EXECUTIVE OFFICES
INTERMOUNTAIN GAS COMPANY
555 SOUTH COLE ROAD • P.O. BOX 7608 • BOISE, IDAHO 83707 • (208) 377-6000 • FAX: 377-6097

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2018 AUG 10 PM 2:45
IDAHO PUBLIC
UTILITIES COMMISSION

August 10, 2018

Ms. Diane Hanian
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington Street
P.O. Box 83720
Boise, ID 83720-0074

RE: Case No. INT-G-18-02

Dear Ms. Hanian:

Attached for consideration by this Commission are the original and seven (7) copies of Intermountain Gas Company's Application for Authority to Change Its Prices on October 1, 2018.

Please acknowledge receipt of this filing by stamping and returning a copy of this Application cover letter to us.

Should you have any suggestions regarding the attached, please don't hesitate to contact me at (208) 377-6168.

Very truly yours,

Michael P. McGrath
Director, Regulatory Affairs
Intermountain Gas Company

Enclosure

cc: Mark Chiles
Scott Madison
Preston Carter

INTERMOUNTAIN GAS COMPANY

CASE NO. INT-G-18-02

APPLICATION,

EXHIBITS,

AND

WORKPAPERS

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY

For Authority to Change its Prices on October 1, 2018

(October 1, 2018 Purchased Gas Cost Adjustment Filing)

Preston N. Carter, ISB No. 8462
Givens Pursley LLP
601 W. Bannock St.
Boise, Idaho 83702
Telephone: (208) 388-1200
Attorneys for Intermountain Gas Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY for Authority to Change its Prices	Case No. INT-G-18-02 **APPLICATION**

Intermountain Gas Company ("Intermountain" or "Company"), a subsidiary of MDU Resources Group, Inc. with general offices located at 555 South Cole Road, Boise, Idaho, pursuant to the Rules of Procedure of the Idaho Public Utilities Commission ("Commission"), hereby requests authority, pursuant to Idaho Code Sections 61-307 and 61-622, to place into effect October 1, 2018 new rate schedules which will decrease its annualized revenues by $24.5 million. Because of changes in Intermountain's gas related costs, as described more fully in this Application, Intermountain's earnings will not be impacted as a result of the proposed changes in prices and revenues. Exhibit No. 1 is a summary of the overall price changes by class of customer and is attached hereto and incorporated herein by reference. Intermountain's current rate schedules showing proposed changes are attached hereto and included within Exhibit No. 2 and is incorporated herein by reference. Intermountain's proposed rate schedules are attached hereto as Exhibit No. 3 and is incorporated herein by reference.

Communications in reference to this Application should be addressed to:

Michael P. McGrath
Director – Regulatory Affairs
Intermountain Gas Company
Post Office Box 7608
Boise, ID 83707
and
Preston N. Carter
Givens Pursley LLP
601 W. Bannock St.
Boise, Idaho 83702

In support of this Application, Intermountain does allege and state as follows:

I.

Intermountain is a gas utility, subject to the jurisdiction of the Commission, engaged in the sale of and distribution of natural gas within the State of Idaho under authority of Commission Certificate No. 219, issued December 2, 1955, as amended and supplemented by Order No. 6564, dated October 3, 1962.

Intermountain provides natural gas service to the following Idaho communities and counties and adjoining areas:

Ada County - Boise, Eagle, Garden City, Kuna, Meridian, and Star;
Bannock County - Arimo, Chubbuck, Inkom, Lava Hot Springs, McCammon, and Pocatello;
Bear Lake County - Georgetown, and Montpelier;
Bingham County - Aberdeen, Basalt, Blackfoot, Firth, Fort Hall, Moreland/Riverside, and Shelley;
Blaine County - Bellevue, Hailey, Ketchum, and Sun Valley;
Bonneville County - Ammon, Idaho Falls, Iona, and Ucon;
Canyon County - Caldwell, Greenleaf, Middleton, Nampa, Parma, and Wilder;
Caribou County - Bancroft, Grace, and Soda Springs;
Cassia County - Burley, Declo, Malta, and Raft River;
Elmore County - Glenns Ferry, Hammett, and Mountain Home;
Fremont County - Parker, and St. Anthony;
Gem County - Emmett;
Gooding County - Gooding, and Wendell;
Jefferson County - Lewisville, Menan, Rigby, and Ririe;
Jerome County - Jerome;
Lincoln County - Shoshone;
Madison County - Rexburg, and Sugar City;
Minidoka County - Heyburn, Paul, and Rupert;
Owyhee County - Bruneau, and Homedale;
Payette County - Fruitland, New Plymouth, and Payette;
Power County - American Falls;
Twin Falls County - Buhl, Filer, Hansen, Kimberly, Murtaugh, and Twin Falls;
Washington County - Weiser.

Intermountain's properties in these locations consist of transmission pipelines, liquefied natural gas storage facilities, a compressor station, distribution mains, services, meters and regulators, and general plant and equipment.

II.

Intermountain seeks with this Application to pass through to each of its customer classes changes in gas related costs resulting from: 1) costs billed to Intermountain from firm transportation providers including Northwest Pipeline LLC ("Northwest" or "Northwest Pipeline"), 2) a decrease in Intermountain's Weighted Average Cost of Gas ("WACOG"), 3) an updated customer allocation of gas related costs pursuant to the Company's Purchased Gas Cost Adjustment ("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, 5) benefits resulting from Intermountain's management of its storage and firm capacity rights on various pipeline systems, 6) a portion of the costs accrued related to Intermountain's Case No. INT-G-16-02 General Rate Case and, 7) customer benefits generated by changes to the federal and state income tax codes. 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 Case No. INT-G-17-05. The aforementioned changes would result in a price decrease to Intermountain's RS, GS-1 and LV-1 customers and a price increase to Intermountain's T-3 and T-4 customers.

These price changes are applicable to service rendered under rate schedules affected by and subject to Intermountain's PGA, initially approved by this Commission in Order No. 26109, Case No. INT-G-95-1, and additionally approved through subsequent proceedings.

Exhibit No. 4 contains pertinent excerpts from applicable pipeline tariffs. Exhibit No. 5 summarizes the price changes in: 1) Intermountain's base rate gas costs, 2) its rate class allocation, and 3) adjusting temporary surcharges or credits flowing through to Intermountain's customers. Exhibit Nos. 4 and 5 are attached hereto and incorporated herein by reference.

III.

The current temporary and cost of gas related prices of Intermountain are those approved by this Commission in Order No. 33887, Case No. INT-G-17-05.

IV.

Intermountain's proposed prices 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 PGA filing in Case No. INT-G-17-05.

The permanent transportation and storage costs included with this Application reflect a net increase of $620,781 as compared to those same costs included in Case No. INT-G-17-05. Northwest Pipeline transportation and storage costs reflect the reduction in transportation and storage rates pursuant to FERC Docket No. RP17-346-000 resulting in a reduction of $694,908 in annual transportation and storage costs to the Company's customers. The Company's upstream transportation charges increased $1.3 million resulting from rate changes from the Company's upstream transportation providers in addition to the acquisition of additional upstream capacity. This same additional capacity puts the Company in a stronger position to leverage the capacity releases that provide benefits to the Company's customers as well as gain access to gas supplies through southern Alberta, Canada, which are projected to be some of the lowest cost supplies over the next 5 to 10 years.

Intermountain continues to effectively manage its natural gas storage assets at Northwest's Jackson Prairie and Questar Pipeline's Clay Basin storage facilities. Supporting documents relating to Line 20 of Exhibit No. 5 include $1.8 million in savings from Intermountain's management of these storage assets.

Exhibit No. 5, Lines 1 through 20, details the proposed changes to Intermountain's prices resulting from Intermountain's cost of storage, interstate and upstream capacity from its various suppliers.

V.

The WACOG reflected in Intermountain's proposed prices is $0.22724 per therm, as shown on Exhibit No. 5, Line 22, Col. (f). This compares to $0.26020 per therm currently included in the Company's tariffs.

Advanced drilling technologies continue to increase drilling efficiencies resulting in even higher production in shale gas wells. Deliverable shale gas reserves in North America are abundant and supplies, in the face of growing demand for natural gas, have continued to outpace the demand for this natural resource. This supply/demand imbalance has contributed greatly to the decrease in the Company's WACOG. From a historical perspective, robust natural gas supplies combined with significant storage balances have kept natural gas prices lower as compared to even a year ago.

Additionally, the proposed WACOG includes benefits to Intermountain's customers generated by the Company's management of its significant natural gas storage assets. Because gas added to storage is procured during the summer season when prices are typically lower than during the winter, the cost of Intermountain's storage gas is normally less than what could be obtained on the open market in winter months. Additionally, in an effort to further stabilize the prices paid by our customers during the upcoming winter period, Intermountain has entered into various fixed price agreements to lock-in the price for portions of its underground storage and other winter "flowing" supplies.

Intermountain believes that the WACOG proposed in this Application, subject to the effect of actual supply and demand and based on current market conditions, provides today's most reasonable forecast of gas costs for the 2018 - 2019 PGA period. Intermountain will employ, in addition to those fixed price agreements already in place, cost effective price arrangements to further secure the price of flowing gas embedded within this Application when, and if, those pricing opportunities materialize in the marketplace.

Intermountain believes that timely natural gas price signals enhance its customers' ability to make informed and appropriate energy use decisions. The Company is committed to alert customers to any significant impending price changes before their winter natural gas usage occurs. By employing the Company's Energy Efficiency programs, customer mailings, the Company's website, and various media resources, Intermountain will continue to educate its customers regarding the wise and efficient use of natural gas, billing options available to help manage their energy budget, and any pending natural gas price changes.

VI.

Pursuant to the Commission's Order in Case No. INT-G-17-05, Intermountain included temporary credits in its October 1, 2017 prices for the principal reason of passing back to its customers deferred gas cost benefits. Line 27 of Exhibit No. 5 reflects the elimination of these temporary credits.

VII.

Intermountain's PGA tariff includes provisions whereby Intermountain's proposed prices will be adjusted for updated customer class sales volumes and purchased gas cost allocations. Intermountain's proposed prices include a fixed cost collection adjustment pursuant to these PGA provisions, as outlined on Exhibit No. 6, Line 25. The price impact of this adjustment is included on Exhibit No. 5, Line 28. The Fixed Cost Collection Rate resulting from the adjustment plus the annual difference in demand charges from Exhibit No. 5, Lines 1 – 20, Col. (h) is shown on Exhibit No. 6, Line 29. Exhibit No. 6 is attached hereto and incorporated herein by reference.

VIII.

Intermountain proposes to pass through to its customers the benefits that will be generated from the management of its transportation capacity totaling $5.5 million as outlined on Exhibit No. 8. These benefits include credits from a segmented release of a portion of Intermountain's firm capacity rights on Northwest Pipeline as well as credits generated from Intermountain's upstream pipeline capacity. Intermountain proposes to pass back these credit amounts via the per therm credits, as detailed on Exhibit No. 8 and included on Exhibit No. 7, Line 1. Exhibit Nos. 7 and 8 are attached hereto and incorporated herein by reference.

IX.

Intermountain proposes to allocate deferred gas costs from its Account No. 191 balance to its customers through temporary price adjustments to be effective during the 12-month period ending September 30, 2019, as follows:

1) Intermountain has deferred fixed gas costs in its Account No. 191. The credit amount shown on Exhibit No. 9, Line 7, Col. (b) of $15.1 million is attributable to a true-up of the collection of interstate pipeline capacity costs, the true-up of expense issues previously ruled on by this Commission, and mitigating capacity release credits generated from the incremental release of Intermountain's pipeline capacity. Intermountain proposes to true-up these balances via the per therm debits and credits, as detailed on Exhibit No. 9 and included on Exhibit No. 7, Line 2. Exhibit No. 9 is attached hereto and incorporated herein by reference.

2) Intermountain has also deferred in its Account No. 191 a variable gas cost credit of $5.0 million, as shown on Exhibit No. 10, Line 2, Col. (b). This deferred debit is attributable to Intermountain's variable gas costs since October 1, 2017. Intermountain proposes to pass back this balance via a per therm credit, as shown on Exhibit No. 10, Line 4, Col. (b) and included on Exhibit No. 7, Line 3.

3) Finally, Intermountain has deferred in its Account No. 191 deferred gas costs related to Lost and Unaccounted for Gas as shown on Exhibit No. 10, Lines 5 through 26, Col. (b). This deferral results in a per therm increase to Intermountain's sales and transportation customers, as illustrated on Exhibit No. 10. This per therm increase is included on Exhibit No. 7, Line 3. Exhibit No. 10 is attached hereto and incorporated herein by reference.

X.

Pursuant to Commission Order No. 32793, Case No. INT-G-13-02, Intermountain has deferred in its Account No. 191 variable gas cost credits associated with sales of liquefied natural gas at its Nampa, Idaho facility. Intermountain proposes to pass back this $529,445 sales credit as outlined on Exhibit No. 11, Line 7. Exhibit No. 11 is attached hereto and incorporated herein by reference.

XI.

Pursuant to Commission Order No. 33887, Case No. INT-G-17-05, Intermountain established a regulatory asset to amortize over a five-year period $378,614 related to external General Rate Case costs associated with Case No. INT-G-16-02. Exhibit No. 12 summarizes the amortization of those costs which are included on Exhibit No. 7, Lines 5 & 6. Exhibit No. 12 is attached hereto and incorporated herein by reference.

XII.

Pursuant to Commission Order No. 34073, Case No. GNR-U-18-01, the Company was directed to credit customers for tax-related benefits it received from January 1 – May 31, 2018 which amounted to $2.7 million. Exhibit 13 summarizes the customer class credits associated with this same tax benefit and is included on Exhibit No. 7, Line 7. Exhibit No. 13 is attached hereto and incorporated herein by reference.

XIII.

Intermountain has allocated the proposed price changes to each of its customer classes based upon Intermountain's PGA provision. However, a straight cents per therm price change was not utilized for the LV-1 tariff as no fixed costs are currently recovered in the tail block of the LV-1 tariff. The proposed changes in the WACOG, and variable deferred debits and credits as outlined on Exhibit Nos. 10 and 11, are applied to all three blocks of the LV-1 tariff. However, all adjustments relating to fixed costs are applied only to the first two blocks of the LV-1 tariff.

XIV.

As outlined on Exhibit No. 2, Page 1, Lines 21 through 29, the T-3 and T-4 tariffs include the following adjustments: a) the removal of existing temporary price changes; b) the Lost and Unaccounted for Gas increase as outlined on Exhibit No. 10; c) the LNG Sales Credits are applied to the T-4 tariff as illustrated on Exhibit No. 11, Line 7, Col. (f); d) a temporary adjustment to recover a portion of Intermountain's Case No. INT-G-16-02 General Rate Case related expenses and; e) deferred credits associated with federal and state income tax reform. The net change from these aforementioned adjustments result in a rate increase for the Company's T-3 and T-4 customers.

XV.

The proposed price changes herein requested among the classes of service of Intermountain reflect a just, fair, and equitable pass-through of changes in gas related costs to Intermountain's customers.

XVI.

This Application has been brought to the attention of Intermountain's customers through a Customer Notice and by a Press Release sent to daily and weekly newspapers, and major radio and television stations in Intermountain's service area. The Press Release and Customer Notice are attached hereto and incorporated herein by reference. Copies of this Application, its Exhibits, and Workpapers have been provided to those parties regularly intervening in Intermountain's rate proceedings.

XVII.

Intermountain requests that this matter be handled under modified procedure pursuant to Rules 201-204 of the Commission's Rules of Procedure. Intermountain stands ready for immediate consideration of this matter.

XVIII.

WHEREFORE, Intermountain respectfully petitions the Idaho Public Utilities Commission as follows:

a. That the proposed rate schedules herewith submitted as Exhibit No. 3 be approved without suspension and made effective as of October 1, 2018 in the manner shown on Exhibit No. 3.

b. That this Application be heard and acted upon without hearing under modified procedure, and

c. For such other relief as this Commission may determine proper herein.

DATED at Boise, Idaho, this 10th day of August, 2018.

