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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF INTERMOUNTAIN GAS COMPANY'S APPLICATION FOR AUTHORITY TO CHANGE ITS PRICES (2014 PURCHASED GAS COST ADJUSTMENT).	**CASE NO. INT-G-14-01** **COMMENTS OF THE COMMISSION STAFF**

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

BACKGROUND

On August 8, 2014, Intermountain Gas Company (the "Company") filed its annual Purchased Gas Cost Adjustment ("PGA") Application. The PGA adjusts rates to reflect annual changes in the Company's costs to buy natural gas from suppliers—including transportation, storage, and other related costs. *See* Order No. 26019. With this Application, the Company asks the Commission to let it recover its increased gas costs through new PGA rates that would increase its annualized revenues by $6.7 million (about 2.64%).

The Company says the proposed changes would not affect its earnings. But they would increase overall prices for customers. More specifically, the Company says residential customers using gas for space and water heating would see a $1.89/month (3.81%) average increase, customers using natural gas only for space heating would see a $1.40/month (3.64%) average increase, and commercial customers would see a $0.31/month (0.15%) average increase.

The Company says its proposed PGA rates incorporate all changes in costs relating to the Company's firm interstate transportation capacity including, but not limited to, any price changes or projected cost adjustments implemented by the Company's pipeline suppliers and any volumetric adjustments in contracted transportation agreements that have occurred since the Company's last PGA filing, Case No. INT-G-13-05.

The Company proposes increasing the Weighted Average Cost of Gas to be recovered through new PCA rates (WACOG) from the currently approved $0.37341 per therm to $0.39482 per therm. The Company says while there are significant shale gas reserves, modest improvements in the economy and an increase in natural-gas-fired electric generation have increased demand and caused natural gas prices to rise. The Company notes, however, that natural gas prices remain much lower than they were a few years ago.

The Company says it has entered into agreements that lock-in its price for significant portions of its underground storage and other winter "flowing" supplies.

The Company seeks to provide its customers with $3.9 million in benefits that will be generated from the management of the Company's transportation capacity, as outlined on Exhibit No. 7 to the Application. The Company also proposes temporarily adjusting prices for 12-months — until September 30, 2015 — to allocate to customers the fixed, variable, and lost and unaccounted-for gas costs from the Company's deferred Account No. 186 balance. The Company notes that pursuant to Order No. 32793, its deferred variable gas cost reflects credits associated with liquefied natural gas (LNG) sales from the Company's Nampa, Idaho facility.

The Company proposes an October 1, 2014 effective date for the new PGA rates.

STAFF ANALYSIS

Staff has thoroughly reviewed the Company's Application and gas purchases for the year and has verified that the Company's PGA proposal would not change the Company's earnings, that the Company's deferred costs are prudent, and that the Company's WACOG request is reasonable.

In this year's PGA, the Company proposes increasing customer rates by about $6.7 million, or 2.64%. This increase is due to the pass through of transportation costs billed to the Company from firm transportation providers, an increase in the Company's weighted average cost of gas, an updated customer allocation of gas-related costs under the Company's PGA provision, the inclusion of temporary surcharges and credits for one year relating to natural gas purchases and interstate transportation costs from the Company's deferred gas cost accounts, and benefits resulting from the Company's management of its storage and firm capacity rights on various pipeline systems. Temporary surcharges and credits included in the prior year's PGA have also been eliminated. Table No. 1 shows how these changes would increase overall prices for the Company's customer classes:

Table 1:

Customer Class:	Proposed Change in Class Revenue	Proposed Average Change in $/Therm	Proposed Average % Change	Proposed Average Price $/Therm
RS-1 Residential	$1,056,105	0.03188	3.64%	0.90887
RS-2 Residential	$5,112,890	0.02911	3.81%	0.79373
GS-1 General Service	$ 114,825	0.00107	0.15%	0.73195
LV-1 Large Volume	$ 83,858	0.01538	2.94%	0.78063
T-3 Transportation	$ 122,319	0.00158	9.42%	0.01835
T-4 Transportation	$ 176,147	0.00102	2.43%	0.04307
T-5 Transportation	$ 25,790	0.00134	92.41%	0.00279
	$6,691,934		**2.64%**	

Table No. 2 shows how the overall effect of the proposed changes would increase the Company's annual revenue by $6,691,934.[1] This increase consists of the following items:

[1] The difference between the totals reflected on Table No. 1 and Table No. 2 is $1,555. Intermountain Gas has attributed this difference to rounding.

