whole Home measures.

Overall, Staff does not anticipate any significant impact to the IRP demand forecasts due to changes in the CPA savings potential. Currently the Company's CPA estimates less than 1.5 mmtherms saved per year, which is not a significant amount relative to the demand forecast in the scale of hundreds of mmtherms. As the Company's DSM portfolio matures and begins to achieve higher levels of savings, the Company's DSM portfolio will begin to have a bigger impact on avoiding costly upgrades to the Company's system. Therefore, it is important to have accurate CPA results. Staff notes that its observations may mean that portions of the CPA are not used or useful because of the overstated input data; however, this does not necessarily apply to the entire study. If possible, Staff recommends that the Company update the CPA model inputs utilizing the Billing Analysis therm savings estimates to improve the usefulness of the CPA results for EE program planning. Staff will review the CPA expense in the next DSM prudence filing.

Whole Home Measure Continuity

Following the 2020 EM&V, the Company implemented several of the evaluation's recommendations into its Whole Home offering. The Company explains in its response to Production Request No. 33, that it considers its current Whole Home offering ("Post-EM&V") as a new measure distinct from the original Whole Home rebate ("Pre-EM&V") offered between

2019-2021. Operating under this definition, it may not be appropriate to use the results of the 2020 EM&V's Billing Analysis to calibrate the CPA's models, invalidating Staff concern stated above. However, Staff strongly disagrees with the Company's interpretation of the evaluation's recommendation.

The 2020 EM&V Impact evaluation provided the following recommendations for the Whole Home program: (1) imposing a more stringent Home Energy Rating System ("HERS") Index Requirement for the program; (2) removing the ENERGY STAR certification requirement; and (3) to directly target natural gas savings through specific requirements. INT-G-22-03 Supplement to Application at 106. Additionally, in the Memorandum: Residential Whole Home Modeling Results, recommendations were provided to offer tiered rebates for the offering and gave specific requirements for building envelope upgrades that target natural gas savings. *Id.* at 391 & 392. Staff's review of these recommendations suggests that the changes are not intended to retire and rebuild the rebate, rather they are incremental adjustments to the continued offering. It is common for EE programs to adjust incentives and program requirements in response to participation and to increase realization of energy savings. Staff analysis of Pre-EM&V offering and the Post-EM&V Whole Home savings mechanisms is provided in Table No. 1 below. This table demonstrates that while the ENERGY STAR certification was removed, the savings mechanisms used by the rebate remains the same, establishing continuity between the Pre- and Post- EM&V offerings. Analysis of the evaluation recommendations and savings mechanisms suggest that the Whole Home offering is a continuation of the original program; therefore, the results of the 2020 EM&V Billing Analysis are applicable; and the CPA models should be calibrated using the historical therm savings as indicated by the Billing Analysis.

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Table No. 1: Comparison of the Savings Mechanisms of the ENERGY STAR Certified New Construction and Company's Post-EM&V Whole Home Offering

Pre-EM&V	Post EM&V	
ENERGY STAR certified new construction (v 3.1)[3]	Tier 1	Tier 2
Cooling Equipment	N/A	N/A
Heating Equipment: 95 AFUE ENERGY STAR gas furnace	Furnace efficiency >= 97%AFUE	Furnace efficiency >= 95%AFUE
Envelope, Windows & Doors: 3 ACH50	Air sealing <= 3ACH50 Ceiling insulation >= R-49	Air sealing <= 4ACH50
Water Heater	N/A	N/A
Thermostat & Ductwork: All ducts and air handlers modeled within conditioned space	Ducts and air handler located inside conditioned space or duct leakage to outside of less than 4 CFM25/100ft^2 CFA.	Ducts and air handler located inside conditioned space or duct leakage to outside of less than 4 CFM25/100ft^2 CFA.
Lighting & Appliances (refrigerators dishwasher and ceiling fans)	N/A	N/A
HERS rated at <75	HERS rated	HERS rated

DSM Avoided Cost

In Order No. 33314, the Commission directed the Company to include more detail in future IRPs about how the Company calculates avoided costs and uses those calculations to determine whether natural gas DSM opportunities are cost-effective. Order No. 33314 at 9. In Order No. 33997, the Commission directed the Company to describe how avoided costs change because of the IRP. In describing the avoided cost calculation in the 2021 IRP, the Company clearly identified how the avoided cost are calculated and how they changed because of the IRP. 2021 IRP at 90-91. In the 2021 IRP, the avoided cost calculation did not include distribution costs.