INTERMOUNTAIN GAS COMPANY

By /s/ Michael P. McGrath
Michael P. McGrath
Director – Regulatory Affairs

Givens Pursley LLP

By /s/ Preston N. Carter
Preston N. Carter
Attorney for Intermountain Gas Company

CERTIFICATE OF MAILING

I HEREBY CERTIFY that on this 10th day of August, 2018, I served a copy of the foregoing Case No. INT-G-18-02 upon:

Ed Finklea
Alliance of Western Energy Consumers
545 Grandview Drive
Ashland, OR 97520

Chad Stokes
Cable Huston et al.
1001 SW Fifth Avenue, Suite 2000
Portland, Oregon 97204-1136

Don Sturtevant
J. R. Simplot Company
PO Box 27
Boise, ID 83707

by depositing true copies thereof in the United States Mail, postage prepaid, in envelopes addressed to said persons at the above addresses.

/s/ Michael P. McGrath
Michael P. McGrath
Director – Regulatory Affairs

EXHIBIT NO. 1

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

SUMMARY OF PRICE CHANGES

(2 pages)

INTERMOUNTAIN GAS COMPANY
Analysis of Annualized Price Change by Class of Service
Normalized Volumes for Twelve Months Ended December 31, 2017

		Average Prices Effective per Case No. GNR-U-18-01 Commission Order No. 34073			Proposed Adjustments Effective 10/1/2018		Proposed Average Prices Effective 10/1/2018		
Line No.	Description (a)	Annual Therms/CD Vols. (b)	Revenue (c)	$/Therm (d)	Revenue (e)	$/Therm (f)	Revenue (g)	$/Therm (h)	Percent Change (i)
1	Gas Sales:								
2	RS Residential	234,193,235	$ 156,335,694	$ 0.66755	$ (15,632,398)	$ (0.06675)	$ 140,703,296	$ 0.60080	-10.00%
3	GS-1 General Service	121,147,021	71,733,574	0.59212	(8,539,654)	(0.07049)	63,193,920	0.52163	-11.90%
4	LV-1 Large Volume	7,373,615	2,928,800	0.39720	(505,240)	(0.06852)	2,423,560	0.32868	-17.25%
5	**Total Gas Sales**	362,713,871	230,998,068	0.63686	(24,677,292)	(0.06804)	206,320,776	0.56882	-10.68%
6	T-3 Transportation (Volumetric)	43,559,771	528,816	0.01214	36,155	0.00083	564,971	0.01297	6.84%
7	T-4 Transportation (Volumetric)	313,530,305	4,169,953	0.01330	-	-	4,169,953	0.01330	0.00%
8	T-4 Demand Charge	17,280,720 [1]	4,854,500	0.28092	111,806	0.00647	4,966,306	0.28739	2.30%
9	**Total Transportation**	357,090,076	9,553,269	0.02675	147,961	0.00041	9,701,230	0.02716	1.53%
10	**Total**	719,803,947	$ 240,551,337	$ 0.33419	$ (24,529,331)	$ (0.03408)	$ 216,022,006	$ 0.30011	-10.20%

[1] Non-additive demand charge determinants

INTERMOUNTAIN GAS COMPANY
ANALYSIS OF INT-G-18-02 PRICE CHANGE

Line No.	Description	Amount	Total
	(a)	(b)	(c)
1	**Deferrals:**		
2	INT-G-17-05 Temporaries Removed		$ 20,840,697 [(1)]
3	Add INT-G-18-02 Temporaries:		
4	Fixed Deferred Gas Costs	$ (20,553,645) [(2)]	
5	Variable Deferred Gas Costs	(5,040,702) [(3)]	
6	Lost & Unaccounted For Gas Costs	786,421 [(4)]	
7	LNG Sales Credit	(529,445) [(5)]	
8	Deferred General Rate Case Costs	66,986 [(6)]	
9	Tax Reform Deferral	(2,731,841) [(7)]	
10	Total Temporaries Added		(28,002,226)
11	**Total Deferrals**		$ (7,161,529)
12	**Base Rate Price Change:**		
13	Fixed Cost Changes:		
14	NWP Full Rate Reservation	$ (619,134) [(8)]	
15	NWP Discounted Reservation	(44,126) [(9)]	
16	Upstream Full Rate	2,913,851 [(10)]	
17	Upstream Discounted	(1,598,162) [(11)]	
18	SGS & LS	(31,648) [(12)]	
19	Other Storage Facility	- [(13)]	
20	Total Fixed Cost Change	620,781	
21	Changes in WACOG	(11,955,049) [(14)]	
22	Reallocation of Fixed Costs	(6,034,110) [(15)]	
23	**Total Base Rate Price Changes**		(17,368,378)
24	**Total Annual Price Change**		$ (24,529,907)
25	Annual Price Change per Exhibit No. 1, Page 1		$ (24,529,331) [(16)]
26	Difference Due to Rounding		$ (576)

(1) See Workpaper No. 8, Line 2, Columns (b) - (f) times Exhibit No. 1, Page 1, Lines 2 - 4, 6 & 8, Column (b)
(2) See Exhibit No. 8, Line 3, Column (b), plus Exhibit No. 9, Line 7, Column (b)
(3) See Exhibit No. 10, Line 2, Column (b)
(4) See Exhibit No. 10, Line 10 plus Line 18, Column (b)
(5) See Exhibit No. 11, Line 5, Column (b)
(6) See Exhibit No. 12, Page 1, Line 6, Column (b) plus Exhibit No. 12, Page 2, Line 4, Column (b)
(7) See Exhibit No. 13, Line 1, Column (b)
(8) See Exhibit No. 5, Line 3, Column (h)
(9) See Exhibit No. 5, Line 4, Column (h)
(10) See Exhibit No. 5, Line 5, Column (h)
(11) See Exhibit No. 5, Line 6, Column (h)
(12) See Exhibit No. 5, sum of Lines 8 - 19, Column (h)
(13) See Exhibit No. 5, Line 20, Column (h)
(14) See Exhibit No. 5, Line 22, Column (h)
(15) See Exhibit No. 5, Line 28, Columns (i) - (k), times Line 24, Columns (i) - (k)
(16) See Exhibit No. 1, Page 1, Line 10, Column (e)

EXHIBIT NO. 2

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

CURRENT TARIFFS

Showing Proposed Price Changes

(10 pages)

INTERMOUNTAIN GAS COMPANY
Comparison of Proposed October 1, 2018 Prices
To June 1, 2018 Prices

Line No.	Rate Class	Prices per Case No. GNR-U-18-01 Order No. 34073	Proposed Adjustment	Proposed October 1, 2018 Prices
	(a)	(b)	(c)	(d)
1	**RS**	$ 0.57231	$ (0.06675)	$ 0.50556
2	**GS-1**			
3	Block 1	0.58312	(0.07049)	0.51263
4	Block 2	0.55964	(0.07049)	0.48915
5	Block 3	0.53697	(0.07049)	0.46648
6	Block 4	0.46841	(0.07049)	0.39792
7	CNG Fuel			
8	Block 1	0.53697	(0.07049)	0.46648
9	Block 2	0.46841	(0.07049)	0.39792
10	**IS-R** [1]	0.56864	(0.06675)	0.50189
11	**IS-C** [2]			
12	Block 1	0.58312	(0.07049)	0.51263
13	Block 2	0.55964	(0.07049)	0.48915
14	Block 3	0.53697	(0.07049)	0.46648
15	Block 4	0.46841	(0.07049)	0.39792
16	**LV-1**			
17	Demand Charge	0.30000	-	0.30000
18	Block 1	0.37581	(0.06852) [3]	0.30729
19	Block 2	0.35792	(0.06852) [3]	0.28940
20	Block 3	0.26956	(0.05446) [4]	0.21510
21	**T-3**			
22	Block 1	0.03790	0.00083 [5]	0.03873
23	Block 2	0.01506	0.00083 [5]	0.01589
24	Block 3	0.00515	0.00083 [5]	0.00598
25	**T-4**			
26	Demand Charge	0.28092	0.00647 [6]	0.28739
27	Block 1	0.02395	-	0.02395
28	Block 2	0.00847	-	0.00847
29	Block 3	0.00260	-	0.00260

(1) The IS-R price is based on the RS price and receives the same PGA adjustments

(2) The IS-C price is based on the GS-1 price and receives the same PGA adjustments

(3) See Workpaper No. 6, Line 13, Column (e)

(4) See Workpaper No. 6, Line 17, Column (e)

(5) Remove INT-G-17-05 temporary from Workpaper No. 8, Line 5, Column (e) plus temporary from Exhibit No. 7 Line 8, Column (e)

(6) Remove INT-G-17-05 temporary from Workpaper No. 8, Line 5, Column (f) plus temporary from Exhibit No. 7 Line 8, Column (f)

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Tariff Components & Line Break Pricing

Line No.	Description (a)	RS (b)	GS-1 (c)	LV-1 (d)	T-3 (e)	T-4 (f)
1	**Cost of Gas:**					
2	Temporary Purchased Gas Cost Adjustment [1]	$ (0.07741)	$ (0.07698)	$ (0.04583) [5]	$ 0.00020	$ (0.01261)
3	Weighted Average Cost of Gas [2]	0.22724	0.22724	0.22724	-	-
4	Gas Transportation Cost [3]	0.18901	0.17772	0.09588	-	-
5	**Total Proposed Cost of Gas**	$ 0.33884	$ 0.32798	$ 0.27729	$ 0.00020	$ (0.01261)
6	**Distribution Cost:** [4]					
7	Block 1	$ 0.16305	$ 0.18465	$ 0.03000	$ 0.03853	$ 0.02395
8	Block 2		0.16117	0.01211	0.01569	0.00847
9	Block 3		0.13850	0.00307	0.00578	0.00260
10	Block 4		0.06994			
11	Demand Charge			0.30000		0.30000
12	Energy Efficiency Charge [6]	0.00367				
13	**Proposed Prices:**					
14	Block 1	$ 0.50556	$ 0.51263	$ 0.30729	$ 0.03873	$ 0.02395
15	Block 2		0.48915	0.28940	0.01589	0.00847
16	Block 3		0.46648	0.21510 [7]	0.00598	0.00260
17	Block 4		0.39792			
18	Demand Charge			0.30000		0.28739
19	Line Break Pricing [8]	$ 0.41625				

[1] See Exhibit No. 7, Line 8, Columns (b) - (f)
[2] See Exhibit No. 5, Line 22, Column (f)
[3] See Exhibit No. 6, Line 29, Columns (e) - (g)
[4] See Case No. GNR-U-18-01
[5] LV-1 Block 3 temporary is Exhibit No. 7, Column (d), Lines 3 through 7 only, a credit of ($0.01521)
[6] See Case No. INT-G-17-03
[7] Column (d), Line 9 plus Line 3 plus the ($0.01521) from Footnote 5
[8] Sum of Line 3 and 4, Column (b)

I.P.U.C. Gas Tariff Rate Schedules ~~Third~~ Revised Fourth	Sheet No. 1 (Page 1 of 1)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~May 31, 2018~~ ~~June 1, 2018~~
~~Per O.N. 34073~~
Diane M. Hanian Secretary

Rate Schedule RS
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$5.50 per bill
Per Therm Charge:	~~$0.57231~~* $0.50556

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~($0.05425)~~ ($0.07741)
	2) Weighted average cost of gas	~~$0.26020~~ $0.22724
	3) Gas transportation cost	~~$0.19964~~ $0.18901
Distribution Cost:		$0.16305
EE Charge:		$0.00367

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

ENERGY EFFICIENCY CHARGE ADJUSTMENT:

This tariff is subject to an adjustment for costs related to the Company's Energy Efficiency program as provided for in Rate Schedule EEC. The Energy Efficiency Charge is separately stated on customer bills.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

I.P.U.C. Gas Tariff Rate Schedules ~~Fifty Seventh~~ Revised Fifty-Eighth	Sheet No. 3 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~**May 31, 2018**~~ ~~**June 1, 2018**~~
~~**Per O.N. 34073**~~
Diane M. Hanian Secretary

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$9.50 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	~~$0.58312~~* $0.51263
	Block Two:	Next	1,800 therms per bill @	~~$0.55964~~* $0.48915
	Block Three:	Next	8,000 therms per bill @	~~$0.53697~~* $0.46648
	Block Four:	Over	10,000 therms per bill @	~~$0.46841~~* $0.39792

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment			~~($0.06300)~~ ($0.07698)
	2) Weighted average cost of gas			~~$0.26020~~ $0.22724
	3) Gas transportation cost			~~$0.20127~~ $0.17772
Distribution Cost:	Block One:	First	200 therms per bill @	$0.18465
	Block Two:	Next	1,800 therms per bill @	$0.16117
	Block Three:	Next	8,000 therms per bill @	$0.13850
	Block Four:	Over	10,000 therms per bill @	$0.06994

I.P.U.C. Gas Tariff Rate Schedules ~~Fifty-Seventh~~ Revised Fifty-Eighth	Sheet No. 3 (Page 2 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~May 31, 2018~~ ~~June 1, 2018~~
~~Per O.N. 34073~~
Diane M. Hanian Secretary

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge:	$9.50 per bill		
Per Therm Charge:	Block One:	First 10,000 therms per bill @	~~$0.53697~~* $0.46648
	Block Two:	Over 10,000 therms per bill @	~~$0.46841~~* $0.39792

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~($0.06300)~~ ($0.07698)
	2) Weighted average cost of gas	~~$0.26020~~ $0.22724
	3) Gas transportation cost	~~$0.20127~~ $0.17772

Distribution Cost:	Block One:	First 10,000 therms per bill @	$0.13850
	Block Two:	Over 10,000 therms per bill @	$0.06994

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

I.P.U.C. Gas Tariff Rate Schedules ~~Fourteenth~~ Revised Fifteenth	Sheet No. 4 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~May 31, 2018~~ ~~June 1, 2018~~
~~Per O.N. 34073~~
Diane M. Hanian Secretary

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$5.50 per bill
Per Therm Charge:	~~$0.56864~~* $0.50189

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~($0.05425)~~	($0.07741)
	2) Weighted average cost of gas	~~$0.26020~~	$0.22724
	3) Gas transportation cost	~~$0.19964~~	$0.18901
Distribution Cost:		$0.16305	

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

I.P.U.C. Gas Tariff Rate Schedules ~~Fourteenth~~ Revised Fifteenth	Sheet No. 5 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~May 31, 2018~~ ~~June 1, 2018~~
~~Per O.N. 34073~~
Diane M. Hanian Secretary

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$9.50 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	~~$0.58312~~* $0.51263
	Block Two:	Next	1,800 therms per bill @	~~$0.55964~~* $0.48915
	Block Three:	Next	8,000 therms per bill @	~~$0.53697~~* $0.46648
	Block Four:	Over	10,000 therms per bill @	~~$0.46841~~* $0.39792

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment			~~($0.06300)~~ ($0.07698)
	2) Weighted average cost of gas			~~$0.26020~~ $0.22724
	3) Gas transportation cost			~~$0.20127~~ $0.17772
Distribution Charge:	Block One:	First	200 therms per bill @	$0.18465
	Block Two:	Next	1,800 therms per bill @	$0.16117
	Block Three:	Next	8,000 therms per bill @	$0.13850
	Block Four:	Over	10,000 therms per bill @	$0.06994

Issued by: **Intermountain Gas Company**
By: Michael P. McGrath Title: Director – Regulatory Affairs
Effective: ~~June 1, 2018~~ October 1, 2018

I.P.U.C. Gas Tariff Rate Schedules ~~Sixty-Fifth~~ Revised	Sixty-Sixth	Sheet No. 7 (Page 1 of 2)
Name of Utility	Intermountain Gas Company	

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~May 31, 2018~~ ~~June 1, 2018~~
~~Per O.N. 34073~~
Diane M. Hanian Secretary

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.30000 per MDFQ therm

Per Therm Charge:	Block One:	First	250,000 therms per bill @	~~$0.37581~~* $0.30729
	Block Two:	Next	500,000 therms per bill @	~~$0.35792~~* $0.28940
	Block Three:	Over	750,000 therms per bill @	~~$0.26956~~* $0.21510

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	
	Block One and Two	~~($0.01984)~~ ($0.04583)
	Block Three	~~$0.00629~~ ($0.01521)
	2) Weighted average cost of gas	~~$0.26020~~ $0.22724
	3) Gas transportation cost (Block One and Two only)	~~$0.10545~~ $0.09588

Distribution Cost:	Block One:	First	250,000 therms per bill @	$0.03000
	Block Two:	Next	500,000 therms per bill @	$0.01211
	Block Three:	Over	750,000 therms per bill @	$0.00307

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such excess usage will be billed under rate schedule LV-1. Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