Table 2:

Deferrals:		
Removal of INT-G-13-05 Temporary Credits and Charges	$9,833,175	
Fixed Deferred Gas Costs	$(15,316,555)	
Variable Deferred Gas Costs	$5,343,108	
Total Deferrals		$(140,272)
Fixed Cost Changes:		
Full Rate Demand Changes	$(2,242,657)	
Discounted Demand Changes	$1,108,717	
Upstream Capacity Cost Changes	$261,441	
Other Storage Facility Cost Changes	$(489,915)	
Total Fixed Cost Changes		$(1,362,414)
Lost and Unaccounted for Gas		$634,067
LNG Sales Credit		$(405,441)
Re-allocation of Fixed Costs		$1,083,514
Changes in WACOG		$6,884,035
Total Annual Price Change		$6,693,489

Weighted Average Cost of Gas (WACOG)

The WACOG is the Company's average variable cost to buy and transport gas to satisfy its customers' estimated annual gas needs. The WACOG includes the volumetric interstate transportation rate and city gate costs. It does not include fixed capacity costs for interstate transportation, liquid storage, and underground storage. The WACOG is about 66% of the Company's total annual gas cost.

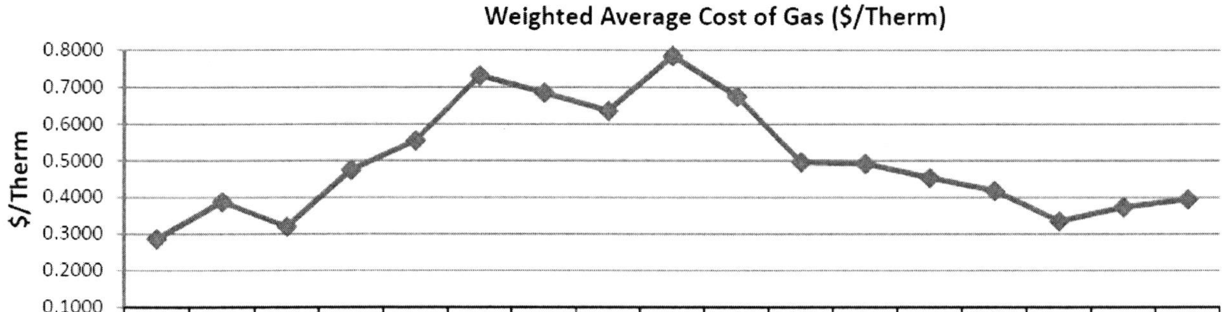
By the time the PGA is filed each year, the Company has injected most of its gas into storage for withdrawal during the heating season. Consequently, the Company's estimated cost of gas in storage when it files the PGA is usually close to the Company's actual cost, because most of those costs are "locked-in" and won't change due to market conditions.[2] According to the Company, about 30% of the Company's storage injections that can be withdrawn during the heating season have been managed at a WACOG of $0.38431 per therm. Similarly, the price of some "flowing gas supplies" may be known because they are already hedged.[3] The Company also advises that, by mid-August, about 38% of its flowing gas supplies for the heating season were hedged at a WACOG of $0.38527 per therm. Combined, about 68% of the Company's

[2] "Locked-in" means that the gas price is fixed and won't change due to market conditions.

