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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE ANNUAL PURCHASED GAS ADJUSTMENT (PGA) FILING OF INTERMOUNTAIN GAS COMPANY.	**CASE NO. INT-G-12-01** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Neil Price, Deputy Attorney General, in response to the Notice of Application, Notice of Modified Procedure and Notice of Intervention Deadline, issued on September 5, 2012, Order No. 32632, submits the following comments.

BACKGROUND

On August 10, 2012, Intermountain Gas Company ("Intermountain" or "Company") filed its annual Purchased Gas Cost Adjustment ("PGA") and requested a Commission Order, pursuant to *Idaho Code* §§ 61-307 and 61-622, to institute new rate schedules which will decrease its annualized revenues by $6.0 million. Intermountain attached copies of its current rate schedules and proposed rate schedules to its Application.

Intermountain's Application also seeks to refund approximately $11.9 million of variable deferred credits through a one-time credit. It is proposing to divide the credit balance by actual sales volumes over the time period it was generated to arrive at the per therm credit. The calculated credit would be reflected as a line item on customer bills in December 2012.

Intermountain's Application lists the following cost variations that it seeks to pass-through to each of its customer classes:

> (1) an increase in costs billed Intermountain from Northwest Pipeline GP ("Northwest" or "Northwest Pipeline") reflecting a January 1, 2013 price increase and the purchase of additional Northwest capacity, (2) a decrease in Intermountain's weighted average cost of gas, or "WACOG," (3) an updated customer allocation of gas related costs pursuant to the Company's PGA provision, (4) the inclusion of temporary surcharges and credits for one year relating to natural gas purchases and interstate transportation costs from Intermountain's deferred gas cost accounts, and (5) benefits resulting from Intermountain's management of its storage and firm capacity rights on various pipeline systems. Intermountain also seeks with this Application to eliminate the temporary surcharges and credits included in its current prices during the past 12 months, pursuant to Order No. 32372 per Case No. INT-G-11-01.

The net effect of the above changes would result in an overall price decrease to Intermountain's customers.

Intermountain claims that its proposed price changes 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 as well as any volumetric adjustments in contracted transportation agreements which have occurred since Intermountain's last PGA filing, Case No. INT-G-11-01.

Intermountain's Application states that natural gas prices have continued to fall. Record storage levels combined with ample natural gas supplies have kept the near-term prices for natural gas low.

Intermountain states that it has entered into various fixed price agreements to lock-in the price for significant portions of its underground storage and other winter "flowing" supplies.

Intermountain seeks to pass through to its customers the benefits that will be generated from the management of its transportation capacity totaling $3.7 million. Further, Intermountain's proposal seeks to allocate deferred gas costs from its Account No. 186 balance to its customers through temporary price adjustments to be effective during the 12-month period ending September 30, 2013.

Intermountain states the Company provided notice of the proposed changes to its tariff schedules through the issuance of a formal Customer Notice and Press Release.

Intermountain proposes an effective date for the proposed changes of October 1, 2012.

STAFF ANALYSIS

Staff has thoroughly reviewed the Company's Application and gas purchases for the year to verify that the filing will not change the Company's earnings, that the deferred costs are prudent, and to determine the reasonableness of the WACOG request.

In this year's PGA, the Company is proposing to credit a grand total of approximately $17.9 million to customers. Approximately $11.9 million of this total is being passed back to customers as a one-time credit on their December bill. This amount is the difference between the actual cost of purchased gas and the WACOG embedded in rates during the period of July 2011 through June of 2012. An additional $6.0 million in revenue is being passed back to customers through an average decrease in rates of 2.4% starting October 1, 2012. This is primarily due to a continued decline in the future cost of purchased gas. The combination of both credits provides customers with an overall price decrease of 7.1%.