I.P.U.C. Gas Tariff Rate Schedules ~~Sixteenth~~ Revised Seventeenth	Sheet No. 8 (Page 1 of 2)
Name of Utility	Intermountain Gas Company

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~May 31, 2018~~ ~~June 1, 2018~~
~~Per O.N. 34073~~
Diane M. Hanian Secretary

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Per Therm Charge:	Block One:	First	100,000 therms transported @ ~~$0.03790~~*	$0.03873
	Block Two:	Next	50,000 therms transported @ ~~$0.01506~~*	$0.01589
	Block Three:	Over	150,000 therms transported @ ~~$0.00515~~*	$0.00598

*Includes temporary purchased gas cost adjustment of ~~($0.00063)~~ $0.00020

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.
2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.
3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.
4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company's distribution system.
5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.
6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.
7. An existing T-4 customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

I.P.U.C. Gas Tariff Rate Schedules ~~Fifteenth~~ Revised Sixteenth	Sheet No. 9 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~**May 31, 2018**~~ ~~**June 1, 2018**~~
~~**Per O.N. 34073**~~
Diane M. Hanian Secretary

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: ~~$0.28092~~ per MDFQ therm* $0.28739

Per Therm Charge:	Block One:	First	250,000 therms transported @ $0.02395
	Block Two:	Next	500,000 therms transported @ $0.00847
	Block Three:	Over	750,000 therms transported @ $0.00260

*Includes temporary purchased gas cost adjustment of ~~($0.01908)~~ ($0.01261)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

4. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

5. The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

6. An existing LV-1 or T-3 customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer's same or contiguous property.

EXHIBIT NO. 3

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

PROPOSED TARIFFS

(8 pages)

Rate Schedule RS
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$5.50 per bill
Per Therm Charge:	$0.50556*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.07741)
	2) Weighted average cost of gas	$0.22724
	3) Gas transportation cost	$0.18901
Distribution Cost:		$0.16305
EE Charge:		$0.00367

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

ENERGY EFFICIENCY CHARGE ADJUSTMENT:

This tariff is subject to an adjustment for costs related to the Company's Energy Efficiency program as provided for in Rate Schedule EEC. The Energy Efficiency Charge is separately stated on customer bills.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be served under this rate schedule upon execution of a one-year written service contract.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$9.50 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$0.51263*
	Block Two:	Next	1,800 therms per bill @	$0.48915*
	Block Three:	Next	8,000 therms per bill @	$0.46648*
	Block Four:	Over	10,000 therms per bill @	$0.39792*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment			($0.07698)
	2) Weighted average cost of gas			$0.22724
	3) Gas transportation cost			$0.17772
Distribution Cost:	Block One:	First	200 therms per bill @	$0.18465
	Block Two:	Next	1,800 therms per bill @	$0.16117
	Block Three:	Next	8,000 therms per bill @	$0.13850
	Block Four:	Over	10,000 therms per bill @	$0.06994

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge:	$9.50 per bill		
Per Therm Charge:	Block One:	First 10,000 therms per bill @	$0.46648*
	Block Two:	Over 10,000 therms per bill @	$0.39792*
*Includes the following:			
Cost of Gas:	1) Temporary purchased gas cost adjustment		($0.07698)
	2) Weighted average cost of gas		$0.22724
	3) Gas transportation cost		$0.17772
Distribution Cost:	Block One:	First 10,000 therms per bill @	$0.13850
	Block Two:	Over 10,000 therms per bill @	$0.06994

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

BILLING ADJUSTMENTS:

1. Any GS-1 customer who leaves the GS-1 service will pay to Intermountain Gas Company, upon exiting the GS-1 service, all gas and transportation related costs incurred to serve the customer during the GS-1 service period not paid by the customer during the time the customer was using GS-1 service. Any GS-1 customer who leaves the GS-1 service will have refunded to them, upon exiting the GS-1 service, any excess gas commodity or transportation payments made by the customer during the time they were a GS-1 customer.

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$5.50 per bill	
Per Therm Charge:	$0.50189*	
*Includes the following:		
Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.07741)
	2) Weighted average cost of gas	$0.22724
	3) Gas transportation cost	$0.18901
Distribution Cost:		$0.16305

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$9.50 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$0.51263*
	Block Two:	Next	1,800 therms per bill @	$0.48915*
	Block Three:	Next	8,000 therms per bill @	$0.46648*
	Block Four:	Over	10,000 therms per bill @	$0.39792*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.07698)
	2) Weighted average cost of gas	$0.22724
	3) Gas transportation cost	$0.17772

Distribution Charge:	Block One:	First	200 therms per bill @	$0.18465
	Block Two:	Next	1,800 therms per bill @	$0.16117
	Block Three:	Next	8,000 therms per bill @	$0.13850
	Block Four:	Over	10,000 therms per bill @	$0.06994

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.30000 per MDFQ therm

Per Therm Charge:	Block One:	First	250,000 therms per bill @	$0.30729*
	Block Two:	Next	500,000 therms per bill @	$0.28940*
	Block Three:	Over	750,000 therms per bill @	$0.21510*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	
	Block One and Two	($0.04583)
	Block Three	($0.01521)
	2) Weighted average cost of gas	$0.22724
	3) Gas transportation cost (Block One and Two only)	$0.09588

Distribution Cost:	Block One:	First	250,000 therms per bill @	$0.03000
	Block Two:	Next	500,000 therms per bill @	$0.01211
	Block Three:	Over	750,000 therms per bill @	$0.00307

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract.

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to serve Intermountain's system, all such excess usage will be billed under rate schedule LV-1. Additionally, all excess MDFQ above the customer's contracted MDFQ for the month will be billed at the monthly Demand Charge rate.

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Per Therm Charge:	Block One:	First	100,000 therms transported @ $0.03873*
	Block Two:	Next	50,000 therms transported @ $0.01589*
	Block Three:	Over	150,000 therms transported @ $0.00598*

*Includes temporary purchased gas cost adjustment of $0.00020

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill of $30,000 during each annual contract period, unless a higher minimum is required under the service contract to cover special conditions.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.

2. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

3. Interruptible Distribution Transportation Service may be made firm by a written agreement between the parties if the customer has a dedicated line.

4. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company's distribution system.

5. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this rate.

6. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated and accepted for delivery by the interstate pipeline.

7. An existing T-4 customer electing this schedule may concurrently utilize Rate Schedule T-3 on the same or contiguous property.

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Demand Charge: $0.28739 per MDFQ therm*

Per Therm Charge:	Block One:	First	250,000 therms transported @ $0.02395
	Block Two:	Next	500,000 therms transported @ $0.00847
	Block Three:	Over	750,000 therms transported @ $0.00260

*Includes temporary purchased gas cost adjustment of ($0.01261)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for cost of purchased gas as provided for in the Company's Purchased Gas Cost Adjustment Schedule.

SERVICE CONDITIONS:

1. This service excludes the service and cost of firm interstate pipeline charges.

2. The customer is responsible for procuring its own supply of natural gas and interstate transportation under this Rate Schedule. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

3. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

4. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

5. The monthly demand charge will be equal to the MDFQ times the demand charge rate. Demand charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

6. An existing LV-1 or T-3 customer electing this schedule may concurrently utilize Rate Schedule T-4 on the customer's same or contiguous property.

EXHIBIT NO. 4

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

PERTINENT EXCERPTS PERTAINING TO INTERSTATE PIPELINES AND RELATED FACILITIES

(35 pages)

NORTHWEST PIPELINE LLC

(10 pages)

160 FERC ¶ 61,008
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

August 18, 2017

In Reply Refer To:
Northwest Pipeline LLC
Docket No. RP17-346-000

Northwest Pipeline LLC
295 Chipeta Way
P.O. Box 58900
Salt Lake City, UT 84158-0900

Attention: Laren Gertsch
Director, Rates & Tariffs

Reference: Petition for Approval of a Stipulation and Settlement Agreement

Dear Mr. Gertsch:

1. On January 23, 2017, Northwest Pipeline LLC (Northwest) petitioned the Commission for approval of a Stipulation and Settlement Agreement (2017 Settlement), in lieu of its obligation to file a Natural Gas Act (NGA) general section 4 rate case.[1] Northwest states that on April 26, 2012, the Commission approved its Petition for Approval of Settlement in Docket No. RP12-490-000 (2012 Settlement) which satisfied its requirement to file a NGA general section 4 rate case. In the instant petition, Northwest states that section 14.4 of the 2012 Settlement requires it to file an NGA general section 4 rate case not later than July 1, 2017, for rates to become effective not later than January 1, 2018, unless Northwest has entered into a pre-filing settlement effectively satisfying the NGA general section 4 rate case filing requirement.[2] Northwest states that the Settling Parties[3] agree that if this 2017 Settlement is timely approved by

[1] The filing is made pursuant to Rule 207(a)(5) of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.207(a)(5) (2017).

[2] *Northwest Pipeline GP*, 139 FERC ¶ 61,071 (2012).

[3] Article II of the 2017 Settlement defines Settling Parties as (a) any party identified in Appendix A of the 2017 Settlement or (b) any party or shipper not identified
(continued)

the Commission, Northwest will have satisfied the requirement to make a rate filing in 2017 as to the Settling Parties. Northwest states that the Settling Parties have successfully resolved their issues through the 2017 Settlement in a practical and carefully constructed fashion, eliminating the need for testimony, discovery, hearing and briefing of the matters resolved. Northwest states that the avoidance of litigation is a valuable outcome, benefiting the Settling Parties, the Commission and the public interest. Northwest states that it does not expect the 2017 Settlement to be contested because 100 percent of the shippers who actively participated in the settlement discussions support this 2017 Settlement. Northwest states that 92 percent of Northwest's long-term firm transportation and storage capacity shippers support and 8 percent do not oppose the 2017 Settlement.

2. In a separate filing made on March 29, 2017 (March Filing) in Docket No. RP17-567-000, Northwest states that three days after Northwest filed its 2017 Settlement, the Commission was left without a quorum. Northwest states that due to the lack of a quorum, no action has been taken by the Commission to approve the uncontested 2017 Settlement and that Commission staff lacks the authority to approve the 2017 Settlement pursuant to the *Order Delegating Further Authority to Staff in Absence of Quorum*.[4] Consequently, Northwest filed revised tariff records in the March Filing to extend the time by which it must file an NGA general section 4 rate case and otherwise amend (1) section 14.4 of the 2012 Settlement; and (2) Article X and sections 14.1 and 14.2 of the 2017 Settlement. Northwest states that the extension of time is necessary to preserve the rate reductions agreed to in the 2017 Settlement and accommodate the delay in Commission action on the 2017 Settlement due to a lack of quorum. The March Filing was accepted on April 12, 2017.[5]

3. The Commission by this letter order approves the 2017 Settlement to be effective according to its terms,[6] and directs Northwest to file tariff records consistent with the *pro forma* tariff records included in Appendix F of the 2017 Settlement, to be effective January 1, 2018.

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in Appendix A that either supports, or does not oppose the 2017 Settlement as a whole and/or any of its underlying provisions.

[4] *Agency Operations in the Absence of a Quorum*, 158 FERC ¶ 61,135 (2017).

[5] *Northwest Pipeline LLC*, Docket No. RP17-567-000 (Apr 12, 2017) (delegated letter order) (April 2017 Order).

[6] According to Article XI, the 2017 Settlement will become effective on the date that an order approving the 2017 Settlement becomes a final order.

4. Public notice of the 2017 Settlement filing was issued on January 24, 2017. Interventions and protests were due as provided in section 154.210 of the Commission's regulations (18 C.F.R. § 154.210 (2017)). Pursuant to Rule 214 (18 C.F.R. § 385.214 (2017)), all timely filed motions to intervene and any unopposed motion to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties. No comments in opposition to the settlement were filed.

5. The following is a summary of the major provisions of the 2017 Settlement.

6. Article I states that the terms of the 2017 Settlement are a carefully crafted compromise and that the Settling Parties request that it be approved in its entirety without modification or condition.

7. Article II defines the Settling Parties and states that the 2017 Settlement is a negotiated resolution of only those issues expressly set forth in the 2017 Settlement.

8. Article III identifies the annual cost-of-service underlying the Settlement Rates, and provides the two phases of rates that will be implemented.

9. Article IV describes the agreed rate design principles used in deriving the Settlement Rates. According to section 4.1, General Transmission System, the rates for all transportation Rate Schedules are based on a straight fixed variable ("SFV") rate design. Section 4.2, Storage, provides that the rates under the Plymouth LNG and Jackson Prairie rate schedules will be the same as those established in the 2012 Settlement. Section 4.3, Evergreen 15-Year Contract Roll-In, provides that the rates for Rate Schedule TF-1 (Large Customer), TF-1 (25-Year Evergreen), Rate Schedule TF-2 and Rate Schedule TI-1 to be effective January 1, 2018, through September 30, 2018, as shown on Appendix B, reflect the allocation of costs to the TF-1 (15-Year Evergreen) contracts. The section states that the rates for Rate Schedule TF-1 (Large Customer), TF-1 (25-Year Evergreen), Rate Schedule TF-2, and Rate Schedule TI-1 to be effective October 1, 2018, through the remainder of the Settlement Term, as shown on Appendix C, reflect the roll-in of the TF-1 (15-Year Evergreen) contracts that will expire on September 30, 2018.

10. Article V states that the depreciation, amortization and net negative salvage rates used in deriving the Settlement Rates are shown in Appendix D to the 2017 Settlement.

11. Article VI states that if the U.S. federal income tax rate applicable to corporations should be reduced or increased for any taxable period(s) between January 1, 2018, and the end of the Settlement Term, then Northwest will record a regulatory liability or asset account. It explains how the amount to be placed into that regulatory liability or asset account will be determined and how Northwest will amortize the balance in that account over a period of five years after the Settlement Term.

12. Article VII refers to the surviving terms of Article VI of Northwest's prior rate case settlement in Docket No. RP12-490-000 relating to its ongoing treatment of Post-Retirement Benefits Other than Pensions (PBOP), and updates the amount of Northwest's regulatory liability related to PBOPs.

13. Article VIII states that the Settlement Rates for Phase 1 Rates are set forth in Appendix B of the 2017 Settlement and shall become effective January 1, 2018, and remain in effect through September 30, 2018, and that the Settlement Rates for Phase 2 Rates are set forth in Appendix C of the 2017 Settlement and shall become effective October 1, 2018, and remain in effect through the end of the Settlement Term.

14. Article IX states that the Settling Parties may not submit comments to the Commission that oppose any provision of the 2017 Settlement.

15. Article X defines the term Contesting Parties and explains that if there are any Contesting Parties, Northwest will file an NGA section 4 general rate case by June 30, 2017, with regard to such Contesting Parties consistent with the 2017 Rate Filing requirement. It also provides that Contesting Parties forego any and all rights or obligations under the 2017 Settlement.[7]

16. Article XI describes when the 2017 Settlement will become effective depending upon whether it is approved by the Commission (a) without modification or condition or (b) with modification or condition. It details the Settling Parties' rights and the procedures to be followed if the Commission approves the 2017 Settlement with modification or condition. It explains what happens to the 2017 Settlement if it is withdrawn by Northwest or if it is rejected by the Commission in its entirety. It also defines the Settlement Term.

17. Article XII defines the nine month and one day Moratorium during which the Settling Parties are prohibited from taking certain actions inconsistent with the 2017 Settlement. It provides the standards of review to be applied if the Commission were to consider any change to the terms of the 2017 Settlement during the Moratorium as follows: "the standard of review for any changes to this Settlement proposed by a Settling Party shall be the *Mobile-Sierra* 'public interest' standard."[8] The standard of review for changes proposed by a non-Settling Party, or the Commission acting *sua sponte,* shall be

[7] Amended by the March Filing and accepted by the April 2017 Order.

[8] Article XII (citing *United Gas Pipe Line v. Mobile Gas Service Corp.,* 350 U.S. 332 (1956), *Federal Power Commission v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956), and *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County,* 554 U.S. 527 (2008) (*Morgan Stanley*)).

"the ordinary 'just and reasonable' standard."[9] Article XII also requires Northwest to file an NGA section 4 general rate case with rates to become effective not later than January 1, 2023, unless Northwest has entered into a Pre-Filing Settlement or a post-Moratorium NGA section 5 general rate case has been filed on or before January 1, 2023, regarding Northwest's rates.