[3] "Flowing gas supply" is gas purchased using hedges or spot market purchases. It does not include stored gas.

weather normalized throughput for the heating season has been hedged at a WACOG of $0.38516. The supplies that have not been hedged are estimated based upon an independent, third-party price forecast. The Company anticipates its remaining throughput needs will be at a slightly lower WACOG. With the additional fuel charges to move gas at the city gate, plus some variable transport costs, administrative fees and contributions, the Company's proposed WACOG is $0.39482 per therm. As reflected in Chart 1, the proposed WACOG will be the second increase following several years of consecutive decreases.

Chart 1



	'00	'01	'02	'03	'04	'05	'06	'07	'08	'08* Dec.	'09**	'10	'11	'11* Dec.	'12**	'13	'14 Prop.
WACOG ($/Therm)	0.286	0.388	0.320	0.475	0.554	0.732	0.685	0.635	0.784	0.674	0.496	0.492	0.453	0.418	0.334	0.373	0.394

* % Change based on previous regularly scheduled PGA filing

** % Change based on previous December filing

Market Fundamentals & Price Analysis

Even though most of the Company's forecasted throughput has already been hedged or injected into storage at fixed prices, changes in market conditions can still impact the WACOG. Consequently, Staff closely analyzed the Company's projected monthly cost to buy gas. Staff compared the Company's forecast to forecasts from national and regional organizations, including the Energy Information Administration (EIA), the Northwest Gas Association (NWGA), and the Northwest Power and Conservation Council (NWPCC).[4] Overall, the 2014-2015 forecasts are consistent, predicting relatively stable near term gas prices. A few factors that might cause uncertainty include: 1) Increased gas-fired electric generation; 2)

[4] Staff used the most recent EIA Annual Energy Outlook 2014, the NWGA's 2014 Gas Outlook, and the NWPCC's Revised Fuel Price Forecasts for the Seventh Power Plan.

Increased demand for exports of LNG from Canada and the United States; and 3) Increased demand from gas-to-liquid projects.

The EIA projects Henry Hub prices to decrease in 2015 from an average price of \$4.46/MMBtu in 2014 to \$4.00/MMBtu in 2015. Similarly, the NWPCC's medium case scenario predicts Henry Hub prices in 2015 to drop slightly, from \$4.73/MMBtu in 2014 to \$4.59/MMBtu in 2015. The Company buys most of its gas from the AECO basin, which this year is discounted by about 10% compared to Henry Hub Futures prices.

Staff developed its own forecast using the NYMEX/NGX Futures prices at each of the three hubs where the Company buys gas. Using the Company's estimated volume allocation percentages for these three hubs, Staff forecasts the volume-weighted cost of gas to be \$3.6816/MMBtu. The Company's forecasted mainline fuel cost of \$3.8263/MMBtu is comparable to Staff's forecast. The Company's proposed WACOG of \$3.9482/MMBtu is slightly higher than its mainline fuel cost because the proposed WACOG includes variable interstate transportation costs, British Petroleum (BP) administrative fees, and Gas Research Institute (GRI) contributions. Based on Staff's review of the market, the Company's weighted average cost of its current hedges, and the Company's estimated cost of forward-looking index purchases, Staff believes that the Company's proposed WACOG of \$0.39482 per therm is reasonable. Staff recommends that the Commission accept the proposed WACOG and direct the Company to return to the Commission with a new filing if prices materially deviate from proposed rates during the upcoming year.

Risk Management

Staff evaluated the Company's operations to determine whether the Company bought gas at market prices and whether the Company minimized risk to ratepayers. Staff paid particular attention to how the Company manages price and risk given the Company's market purchases, storage, and interstate transportation capacity.

The Company supplies its mainline requirement with hedges, spot market purchases and underground storage. Underground storage lets the Company buy gas for the winter during the summer when gas typically costs less. The Company also sells LNG from its above-ground storage facility to provide customers with a \$405,411 PGA credit while still using the LNG to meet its customers' peak day gas needs. When opportunities are available, the Company continues to manage its interstate transportation capacity so it can sell surplus capacity in the market.