The table below illustrates how the proposed decrease will impact the customer classes served by the Company:

Table 1

Customer Class:	Proposed Change in Class Revenue	Proposed Average Change in $/Therm	Proposed Average % Change	Proposed Average Price $/Therm
1 Residential	$ (129,157)	(0.00375)	-0.43%	0.86083
RS-2 Residential[1]	(4,257,533)	(0.02371)	-3.12%	0.73575
GS-1 General Service[2]	(2,390,316)	(0.02206)	-3.14%	0.68142
LV-1 Large Volume	(165,981)	(0.05126)	-10.14%	0.45443
T-3 Transportation	304,548	0.00419	25.90%	0.02037
T-4 Transportation	594,418	0.00419	10.10%	0.04566
T-5 Transportation	77,952	0.00419	13.61%	0.03498
	$(5,966,069)		-2.37%	

The overall effect of the proposed changes in the Company's Application is a decrease in annual revenue received by Intermountain Gas Company of $5,966,069. This decrease is comprised of the following items:

[1] There were no therm sales under the IS-R and IS-C tariffs. However, the IS-R price is based on the RS-2 December-March price and receives the same PGA adjustments and the IS-C price is based on the GS-1 December-March price and receives the same PGA adjustments.

Table 2

Deferrals:		
Removal of INT-G-11-01 Temporary Credits	$ 21,807,555	
Removal of INT-G-11-01 Lost and Unaccounted for Gas	$ 1,446,804	
INT-G-12-01 Temporary Credits	$ (9,816,649)	
Total Deferrals		$ 13,437,710
Lost and Unaccounted for Gas (INT-G-12-01)		$ 2,138,220
Reallocation of fixed costs		$ (261,440)
Changes in the Weighted Average Cost of Gas		$ (27,099,859)
Fixed Cost Changes:		
Northwest Pipeline	$ 6,255,437	
New Upstream Capacity Costs	$ (644,033)	
SGS & LS Changes	$ 50,223	
Other Storage Facilities Cost Changes	$ 157,673	
Total Fixed Cost Changes		$ 5,819,300
Total Annual Price Change		**$ (5,966,069)**

Weighted Average Cost of Gas (WACOG)

Intermountain Gas proposes to reduce the WACOG from $0.4181 per therm to $0.3349 per therm. This is a 19.9% decrease from the WACOG authorized in the Company's December 2011 WACOG decrease filing that went into effect on February 1, 2012 (Commission Order No. 32450), and a 26.1% decrease from the WACOG approved in the normally scheduled 2011 PGA that went into effect on October 1, 2011 (Commission Order No. 32372). Based on the following analysis, Staff believes: (a) the Company's methods are solid and accurate; (b) the proposed WACOG reduction compared to the previous WACOG correlates with current and future economic factors that influence the natural gas market; and (c) the proposed WACOG reasonably compares to benchmark market prices. Staff recommends the Commission accept the Company's proposed WACOG. However, Staff recommends that the Company return to the Commission with a new filing if prices materially deviate from the proposed rates during the upcoming year.

The WACOG is used to determine the rate changes proposed by the Company's PGA filing. The Company estimates a volume-weighted average cost by averaging the sum of forward natural gas prices multiplied by projected purchase volumes for each supply source and contracting instrument the Company utilizes. First, forward natural gas prices are established for each supply source using various future price indexes and forecasts adjusted by economic factors that affect the natural gas market and by the Company's established purchasing practices. Then, projected purchase volumes are allocated for each source and contract instrument considering pipeline capacity constraints, current contracts, and future prices.

Because previously authorized WACOG's (INT-G-11-03, INT-G-11-01, and INT-G-10-03) embedded in rates exceeded actual gas cost, the Company over-collected an estimated $13.2 million in variable cost in spite of filing a WACOG decrease authorized on February 1, 2012. The Company proposes reimbursing customers for $11.9 million of this amount through a one-time credit on their December bill (See section on "One-time Credit" under Customer Relations). The remaining amount is proposed to be netted out of the 2012 PGA filing through adjusted rates over the next year.

Staff reviewed the Company's proposed WACOG in three different ways. First, Staff reviewed the Company's filing to determine if the Company's methodology and calculations were sound. Second, Staff analyzed trends in the Company's WACOG to judge whether the Company's proposal is reasonable given current and future market conditions. Finally, Staff analyzed whether the proposed WACOG reasonably compares to third-party market prices.