In Order No. 34536, the Commission ordered the Company to review its avoided cost calculation as part of its Energy Advisory Group. Through this group, the Energy Efficiency Stakeholder Committee's ("EESC") avoided cost subcommittee reached a census on the

[3] ENERGY STAR feature categories contain several options depending on fuel type and climate zone. Continuous requirements are noted as applicable.

calculation of avoided costs for the Company's DSM programs. In Case No. INT-G-22-03, the Company proposed several changes to its avoided cost practices. The Commission approved the proposals in Order No. 35662. Because of these changes, DSM related considerations have additional significance in the IRP. Accordingly, Staff has placed additional scrutiny on its review of the DSM avoided costs and CPA used to inform future DSM offerings.

The 2023 IRP describes the three major components of the DSM avoided costs as the commodity cost, transportation cost, and variable distribution cost. 2023 IRP at 83. The commodity cost represents the purchase price of natural gas. In this IRP, the Company forecasted the commodity cost of gas using a weighted average price from the Company's three primary supply basins and adjusting the prices by the Heating Degree Days ("HDD") of each month. The transportation cost is the cost incurred by the Company for the delivery of gas to its distribution system. For this IRP, the Company used the transportation and storage costs incurred as of the 2022 Purchased Gas Adjustment ("PGA"). These prices rarely change by significant amounts. The variable distribution cost is the cost associated with deferred or delayed capacity expansion projects. In this IRP, the distribution cost remains at zero. In support, the Company compared its demand forecast with and without the energy savings forecast provided by its CPA. The lack of delayed or deferred capacity expansion projects supports the conclusion that the DSM offerings have not offset any capacity projects.

This avoided cost calculation and the support for its components are consistent with discussions from the EESC avoided cost subcommittee. Staff believes that the Company's 2023 DSM avoided costs and supporting methodologies are reasonable. Staff recommends that the Commission establish the practice of authorizing the Company's DSM avoided costs as part of IRP filings and authorize the DSM avoided costs associated with this filing.

Renewable Natural Gas

Renewable Natural Gas ("RNG") is pipeline quality gas that is fully interchangeable with conventional natural gas. RNG is produced from the decomposition of organic material aka biomass and is processed to meet purity standards. After processing RNG to industry purity standards, the gas can then be used within the Company's system. 2023 IRP at 66.

The Company is involved with the growth and development of the RNG industry in Idaho. In 2020, the Company filed an application with the Commission for authority to facilitate RNG access. In Order No. 34693, the Commission approved the Company's RNG facilitation plan.

The Company's RNG Facilitation Agreement allows RNG producers access to the Company's distribution system to transport RNG to their end use customers. *Id*. at 9. Currently, the Company has multiple RNG producers located in the Magic Valley supplying RNG from dairy operations and expects additional RNG producers to come onto its system.

Progress Since the Previous IRP

In Order No. 35438, Case No. INT-G-21-06, the Commission acknowledged Staff's comments and recommendations and stated:

> The Commission also acknowledges Staff's comments and recommendations. In particular, we find it reasonable that the Company provide capacity enhancement project costs and NPV information when capacity improvement projects are completed and placed in service. We further find it reasonable that the Company continue to enhance public participation through the IGRAC process by providing materials to members before meetings and making IRP information accessible on its website.

The Company discussed each of Staff's recommendations in the 2023-2028 IRP.

Capacity Enhancement Project Cost and NPV Information

The Company did not provide information on project enhancements when they were completed and placed in service or include details *within* this IRP. Staff requested in Production Request No. 1 that the Company provide activities and results achieved in providing the Commission with capacity enhancement project costs and NPV information. The Company provided the following response:

> The enhancement projects included in the 2021 IRP were as follows:
>
> 1. 12-inch Ustick Phase II;
> 2. Shoshone Compressor Station;
> 3. 12-inch Boise Loop;
> 4. State Street Uprate;
> 5. 12-inch Ustick Phase 3; and
> 6. Idaho Falls Lateral Compressor Station.
>
> The Ustick Phase II project was completed in 2021. Because Intermountain filed a general rate case in 2022, detailed project information on this project was filed as part of INT-G-22-01. As explained in the Response to Production Request No. 13 the Shoshone Compressor Station was completed in December 2023. Intermountain is still awaiting final project costs on this project. It is not uncommon for the closeouts on a project to take several months after project completion. Once the final information is available, Intermountain will provide

> project cost data to the Commission. None of the remaining projects have been placed in service. Intermountain is open to discussing with Staff the best way to provide the reports contemplated by Order No. 35438. Some potential options may be 1) an annual report in late spring on any projects that close during the previous year, 2) a late spring report only in the years between IRPs with the IRP filing serving as the report in years that it is filed, and 3) individual reports after final costs are available on a project.