18. Article XIII states that the provisions of the 2017 Settlement are not severable and if the 2017 Settlement is not approved, then it shall be treated as privileged. It also states that the 2017 Settlement does not establish precedent, long standing practice or settled practice of the Commission. It states that no party shall be deemed to be the drafter of the 2017 Settlement and that it shall be interpreted in accordance with the laws of Utah.

19. Article XIV describes the actions Northwest will take if the 2017 Settlement approval process is completed before June 30, 2017; after June 30, 2017; before January 1, 2018; or on, or after, January 1, 2018.[10]

20. Article XV provides that the 2017 Settlement does not constitute a recent rate review under the Commission's *Policy Statement on Cost Recovery Mechanisms for Modernization of Natural Gas Facilities*, 151 FERC ¶ 61,047, *clarification denied*, 152 FERC ¶ 61,046 (2015), but that Northwest will not be precluded from seeking Commission approval for a cost recovery mechanism pursuant to such policy statement that would take effect after the Moratorium.

21. The Commission has stated that when a pipeline has negotiated an agreement with its customers and others to change its rates or terms and conditions of service and the pipeline desires approval of the agreement before making an actual NGA section 4 tariff filing, the pipeline should simply file, pursuant to section 385.207 of the Commission's regulations,[11] a petition for approval of the agreement. If the Commission approves the agreement, it will direct that the pipeline file, pursuant to NGA section 4(d) and section 154.203[12] of the Commission's regulations, actual tariff records implementing

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[9] *See Morgan Stanley,* 554 U.S. at 535.

[10] On March 29, 2017, Northwest filed tariff records to extend the time by which it must file an NGA section 4 general rate case and to make other changes to preserve and implement rate reductions agreed to by Northwest and its shippers in the 2017 Settlement. *See* April 12, 2017 delegated letter order in Docket No. RP17-567-000 approving these revisions.

[11] 18 C.F.R. § 385.207(a)(5) (2017).

[12] 18 C.F.R. § 154.203 (2017).

the agreement consistent with the terms of the agreement as approved by the Commission. The Commission will treat such a filing as a filing to comply with the Commission's order approving the agreement, and the Commission will place tariff records that properly implement the agreement, as approved, into effect on the date provided for in the agreement.[13]

22. The 2017 Settlement was such a negotiated agreement filed in lieu of a rate case, relieving participants from litigation and administration costs of such a proceeding and, in addition, resolving system-wide rate issues consistent with the Commission's guidance for settlements outside the context of an existing proceeding.[14] In particular, the 2017 Settlement will provide a reduction from Northwest's currently effective rates and provides rate stability until January 1, 2023.

Accordingly, the Commission finds that the uncontested 2017 Settlement appears to be fair, reasonable and in the public interest, and therefore, the Commission approves the 2017 Settlement. The Commission directs Northwest to file tariff records through the eTariff portal that implement the 2017 Settlement consistent with its terms. The Commission's approval of the 2017 Settlement does not constitute acceptance of, or precedent regarding, any principle or issue in this proceeding.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[13] *Dominion Transmission, Inc.*, 111 FERC ¶ 61,285 (2005).

[14] *Id.*

Appendix C

NORTHWEST PIPELINE LLC
Docket No. RP17-
Summary of Daily Settlement Rates 1/
Exclusive of Surcharges
Effective October 1, 2018

Line	Rate Schedule (a)	Rate (b)
1	TF-1	
2	Reservation Charge - Large Customer	$0.39033
3	- Evergreen - 25-year	$0.32039
5	Volumetric Charge - Large Customer	$0.00832
6	- Evergreen - 25-year	$0.00832
7	- Small Customer	$0.69427
8	TF-2	
9	Reservation Charge	$0.39033
10	Volumetric Charge	$0.00832
11	TI-1	
12	Maximum Volumetric Charge 2/	$0.39865
13	Minimum Volumetric Charge	$0.00832
14	SGS-2F Pre-Expansion	
15	Demand Charge	$0.01562
16	Capacity Demand Charge	$0.00057
17	SGS-2F Expansion	
18	Demand Charge	$0.04056
19	Capacity Demand Charge	$0.00348
20	SGS-2I	
21	Volumetric Charge	$0.00224
22	SGS-2F Volumetric Bid Rates Pre-Expansion	
23	Withdrawal Charge	$0.01562
24	Storage Charge	$0.00057
25	SGS-2F Volumetric Bid Rates Expansion	
26	Withdrawal Charge	$0.04056
27	Storage Charge	$0.00348
28	LS-2F	
29	Demand Charge	$0.02587
30	Capacity Demand Charge	$0.00331
31	Liquefaction Charge	$0.90855
32	Vaporization Charge	$0.03386
33	LS-2I 3/	
34	Maximum Volumetric Charge	$0.00662
35	Minimum Volumetric Charge	$0.00000
36	LS-2F Volumetric Bid 3/	
37	Vaporization Demand Related Charge	$0.02587
38	Storage Capacity Charge	$0.00331
39	DEX-1	
40	Maximum Volumetric Charge	$0.39865
41	Minimum Volumetric Charge	$0.00000
42	PAL	
43	Maximum Volumetric Charge	$0.39865
44	Minimum Volumetric Charge	$0.00000
45	Facilities Reservation Surcharge for the Columbia Gorge 1999 Expansion 4/	$0.09855

1/ Reflects reservation, demand and capacity demand charges as daily rates.
2/ Designed on a 100% load factor basis of the Rate Schedule TF-1 (Large Customer) rates.
3/ LS-2I and LS-2F volumetric bid service will also be assessed Rate Schedule LS-2F liquefaction and vaporization charges.
4/ Rates for the years 2018 forward are as follows (surcharge ends March 31, 2025):

2018	$0.09855
2019	$0.09189
2020	$0.08667
2021	$0.08194
2022	$0.07696
2023	$0.07199
2024	$0.06680
2025	$0.06552

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Letter Order Pursuant to § 375.307
Northwest Pipeline LLC
Docket No. RP18-488-000

Issued: March 23, 2018

Northwest Pipeline LLC
P.O. Box 58900
Salt Lake City, UT 84158-0900

Attention: Laren Gertsch, Director
Rates and Tariffs

Reference: 2018 Summer Fuel Filing

Dear Ms. Gertsch:

On February 28, 2018, Northwest Pipeline LLC (Northwest) filed a tariff record[1] to comply with sections 14.12 and 14.20 of the General Terms and Conditions in its tariff, which require adjustments to its fuel reimbursement factors by April 1 of each year. Northwest proposes the following adjustments to its factors: a) an increase from 1.00 percent to 1.16 percent for Rate Schedules TF-1, TF-2, TI-1, and DEX-1 (transportation and exchange services); b) an increase from 0.15 percent to 0.17 percent for Rate Schedules SGS-2F and SGS-2I (underground storage services); c) no change to the current 0.53 percent for Rate Schedules LS-2F, LS-3F, LS-2I, and LD-4I (liquefaction and storage services); and d) no change to the current 0.53 percent for Rate Schedules LS-2F, LS-3F and LS-2I (vaporization services). Northwest also proposes no change for 2018 to facility charges under Rate Schedules LS-3F and LD-4I. The referenced tariff record is accepted, effective April 1, 2018, as proposed.

Public notice of the filing was issued on March 1, 2018. Interventions and protests were due as provided in section 154.210 of the Commission's regulations (18 C.F.R. § 154.210 (2017)). Pursuant to Rule 214 (18 C.F.R. § 385.214 (2017)), all timely filed

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[1] Northwest Pipeline LLC; FERC NGA Gas Tariff; Fifth Revised Volume No. 1, Sheet No. 14, Fuel Use Factors, 21.0.0.

motions to intervene and any unopposed motion to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties. No protests or adverse comments were filed.

This acceptance for filing shall not be construed as a waiver of the requirements of section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your company.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date this order issues, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

Marsha K. Palazzi, Director
Division of Pipeline Regulation

STATEMENT OF FUEL USE REQUIREMENTS FACTORS
FOR REIMBURSEMENT OF FUEL USE

Applicable to Transportation Service Rendered Under
Rate Schedules Contained in this Tariff, Fifth Revised Volume No. 1

The rates set forth on Sheet Nos. 5, 6, 7, 8 and 8-A are exclusive of fuel use requirements. Shipper shall reimburse Transporter in-kind for its fuel use requirements in accordance with Section 14 of the General Terms and Conditions contained herein.

The fuel use reimbursement furnished by Shippers shall be as follows for the applicable Rate Schedules included in this Tariff:

Rate Schedules TF-1, TF-2, TI-1, and DEX-1	1.16%
Rate Schedule TF-1 - Evergreen Expansion	
Incremental Surcharge (1)	0.50%
Rate Schedule TFL-1	-
Rate Schedule TIL-1	-
Rate Schedules SGS-2F and SGS-2I	0.17%
Rate Schedules LS-2F, LS-3F and LS-2I	
Liquefaction	0.53%
Vaporization	0.53%
Rate Schedule LD-4I	
Liquefaction	0.53%

The fuel use factors set forth above shall be calculated and adjusted as explained in Section 14 of the General Terms and Conditions. Fuel reimbursement quantities to be supplied by Shippers to Transporter shall be determined by applying the factors set forth above to the quantity of gas nominated for receipt by Transporter from Shipper for transportation, Jackson Prairie injection, Plymouth liquefaction, Plymouth vaporization, or for deferred exchange, as applicable.

Footnote

(1) In addition to the Rate Schedule TF-1 fuel use requirements factor, the Evergreen Expansion Incremental Surcharge will apply to the quantity of gas nominated for receipt at the Sumas, SIPI or Pacific Pool receipt points under Evergreen Expansion service agreements.

NOVA GAS TRANSMISSION LTD.

(7 pages)

National Energy Board | Office national de l'énergie

ORDER TG-004-2018

IN THE MATTER OF the *National Energy Board Act* (Act) and the regulations made thereunder; and

IN THE MATTER OF an application filed by NOVA Gas Transmission Ltd. (NGTL) with the National Energy Board (Board) pursuant to subsection 19(2) and Part IV of the Act filed under file OF-Tolls-Group1-N081-2018-01.

BEFORE the Board on 19 June 2018:

WHEREAS on 12 August 2010, the Board issued Order TG-004-2010 approving the toll design methodology and terms and conditions of service on the NGTL System;

AND WHEREAS on 24 November 2017, the Board approved in Order TGI-001-2017 NGTL's application for interim 2018 rates, tolls and charges (2018 Interim Tolls) for services on the NGTL System effective 1 January 2018, and NGTL's abandonment surcharges for 2018 effective 1 January 2018 (2018 Abandonment Surcharges);

AND WHEREAS on 21 March 2018, NGTL's Tolls, Tariff, Facilities and Procedures Committee endorsed, through Resolution T2017-02 a settlement for establishing the NGTL System revenue requirement and its components for the period 1 January 2018 to 31 December 2019 (the Settlement);

AND WHEREAS on 23 March 2018, NGTL filed an application requesting Board approval of the Settlement and the resulting revised 2018 interim rates effective 1 May 2018 (Revised 2018 Interim Tolls) and final 2018 rates (the Application);

AND WHEREAS on 17 April 2018 NGTL filed revised versions of Attachment 1 (Receipt Point Rates) and Attachment 2 (Delivery Point Rates) to the Table of Rates that were provided as part of Attachment B, Tab-4 to the Application;

AND WHEREAS on 19 April 2018, the Board approved in Order TGI-002-2017 NGTL's application for Revised 2018 Interim Tolls effective 1 May 2018, and continuation of NGTL's 2018 Abandonment Surcharges approved in Order TGI-001-2017;

AND WHEREAS on 31 May 2018 NGTL filed Updated Attachment 1, (Receipt Point Rates) to the Table of Interim 2018 Revised Rates (Table) of NGTL's Gas Transportation Tariff, effective 1 June 2018;

AND WHEREAS in the Application NGTL advised the Board that the Revised 2018 Interim Tolls are consistent with the Settlement and NGTL's existing toll design approved in Order TG-004-2010;

AND WHEREAS in the Application NGTL advised the Board that the proposed 2018 Abandonment Surcharges have been calculated in accordance with the Board approved methodology from the MH-001-2013 Decision;

AND WHEREAS no party has actively opposed the Settlement or has proposed an alternative to the Board;

AND WHEREAS the Board has considered the Application for approval of the Settlement, Final 2018 Rates and 2018 Abandonment Surcharges and has decided to approve the Application as filed;

THEREFORE, IT IS ORDERED pursuant to subsection 19(2) and Part IV of the Act that:

1. The Settlement is approved as filed;

2. NGTL's 2018 Interim Tolls for the period 1 January 2018 to 30 April 2018 and Revised 2018 Interim Tolls for the period 1 May 2018 to 31 December 2018, as approved, respectively, in Order TGI-001-2017 and Order TGI-002-2018, are approved as 2018 Final Tolls;

3. NGTL's 2018 Abandonment Surcharges, as approved in Order TGI-001-2017 and in Order TGI-002-2018 are approved as 2018 Final Abandonment Surcharges;

1. NGTL's Settlement Reporting Obligations to the Board are those described in Application, Attachment A – 2018-2019 Settlement, item 2(F)(v), PDF page 8 of 54[1], and item 2(F)(iii) as modified in item 5. below;

2. NGTL shall provide the Board with the capital project information on a quarterly basis as specified in item 2(F) (iii) of the Tolls, Tariff, Facilities, and Procedures Committee Reporting of the Application, Attachment A – 2018-2019 Settlement, PDF page 8 of 54; and

[1] NEB Filing ID A90751-1

3. NGTL shall provide the NGTL System unit transportation cost data in the Annual Plan for three historical years and the five forecast years covered in each year's Annual Plan. The unit transportation cost will be calculated by dividing NGTL's actual or forecast revenue requirement by the System's actual or forecast annual throughput. This filing requirement will take effect with NGTL's filing of its 2018 Annual Plan with the Board, which is expected in December 2018.

NATIONAL ENERGY BOARD

Original signed by

Sheri Young
Secretary of the Board

NOVA Gas Transmission Ltd.

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month based on a three-year term (Price Point "B") & Surcharge for each Receipt Point		
	Average Firm Service Receipt Price (AFSRP)		\$207.20 $/10^3m^3$ / month
2. Rate Schedule FT-RN	Refer to Attachment "1" for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D [1]	Refer to Attachment "2" for applicable FT-D Demand Rate per month based on a one year term (Price Point "Z") & Surcharge for each Group 1 or Group 2 Delivery Point		
	Average FT-D Demand Rate for Group 1 Delivery Points		\$5.24 /GJ
	FT-D Demand Rate for Group 2 Delivery Points		\$4.99 /GJ
	FT-D Demand Rate for Group 3 Delivery Points		\$5.99 /GJ
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one year term (Price Point "Z") for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three year term (Price Point "Y") for each Group 1 Delivery Point		
6. Rate Schedule FT-P [1]	Refer to Attachment "3" for applicable FT-P Demand Rate per month		
7. Rate Schedule LRS-3	LRS-3 Demand Rate per month		\$129.55 $/10^3m^3$ / month
8. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate for each Receipt Point		
9. Rate Schedule IT-D [1]	Refer to Attachment "2" for applicable IT-D Rate for each Delivery Point		
10. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service		
11. Rate Schedule PT	The PT Charge is determined in accordance with the applicable Schedule of Service		
12. Rate Schedule OS	Schedule No.	Charge	
	2017943711	\$121.30	$/10^3m^3$ / month
	2017939621	\$121.30	$/10^3m^3$ / month
	2017939620	\$121.30	$/10^3m^3$ / month
	2017939619	\$121.30	$/10^3m^3$ / month
	2017944787	\$121.30	$/10^3m^3$ / month
	2011475772	\$9,250.00	/ month
	2017849279	\$788.00	/ month
	2003004522	Applicable IT-R and IT-D Rate	
	2011476052 /	\$0.1641	/ GJ subject to
	2011476054	\$717,000.00	Minimum Annual Charge
	2017887638 / 2011476092 /	\$0.095	/ GJ and
	2016721799 / 2016759254	\$1,000.00	/ month
13. Rate Schedule CO2		Tier	CO_2 Rate (\$/10^3m^3)
		1	543.57
		2	430.09
		3	279.27
14. Monthly Abandonment Surcharge [2]	\$10.51 $/10^3m^3$ / month		\$0.28 /GJ/month
15. Daily Abandonment Surcharge [3]	\$0.35 $/10^3m^3$ /day		\$0.0091 /GJ/day

1. Service under rate Schedules FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and stations identified on rate Schedules OS No. 2011476092, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.