Method and Accuracy Review

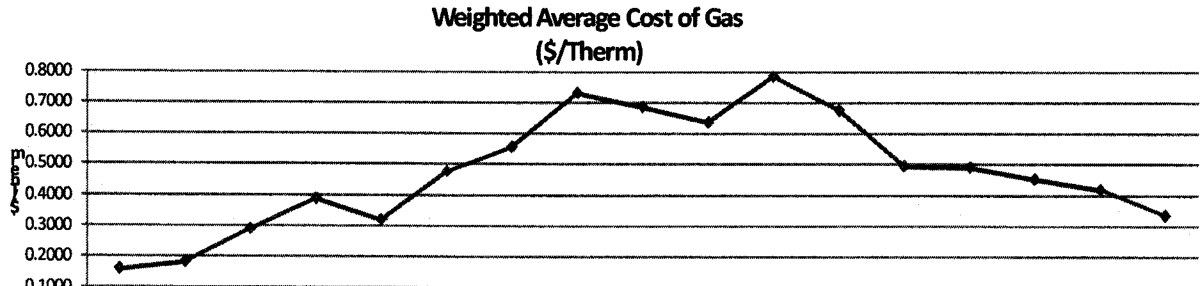
After completing the first part of the analysis, Staff believes that the Company's methodology is sound and that the calculations in the filing are accurate. In addition, Intermountain Gas has implemented two improvements from recommendations Staff made in last year's comments related to the Company's methods. First, approval of the fixed cost collection rate was incorporated as part of the Company's PGA filing rather than through a separate approval by Staff after the PGA is authorized. Second, the Company has organized gas contracts and documents that the Company used to develop the WACOG so that Staff can more easily locate and review them; however, transportation and storage contracts were not easily traceable to figures in the PGA and could use improvement.

From a review of this year's filing, Staff recommends the Company include all electronic versions of exhibits and workpapers as part of its initial filing. This will assist the Commission Staff in expediting processing the application.

Market Trend Analysis

After analyzing the WACOG trend given current and future market conditions, Staff concludes that a continued trend for a decrease in the Company's WACOG is reasonable. As reflected in Chart 1, the proposed WACOG, if approved, will be the sixth consecutive decrease. It is about equivalent to the 2002 WACOG in nominal dollars.

Chart 1



	'98	'99	'00	'01	'02	'03	'04	'05	'06	'07	'08	'08* (Dec.)	'09**	'10	'11	'11* (Dec.)	12**
WACOG ($/Therm)	0.1568	0.1825	0.2867	0.3880	0.3200	0.4750	0.5549	0.7322	0.6850	0.6358	0.7848	0.6748	0.4960	0.4921	0.4534	0.4181	0.3349
% Inc. or Dec. from Prev. Year	0.0%	16.4%	57.1%	35.3%	(17.5%)	48.4%	16.8%	31.9%	(6.4%)	(7.2%)	23.4%	6.1%	(26.5%)	(0.8%)	(7.9%)	(7.8%)	(19.9%)

* % Change based on previous regularly scheduled PGA filing
** % Change based on previous December filing

There are several factors that have driven the price of gas to the lowest levels seen in over ten years, all related to continued soft demand and a steady supply of working natural gas. This is reflected by the amount of gas in storage nationally which is currently 13.1% higher than this time last year and 10.7% higher than the 5-year average.[2] Factors include:

