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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF INTERMOUNTAIN GAS COMPANY'S 2015-2019 INTEGRATED RESOURCE PLAN.	**CASE NO. INT-G-15-01** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Intermountain Gas Company's Application.

BACKGROUND

On January 13, 2015, Intermountain Gas Company filed its Integrated Resource Plan ("IRP") for the years 2015-2019. The IRP represents a snapshot in time of the Company's ongoing planning process; it describes the currently anticipated conditions over a five-year planning horizon, the anticipated resource selections, and the process for making resource decisions.

Every two years, the Company files an IRP that describes the Company's plans to meet its customers' future natural gas needs. The IRP illustrates how the Company plans to meet future load requirements given three (low growth, base case, and high growth) demand scenarios. The Company includes the influence of weather on its system, and its ability to use both traditional and non-traditional supply side resources to meet demand. The Company regularly forecasts the demand of its customer base and determines how to best meet the load requirements brought on by this demand.

IRP REQUIREMENTS

In Order No. 25342, the Commission adopted IRP requirements for local gas distribution companies in response to amended Section 303 of the Public Utility Regulatory Policies Act of 1978 (PURPA). In Order No. 27024, the Commission shortened the required planning horizon from 20 years to at least five years. Order No. 27098 removed any requirement that IRPs formally evaluate potential demand-side management (DSM) programs, and instead directed the companies to explain whether cost-effective DSM opportunities exist. In summary, these three Orders direct gas utilities to file an IRP every two years that includes:

1. A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and 20 years using methods that examine the effect of economic forces on the consumption of gas, and that address changes in the number, type, and efficiency of gas end-uses;
2. An analysis of gas supply options for each customer class, which includes a projection of spot market versus long-term purchases for both firm and interruptible markets, an evaluation of the opportunities for using Company-owned or contracted storage or production, an analysis of prospects for Company participation in a gas futures market, and an assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers;
3. A comparative evaluation of gas purchasing options, and an explanation of whether or not there are cost-effective DSM opportunities;
4. The integration of the demand forecast and resource evaluations into a long range (at least a five-year) integrated resource plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers;
5. A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the IRP;
6. A progress report that relates the new plan to the previously filed plan; and
7. Public participation.

Additionally, in the Company's 2013 IRP, Order No. 32855, the Commission allowed the Company to stop filing semi-annual lost and unaccounted for gas (LAUF Gas) reports.[1] Instead, the Company was to discuss LAUF Gas in the Company's future IRPs and Purchased Gas Cost

[1] LAUF Gas is the difference between the amount of natural gas delivered to the Company's distribution system at the city gate and the amount of gas ultimately recorded at the customers' meters.

Adjustment (PGA) cases.[2] The IRP's LAUF Gas section must explain the Company's: (a) framework for how it has tested for, identified, and remediated equipment measurement errors or leaks; and (b) business process for alleviating measurement errors through its financial accounting of nominations, scheduling, measurements, flow volume allocation, and billing.

STAFF REVIEW

Staff thoroughly reviewed the Company's IRP and supporting exhibits to determine whether it contains information required by Commission orders, and adequately plans for supply and demand from 2015-2019. Staff also analyzed information supplied by the Company in response to discovery. Staff's observations, concerns, and recommendations are detailed below.

Forecast, Peak Day Send-Out, and Gas Supply

The Company sells natural gas to residential, commercial, and industrial customers. In 2013, the Company sold more than 630 million therms to over 326,000 customers. The Company's system transported 36% of the gas to residential customers, 19% to commercial customers, and 45% to industrial customers. The Company forecasts that peak day load on the system will grow from 2015-2019 at 2.32% per year under the Base Case Scenario. Both residential and commercial customers use natural gas primarily for space and water heating. Industrial customers typically use natural gas for boiler and manufacturing applications. According to the Company's IRP, the agricultural economy and the price of alternative fuels strongly influences industrial demand for natural gas.

The IRP shows the Company analyzed several peak day send-out (delivery) studies to determine the magnitude and timing of future deficiencies in firm peak day delivery capabilities, looking at both interstate mainline capacity and geographic location. The Company matched residential, commercial, and industrial customer peak day load against available resources to determine which resource combination would most cost effectively meet the Company's future peak day delivery requirements. Peak day typically occurs in January when demand spikes for space heating. The Company delineates its peak day send-out by Core Market (non-transportation customers) and Industrial Firm customers.