Overall, the Company's strategy for managing its resource portfolio continues to provide price stability for customers. The Company's approach is flexible, which allows it to be opportunistic in buying gas, managing storage, and using interstate transportation capacity if market conditions change.

Purchasing

Staff reviewed the Company's purchasing strategies to see whether the Company reasonably changed them to meet current market conditions. When compared to last year, the Company plans to buy about the same percentage of its mainline throughput requirement using index or spot purchases. About 28.3% of the Company's total throughput is now index or spot purchases, compared to 28.6% last year. The Company's hedged supply went from 42.9% of total throughput last year to 44.1% this year. Including the Company's storage gas, about 72% of its total throughput is essentially hedged.

The Company has increased its hedging ratios during the summer months, but decreased its hedging ratios in the non-summer months. According to the Company, prices dropped low enough in the summer to meet its trigger prices. Table 3 compares the Company's proposed WACOG hedging ratios with those from the past four regularly scheduled PGA filings.

Table 3

	% Locked-in Gas by PGA Year*				
	2010	2011	2012	2013	2014
Non-Summer Months (Oct.-Mar.)	68	69	63	79	74
Summer Months (Apr.-Sept.)	29	0	45	48	63
Full Year	59	52	59	71	72

* % Locked-in gas includes storage volumes that are both hedged and index purchases.

Staff believes the Company's hedging ratio adjustments match current market conditions, particularly given that natural gas is expected to be used more for electric generation, which could cause short term variability in summer prices. The Company continues to rely on its index or spot purchases, but Staff believes the Company can react to upward price risk given that most of the Company's hedged volumes are locked-in at reasonable prices.

Natural Gas Underground Storage

The Company uses two underground storage facilities: Jackson Prairie owned by Northwest Pipeline, and Clay Basin owned by Questar. These facilities' combined capacity is about 94 million therms. This year, the Company credited $489,915 after the Company changed its asset manager for part of Clay Basin storage. The credit issued because the Company's new Asset Management Agreement excludes cycling costs and increases the market value of the Company's storage gas when it is not needed, which consequently lowers the Company's overall payment for storing gas at Clay Basin.

The capacity of underground storage is fixed. In general, underground storage capacity becomes a proportionately smaller piece of the Company's potential hedging strategy as throughput increases. The Company decides whether to serve load using storage withdrawals based on the price of its locked-in hedges and its forecasted spot market prices. Customers typically benefit from underground storage because the Company can buy low-priced gas during the summer for use in the winter, when prices are generally higher. Storage also provides system peaking capacity for unusually high demand events or backup for potential pipeline disruptions and curtailments.

Staff reviewed the Company's strategy for utilizing underground storage, specifically focusing on whether changes from last year make sense given the market fundamentals. When compared to last year, the Company plans to use storage to meet about the same percentage of total throughput. Last year, storage gas served approximately 28.5% of total throughput, whereas this year it is expected to serve 27.4% of total throughput. The Company plans to withdraw slightly less of its underground storage because its hedged supply is locked in at prices comparable to the storage WACOG, plus it expects spot market prices to remain low. Staff supports the Company's decision to rely less on underground storage, particularly given its hedges are locked at reasonable rates and current market forecasts indicate stable prices and mild winter weather.