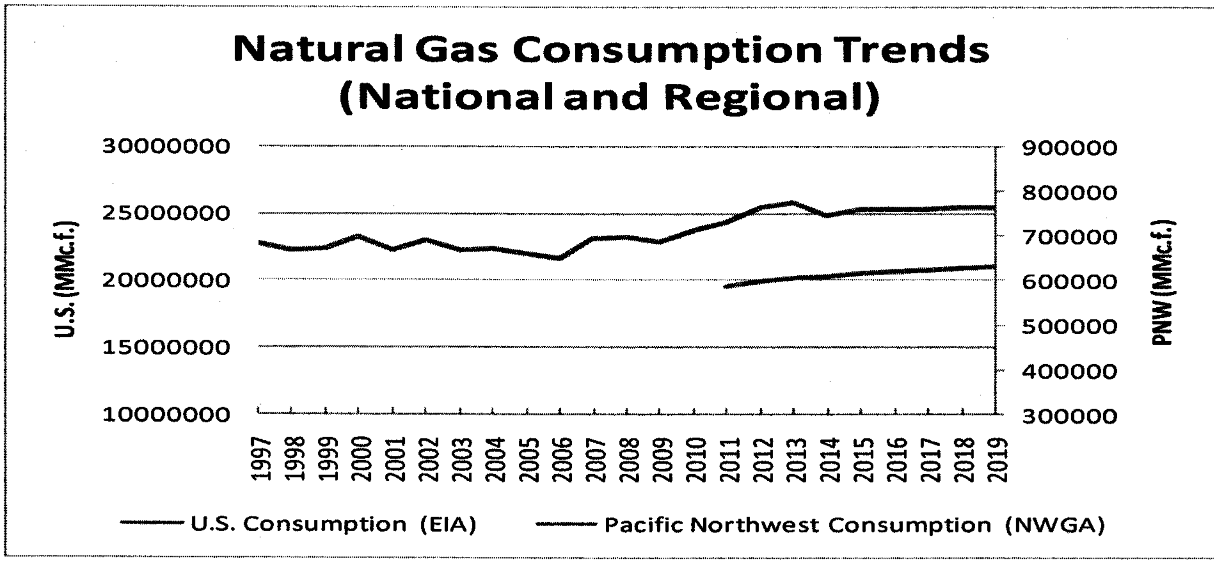
- Continued weak economic conditions;
- A mild winter of 2011-2012;
- A prolific increase in the supply of shale and unconventional gas;
- An increase in the amount of natural gas from oil drilling; and
- Storage balances filled to capacity sooner than expected.

One of the biggest factors is related to a lack of demand pressure on prices. Weak national and regional economic conditions have persisted since the recession as reflected by the relatively

[2] EIA, Natural Gas Weekly, September 5, 2012.

low near-term demand growth in both regional and national natural gas markets as forecasted by the EIA and Norwest Gas Association (See Chart 2 below). However, one trend to watch over the next few years is an increase in natural gas use for electricity generation which has increased 7.2% over last year's figures.[3] Electric utilities are increasingly relying on natural gas generation to fill baseload needs vacated by retirement of aging coal plants and the cost-prohibitive option of building new coal plants to meet future needs that can meet new federal emission control regulations.[4]

Chart 2



On the supply side, production of natural gas continues to grow in spite of lower natural gas prices. This is due to reduced costs in accessing shale and other non-traditional gas resources and the use of newer more advanced drilling technology which has increased well productivity. In fact, EIA reports increases in dry shale gas production even though the number of active rigs show a steady decline over the same period.[5]

[3] EIA, U.S. consumption of natural gas by end use, Sept. 7, 2012 STEO: (http://www.eia.gov/emeu/steo/pub/cf_tables/steotables.cfm?tableNumber=8) in bold and italics; all others from Annual Energy Outlook 2012: (http://www.eia.gov/oiaf/aeo/tablebrowser/)

[4] The primary regulations driving reduced coal plant investment includes Mercury and Air Toxics Standard Rules (MATS), Regional Haze Rules (BART), and EPA's proposed Carbon Pollution Standard.