The IRP shows annual household growth starts to decline in 2019. Household growth tends to drive small commercial customer growth. Consequently, small commercial customer growth also declines in 2019. Staff evaluated the forecasts of other utilities in the region and did not observe

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[2] The Company files a PGA each year to adjust rates to reflect changes in the Company's costs to buy natural gas from suppliers — including transportation, storage, and related costs.

similar declines in their residential and commercial customer growth. However, Staff recognizes that the Company continues to develop and review forecasts; additionally the Company will update projections in the 2017 IRP. The IRP indicates that there are no peak day delivery deficits when forecasted peak day send-out is matched against existing and planned resources. However, Staff encourages the Company to closely evaluate the lead times necessary to add resources if growth does not decrease in 2019 as forecasted.

Regional Summary

Idaho Falls

The Idaho Falls Lateral ("IFL") is 104 miles long and serves cities between Pocatello and St. Anthony in eastern Idaho. The IFL serves about 16% of the Company's total customers and accounts for 14% of the projected peak day send-out.

The IFL currently uses a LNG (Liquefied Natural Gas) facility in Rexburg to supplement the lateral's capacity during a peak day. Every six months, the Company trucks 20,000 gallons of LNG to Rexburg from the Nampa LNG facility. Five trucks (10,000 gallons each) are reserved and available for firm transport of LNG from Nampa to Rexburg if needed.

The Rexburg facility can accommodate three LNG storage tanks, one of which is currently built and operational. A single tank will store enough gas to cover approximately two peak days. The Company plans to install a second tank in 2018. The Company plans to use the Rexburg plant's LNG capacity to meet peak day load in 2017, 2018, and 2019. The IFL's distribution transport capacity of 1,240,000 therms includes 282,000 therms of incremental capacity from the Rexburg LNG facility and covers all peak day demands from 2015-2019.

Sun Valley

The Sun Valley Lateral ("SVL") is a 70 mile long 8" high pressure pipeline that serves about 4% of the Company's customers and accounts for 4% of the projected peak day send-out.

During the winter of 2010/2011, the Company installed a compressor station to boost line pressure, which increased the SVL's capacity by 15% to 202,000 therms. The SVL's distribution transport capacity of 202,000 therms covers all peak day demands from 2015-2019.

Canyon County

The Canyon County Region ("CCR") serves about 15% of the Company's customers and accounts for 14% of the Company's projected peak day send-out. In 2013, the Company increased

CCR capacity 21% by replacing the aging Parma lateral with 18 miles of 6" pipe. The Company conducted an engineering study and determined that replacing the Parma lateral with a 6" pipe satisfied and increased the CCR's capacity, and eliminated the need for a previously planned Orchard-Farmway Loop. The CCR's 790,000 therm distribution transport capacity covers all peak day demands from 2015-2019.

State Street

The State Street Lateral ("SSL") is 16.2 miles long and serves about 14% of the Company's customers (residential and commercial only). It accounts for 12% of the Company's projected peak day send-out. The SSL's distribution transport capacity is 644,000 therms for 2015-2016, and 695,000 therms for 2017-2019, which covers all peak day demands from 2015-2019. Completing the Cloverdale Betterment Project in late 2016 will add 51,000 therms of capacity in 2017 and beyond. The project involves installation of 8" pipe and an isolation valve on the line that runs between Chinden Blvd and Lake Hazel Road. This will enable the Company to balance the delivery of gas through the State Street, Chinden, and Lake Hazel lines.

Central Ada

The Central Ada Area ("CAA") consists of 24 miles of high-pressure pipeline. It serves about 15% of the Company's customers (residential and commercial), and accounts for 12% of the Company's projected peak day send-out. The CCA distribution transport capacity of 625,000 therms for 2015-2016 and 702,000 therms for 2017-2019 covers all peak day demands from 2015-2019. As mentioned in the SSL summary, completing the Cloverdale Betterment Project line (3 miles of 8" pipeline) will increase capacity by 12%.