2. Monthly Abandonment Surcharge applicable to Rate Schedules FT-R, FT-D, FT-P, FT-RN, FT-DW, STFT, LRS-3, and the following Rate Schedules OS: 2017943711, 2017939621, 2017939620, 2017939619, 2017944787.

3. Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, LRS, the following Rate Schedules OS: 2011476052, 2011476054, 2017887638, 2011476092, 2016721799, 2016759254, 2003004522, and if applicable Over-Run Gas.

TransCanada
In business to deliver

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June 28, 2018

Filed Electronically

National Energy Board
Suite 210, 517 Tenth Avenue SW
Calgary, Alberta T2R 0A8

Attention: Ms. Sheri Young, Secretary of the Board

Dear Ms. Young:

**Re: NOVA Gas Transmission Ltd. (NGTL)
Gas Transportation Tariff (Tariff)
Updated Attachment 1 and Attachment 2 to the Table of Final 2018 Rates, Tolls and Charges (Final 2018 Rates)**

NGTL attaches for filing with the Board pursuant to section 60(1)(a) of the *National Energy Board Act* an updated Attachment 1 (Receipt Point Rates) and Attachment 2 (Delivery Point Rates) to the Table of Final 2018 Rates (Table) of the Tariff, effective July 1, 2018.

The Board approved on June 19, 2018 the previously approved Interim 2018 Revised Tolls[1] as the Final 2018 Rates effective May 1, 2018 with Order TG-004-2018 (NEB Filing ID: A92601). The updates to Attachment 1 and Attachment 2 of the Table reflects the new meter stations that are expected to go into service during July 2018.

Attachment 1 to the Table has been updated to include a new receipt point at the Wildrose receipt meter station. The Final 2018 FT-R and IT-R rates for the station are provided in the following table:

Station Number	Station Name	Legal Description	FT-R Demand Rate ($\$/10^3m^3$/month)	IT-R Rate ($\$/10^3m^3$/d)	Page No. on Attachment 1
5172	Wildrose	SW-25-067-05 W6M	194.45	7.35	24

Attachment 2 to the Table has been updated to include the Hays Sales delivery point at the existing Hays receipt meter station, the North Heart River Sales delivery point at the existing North Heart River receipt meter station and the Wildcat Hills Sales delivery point at the existing Wildcat Hills receipt meter station. The Final 2018 FT-D and IT-D rates for the stations are provided in the following table:

[1] NGTL's 2018 Interim Tolls for the period January 1, 2018 to April 30, 2018 and Revised 2018 Interim Tolls for the period May 1, 2018 to December 31, 2018, as approved respectively, in Order TGI-001-2017 and Order TGI-002-2018.

Station Number	Station Name	Legal Description	FT-D Demand Rate ($/GJ/month)	IT-D Rate ($/GJ/d)	Page No. on Attachment 2
3694	Hays Sales	11-31-013-14 W4M	4.99	0.1805	4
3693	North Heart River Sales	09-20-085-17 W5M	4.99	0.1805	6
3695	Wildcat Hills Sales	16-15-026-05 W5M	4.99	0.1805	8

The rates were determined in accordance with NGTL's current rate design methodology approved by the Board in Reasons for Decision RHW-1-2010 and Order TG-04-2010 on August 12, 2010.

If the Board requires additional information regarding this filing, please contact Mark Manning by phone at (403) 920-6098 or by email at mark_manning@transcanada.com.

Yours truly,
NOVA Gas Transmission Ltd.

Original signed by

Bernard Pelletier
Director, Regulatory Tolls and Tariffs
Canadian Natural Gas Pipelines

Attachment

cc: TTFP
NGTL System Shippers

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate Price Point "Z" ($/GJ/mo)	IT-D Rate ($/GJ/d)
2000	ALBERTA-B.C. BORDER	4.99	0.1805
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	4.99	0.1805
31110	ALLIANCE EDSON INTERCONNECT APN	4.99	0.1805
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	4.99	0.1805
3002	BOUNDARY LAKE BORDER	4.99	0.1805
1958	EMPRESS BORDER	5.38	0.1945
3886	GORDONDALE BORDER	4.99	0.1805
6404	MCNEILL BORDER	5.38	0.1945

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate Price Point "Z" ($/GJ/mo)	IT-D Rate ($/GJ/d)	Subject to ATCO Pipelines Franchise Fees[1]
31000	A.T. PLASTICS SALES APN	4.99	0.1805	Yes
31001	ADM AGRI INDUSTRIES SALES APN	4.99	0.1805	Yes
3880	AECO INTERCONNECTION	4.99	0.1805	
31003	AGRIUM CARSELAND SALES APS	4.99	0.1805	
31002	AGRIUM FT. SASK SALES APN	4.99	0.1805	Yes
31004	AGRIUM REDWATER SALES APN	4.99	0.1805	
31005	AINSWORTH SALES APGP	4.99	0.1805	
31006	AIR LIQUIDE SALES APN	4.99	0.1805	
3214	AKUINU RIVER WEST SALES	4.99	0.1805	
31007	ALBERTA ENVIROFUELS SALES APN	4.99	0.1805	Yes[2]
31008	ALBERTA HOSPITAL SALES APN	4.99	0.1805	Yes
3868	ALBERTA-MONTANA BORDER	4.99	0.1805	
3297	ALDER FLATS SOUTH NO 2 SALES	4.99	0.1805	
3059	ALLISON CREEK SALES	4.99	0.1805	
31009	ALTASTEEL SALES APN	4.99	0.1805	Yes[2]
3562	AMOCO SALES (BP SALES TAP)	4.99	0.1805	
31012	APL JASPER SALES APN	4.99	0.1805	Yes
3488	ARDLEY SALES	4.99	0.1805	
3237	ASPEN SALES	4.99	0.1805	
3662	ATUSIS CREEK EAST SALES	4.99	0.1805	
3216	AURORA NO 2 SALES	4.99	0.1805	
3135	AURORA SALES	4.99	0.1805	
3288	BANTRY SALES	4.99	0.1805	
3423	BASHAW WEST SALES	4.99	0.1805	
31013	BAYMAG SALES APS	4.99	0.1805	
31014	BEAR CREEK COGEN SALES APGP	4.99	0.1805	
3299	BEAR RIVER WEST SALES	4.99	0.1805	
3068	BEAVER HILLS SALES	4.99	0.1805	
3268	BENBOW SOUTH SALES	4.99	0.1805	
3933	BIG EDDY INTERCONNECTION	4.99	0.1805	
3655	BIG PRAIRIE SALES	4.99	0.1805	
3067	BIGSTONE SALES	4.99	0.1805	
3285	BILBO SALES	4.99	0.1805	
3468	BLEAK LAKE SALES	4.99	0.1805	
3295	BOOTIS HILL SALES	4.99	0.1805	
3225	BOTHA SALES	4.99	0.1805	
3259	BOULDER CREEK SALES	4.99	0.1805	

FOOTHILLS PIPE LINES LTD.

(3 pages)

TransCanada
In business to deliver

450 – 1 Street SW
Calgary, Alberta T2P 5H1

Tel: (403) 920-2603
Fax: (403) 920-2347
Email: bernard_pelletier@transcanada.com

October 31, 2017

National Energy Board
Suite 210, 517 Tenth Avenue SW
Calgary, Alberta T2R 0A8

Filed Electronically

Attention: Ms. Sheri Young, Secretary of the Board

Dear Ms. Young:

Re: Foothills Pipe Lines Ltd. (Foothills)
Statement of Rates and Charges effective January 1, 2018

Foothills encloses for filing pursuant to section 60(1)(a) of the *National Energy Board Act*[1] rates and charges for transportation service on Foothills Zones 6, 7, 8 and 9 to be effective January 1, 2018 (Effective 2018 Rates).

The following attachments are included with this letter:

- Attachment 1 consists of supporting Schedules A through G
- Attachments 2 and 3 are black-lined and clean copies, respectively, of the Table of Effective Rates for 2018

The rates and charges are based on the methodology approved by the Board in Decision TG-8-2004, as amended by Order TG-03-2007.

The filing is also made in accordance with the MH-001-2013 Decision with respect to Foothills' Abandonment Surcharges effective January 1, 2018, which are also included in the Table of Effective Rates for 2018. The supporting information on the Abandonment Surcharges calculation is provided in the attached Schedule G.

Foothills met with shippers and interested parties on October 18, 2017, and presented the preliminary 2018 revenue requirement and preliminary Effective 2018 Rates. Based on this consultation, Foothills is not aware of any objections to its proposal for establishing the Effective 2018 Rates.

[1] R.S.C. 1985, c. N-7, as amended, and the regulations made thereunder.

Foothills understands that any party that is opposed to the rates and charges will advise the Board accordingly.

Foothills will notify its shippers and interested parties of this filing and post a copy of it on TransCanada's Foothills System website at:

http://www.tccustomerexpress.com/934.html

Communication regarding this application should be directed to:

Mark Manning
Senior Project Manager, Tolls and Tariffs
Canadian Gas Pipelines
TransCanada PipeLines Limited
450 – 1 Street SW
Calgary, Alberta T2P 5H1
Telephone: (403) 920-6098
Facsimile: (403) 920-2347
Email: mark_manning@transcanada.com

Joel Forrest
Director Canadian Law
Natural Gas Pipelines
TransCanada PipeLines Limited
450 – 1 Street SW
Calgary, Alberta T2P 5H1
Telephone: (403) 920-6156
Facsimile: (403) 920-2308
Email: joel_forrest@transcanada.com

Yours truly,
Foothills Pipe Lines Ltd.

Original signed by

Bernard Pelletier
Director, Regulatory Tolls and Tariffs
Canadian Gas Pipelines

Attachments

cc: Foothills Firm Shippers
Interruptible Shippers and Interested Parties

TABLE OF EFFECTIVE RATES

1. Rate Schedule FT, Firm Transportation Service

	Demand Rate ($/GJ/Km/Month)
Zone 6	0.0053089826
Zone 7	0.0024594335
Zone 8*	0.0130154360
Zone 9	0.0077406397

2. Rate Schedule OT, Overrun Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 6	0.0001919961
Zone 7	0.0000889439

3. Rate Schedule IT, Interruptible Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 8*	0.0004706952
Zone 9	0.0002799355

4. Monthly Abandonment Surcharge**

All Zones	0.0941626428 ($/GJ/Month)

5. Daily Abandonment Surcharge***

All Zones	0.0030957522 ($/GJ/Day)

* For Zone 8, Shippers Haul Distance shall be 170.7 km.

**Monthly Abandonment Surcharge applicable to Rate Schedule Firm Transportation Service, and Short Term Firm Transportation Service for all zones.

***Daily Abandonment Surcharge applicable to Rate Schedule Overrun Transportation Service for Zone 6 & 7, Interruptible Transportation Service for zone 8 & 9, and Small General Service for Zone 9.

GAS TRANSMISSION NORTHWEST LLC

(5 pages)

161 FERC ¶ 61,305
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

December 28, 2017

In Reply Refer To:
Gas Transmission Northwest LLC
Docket No. RP18-184-000

Gas Transmission Northwest LLC
700 Louisiana Street
Suite 700
Houston, TX 77002

Attention: John A. Roscher, Director
Rates & Tariffs

Dear Mr. Roscher:

1. On November 27, 2017, pursuant to section 4 of the Natural Gas Act, Gas Transmission Northwest LLC (GTN) submitted proposed tariff records[1] to implement two new hourly services: Rate Schedule Firm Hourly Service (FHS) and Rate Schedule Interruptible Hourly Service (IHS). GTN states that the proposed new services will provide additional transportation options and flexibility to shippers whose intra-day gas requirements may not be uniform and who may require accelerated flow rates during particular periods of the gas day.

2. GTN states that FHS will provide shippers greater flexibility by allowing GTN to offer firm transportation service at hourly flow rates greater than 1/24th of a shipper's Maximum Daily Quantity (MDQ). GTN states that under FHS, a shipper may contract for firm transportation service up to a specified Maximum Hourly Quantity (MHQ), and an hourly flow rate ranging between 1/4th and 1/24th of the shipper's MDQ.[2] GTN explains that the MHQ allows the shipper to receive delivery of its MDQ at an

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[1] *See* Appendix.

[2] Proposed Rate Schedule FHS, section 5.6.

accelerated rate over a specified number of hours during the day. GTN states that, once a shipper has received quantities equal to its MDQ or MHQ, GTN will only offer further capacity to the shipper on an interruptible basis as overrun. GTN states that it shall offer FHS on both its Mainline and Extension Facilities and only when there is available, unsubscribed system capacity. GTN states that the addition of FHS will not degrade existing firm services, nor the operations of interconnection pipelines. GTN states that FHS will have the same scheduling and curtailment priority as firm service (Rate Schedule FTS-1) and limited firm service and that FHS overrun volumes will have a scheduling and curtailment priority equal to interruptible service (Rate Schedule ITS-1) and IHS. GTN states that the reservation rates for FHS are derived from GTN's currently effective Rate Schedule FTS-1 mileage and non-mileage reservation rate components.[3]

3. In addition, GTN proposes to implement IHS to provide similar hourly flow flexibility on an interruptible basis to shippers who do not wish to contract for hourly service on a firm basis. GTN states that although IHS shippers will not be entitled to reserve an hourly quantity, GTN will attempt to flow the daily nomination at an hourly flow rate designated by the shipper as part of its nomination, on a best efforts basis. GTN states that IHS service will not adversely affect existing firm service on its system or the operations of interconnection pipelines. GTN indicates that interruptible service under IHS will have the same scheduling and curtailment priority as Rate Schedule ITS-1 and overruns on any of GTN's firm services. GTN describes the rates for IHS as derived from the 100 percent load factor rate equivalent of the effective rate components (i.e., Mileage, Non-Mileage, and Delivery Charge Components) for a shipper selecting an MHQ equal to 1/10th of the MDQ under FHS. According to GTN, the derived rate represents the maximum recourse rate for IHS shippers regardless of their nominated level of hourly flow.[4]

4. GTN states that as FHS and IHS are new services and GTN is not able to predict the extent to which these services will be utilized, GTN is unable to adequately predict the revenue that may be expected from these services for the 12 months commencing January 1, 2018. Accordingly, GTN requests waiver of section 154.202(a)(1)(viii) of the Commission's regulations, which requires that tariff filings for a new service include an estimate of the effect on costs and revenues for the 12-month period commencing on the effective date of the new service.[5] GTN seeks an effective date for the tariff provisions of January 1, 2018.

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[3] Filing at 3.

[4] *Id.* at 4-5.

[5] 18 C.F.R. § 154.202(a)(1)(viii) (2017).

5. GTN's filing was noticed on November 28, 2017, with interventions and protests due on or before December 11, 2017. Pursuant to Rule 214 (18 C.F.R. § 385.214 (2017)), all timely filed motions to intervene and any unopposed motions to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt this proceeding or place additional burdens on existing parties. No protests or adverse comments were filed.

6. The Commission finds that FHS and IHS increase shippers' options without degrading previously contracted-for services. The Commission encourages pipelines to develop new services to use their systems more efficiently.[6] Similar to the Commission's finding in *Texas Eastern*, we find the hourly services proposed by GTN to be just and reasonable.[7] GTN has satisfactorily demonstrated that Rate Schedule FHS and Rate Schedule IHS will not have any adverse impact on existing customers on its system.

7. When a pipeline proposing a new rate schedule lacks the operating experience necessary to provide a reliable projection of possible revenues or costs related to the new service, the Commission has often conditioned its approval upon the filing of an activity report following the first year of service.[8] This appears appropriate here where GTN acknowledges that it is unable to adequately predict the revenue that may be expected from these services for the 12 months commencing January 1, 2018. Therefore, the Commission will require GTN to file an activity report within 45 days after the conclusion of the FHS and IHS Rate Schedules' first year of operation. The report must detail (1) the date service was rendered for each transaction, (2) the volume shipped under each transaction, (3) monthly volumes, (4) the name of the shipper for each transaction, (5) whether the shipper is an affiliate of GTN, (6) the rate charged for each transaction, (7) the revenues received for each transaction, and (8) the monthly revenues for this service. Such information will provide interested parties actual information that can be used to monitor GTN's FHS and IHS activity and revenues.