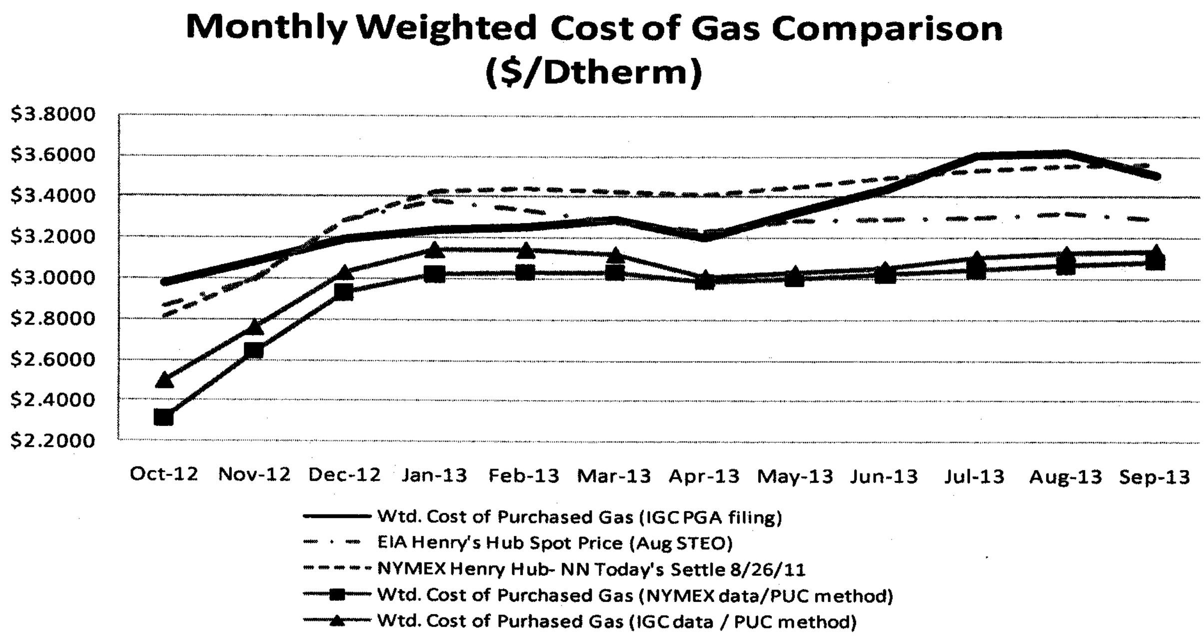
[5] See EIA Natural Gas Weekly Update, week ending September 5, 2012.

Price Benchmark Analysis

Staff compared the Company's projected monthly cost of purchased gas used to determine the proposed WACOG to EIA's monthly forecasts[6] and to NYMEX futures prices.[7] Staff believes that the Company's proposed WACOG is conservative but reasonably compares to recognized natural gas price benchmarks.

For comparison purposes, Staff calculated two volume-weighted cost of purchased gas estimates using volume allocation percentages for the three hubs where Intermountain purchases gas.[8] The first estimate used NYMEX/NGX futures prices and differentials based on August 20 settles; the second used Company-adjusted price forecasts based on NYMEX/NGX futures prices and differentials based on August 3rd settles included in the PGA Application.[9]

Chart 3



The analysis, illustrated in Chart 3, shows the Company's monthly purchased gas cost to be generally higher than Staff's estimates, especially during the early winter months (October and

[6] EIA, *STEO* (Sept 7, 2012 STEO), Table 5b. U.S.Regional Natural Gas Prices, (http://www.eia.gov/emeu/steo/pub/cf_tables/steotables.cfm?tableNumber=16)

[7] Prices are based on settlements that occurred on August 20, 2012.

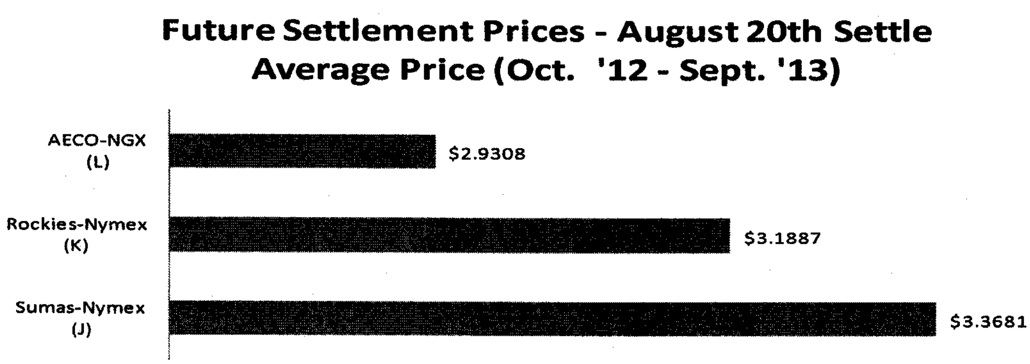
[8] These allocation percentages are forecasts based on historical allocations supplied by the company through audit requests. These are not the same allocations used in the WACOG calculation for the PGA.