Future Plans/Strategy

The Company will complete the Cloverdale Betterment Project in late 2016, which will provide additional capacity and balancing capability on the SSL and CAA lines. The Company continues to monitor building in the area served by the SSL, and it is exploring uprate alternatives for 6.6 miles of 12" pipe within the lateral. The Rexburg LNG facility provides expansion alternatives, such as adding a second storage tank in 2018. The table below illustrates potential and actual maintenance and capacity improvements for the Company's system.

Recently Completed	In Process	Planned	Under Evaluation
-2013- Added 149 miles of distribution and service lines -2013- Parma lateral replacement -2012- Phase V (15.5 miles of high pressure 16" pipe) on IFL -2010-2011-Compressor installed SVL	-Cloverdale Betterment Project to be completed late 2016	-Addition of a second LNG storage tank at the Rexburg facility, target completion 2018	-SSL pipeline retest -Up rate 6.6 miles of SSL -CCR capacity enhancements

The IRP lacks details on projects in process, planned or under evaluation. Staff recommends that the Company include more detailed descriptions of these projects in its next IRP, including scope of work, estimated costs, and target completion dates.

Paying for Growth

The Company forecasts industrial load using models which incorporate customers' Maximum Daily Firm Quantity ("MDFQ") data. In order to improve the accuracy of its forecast, the Company compared customers' actual MDFQ using Supervisory Control and Data Acquisition ("SCADA"), to their contract MDFQ. On page 46 of the IRP, the Company describes the analysis as follows:

> It was discovered the historical daily SCADA data indicated that quite a few of the large volume customer's peak day usage exceeded their actual contract MDFQ. The variance between these figures [SCADA vs. contract MDFQ] were compared and assessed customer-by-customer by AOI [Area Of Impact] with the assistance of the engineering group to determine which of the customers were located in geographic areas that currently have available peak day capacity. Where possible, Intermountain will allow those customers to adjust the contract MDFQ to levels consistent with actual peak day use. Those located in areas that do not have available capacity will be required to invest in new facilities in order to increase their MDFQ. The Base Case MDFQ quantities beginning in 2015 include these adjusted MDFQ assumptions.

Staff evaluated how many customers might be required to increase their MDFQ. Through discovery, Staff determined that 29% of the LV-1 customers had actual peak day use beyond their contract MDFQ. Customers on the LV-1 schedule take fully bundled service, which means they pay the Company for gas molecules, interstate transportation capacity, and distribution service. The Base Case assumed either the then existing customer MDFQ or the higher MDFQ if it was approved according to the Company's engineering variance study. However, the Company's response to Staff's discovery was unclear on exactly how many LV-1 customers might be required, or have the financial means, to invest in new facilities to increase their MDFQ.

If existing LV-1 customers share a lateral with other customers but are located in geographic areas *without* currently available peak day capacity, Staff questions whether LV-1 customers should be solely responsible for capacity upgrade costs that may benefit other core customers. In addition, the Company might also consider other least-cost options to reduce the need for further peak day capacity expansions, such as: 1) encouraging customers to take interruptible service; or 2) implementing cost-effective DSM programs in areas without available peak day capacity.

Demand Side Management (DSM)

According to the IRP, the Company reviewed traditional and non-traditional resource alternatives and potential DSM measures to mitigate potential capacity constraints in certain areas. The Company performed its DSM analysis to: 1) ascertain whether achievable and economically viable DSM could provide a reliable peak-load management resource; and 2) facilitate year-round improvements in natural gas usage.

The Company notes that natural gas prices have continued to fall since completion of the 2010 IRP, and that its core customers have seen a 40% price reduction since 2008. Because of this, the Company claims that DSM programs are no longer cost effective. The Company offers a $200 rebate to customers who install a natural gas furnace with a 90% or greater efficiency when converting to natural gas from another fuel source. Existing customers do not qualify for an incentive for installing a high-efficiency furnace. The Company issued total rebates of $35,600 in 2011, $43,000 in 2012, and $46,000 in 2013.