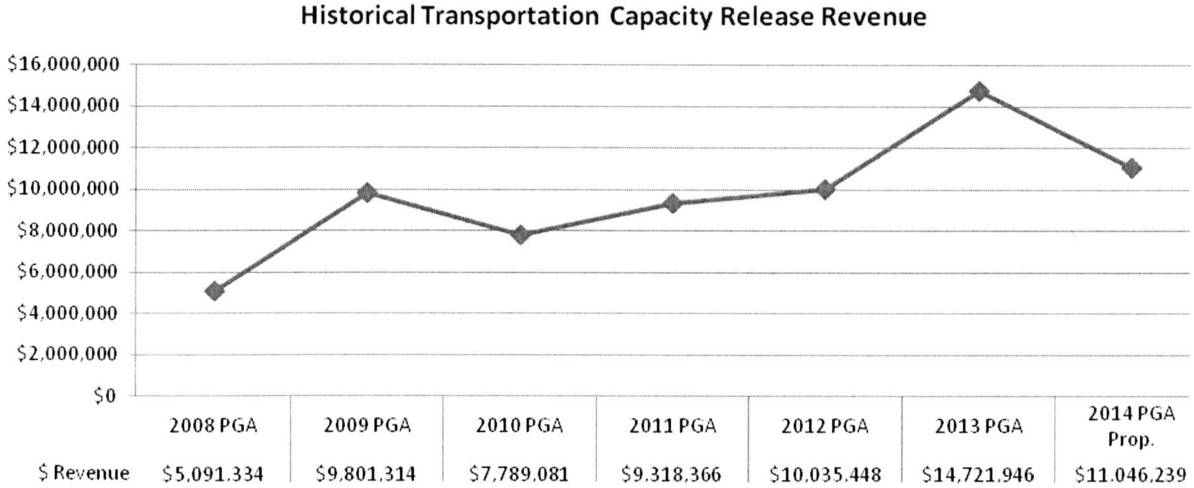
Interstate Transportation

The Company delivers domestically produced natural gas to its city gates through Northwest Pipeline, an interstate transportation provider whose pipeline runs through the Company's service territory. The Company also delivers natural gas from Canada by using capacity on Gas Transmission Northwest (GTN), TransCanada's Foothills Pipeline system (Foothills), and TransCanada's Alberta system known as Nova Gas Transmission (NOVA).

The Company continues to lower its fixed costs by managing its interstate transportation capacity. For example, this year the Company replaced some of its year-round capacity with winter-only capacity, and purchased discounted capacity to match its upstream take-away capacity at Stanfield. Combined, this saved customers $872,499 and allowed more deliverability into Northwest Pipeline at the Stanfield receipt point. This allows the Company access to Alberta based supplies, which the Company currently believes will deliver the lowest priced supply in future months.

Whenever the Company has surplus capacity because demand is low, it sells that capacity at the highest market price available that day. All benefits made from these sales are credited to customers. Staff analyzed the Company's historical capacity release revenue to see how that revenue varies annually. The Company's total capacity release revenue this year is about $11 million, which consists of revenues from firm capacity releases on a segment of Northwest Pipeline and from non-segmented upstream capacity releases on pipelines delivering gas from Canada. Over all, Staff discovered the capacity release revenue generated during the 2013 PGA year was considerably higher than it was in most other years as shown in Chart 2:

Chart 2



According to the Company, slow economic growth contributes to higher capacity release revenue. The increased revenue occurs because the Company has more surplus capacity to sell because customers are using less gas, and because some marketers try to remain financially viable by giving up the capacity they've previously nominated. Consequently, fewer parties hold available capacity to meet demand or sell in the marketplace in competition with the Company, which makes it more likely that the Company's extra capacity will be purchased by others.

The Company seems to actively manage its capacity, but Staff encourages the Company to continue aggressively marketing its surplus capacity when it is available, particularly given that the Company is ideally positioned geographically to take advantage of liquidity at the various purchase points it utilizes.

Recovery of Lost and Unaccounted for Gas (LAUF Gas)

LAUF Gas is the difference between the volumes of natural gas delivered to the distribution system at the city gate and volumes of natural gas billed to customers at the meter. The Company recovers LAUF Gas amounts through a per therm surcharge if the amount is above what was included in Commission-approved base rates. Conversely, the Company credits customers if the amount is below what was included in base rates.