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[6] *E.g.*, *Gulf South Pipeline Co., LP*, 157 FERC ¶ 61,054, at P 7 (2016).

[7] *Texas Eastern Transmission, L.P.*, 134 FERC ¶ 61,068 (2011).

[8] *See Gulf South Pipeline Co., LP*, 136 FERC ¶ 61,086, at P 24 (2011); *Northwest Pipeline Corp.*, 100 FERC ¶ 61,336, at PP 9, 12 (2002).

8. Accordingly, the Commission accepts the GTN tariff records referenced in the Appendix, effective January 1, 2018, and grants GTN's request for waiver of section 154.202(a)(1)(viii) of the Commission's regulations. GTN is hereby directed to file an activity report within 45 days after the first year of service of Rate Schedule FHS and Rate Schedule IHS, as discussed above.

By direction of the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR TRANSPORTATION OF NATURAL GAS

Rate Schedules FTS-1, LFS-1, and FHS

For Rate Schedules FTS-1 and LFS-1:

	RESERVATION DAILY MILEAGE (a) (Dth-MILE)		RESERVATION DAILY NON-MILEAGE (b) (Dth)		DELIVERY (c) (Dth-MILE)		FUEL (d) (Dth-MILE)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	0.000434	0.000000	0.034393	0.000000	0.000016	0.000016	0.0050%	0.0000%
STF (e)	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (f)	0.002759	0.000000	0.004641	0.000000	0.000026	0.000026	---	---
E-2 (h) (Diamond 1)	0.002972	0.000000	---	---	0.000000	0.000000	---	---
E-2 (h) (Diamond 2)	0.001166	0.000000	---	---	0.000000	0.000000	---	---
COYOTE SPRINGS								
E-3 (i)	0.001282	0.000000	0.001283	0.000000	0.000000	0.000000	---	---
CARTY LATERAL								
E-4 (p)		--- ---	---	0.166475	0.000000	0.000000	0.000000	---
OVERRUN CHARGE (j)	---	---	---	---	---	---	---	---
SURCHARGES								
ACA (k)	---	---	---	---	(k)	(k)	---	---

DOMINION ENERGY QUESTAR PIPELINE, LLC

(3 pages)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
Letter Order Pursuant to § 375.307
Dominion Energy Questar Pipeline, LLC
Docket No. RP18-206-000

December 19, 2017

Dominion Energy Questar Pipeline, LLC
c/o Dominion Energy Services, Inc.
333 South State Street
P.O. Box 45360
Salt Lake City, UT 84145-0360

Attention: L. Bradley Burton
Director - Regulatory Rates, Certificates and Tariffs

Reference: Fuel Gas Reimbursement Percentage Filing

Dear Mr. Burton:

On November 30, 2017, Dominion Energy Questar Pipeline, LLC (DEQP) filed a tariff record[1] to reflect a change in its Fuel Gas Reimbursement Percentage (FGRP). DEQP requests the tariff record be accepted with an effective date of January 1, 2018. DEQP's tariff record is accepted to be effective January 1, 2018, as proposed.

Public notice of the filing was issued on November 30, 2017. Interventions and protests were due as provided in section 154.210 of the Commission's regulations (18 C.F.R. § 154.210 (2017)). Pursuant to Rule 214 (18 C.F.R. § 385.214 (2017)), all timely filed motions to intervene and any unopposed motions to intervene out-of-time filed before the issuance date of this order are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties. No protests or adverse comments were filed.

[1] Dominion Energy Questar Pipeline, LLC, FERC NGA Gas Tariff, Tariffs, Statement of Rates, Statement of Rates, 13.0.0.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or any which may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your company.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

Marsha K. Palazzi, Director
Division of Pipeline Regulation

STATEMENT OF RATES

Rate Schedule/ Type of Charge (a)	Base Tariff Rate ($) (b)
PEAKING STORAGE	
Firm Peaking Storage Service - PKS	
Monthly Reservation Charge	
Maximum 4/	2.87375
Minimum	0.00000
Usage Charge	
Injection	0.03872
Withdrawal	0.03872
CLAY BASIN STORAGE	
Firm Storage Service - FSS	
Monthly Reservation Charge	
Deliverability	
Maximum 4/	2.85338
Minimum	0.00000
Capacity	
Maximum	0.02378
Minimum	0.00000
Usage Charge	
Injection1/	0.01049
Withdrawal	0.01781
Authorized Overrun Charge	
Maximum1/	0.30315
Minimum1/	0.01781
Interruptible Storage Service - ISS	
Usage Charge	
Inventory 5/	
Maximum	0.05927
Minimum	0.00000
Injection1/	0.01049
Withdrawal	0.01781
OPTIONAL VOLUMETRIC RELEASES /	
Peaking Storage Service - PKS	
Maximum 4/	3.40890
Minimum	0.00000
Firm Storage Service - FSS	
Maximum 4/	0.57068
Minimum	0.00000
Storage Usage Charges Applicable to Volumetric Releases 6/	
Peaking Storage Service - PKS:	
Injection	0.03872
Withdrawal	0.03872
Clay Basin Storage Service - FSS:	
Injection1/	0.01049
Withdrawal	0.01781
PARK AND LOAN SERVICE - PAL1	
Daily Charge	
Maximum	0.30315
Minimum	0.00000
Delivery Charge1/	0.02830

FUEL REIMBURSEMENT - 2.0% (0.2% utility and 1.8% compressor fuel) for Rate Schedule PAL1

FEDERAL ENERGY REGULATORY COMMISSION

ANNUAL CHARGES UNIT CHARGE

(1 pages)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2017 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 26, 2018

The annual charges unit charge (ACA) to be applied to in fiscal year 2019 for recovery of FY 2018 Current year and 2017 True-Up is **$0.0013** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2018.

The following calculations were used to determine the FY 2018 unit charge:

2018 CURRENT:

Estimated Program Cost $66,791,000 divided by 49,985,774,086 Dth = 0.0013362002

2017 TRUE-UP:

Debit/Credit Cost ($316,993) divided by 47,717,356,257 Dth = (0.0000066431)

TOTAL UNIT CHARGE = 0.0013295571

If you have any questions, please contact Raven A. Rodriguez at (202)502-6276 or e-mail at Raven.Rodriguez@ferc.gov.

EXHIBIT NOS. 5-13

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

(10 pages)

Exhibit No. 5
Case No. INT-G-18-02
Intermountain Gas Company
Page 1 of 1

INTERMOUNTAIN GAS COMPANY
Summary of Gas Cost Changes

Line No.	Description	Annual Therms/ Billing Determinants INT-G-17-05	10/1/2017 Prices INT-G-17-05	Total Annual Cost INT-G-17-05	Annual Therms/ Billing Determinants INT-G-18-02	10/1/2018 Prices INT-G-18-02	Total Annual Cost INT-G-18-02	Annual Difference	INT-G-18-02 Cost of Gas Allocators [1] RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**DEMAND CHARGES:**										
2	**Transportation:**										
3	NWP TF-1 Reservation (Full Rate) [2]	894,757,350	$ 0.04047	$ 36,208,696	894,757,350	$ 0.03978	$ 35,589,562	$ (619,134)	$ (410,432)	$ (202,187)	$ (6,515)
4	NWP TF-1 Reservation (Discounted) [3]	191,431,900	0.02306	4,413,893	191,431,900	0.02283	4,369,767	(44,126)	(29,252)	(14,410)	(464)
5	Upstream Capacity (Full Rate) [4]	673,918,880	0.00986	6,643,132	847,058,880	0.01128	9,556,983	2,913,851	1,931,627	951,562	30,662
6	Upstream Capacity (Discounted) [5]	588,993,200	0.01738	10,236,180	526,943,200	0.01639	8,638,018	(1,598,162)	(1,059,441)	(521,904)	(16,817)
7	**Storage:**										
8	SGS-2F										
9	Demand	303,370	0.00156	172,962 [6]	303,370	0.00156	172,962 [7]	-	-	-	-
10	Capacity Demand	10,920,990	0.00006	227,209 [6]	10,920,990	0.00006	227,209 [7]	-	-	-	-
11	TF-2 Reservation	10,920,990	0.03972	433,817	10,920,990	0.03903	426,272	(7,545)	(5,002)	(2,464)	(79)
12	TF-2 Redelivery Charge	10,920,990	0.00137	15,005	10,920,990	0.00083	9,086	(5,919)	(3,924)	(1,933)	(62)
13	LS-2F										
14	Demand	1,551,750	0.00259	1,465,249 [6]	1,551,750	0.00259	1,465,249 [7]	-	-	-	-
15	Capacity	14,751,350	0.00033	1,782,187 [6]	14,751,350	0.00033	1,782,187 [7]	-	-	-	-
16	Liquefaction	14,751,350	0.09086	1,340,234	14,751,350	0.09086	1,340,234	-	-	-	-
17	Vaporization	14,751,350	0.00339	49,948	14,751,350	0.00339	49,948	-	-	-	-
18	TF-2 Reservation	14,751,350	0.03972	585,914	14,751,350	0.03903	575,725	(10,189)	(6,755)	(3,327)	(107)
19	TF-2 Redelivery Charge	14,751,350	0.00137	20,268	14,751,350	0.00083	12,273	(7,995)	(5,300)	(2,611)	(84)
20	Other Storage Facilities							- [8]	-	-	-
21	**COMMODITY CHARGES:**										
22	Total Producer/Supplier Purchases Including Storage	362,713,871	0.26020	94,378,149	362,713,871	0.22724	82,423,100	(11,955,049) [9]	(7,719,009)	(3,993,006)	(243,034)
23	**TOTAL ANNUAL COST DIFFERENCE**							$ (11,334,268)	$ (7,307,488)	$ (3,790,280)	$ (236,500)
24	Normalized Sales Volumes (1/1/17 - 12/31/17)								234,193,235	121,147,021	7,373,615
25	Average Base Rate Change (Line 23 divided by Line 24)								$ (0.03120)	$ (0.03129)	$ (0.03207)
26	**Other Permanent Changes Proposed:**										
27	Elimination of Temporary Credits (Surcharges) from Case No. INT-G-17-05								0.05425	0.06300	0.01984
28	Adjustment to Fixed Cost Collection Rate [10]								(0.01239)	(0.02522)	(0.01046)
29	**Total Permanent Changes Proposed (Lines 25 through 28)**								0.01066	0.00649	(0.02269)
30	Temporary Surcharge (Credit) Proposed [11]								(0.07741)	(0.07698)	(0.04583)
31	**Proposed Average Per Therm Change in Intermountain Gas Company Tariff (Lines 29 through 30)**								$ (0.06675)	$ (0.07049)	$ (0.06852)

(1) See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)
(2) See Workpaper No. 1, Page 1
(3) See Workpaper No. 1, Page 2
(4) See Workpaper No. 2, Page 1
(5) See Workpaper No. 2, Page 2
(6) Price Reflects Daily Charge; Column (d) equals Column (c) times Column (b) times 365. Actual prices include 6 decimals.
(7) Price Reflects Daily Charge; Column (g) equals Column (f) times Column (e) times 365. Actual prices include 6 decimals.
(8) See Workpaper No. 3, Line 29, Column (e)
(9) Line 22 Column (f) minus Column (c) times Line 24 Columns (i) - (k)
(10) See Exhibit No. 6, Line 25, Columns (e) - (g)
(11) See Exhibit No. 7, Line 8, Columns (b) - (d)

INTERMOUNTAIN GAS COMPANY
Gas Transportation & Storage Costs
From Case No. INT-G-17-05

Line No.	Description	Annual Therms/ Billing Determinants INT-G-17-05	10/1/2017 Prices INT-G-17-05	Annual Cost INT-G-17-05	INT-G-18-02 Cost of Gas Allocators [1] RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**DEMAND CHARGES:**						
2	**Transportation:**						
3	NWP TF-1 Reservation (Full Rate)	894,757,350	$ 0.04047	$ 36,208,696	$ 24,003,179	$ 11,824,493	$ 381,024
4	NWP TF-1 Reservation (Discounted)	191,431,900	0.02306	4,413,893	2,926,023	1,441,423	46,447
5	Upstream Capacity (Full Rate)	673,918,880	0.00986	6,643,132	4,403,812	2,169,414	69,906
6	Upstream Capacity (Discounted)	588,993,200	0.01738	10,236,180	6,785,687	3,342,778	107,715
7	**Storage:**						
8	SGS-2F						
9	Demand	303,370	0.00156	172,962 [2]	114,659	56,483	1,820
10	Capacity Demand	10,920,990	0.00006	227,209 [2]	150,619	74,199	2,391
11	TF-2 Reservation	10,920,990	0.03972	433,817	287,583	141,669	4,565
12	TF-2 Redelivery Charge	10,920,990	0.00137	15,005	9,947	4,900	158
13	LS-2F						
14	Demand	1,551,750	0.00259	1,465,249 [2]	971,331	478,499	15,419
15	Capacity	14,751,350	0.00033	1,782,187 [2]	1,181,433	582,000	18,754
16	Liquefaction	14,751,350	0.09086	1,340,234	888,457	437,674	14,103
17	Vaporization	14,751,350	0.00339	49,948	33,111	16,311	526
18	TF-2 Reservation	14,751,350	0.03972	585,914	388,409	191,339	6,166
19	TF-2 Redelivery Charge	14,751,350	0.00137	20,268	13,436	6,619	213
20	Other Storage Facilities			3,080,420 [3]	2,042,048	1,005,957	32,415
21	**Total Fixed Gas Cost Charges**			$ 66,675,114	$ 44,199,734	$ 21,773,758	$ 701,622
22	Estimated Sales Volumes [4]				236,042,592	123,680,471	7,386,357
23	Fixed Cost Collection per Therm (Line 21 divided by Line 22)				$ 0.18725	$ 0.17605	$ 0.09499
24	INT-G-17-05 Fixed Cost Collection per Therm				0.19964	0.20127	0.10545
25	**Adjustment to Fixed Cost Collection (Line 23 minus Line 24)**				$ (0.01239)	$ (0.02522)	$ (0.01046)
26	**GAS TRANSPORTATION COST CALCULATION:**						
27	Adjusted Fixed Cost Collection Per Therm (Line 23)				$ 0.18725	$ 0.17605	$ 0.09499
28	Incremental Fixed Cost Collection [5]				0.00176	0.00167	0.00089
29	**INT-G-18-02 Gas Transportation Cost (Lines 27 through 28)**				$ 0.18901	$ 0.17772	$ 0.09588

[1] See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)
[2] Price Reflects Daily Charge; Column (d) equals Column (c) times Column (b) times 365. Actual prices include 6 decimals.
[3] See Workpaper No. 3, Line 14 ,Column (e)
[4] Sales volumes adjusted for customer growth
[5] See Exhibit No. 5 (Sum of Lines 1 - 20 divided by Line 24)

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Temporary Surcharges (Credits)

Line No.	Description	RS	GS-1	LV-1	T-3	T-4
	(a)	(b)	(c)	(d)	(e)	(f)
1	Management of Pipeline Transportation Capacity [1]	$ (0.01544)	$ (0.01470)	$ (0.00778)	$ -	$ -
2	Proposed Temporary Surcharge (Credit) - Fixed Deferral [2]	(0.04121)	(0.04359)	(0.02284)	-	-
3	Proposed Temporary Surcharge (Credit) - Variable Deferral	(0.01220) [3]	(0.01220) [3]	(0.01340) [4]	0.00050 [5]	0.00907 [6]
4	LNG Sales Credits [7]	(0.00109)	(0.00104)	(0.00055)	-	(0.00826)
5	Proposed Temporary Surcharge (Credit) - General Rate Case Costs [8]	(0.00002)	(0.00002)	-	-	(0.00005)
6	Deferred General Rate Case Costs [9]	0.00021	0.00015	0.00004	0.00001	0.00043
7	Deferred Tax Reform Decrease [10]	(0.00766)	(0.00558)	(0.00130)	(0.00031)	(0.01380)
8	**Total Proposed Temporary Surcharges (Credits)**	$ (0.07741)	$ (0.07698)	$ (0.04583)	$ 0.00020	$ (0.01261)