[9] Intermountain Gas is supplied by three natural gas hubs (Rockies, Sumas, & AECO). Futures settlement prices are reported daily as a price differential from the NYMEX Henry's Hub price.

November) and summer months (April through September). The two factors contributing the largest differences are: (1) the sourcing of higher priced Rockies index-priced gas that is $0.26 per therm more expensive than index-priced gas sourced from AECO; and (2) price premiums embedded in the price of hedged contracts.

The first factor is reflected by the Company's WACOG sourcing more than 50% of its index-priced gas from higher priced Rockies basin and only 17% from price-leader AECO (See Chart 4). This is compared to Staff's estimates of 30% for Rockies and 65% from AECO. However, the Company is contractually obligated to take delivery of Rocky Mountain index gas due to long-term contracts that have been in place for several years. Beyond contractual obligations, Staff believes this is prudent in spite of paying a higher price by maintaining source diversity that contributes to assurance of supply through pipelines that the Company has reserved capacity.

Chart 4



The second factor can be attributed to price premiums and costs embedded in the price of hedged contracts and purchasing strategies. The Company has 59% of its gas volume "locked in" at prices that are generally greater than current natural gas futures prices. As will be discussed in the next section, Staff believes the Company struck a good balance between price stability, protecting consumers from higher price risk, and ability to take advantage of future bargain prices. Given all of these factors, Staff believes that the Company's proposed WACOG is reasonable and recommends approval.

Risk Management and Gas Purchasing

As discussed earlier, there are several factors that have pushed natural gas prices to the lowest levels seen in over ten years. However, there are indications that prices have approached the bottom of the pricing cycle and there is a greater than average upward price risk as reflected by NYMEX futures price confidence intervals published by EIA[10] and high and low price forecasts by the Northwest Power Conservation Council.[11]

Through a review of the Company's Application and current purchased gas contracts, Staff believes that Intermountain has made adjustments in its hedging ratios to match current market conditions and to protect consumers from future upward price risk. The table below compares the proposed WACOG hedging ratios with those from the past two regularly scheduled PGA filings. In comparison to previous years, it illustrates how the Company has reduced its hedging ratios over the winter months to match continued soft prices in the near term, while increasing its hedging ratios substantially through the summer months in anticipation of higher prices. Although the Company has increased its ratios, Staff believes it has done so conservatively to allow opportunities to take advantage of continued soft prices without having to pay premiums required for price certainty.

Table 3

	% Locked-in Gas by PGA Year		
	2010	2011	2012 Proposed
Winter Months (Oct.-Mar.)	68.1%	69.4%	63.3%
Summer Months (Apr.-Sept.)	28.7%	0.0%	44.5%
Full Year	58.5%	52.4%	59.0%

In addition, the Company is actively reviewing current and future market conditions through its Gas Supply Risk Oversight Program and is acting accordingly to protect customers from future upward price risk even beyond the current PGA year. Staff is supportive of these reviews given that the focus of the Commission through the PGA is primarily to look at one-year snapshots.

So far, the Company's ability to dynamically adapt to market conditions continues to offer customers savings and, more importantly, mitigate price volatility by hedging intelligently. As evidence, stagnant economic conditions and the Company's hedging strategies allowed the Company to purchase gas for less than the current WACOG set in rates during the past year. This contributed the previously mentioned over-collection of approximately $13.2 million now being credited back to customers during this year's PGA.

[10] See EIA, Short-Term Energy Outlook, August 2012, futures price confidence intervals.
[11] See Northwest Power Conservation Council, Update to the Council's Forecast of Fuel Prices, August 2011.