This year, the Company estimates about 2.9 million therms of LAUF Gas, or 0.48% of total throughput, below the maximum allowable amount of LAUF Gas specified in Commission

Order No. 30649.[5] The total normalized level of LAUF Gas embedded in base rates yields $1,110,982 of LAUF Gas already collected.[6] The Company wants to collect the difference between the $1,110,982 normalized level of LAUF Gas already collected through base rates and the total estimated October 2013 to September 2014 LAUF Gas of $1,174,738. The difference, or the under-collection, will be a $63,756 surcharge to customers. When the true-up amounts from last year are included, the Company is proposing to surcharge customers a total of $634,066 for LAUF Gas. This surcharge collects the difference between last year's LAUF Gas estimate of 1,977,331 therms, and the Company's actual LAUF Gas of 3,328,777 therms. Last year's forecasted LAUF Gas was about .323% of throughput, while the Company's actual LAUF Gas was about .548% of throughput (still under the Commission's LAUF Gas cap of .85% of throughput).

Each year, to retrospectively audit the Company's actual LAUF Gas percentage of overall throughput, Staff typically requests a modified version of Workpaper No. 8. Since a portion of each year's LAUF Gas and throughput is estimated due to the filing date of the PGA, the modified workpaper allows Staff to review a full year of actual LAUF Gas to ensure the LAUF Gas percentage of overall throughput is less than the cap. Going forward, the Company has agreed to provide a workpaper in its Application that retrospectively looks at the actual LAUF Gas percentage of overall throughput.

Line Break- Lost and Unaccounted for Gas

Staff investigated the Company's LAUF Gas Reports to determine whether the Company's calculations were accurate. The Company completes Gas Loss Reports when known leaks and line breaks occur between the citygate and customers' meters. The reports include an estimate of gas that escapes from the pipeline during the break. At the end of the year, the lost gas is totaled up and subtracted from the annual LAUF Gas statistics. The reports are also used to calculate the cost billed to the responsible party, which also reduces annual PGA costs.

Before this year, the Company only used the WACOG to price the lost gas but excluded the Company's fixed costs to transport the gas through pipelines and the cost of the Company's

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[5] The Company uses actual LAUF Gas results through July and estimates the amount of LAUF gas from August through September. Commission Order No. 30649 caps the Company's allowable LAUF gas at .85% of throughput.

[6] In 1985, the Commission established $0.00182 per therm as the normalized unit cost that can be collected for LAUF Gas as part of base rates.

storage facilities. In Case No. INT-G-13-05, Staff raised concerns about the Company's pricing. In response, the Commission stated: "in the future the Company shall bill the full retail rate to the responsible party when pricing lost gas due to a line break." Order No. 32897. This year, in most instances, the Company priced all gas from line breaks using the WACOG rate, plus the Residential Schedule No. 1 (RS-1) fixed costs of interstate transportation and storage. According to the Company, it believes the Commission's intent when referring to the "full retail rate" was to have the Company include the WACOG, in addition to the fixed cost of interstate transportation and storage, when pricing lost gas due to a line break. According to the Company, using the full retail rate would be administratively burdensome for pricing lost gas, particularly when the party responsible for the line break is not a customer. Overall, Staff agrees that it is less burdensome to have one rate apply to all responsible parties, particularly given the majority of gas lost due to line breaks was the cause of parties who were not customers. The full retail rate may also include costs that are unrelated to the per therm cost of a line break, or occur downstream of the line break (e.g. - meter costs, A&G, O&M, ROR, taxes etc.). Staff recommends that in the future the Company bill the responsible party for a line break by pricing lost gas using the WACOG and the RS-1 fixed cost of interstate transportation and storage.