(1) See Exhibit No. 8, Line 5, Columns (c) - (e)
(2) See Exhibit No. 9, Line 9, Columns (c) - (e)
(3) See Exhibit No. 10, Line 4, Column (b) plus Line 12, Column (b)
(4) See Exhibit No. 10, Line 4, Column (b) plus Line 20, Column (b)
(5) See Exhibit No. 10, Line 20, Column (b)
(6) See Exhibit No. 10, Line 26, Column (b)
(7) See Exhibit No. 11, Line 7, Columns (c) - (f)
(8) See Exhibit No. 12, Page 1, Line 8, Columns (c) - (g)
(9) See Exhibit No. 12, Page 2, Line 6, Columns (c) - (g)
(10) See Exhibit No. 13, Line 3, Columns (c) - (g)

INTERMOUNTAIN GAS COMPANY

Allocation of Annualized Credits Resulting from Management of Pipeline Transportation Capacity

Line No.	Description	Total	INT-G-18-02 Cost of Gas Allocators [1]		
			RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)
1	Long-term Northwest Pipeline Capacity Releases	$ (3,723,000)	$ (2,468,022)	$ (1,215,801)	$ (39,177)
2	Upstream Pipeline Capacity Releases	(1,730,000)	(1,146,838)	(564,957)	(18,205)
3	**Total Management of Pipeline Transportation Capacity**	$ (5,453,000)	$ (3,614,860)	$ (1,780,758)	$ (57,382)
4	Normalized Sales Volumes (1/1/17 - 12/31/17)		234,193,235	121,147,021	7,373,615
5	**Proposed Per Therm Price Adjustment**		$ (0.01544)	$ (0.01470)	$ (0.00778)

[1] See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)

INTERMOUNTAIN GAS COMPANY
Proposed Temporary Surcharges (Credits) - Fixed Costs

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2018 Balance [1]	RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)
1	Fixed Gas Cost Balance Approved in Prior PGA (Accounts 1910.2050 - 2090) [2]	$ 1,680,847	$ 1,073,077	$ 588,272	$ 19,498
2	Fixed Cost Collection Adjustment (Account 1910.2200) [2]	(8,951,891)	(5,536,612)	(3,308,211)	(107,068)
3	Capacity Releases (Account 1910.2320) [3]	(8,219,303)	(5,448,674)	(2,684,137)	(86,492)
4	Interest (Account 1910.2430) [3]	(51,857)	(34,376)	(16,935)	(546)
5	Pipeline Transportation Capacity Release Credit (Account 1910.2530) [2]	(3,740,000)	(2,466,968)	(1,232,345)	(40,687)
6	Amortization of 1910.2530 (Accounts 1910.2540 - 1910.2550) [2]	4,181,559	2,761,680	1,373,007	46,872
7	**Total Fixed Costs**	$ (15,100,645)	$ (9,651,873)	$ (5,280,349)	$ (168,423)
8	Normalized Sales Volumes (1/1/17 - 12/31/17)		234,193,235	121,147,021	7,373,615
9	**Proposed Temporary Surcharge (Credit) - Fixed Costs**		$ (0.04121)	$ (0.04359)	$ (0.02284)

(1) See Workpaper No. 5, Pages 3 and 4
(2) Balance tracked by rate class
(3) See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)

INTERMOUNTAIN GAS COMPANY

Proposed Temporary Surcharges (Credits) - Variable Costs

Line No.	Description	Amount
	(a)	(b)
1	**Account 1910 Variable Amounts Which Apply to RS, GS-1, and LV-1:**	
2	Account 1910 Variable Costs	$ (5,040,702) [1]
3	Normalized Sales Volumes (1/1/17 - 12/31/17)	362,713,871
4	**Proposed Temporary Surcharge (Credit) - Variable Costs**	$ (0.01390)
5	**Lost and Unaccounted For Gas Amounts Which Apply to RS and GS-1:**	
6	Lost and Unaccounted For Gas Amounts from INT-G-17-05 (Account 1910.2120)	$ (639,441) [2]
7	Lost and Unaccounted For Gas Amortization (Account 1910.2130)	725,932 [3]
8	(Over)/Under Collection of Lost and Unaccounted For Gas from INT-G-17-05	86,491
9	Lost and Unaccounted For Gas INT-G-18-02	519,013 [4]
10	Total Lost and Unaccounted For Gas Amounts Which Apply to RS and GS-1	$ 605,504
11	Normalized Sales Volumes (1/1/17 - 12/31/17)	355,340,256
12	**Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs**	$ 0.00170
13	**Lost and Unaccounted For Gas Amounts Which Apply to LV-1, T-3, and T-4:**	
14	Lost and Unaccounted For Gas Amounts from INT-G-17-05 (Account 1910.2120)	$ (218,673) [5]
15	Lost and Unaccounted For Gas Amortization (Account 1910.2140)	226,764 [6]
16	(Over)/Under Collection of Lost and Unaccounted For Gas from INT-G-17-05	8,091
17	Lost and Unaccounted For Gas INT-G-18-02	172,826 [7]
18	Total Lost and Unaccounted For Gas Amounts Which Apply to LV-1, T-3, and T-4	$ 180,917
19	Normalized Sales Volumes (1/1/17 - 12/31/17)	364,463,691
20	**Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs**	$ 0.00050
21	**Convert T-4 Lost and Unaccounted For Temporary from a Volumetric Rate to a Demand Rate**	
22	Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs (Line 20)	$ 0.00050
23	Normalized T-4 Sales Volumes (1/1/17 - 12/31/17)	313,530,305
24	Total Temporary Collected	$ 156,765
25	Billing Determinants Demand Volumes	17,280,720
26	**Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For T-4 Demand Rate (Line 24 Divided by Line 25)**	$ 0.00907

[1] See Workpaper No. 5, Page 1, Line 16, Column (f)
[2] See Workpaper No. 5, Page 2, Line 2, Column (c)
[3] See Workpaper No. 5, Page 2, Line 8, Column (d)
[4] See Workpaper No. 5, Page 2, Line 29, Column (d), plus Line 35, Column (e)
[5] See Workpaper No. 5, Page 2, Line 3, Column (c)
[6] See Workpaper No. 5, Page 2, Line 14, Column (d)
[7] See Workpaper No. 5, Page 2, Line 30, Column (d), plus Line 39, Column (e)

INTERMOUNTAIN GAS COMPANY
Allocation of LNG Sales Credits

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2018 Balance [2]	INT-G-18-02 LNG Sales Credit Demand Allocators [1] RS	GS-1	LV-1	T-4
	(a)	(b)	(c)	(d)	(e)	(f)
1	LNG Sales Credit Approved in Prior PGA (Accounts 1910.2800 - 2810)	$ 41,785	$ 20,229	$ 9,965	$ 321	$ 11,270
2	Interest (Account 1910.2815)	(122)	(59)	(29)	(1)	(33)
3	LNG Sales Deferral - Margin Sharing (Account 1910.2820)	(469,397)	(227,242)	(111,945)	(3,607)	(126,603)
4	LNG Sales Deferral - O&M Recovery (Account 1910.2825)	(101,711)	(49,239)	(24,257)	(782)	(27,433)
5	**Total LNG Sales Credits**	$ (529,445)	$ (256,311)	$ (126,266)	$ (4,069)	$ (142,799)
6	Normalized Sales Volumes (1/1/17 - 12/31/17)		234,193,235	121,147,021	7,373,615	17,280,720 [3]
7	**Proposed Price Adjustment Per Therm**		$ (0.00109)	$ (0.00104)	$ (0.00055)	$ (0.00826)

(1) See Allocation Factor on Workpaper No. 4, Line 10, Columns (b) - (f)
(2) See Workpaper No. 5, Page 4, Lines 20 - 31, Column (d)
(3) Annualized T-4 CDs

INTERMOUNTAIN GAS COMPANY
Proposed Temporary Surcharges (Credits) - General Rate Case Costs

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2018 Balance [2]	Order No. 335757 Allocation of Base Rate Revenues [1]				
			RS	GS-1	LV-1	T-3	T-4
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	General Rate Case Cost Deferral (Account 1910.2600)	$ -	$ -	$ -	$ -	$ -	$ -
2	General Rate Case Intervenor Funding (Accounts 1910.2610 - 2620)	(3,046)	(1,965)	(752)	(12)	(18)	(299)
3	Deferred General Rate Case Costs (Account 2630 - INT-G-17-05) [3]	75,723	48,864	18,697	288	451	7,423
4	Deferred General Rate Case Costs Amortization (Account 1910.2640)	(81,663)	(52,698)	(20,163)	(310)	(487)	(8,005)
5	Interest (Account 1910.2615)	249	162	61	1	1	24
6	**Total General Rate Case Costs**	$ (8,737)	$ (5,637)	$ (2,157)	$ (33)	$ (53)	$ (857)
7	Normalized Sales Volumes (1/1/17 - 12/31/17)		234,193,235	121,147,021	7,373,615	43,559,771	17,280,720 [4]
8	**Proposed Temporary Surcharge (Credit) - General Rate Case Costs**		$ (0.00002)	$ (0.00002)	$ -	$ -	$ (0.00005)

(1) See Allocation Factor on Workpaper No. 4, Line 13, Columns (b) - (f)
(2) See Workpaper No. 5, Page 5, Lines 1 - 6 & 8 - 16, Column (d)
(3) See Exhibit No. 12, Page 2
(4) Annualized T-4 CDs

INTERMOUNTAIN GAS COMPANY
Allocation of Deferred General Rate Case Costs

Line No.	Description	General Rate Case Costs Estimated Sept. 30, 2018 Balance	Order No. 335757 Allocation of Base Rate Revenues [1] RS	GS-1	LV-1	T-3	T-4
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Deferred General Rate Case Costs Approved for Recovery (Account 1910.2630) [2]	$ 378,614					
2	Less: INT-G-17-05 Amortization [3]	(75,723)					
3	Remaining Deferred GRC Costs Approved for Recovery	$ 302,891					
4	Year 2 of 5 - Year Amortization	$ 75,723	$ 48,864	$ 18,697	$ 288	$ 451	$ 7,423
5	Normalized Sales Volumes (1/1/17 - 12/31/17)		234,193,235	121,147,021	7,373,615	43,559,771	17,280,720 [4]
6	**Proposed Price Adjustment Per Therm**		$ 0.00021	$ 0.00015	$ 0.00004	$ 0.00001	$ 0.00043

[1] See Allocation Factor on Workpaper No. 4, Line 13, Columns (b) - (f)
[2] See Workpaper No. 5, Page 5, Line 7, Column (d)
[3] Case No. INT-G-17-05
[4] Annualized T-4 CDs

INTERMOUNTAIN GAS COMPANY
Allocation of Tax Reform Deferral

Line No.	Description	Tax Reform Deferral May 31, 2018 Balance [1]	RS	GS-1	LV-1	T-3	T-4
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Tax Reform Deferral (Account 2292) [2]	$ (2,731,841)	$ (1,794,100)	$ (675,992)	$ (9,593)	$ (13,642)	$ (238,514)
2	Normalized Sales Volumes (1/1/17 - 12/31/17)		234,193,235	121,147,021	7,373,615	43,559,771	17,280,720 [3]
3	**Proposed Price Adjustment Per Therm**		$ (0.00766)	$ (0.00558)	$ (0.00130)	$ (0.00031)	$ (0.01380)

[1] See Workpaper No. 5, Page 6, Line 8, Column (f)
[2] Balance tracked by rate class
[3] Annualized T-4 CDs

NEWS RELEASE

and

CUSTOMER NOTICE

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

(2 pages)

NEWS RELEASE

INTERMOUNTAIN
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

Intermountain Gas Company files decrease in prices as part of annual PGA

BOISE, IDAHO– August 10, 2018– Intermountain Gas Company filed its annual Purchased Gas Cost Adjustment (PGA) application with the Idaho Public Utilities Commission to change its prices by an overall average decrease of 10.2 percent or approximately $24.5 million. If approved, the decrease would be effective Oct. 1, 2018. The primary reason behind the proposed decrease is a decline in the price of natural gas that Intermountain purchases for its customers. Because the price of gas is a pass-through charge directly to its customers, Intermountain's earnings will not decrease because of the proposed change in prices and revenues.

If approved, residential customers using natural gas will see an average decrease of 10.0 percent or $4.12 per month based on average weather and usage. Commercial customers, on average, would see a decrease of 11.9 percent or $21.89 per month.

The company is also proposing to eliminate the temporary surcharges and credits that have been included in its current prices during the past year. Newer temporary surcharges and credits will be included going forward.

"Because of industry-specific technological advances in exploration, production and energy efficiency measures; nationwide supply of natural gas continues to outpace demand, which contributes to lower natural gas prices," said Scott Madison, Executive Vice President, Business Development and Gas Supply. "In addition, Intermountain continues its long tradition of prudent management of pipeline capacity and summer storage to ensure the best prices for our customers. We are proud to offer some of the lowest prices for natural gas in the region and country."

Even with this proposed price decrease, Intermountain continues to urge all its customers to use energy wisely. For more information about the Company's Energy Efficiency program and available rebates for installing high efficiency equipment, visit www.intgas.com/saveenergy. Conservation tips, information on government payment energy assistance and programs to help consumers level out their energy bills over the year can be found on the company's website www.intgas.com .

The Purchased Gas Adjustment application is filed each year to ensure the costs Intermountain incurs on behalf of its customer are reflected in its sales prices. The request is a proposal and is subject to public review and approval by the IPUC. A copy of the application is available for review at the commission, and on its homepage at www.puc.idaho.gov as well as the company's website at www.intgas.com . Written comments regarding the application may be filed with the commission. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email.

Intermountain Gas Company is a natural gas distribution company serving approximately 350,000 residential, commercial and industrial customers in 75 communities in southern Idaho. Intermountain is a subsidiary of MDU Resources Group, Inc., which provides essential products and services through its regulated energy delivery and construction materials and services businesses. It is traded on the New York Stock Exchange as "MDU." For more information about MDU Resources, visit the company's website at www.mdu.com. For more information about Intermountain, visit www.intgas.com.

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Media Contact: Cheryl Imlach, Manager Energy Utilization, 208-377-6179

INTERMOUNTAIN® GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

Customer Notice

Intermountain Gas Company files decrease in prices as part of annual PGA

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The Purchased Gas Adjustment application is filed each year to ensure the costs Intermountain incurs on behalf of its customer are reflected in its sales prices. The request is a proposal and is subject to public review and approval by the IPUC. A copy of the application is available for review at the commission, and on its homepage at www.puc.idaho.gov as well as the company's website at www.intgas.com . Written comments regarding the application may be filed with the commission. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email.