Staff reviewed the DSM portfolios of regional utilities and compared them to the Company's offerings. Puget Sound Energy in Washington offers the following natural gas heating system rebates: boiler $350, forced air furnace $200, space and water heating $800, and fireplace $200. MDU Resources (the Company's parent company) divisions offer a number of rebates. For example, Great Plains Natural Gas Company offers natural gas residential water heating rebates from $85 to $250 depending on equipment installed, and residential heating rebates from $300 to $500 depending on equipment installed; Montana-Dakota Utilities Company offers residential heating rebates from $300 to $500 depending on equipment installed.

In discovery, Staff asked how the Company calculates its avoided cost and how it used the calculations to determine that natural gas DSM is not cost-effective. The Company's response included the following statement: "The only avoided fixed costs would be those that are incremental to our current operating levels. Since this IRP forecasts no need for additional storage or interstate transportation capacity, the fixed component of the avoided cost rate is zero." Staff believes the

Company's response fails to include its plans to upgrade storage and distribution capacity, as summarized on pages 78-79 of the IRP. The Company's avoided-cost calculation includes some avoided supply-side resource costs, but excludes avoided costs related to distribution capacity enhancements. Therefore, the costs and benefits of delayed or avoided distribution enhancements are not captured and used in the Company's DSM evaluations. To the extent these enhancements could be deferred or avoided by DSM at a lower cost, Staff believes it is appropriate to include capacity and or distribution enhancement costs in avoided cost calculations.

Staff is concerned that by excluding the costs of storage and distribution capacity upgrades from the avoided cost calculations, the Company may not be accurately evaluating the benefits of cost-effective DSM programs. Staff encourages the Company to evaluate how it calculates avoided-cost to ensure delayed or avoided storage and distribution capacity upgrade costs are included when evaluating DSM opportunities.

Research and Development (R&D)

The Company states that it promotes the efficient use of natural gas through marketing and education programs, mass-media advertising, and the Company's website. The Company participates in two R&D components of the Gas Technology Institute ("GTI"), Operations Technology Development ("OTD") and Utilization Technology Development ("UTD"). As a part of the GTI Gas Heat Pump ("GHP") project, the Company is testing the first U.S. installation of a cold climate NextAire Multi-Zone Model E GHP. Additionally, the Company is providing the Northwest Energy Efficiency Alliance ("NEEA") with performance data on another GTI project involving a Gas-fired Heat Pump Water Heater ("G-HPWH"). Staff has asked the Company to include a summary (scope, duration, and cost) of R&D projects in the next IRP filing. The Company has agreed to provide the summary.

NEEA recently released the 2015-2019 Natural Gas Market Transformation Business Plan developed by a collaborative of natural gas stakeholders that included Avista, Cascade Natural Gas, Energy Trust of Oregon, Northwest Gas Association, Northwest Natural, and Puget Sound Energy (the "Collaborative"). The Collaborative's objective is: "To accelerate the development and market adoption of efficient natural gas products, practices and services resulting in increased consumer choices and increased efficiency of natural gas use in the Northwest." NEEA believes the Gas Market Transformation Plan is a long-term investment strategy that supports energy efficiency over a 20-year horizon.

The 2015-2019 NEEA Natural Gas Market Transformation Business Plan includes: a portfolio of five residential and commercial gas initiatives, scanning, codes and standards, research and evaluation, a mid-cycle evaluation, and a new natural gas advisory committee. The five residential and commercial gas initiatives include: gas fired Heat Pump Water Heater (G-HPWH), combination heating + hot water Gas Fired-Heat Pump (GF-HP), hearth products, dryers, and rooftop HVAC. NEEA expects the G-HPWH, combination space heating and water heating systems using gas fired heat pump technology, and efficient hearth products programs will offer the greatest efficiency opportunities.

In discovery, Staff asked the Company about its plans to participate in the NEEA Natural Gas Market Transformation Collaborative. The Company responded; "Aside from IGC's collaboration with the GTI/NEEA project, we have not worked independently with NEEA's natural gas efforts. We have no plans at this time for further collaboration, but will consider mutually beneficial opportunities with NEEA."