Temporary Surcharges and Credits

Pursuant to Order No. 32372, Intermountain included temporary credits in its October 1, 2011 prices for the principal reason of passing back to its customers deferred gas cost charges and benefits. The temporary credits consisted of three separate items: (1) a credit of approximately $3.7 million in benefits generated by releasing some pipeline transportation capacity; (2) an additional credit of $5.9 million attributable to the collection of pipeline capacity costs, the true-up of expenses from the 2010 PGA, and capacity release credits generated from the release of Intermountain's pipeline capacity; and (3) the $12.2 million deferred credit balance, which is the difference from the commodity costs that Intermountain actually paid for natural gas and the WACOG that was included in rates. When the temporary credit items are totaled to account for the drop in revenue proposed by the Company, the credits total $21.8 million. In the same case, Lost and Unaccounted for Gas temporary credit deferrals was $1.4 million.

The new temporary credits consist of three separate items: (1) a credit of approximately $3.7 million in benefits generated by releasing some pipeline transportation capacity; (2) an additional credit of $4.8 million attributable to the collection of pipeline capacity costs, the true-up of expenses from the 2011 PGA, and capacity release credits generated from the release of Intermountain's pipeline capacity; and (3) the $1.3 million deferred credit balance, which is the difference from the commodity costs that Intermountain actually paid for natural gas and the WACOG that was included in rates. When the temporary credit items are totaled to account for the drop in revenue proposed by the Company, the credits total $9.8 million. However, when offset by the removal of prior temporaries (including Lost and Unaccounted for Gas) the reduction in revenue is $13.4 million. As shown on page 4, Table 2, the total reduction in revenue is approximately $6 million. This is the combination of the current Lost and Unaccounted for Gas credit of $2.1 million, the proposed $27.1 million revenue reduction due to the reduced WACOG, additional fixed cost changes and the $13.4 million temporary surcharges and credits discussed above.

Natural Gas Storage

Intermountain utilizes natural gas storage to: (1) avoid high winter prices by procuring gas during the summer when prices are cheaper, and (2) provide system designed peaking capacity for unusually high demand events or backup for potential pipeline disruptions and curtailments.

Underground storage is typically used to fulfill the Company's winter storage needs and acts as a hedge to shield consumers from higher winter natural gas prices. The Company has 95 million therms in contracted underground storage capacity at Northwest Pipeline's Jackson Prairie and Questar Pipeline's Clay Basin facilities. All of this capacity will be filled going into the winter heating season. This represents 38% of the Company's November 2012 through April 2013 supply requirement. Through various supply agreements, these storage injections have been locked in at prices ranging from $0.2375 to $0.3852 per therm. These rates bracket this year's proposed WACOG. Any overall differences will be reconciled in customer rates next year.

The Company utilizes Liquid Natural Gas (LNG) storage throughout the year to meet system peaks and to supplement local flows due to pipeline congestion or curtailments. Intermountain has 18.5 million therms in total LNG storage capacity at Northwest Pipeline's Plymouth facility and two Company-owned facilities in Nampa and Rexburg, Idaho. LNG represents approximately 15% of the Company's total storage; however, the Company expects to keep only 50% of its LNG capacity full throughout this winter. Storing significantly more LNG than what is expected to be used during the winter would come at an additional expense to customers because of Intermountain's cost to maintain LNG at a specific temperature.

Pipeline Transportation

Intermountain delivers transported natural gas to its city gates through Northwest Pipeline, an interstate transportation provider whose pipeline runs through Intermountain's service territory. The Company also moves gas from Canada to Northwest Pipeline by utilizing capacity on Gas Transmission Northwest (GTN), TransCanada's Foothills Pipeline system (Foothills), and its Alberta system known as Nova Gas Transmission (Nova). Intermountain's pipeline capacity rates decreased in 2012 resulting in a decrease of approximately $600,000. Northwest Pipeline settled its pre-filed rate case with FERC and will update its rates effective January 1, 2013. Contractual terms with Northwest Pipeline increased daily volume as well as capacity costs by approximately $6 million. Capacity on these pipelines remains a key component in serving customers and maintaining supply diversity. Intermountain will also determine when its contracted interstate transportation is under-utilized due to warmer weather or declines in industrial demand. This capacity will be posted for release to others with the release payments received benefiting Intermountain customers.