As stated earlier, the IRP is foundational to subsequent capital prudence reviews. Staff is receptive to discussing alternatives with the Company to deliver a method of reporting outside of the IRP for when projects are placed in-service, and costs are known. Staff recommends that the Commission order the Company and Staff to work together to complete, within six months, a methodology for reporting to the Commission capacity enhancement projects that include when each are placed in-service and actual and NPV project costs.

Public Participation Materials and Website Access

The Company made some improvements on providing materials in advance of Intermountain Gas Resource Advisory Committee ("IGRAC") meetings and website access improvements. Staff requested in Production Request No. 2 that the Company provide activities and results achieved in providing materials to IGRAC members before meetings and making information accessible on its website. The Company provided the following response:

> For the 2023 IRP, Intermountain updated meeting invites a week in advance with meeting materials. Following the meeting, the Company uploaded the IGRAC presentation, meeting minutes, and the video recording of the meeting on the Company's dedicated IRP webpage. INT-G-23-07 Exhibit No. 1 contains the meeting slides as well as the meeting minutes. Although Intermountain did not receive any pre-meeting questions or post-meeting feedback, the Company did receive several questions during the meetings, which are captured in the meeting minutes and the video recording.

Staff appreciates the improvements implemented by the Company. As a next step, Staff believes there could be merit in making access of meeting materials prior to IGRAC meetings to the Intermountain Gas IRP webpage to allow active participation from the public and parties.

Public Participation

In Order No. 33997, the Commission directed the Company to convene an IRP advisory group and work with it to develop future IRPs that comprehensively and transparently consider demand, existing resources, and potential supply and demand-side options for meeting any deficits.

The Company established the IGRAC with the intent to provide a forum through which public participation can occur as the IRP is developed. 2023 IRP at 4. Advisory committee members were solicited from across the Company's service territory as representatives of the communities served by the Company. The Company stated that it held three IGRAC meetings in 2023 on a virtual platform. The Company states it provided a comment period after each meeting to ensure feedback was timely and could be incorporated into the IRP. *Id*. Staff members attended each of the meetings. Staff recognizes the Company's efforts to enhance public participation, appreciates the opportunity to participate in the IGRAC, and looks forward to the Company improving public involvement in development of future IRPs.

Lost and Unaccounted for Gas

In Order No. 32855, the Commission directed the Company to describe how Lost and Unaccounted for Gas ("LAUF") is managed and explain how results were achieved and ordered the Company to include a LAUF gas section within future IRPs. The Commission permits the Company to recover a maximum of 0.85% of its total throughput as LAUF.[4] The Company's 2023 IRP reports that its LAUF rate for the period of July 2021 through June 2022 was -0.48%, which is one of the best in the industry. 2023 IRP at 68. Staff recognizes the Company's efforts in this area and believes the Commission requirements were satisfied in this filing. Staff will continue to review LAUF in the Company's annual PGA filings and future IRPs.

STAFF RECOMMENDATIONS

The Company's IRP analyzed residential, commercial, and industrial customer growth and its impact on the Company's system under multiple scenarios. The IRP results show that there are peak day delivery deficits when forecasted growth is matched against existing resources for the 2023 through 2028 IRP period. The Company provided sufficient information to describe how deficits were determined and selected alternatives and resource enhancements to resolve them.

[4] Order No. 30649.

Staff believes the Company's 2023-2028 IRP meets Commission IRP requirements. Staff recommends that the Commission:

1. Acknowledge the Company's 2023 IRP;
2. Order the Company to work with Staff to implement IRP reporting that includes system enhancement information in future IRPs, within six months of a Commission order;
3. Order the Company to work with Staff to develop reports to the Commission of capacity enhancement projects that include in-service dates and project costs, within six months of a Commission order; and
4. Establish the practice of authorizing the Company's DSM avoided costs as part of IRP filings and authorize the DSM avoided costs associated with this filing.

Respectfully submitted this 9th day of May 2024.

Chris Burdin
Deputy Attorney General

Technical Staff: Kimberly Loskot
Vicki Stephens
Matt Suess
Jason Talford

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 9th DAY OF MAY 2024, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-23-07, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

LORI BLATTNER
DIR – REGULATORY AFFAIRS
INTERMOUNTAIN GAS CO
PO BOX 7608
BOISE ID 83707
E-MAIL: lori.blattner@intgas.com

PRESTON N CARTER
GIVENS PURSLEY LLP
601 W BANNOCK ST
BOISE ID 83702
E-MAIL: prestoncarter@givenspursley.com
stephaniew@givenspursley.com

Patricia Jordan

PATRICIA JORDAN