Based on the Company's discovery response, Staff is uncertain whether the Company has thoroughly analyzed the costs and benefits of NEEA participation. Market transformation programs are often more cost-effective than directly administered programs because they leverage economies of scale to incent national manufactures and retailers, rather than a utility's individual customers. Therefore, even with potentially low avoided costs, it is possible that market transformation programs can be cost-effective. Such programs offer collaboration with other gas utilities in the region including work the Company is currently doing with the GTI.

Staff believes the Company and its customers might benefit by participation in NEEA and the natural gas Collaborative. Staff encourages the Company to more closely analyze the cost and benefits of such participation and provide the results of the analysis in its next IRP.

Progress Since the Previous (2013-2017) IRP

In Order No. 32855 (2013 IRP), the Commission allowed the Company to stop filing semi-annual lost and unaccounted for gas (LAUF Gas) reports. Instead, the Company was to discuss LAUF Gas in the Company's future Purchased Gas Cost Adjustment (PGA) cases and IRPs. The IRP's LAUF Gas section must explain the Company's: (a) framework for how it has tested for, identified, and remediated equipment measurement errors or leaks, and (b) business process for alleviating measurement errors through its financial accounting of nominations, scheduling, measurements, flow volume allocation, and billing.

A LAUF Gas section is included in the 2015-2019 IRP. The Company explained that it conducts audits, investigates potential sources of lost gas, and acts to keep LAUF Gas levels low. The table below shows that between 2012 and 2013, dead meters and pressure errors increased, gas loss due to line damage decreased, and drive rate errors did not change:

LAUF AUDIT RESULTS (2015 IRP)	**2011**	**2012**	**2013**
Dead Meters	795	513	796
Drive Rate Errors Errors caused by mis-programming of the drive rate when an Encoder Receiver Transmitter is programmed.	14	3	3
Pressure Errors Errors caused by mis-programming of the delivery pressure rate when an Encoder Receiver Transmitter is programmed.	8	8	13
Gas loss occurrences due to line damage	154	177	163

Public Participation

According to Order No. 25342, when the Company is "formulating its plan, the gas utility must provide an opportunity for public participation and comment and must provide methods that will be available to the public of validating predicted performance."

The Company complied with Order No. 25342 and held three public workshops during the IRP cycle in Boise, Caldwell, and Fort Hall, Idaho. Workshop topics included the following: an introduction and overview, demand and supply outlook, economic forecast, growth scenarios, storage resources, distribution system capacities, natural gas supplies, deliverability enhancements, efficiency and DSM, load duration curve data, and a system modeling optimization summary. Public flyers were distributed and individual invitations sent to key stakeholders, customers, and government officials in each area where workshops occurred. However, so Staff can better understand the effectiveness of the Company's public participation efforts, Staff recommends that the Company's next IRP filing include copies of invitation lists, public flyers distributed, and number of attendees.

Conclusion

Based on its review, Staff's opinion is that the IRP satisfies the Commission's orders. The IRP analyzed residential, commercial and industrial customer growth and its impact on the Company's distribution system using design weather conditions under various scenarios for Idaho's economy. Peak day send-out under each of these customer growth scenarios was measured against the available natural gas delivery systems to project the magnitude and timing of delivery deficits, both from a total Company perspective and a regional perspective. The Company analyzed the resources needed to meet the projected deficits within a framework of options to help determine the most cost-effective means to manage the potential deficits. The Company believes these options will allow its customers to rely on uninterrupted service in the years to come. The IRP indicates that there are no peak day delivery deficits when forecasted peak day send-out is matched against existing and planned resources.

STAFF RECOMMENDATIONS

Staff recommends the Commission accept the Company's 2015-2019 IRP as fulfilling the requirements established by the Commission. To improve future IRP filings, Staff also recommends that the Commission require the Company to:

(1) Include detailed descriptions of projects in process, under evaluation, and planned. This should include: scope of work, estimated costs, and target completion dates;

(2) Include a summary (scope, duration, and cost) of R&D projects in the next IRP filing; and

(3) Provide public participation details including invitation lists, public flyers, and number of attendees.

Respectfully submitted this 27th day of April 2015.

Karl T. Klein
Deputy Attorney General

Technical Staff: Kevin Keyt

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 27TH DAY OF APRIL 2015, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-15-01, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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