Intermountain's proximity to several interstate pipelines allows it to effectively allocate its natural gas supply mix from different basins based on price differentials, and to subsequently redeliver that specified volume on its own distribution pipeline network at the lowest possible price.

Intermountain has traditionally sourced a higher percentage of gas from the Rockies Basin because of Northwest Pipeline's close proximity to the Company's service territory and lower price. However, this has changed over the past year. The completion of the Rockies Express (November 2009) and Ruby (July 2011) pipelines has opened access of Rockies Basin natural gas to the East and to the West, respectively. This has changed the market that the Company uses to source its gas by increasing competition and price for Rockies Basin gas while decreasing competition and the price of gas out of Alberta Canada (AECO-C).

Recovery of Lost and Unaccounted (L&U) for Gas

L&U is the variance between the physical purchase of natural gas from suppliers and the volumes billed to customers over the PGA year. Intermountain asks to recover L&U through a per therm surcharge that is considered above and beyond that which is included in Commission-approved base rates from 1985.

This year the Company is in a "lost gas" position with 4.5 million therms more of gas flowing through customer's meters than into Intermountain's service area. This represents a 0.76% L&U rate approaching the 0.85% cap of L&U as a percentage of total throughput allowed under Order No. 30649. This, in addition to large swings in L&U percentages year-to-year, caused Staff to examine potential root causes. Based on its examination, Staff believes that L&U for this year's PGA is accurate and has been adjusted properly for errors in faulty meters and/or measurement control practices. Staff recommends that the Commission allow the Company to surcharge customers $2,060,867 for L&U requested in the PGA. This is based on amounts the Company has already collected and the amount of estimated L&U gas from this past year.

Because this year's L&U was approaching the 0.85% cap and because of relatively large swings in the L&U from year-to-year, Staff investigated the causes for some of the variation. Staff discovered that the Company had found an error that affected a large customer's bill for approximately the past three years. If not caught, the Company would have been over the cap this year. By adjusting the past three years, L&U rates would have changed from previous filings reducing the size of year-to-year variation as reflected in the table below.

Table 4

PGA Year	Lost Gas Rate (% of Throughput)	% Change (from previous yr)	Adjusted Lost Gas Rate (% of Throughput)	% Change (from previous yr)
2007	0.72%	n/a	0.72%	n/a
2008	0.86%	29.7%	0.86%	19.1%
2009	0.44%	-36.8%	0.57%	-48.6%
2010	0.20%	-36.3%	0.35%	-55.5%
2011	-0.16%	-104.3%	-0.01%	-181.2%
2012	1.19%	-5528.9%	0.76%	-849.6%

Note: Historical rates are actual; 2012 rate includes 3 mos. of estimates.

The Company has continued to meet requirements stipulated in Order No. 30649 by filing semi-annual L&U reports. The Company has expressed interest in reviewing L&U through their integrated resource plan rather than through semi-annual reports; however, Staff believes the Company needs to be able to quantify normal causes of variation with fully capable measuring equipment and processes before shifting to less frequent reviews. Because a "normal" amount of losses have not been determined, Staff recommends the Company continue to submit semi-annual L&U reports for review until the Company can propose a better way to monitor losses to identify causes of variation and subsequently make appropriate adjustments.

In 1985, the Commission established $0.00182 per therm as the normalized unit cost that can be collected as part of base rates. This past year, the total normalized level of L&U gas embedded in base rates yields an amount of $1,078,618 of L&U already collected.[12] Intermountain wants to collect the difference between the $1,078,618 normalized level of L&U gas revenue already collected in current base rates and the total estimated October 2011 to September 2012 L&U gas of $3,139,485. This yields a total of $2,060,867 that the Company requests to be surcharged to customers.

Finally, Staff recommends the Commission maintain the maximum L&U gas recovery at 0.85% of total throughput as specified in Order No. 30649.

[12] This is shown on Workpaper No. 8 included in the Company's PGA application.