Similar to last year, this year Staff discovered instances where the Company inadvertently charged the incorrect rate for gas lost due to line breaks. Specifically, in some instances, the Company continued only using the WACOG to bill the responsible party. According to the Company, Staff's review has caused it to reevaluate its internal process for pricing the lost gas due to a line break. In the future, the Company will make its Engineering Department responsible for reconciling the impact of lost gas due to line breaks. Previously, the Company had two separate departments reconciling the impact of lost gas due to line breaks, which apparently caused errors. Also the Company now plans to hard code the price of gas into an electronic system, so the price remains static throughout the PGA year and need not be manually entered by field personnel each time. After meeting with the Company to discuss its LAUF Gas Reports, Staff believes the Company's administrative changes will correct errors that have occurred the last few years. The Company's calculation errors are small and will not impact customers. Staff thus believes the Company's LAUF Gas amount is reasonable.

Other Considerations

The Company allocates the volume-weighted average costs of gas to each customer class based on peak-day usages. Before 2012, the peak day used for allocating the volume-weighted average costs of gas occurred in 1990. But since the 2012 PGA, the Company has used a peak day that occurred December 2009 to allocate the volume-weighted average costs of gas. According to the Company, the update from the 1990 peak-day allocators to the 2009 peak-day allocators appreciably impacted the customer class allocations.

Through discovery, Staff learned the Company exceeded the December 2009 peak day usage in December 2013. According to the Company, updating the allocation factors to the December 2013 peak day would have an immaterial impact. Regardless, Staff believes the Company should use the more recent peak day. The Company's decision to update its demand allocation factors for class cost-of-service should not be subjectively determined. Staff recommends that in the future the Company update its peak demand allocation factors in the PGA filing following a new peak day.

CUSTOMER RELATIONS

The Company's press release and customer notice were included with the Application. Staff reviewed both documents and found one technical deficiency. The press release and customer notice did not include all of the information required by the Commission's Rules of Procedure (IDAPA 31.01.01). Rules 125.01.c and 125.04 require a utility to inform customers that a copy of the utility's application is available for public review at the offices of the utility. The Company's offices are not open to the public, but its application is available on the Company's website. At its Decision Meeting on August 18, 2014, the Commission accepted Staff's recommendation that the Commission deem the Company's posting of the application on its website to substantially comply with Rule 125. *See* Order No. 33099, fn 1.

The customer notice was included with bills mailed to customers beginning August 13 and ending September 11, 2014. Customers have the opportunity to file comments on or before September 17.

As of September 11, the Commission has received four comments. All opposed to the proposed increase.

In comments filed in last year's PGA case (INT-G-13-05), Staff discussed its concerns about the Company's tariff and noted that the Company had agreed to work with Staff to revise its rate schedules and the General Service Provisions. The Commission approved a substantial revision earlier this year, and Staff anticipates that the Company will file rate schedule revisions shortly after the conclusion of this case.

In last year's comments, Staff indicated that it was working with the Company to better understand what actions the Company takes to verify that customers are billed under the most appropriate rate schedule. Staff examined the Company's procedures for reviewing rate classification as well as its audit process for identifying meter/equipment failures. As a result of Staff's discussions with the Company, the Company modified its procedures and audit parameters, and plans to continue to refine and improve its processes. The Company also revised its summary of rules and rates mailed to customers annually. The summary describes the eligibility requirements for each customer class, and advises customers to contact the Company if there has been a change in appliances that would affect their rate classification.

STAFF RECOMMENDATION

After thoroughly examining the Company's Application and gas purchases for the year, Staff recommends the Commission approve the Company's Application and filed tariffs to increase the Company's annual revenue by $6,693,489 and establish a WACOG of $0.39482 per therm. However, Staff recommends that when the Company bills the responsible party for a line break in the future, the Company should price lost gas using the WACOG and the RS-1 fixed cost of interstate transportation and storage. Furthermore, Staff recommends that in the future the Company update its peak demand allocation factors in the PGA filing following a new peak day.

Respectfully submitted this 17th day of September 2014.

Karl T. Klein
Deputy Attorney General

Technical Staff: Matt Elam
Donn English
Daniel Klein

i:umisc/comments/intg14.1kkmededk comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 17TH DAY OF SEPTEMBER 2014, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. INT-G-14-01, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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