WORKPAPER NOS. 1-8

CASE NO. INT-G-18-02

INTERMOUNTAIN GAS COMPANY

(15 pages)

INTERMOUNTAIN GAS COMPANY
Summary of Northwest Pipeline TF-1 Full Rate Demand Costs

Line No.	Transportation	INT-G-17-05 Annual Therms	INT-G-17-05 Prices[1]	INT-G-17-05 Annual Cost[2]
	(a)	(b)	(c)	(d)
1	TF-1 Reservation Contract #1	412,537,600	$ 0.040691	$ 16,786,576
2	TF-1 Reservation Contract #2	25,550,000	0.050152	1,281,371
3	TF-1 Reservation Contract #3	73,000,000	0.039724	2,899,853
4	TF-1 Reservation Contract #4	26,429,650	0.039724	1,049,892
5	TF-1 Reservation Contract #5	32,850,000	0.039724	1,304,933
6	TF-1 Reservation Contract #6	36,500,000	0.039724	1,449,924
7	TF-1 Reservation Contract #7	87,600,000	0.039724	3,479,822
8	TF-1 Reservation Contract #8	18,250,000	0.039724	724,965
9	TF-1 Reservation Contract #9	104,495,850	0.039724	4,150,994
10	TF-1 Reservation Contract #10	26,462,500	0.039724	1,051,195
11	TF-1 Reservation Contract #11	51,081,750	0.039724	2,029,171
12	**Total**	894,757,350		$ 36,208,696

Line No.	Transportation	INT-G-18-02 Annual Therms	INT-G-18-02 Prices[1]	INT-G-18-02 Annual Cost[2]
	(a)	(b)	(c)	(d)
13	TF-1 Reservation Contract #1	412,537,600	$ 0.039995	$ 16,499,624
14	TF-1 Reservation Contract #2	25,550,000	0.049501	1,264,739
15	TF-1 Reservation Contract #3	73,000,000	0.039033	2,849,412
16	TF-1 Reservation Contract #4	26,429,650	0.039033	1,031,629
17	TF-1 Reservation Contract #5	32,850,000	0.039033	1,282,233
18	TF-1 Reservation Contract #6	36,500,000	0.039033	1,424,702
19	TF-1 Reservation Contract #7	87,600,000	0.039033	3,419,296
20	TF-1 Reservation Contract #8	18,250,000	0.039033	712,353
21	TF-1 Reservation Contract #9	104,495,850	0.039033	4,078,784
22	TF-1 Reservation Contract #10	26,462,500	0.039033	1,032,914
23	TF-1 Reservation Contract #11	51,081,750	0.039033	1,993,876
24	**Total**	894,757,350		$ 35,589,562
25	**Total Annual Cost Difference (Line 24 minus Line 12)**			**$ (619,134)** [3]

[1] Column (d) divided by Column (b), rounded to 6 decimal places

[2] Sum of the calculated monthly costs

[3] Includes the decrease in Northwest Pipeline prices, effective Oct. 1, 2018. See Exhibit No. 5, Line 3, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Northwest Pipeline TF-1 Discounted Demand Costs

Line No.	Transportation	INT-G-17-05 Annual Therms	INT-G-17-05 Prices[(1)]	INT-G-17-05 Annual Cost[(2)]
	(a)	(b)	(c)	(d)
1	TF-1 Reservation Contract #1	18,250,000	$ 0.025821	$ 471,230
2	TF-1 Reservation Contract #2	29,404,400	0.023834	700,836
3	TF-1 Reservation Contract #3	58,400,000	0.024327	1,420,691
4	TF-1 Reservation Contract #4	36,500,000	0.027012	985,952
5	TF-1 Reservation Contract #5	32,850,000	0.008500	279,225
6	TF-1 Reservation Contract #6	11,497,500	0.035752	411,059
7	TF-1 Reservation Contract #7	4,530,000	0.031987	144,900
8	**Total**	191,431,900		$ 4,413,893

Line No.	Transportation	INT-G-18-02 Annual Therms	INT-G-18-02 Prices[(1)]	INT-G-18-02 Annual Cost[(2)]
	(a)	(b)	(c)	(d)
9	TF-1 Reservation Contract #1	18,250,000	$ 0.025372	$ 463,030
10	TF-1 Reservation Contract #2	29,404,400	0.023420	688,648
11	TF-1 Reservation Contract #3	58,400,000	0.024396	1,424,702
12	TF-1 Reservation Contract #4	36,500,000	0.026542	968,801
13	TF-1 Reservation Contract #5	32,850,000	0.008500	279,225
14	TF-1 Reservation Contract #6	11,497,500	0.035130	403,904
15	TF-1 Reservation Contract #7	4,530,000	0.031227	141,457
16	**Total**	191,431,900		$ 4,369,767
17	**Total Annual Cost Difference (Line 16 minus Line 8)**			**$ (44,126)** [(3)]

(1) Column (d) divided by Column (b), rounded to 6 decimal places

(2) Sum of the calculated monthly costs

(3) Includes the decrease in Northwest Pipeline prices, effective Oct. 1, 2018. See Exhibit No. 5, Line 4, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Upstream Capacity Full Rate Demand Costs

Line No.	Transportation (a)	INT-G-17-05 Annual Therms (b)	INT-G-17-05 Prices[1] (c)	INT-G-17-05 Annual Cost[2] (d)
1	Upstream Agreement #1	25,933,250	$ 0.007728	$ 200,412
2	Upstream Agreement #2	351,503,260	0.007733	2,718,221
3	Upstream Agreement #3	26,962,550	0.007728	208,368
4	Upstream Agreement #4	37,244,600	0.007728	287,832
5	Upstream Agreement #5	26,126,700	0.016051	419,372
6	Upstream Agreement #6	128,898,520	0.016051	2,068,974
7	Upstream Agreement #7	54,750,000	0.016051	878,801
8	Upstream Agreement #8	-	-	-
9	Upstream Agreement #9	22,500,000	0.016051	361,152
10	Upstream Agreement #10	-	-	-
11	Total	673,918,880		7,143,132
12	Estimated Upstream Capacity Release Credits			(500,000)
13	**Total Annual Cost Including Capacity Release Credits**			$ 6,643,132

Line No.	Transportation (a)	INT-G-18-02 Annual Therms (b)	INT-G-18-02 Prices[1] (c)	INT-G-18-02 Annual Cost[2] (d)
14	Upstream Agreement #1	25,933,250	$ 0.008033	$ 208,320
15	Upstream Agreement #2	351,503,260	0.008038	2,825,484
16	Upstream Agreement #3	26,962,550	0.008033	216,588
17	Upstream Agreement #4	37,244,600	0.008033	299,184
18	Upstream Agreement #5	26,126,700	0.016051	419,372
19	Upstream Agreement #6	128,898,520	0.016051	2,068,974
20	Upstream Agreement #7	54,750,000	0.016051	878,801
21	Upstream Agreement #8	62,050,000	0.016051	995,977 [3]
22	Upstream Agreement #9	-	-	- [4]
23	Upstream Agreement #10	133,590,000	0.016051	2,144,283 [5]
24	Total	847,058,880		10,056,983
25	Estimated Upstream Capacity Release Credits			(500,000)
26	**Total Annual Cost Including Capacity Release Credits**			$ 9,556,983
27	**Total Annual Cost Difference (Line 26 minus Line 13)**			**$ 2,913,851** [6]

[1] Column (d) divided by Column (b), rounded to 6 decimal places
[2] Sum of the calculated monthly costs
[3] See Workpaper No. 2, Page 2, Lines 1 and 6, Column (d)
[4] This short-term seasonal capacity has been replaced by the new long-term contract on line 23
[5] New long-term contract replacing the seasonal short-term capacity listed on Line 9
[6] See Exhibit No. 5, Line 5, Column (h)

INTERMOUNTAIN GAS COMPANY

Summary of Upstream Capacity Discounted Demand Costs

Line No.	Transportation	INT-G-17-05 Annual Therms	INT-G-17-05 Prices[1]	INT-G-17-05 Annual Cost[2]
	(a)	(b)	(c)	(d)
1	Upstream Agreement #1	62,050,000	$ 0.015841	$ 982,922
2	Upstream Agreement #2	36,974,500	0.014194	524,818
3	Upstream Agreement #3	452,311,650	0.017815	8,057,964
4	Upstream Agreement #4	37,657,050	0.017805	670,476
5	**Total**	588,993,200		$ 10,236,180

Line No.	Transportation	INT-G-18-02 Annual Therms	INT-G-18-02 Prices[1]	INT-G-18-02 Annual Cost[2]	
	(a)	(b)	(c)	(d)	
6	Upstream Agreement #1	-	$ -	$ -	(3)
7	Upstream Agreement #2	36,974,500	0.014194	524,818	
8	Upstream Agreement #3	452,311,650	0.016559	7,490,004	
9	Upstream Agreement #4	37,657,050	0.016549	623,196	
10	**Total**	526,943,200		$ 8,638,018	
11	**Total Annual Cost Difference (Line 10 minus Line 5)**			**$ (1,598,162)**	(4)

(1) Column (d) divided by Column (b), rounded to 6 decimal places

(2) Sum of the calculated monthly costs

(3) The discounted rate expired and this contract is now at full rate, effective Nov. 1, 2017. See Workpaper No. 2, Page 1, Line 21, Column (d)

(4) See Exhibit No. 5, Line 6, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Other Storage Facility Costs

Line No.	Storage Facilities	INT-G-17-05 Monthly Billing Determinant		INT-G-17-05 Prices	INT-G-17-05 Monthly Cost	INT-G-17-05 Annual Cost
	(a)	(b)		(c)	(d)	(e)
1	**Demand Costs -**					
2	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652
3	Clay Basin II Reservation	221,880	(1)	0.285338	63,311	759,732
4	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360
5	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724
6	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768
7	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384
8	Total Demand Costs	84,135,000	(3)		$ 400,135	$ 4,801,620
9	**Rexburg LNG Facility -**					
10	Transportation Reservation					$ 66,000
11	Variable Transportation					22,800
12	Total Rexburg LNG Facility Costs					$ 88,800
13	Storage Demand Charge Credit					$ (1,810,000)
14	**Total Costs Including Storage Credit**					$ 3,080,420

Line No.	Storage Facilities	INT-G-18-02 Monthly Billing Determinant		INT-G-18-02 Prices	INT-G-18-02 Monthly Cost	INT-G-18-02 Annual Cost	
	(a)	(b)		(c)	(d)	(e)	
15	**Demand Costs -**						
16	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652	
17	Clay Basin II Reservation	221,880	(1)	0.285338	63,311	759,732	
18	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360	
19	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724	
20	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768	
21	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384	
22	Total Demand Costs	84,135,000	(3)		$ 400,135	$ 4,801,620	
23	**Rexburg LNG Facility -**						
24	Transportation Reservation					$ 66,000	
25	Variable Transportation					22,800	
26	Total Rexburg LNG Facility Costs					$ 88,800	
27	Estimated Storage Demand Charge Credit					$ (1,810,000)	
28	**Total Costs Including Storage Credit**					$ 3,080,420	
29	**Total Annual Cost Difference (Line 28 minus Line 14)**					**$ -**	(4)

(1) Charge Based on Maximum Daily Withdrawal

(2) Charge Based on Maximum Contractual Capacity

(3) Non-additive Billing Determinants. Includes only Capacity Volumes

(4) See Exhibit No. 5, Line 20, Column (h)

INTERMOUNTAIN GAS COMPANY
Allocation Factors

Line No.	Description	Peak Demand					
		RS	GS-1	LV-1	T-3	T-4	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**INT-G-18-02 Cost of Gas Allocators:**						
2	Peak Demand Per Customer	8.01	38.54				
3	January 2018 Actual Customers	322,695	33,039				
4	INT-G-18-02 Peak Demand Therms (Line 2 times Line 3)	2,584,787	1,273,323	41,030 (1)			3,899,140
5	Percent of Total	66.2912%	32.6565%	1.0523%	N/A	N/A	100.00%
6	**INT-G-18-02 LNG Sales Credit Demand Allocators:**						
7	Peak Demand Per Customer	8.01	38.54				
8	January 2018 Actual Customers	322,695	33,039				
9	INT-G-18-02 Peak Demand Therms (Line 7 times Line 8)	2,584,787	1,273,323	41,030 (1)		1,440,060 (1)	5,339,200
10	Percent of Total	48.4115%	23.8486%	0.7685%	N/A	26.9715%	100.00%
11	**Order No. 33757 Allocation of Base Rate Revenues:**						
12	Approved Base Rate Revenues (Case No. INT-G-16-02)	$ 57,675,297	$ 22,067,934	$ 339,403	$ 532,754	$ 8,760,876	$ 89,376,264
13	Percent of Total	64.5309%	24.6910%	0.3797%	0.5961%	9.8022%	100.00%

(1) Contract Demand

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2018

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1910 VARIABLE AMOUNTS:**					
2	Variable Gas Cost Balance Approved in Prior PGA in Acct 1910.2010 at 10/1/17			$ 2,440,939		
3	Amortization in Acct 1910.2020 of Acct 1910.2010 Balance Approved in Prior PGA as of 6/30/18		$ (2,431,209)			
4	Estimated Therm Sales 7/1 through 9/30/18	26,115,340				
5	Amortization Rate	$ (0.00748)	(195,343)			
6	Estimated Amortization in Acct 1910.2020 of Acct 1910.2010 Balance Approved in Prior PGA at 9/30/18			(2,626,552)		
7	Estimated Balance in Acct 1910.2010 at 9/30/18				$ (185,613)	
8	Variable Gas Cost Deferral of Current PGA Year Activity in Acct 1910.2180 at 10/1/17			(714,067)		
9	Deferred Variable Gas Costs in Acct 1910.2180 through 6/30/18			(3,276,847)		
10	Estimated Deferred Variable Gas Costs in Acct 1910.2180 from 7/1 through 9/30/18			(811,257)		
11	Estimated Balance in Acct 1910.2180 of Current PGA Year Activity at 9/30/18				(4,802,171)	
12	PGA Year Interest Deferred in Acct 1910.2340 at 10/1/17			(501)		
13	PGA Year Interest Deferred in Acct 1910.2340 through 6/30/18			(52,205)		
14	Estimated PGA Year Interest from 7/1 through 9/30/18			(212)		
15	Estimated Balance in Acct 1910.2340 at 9/30/18				(52,918)	
16	**ESTIMATED ACCOUNT 1910 VARIABLE BALANCE AT 9/30/18**					$ (5,040,702)

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2018

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1910 LOST AND UNACCOUNTED FOR AMOUNTS:**					
2	RS & GS-1 Cumulative Deferred Lost & Unaccounted For Gas Balance Approved in Prior PGA in Acct 1910.2120 at 10/1/17		$ (639,441)			
3	Industrial Cumulative Deferred Lost & Unaccounted For Gas Balance Approved in Prior PGA in Acct 1910.2120 at 10/1/17		(218,673)			
4	**Net Cumulative Deferred Lost & Unaccounted For Gas Balance Approved in Prior PGA in Acct 1910.2120 at 10/1/17**			$ (858,114)		
5	RS & GS-1 Amortization in Acct 1910.2130 of Acct 1910.2120 Balance Approved in Prior PGA as of 6/30/18		$ 676,599			
6	Estimated Therm Sales 7/1 through 9/30/18	24,666,325				
7	Amortization Rate	$ 0.00200	49,333			
8	Estimated Amortization in Acct 1910.2130 of Acct 1910.2120 Balance Approved in Prior PGA at 9/30/18			725,932		
9	Industrial Amortization in Acct 1910.2140 of Acct 1910.2120 Balance Approved in Prior PGA as of 6/30/18		$ 170,528			
10	Estimated LV-1 & T-3 Therm Sales 7/1 through 9/30/18	8,890,015				
11	Amortization Rate	$ 0.00064	5,690			
12	Estimated T-4 Therms 7/1 through 9/30/18	4,320,180				
13	Amortization Rate	$ 0.01170	50,546			
14	Estimated Amortization in Acct 1910.2140 of Acct 1910.2120 Balance Approved in Prior PGA at 9/30/18			226,764		
15	**Estimated Balance in Acct 1910.2120 at 9/30/18**				$ 94,582	
16	**Lost & Unaccounted For Gas Deferral of Current PGA Year Activity in Acct 1910.2150 at 10/1/17**			$ (454)		
17	Deliveries to System through 6/30/18 (Therms)	608,279,078				
18	Lost & Unaccounted For Gas	0.1172% [1]	712,903			
19	Average WACOG 10/1/17 - 6/30/18		$ 0.195683			
20	Lost & Unaccounted For Gas Deferral through 6/30/18			$ 139,503		
21	Estimated Deliveries to System 7/1 - 9/30/18 (Therms)	93,752,430				
22	Lost & Unaccounted For Gas	0.1172% [1]	109,878			
23	Estimated Average WACOG 7/1 - 9/30/18		$ 0.229231			
24	Estimated Lost & Unaccounted For Gas Deferral 7/1 - 9/30/18			$ 25,187		
25	Plus: Line Breaks			19,082		
26	Plus: L&U Reversal			225,797		
27	Plus: Prior Year Lost & Unaccounted For Gas True-Up			284,246		
28	**Estimated Lost & Unaccounted For Gas For Current PGA Year Activity at 9/30/18**			693,361		
29	RS & GS-1 Allocation of Lost & Unaccounted For Gas Deferral For Current PGA Year Activity	75%		520,021		
30	Industrial Allocation of Lost & Unaccounted For Gas Deferral For Current PGA Year Activity	25%		173,340		
31	**Estimated Balance in Acct 1910.2150 of Current PGA Year Activity at 9/30/18**				693,361	
32	**RS & GS-1 Lost & Unaccounted For Current PGA Interest Deferred in 1910.2420 at 10/1/17**			$ (34)		
33	RS & GS-1 Lost & Unaccounted For Current PGA Interest Deferred in 1910.2420 through 6/30/18			(1,008)		
34	Estimated RS & GS-1 Current PGA Interest from 7/1 through 9/30/18			34		
35	**Estimated Balance in Acct 1910.2420 at 9/30/18**				(1,008)	
36	**Industrial Lost & Unaccounted For Current PGA Interest Deferred in Acct 1910.2360 at 10/1/17**			$ 18		
37	Industrial Lost & Unaccounted For Current PGA Interest Deferred in Acct 1910.2360 through 6/30/18			(541)		
38	Estimated Industrial Lost & Unaccounted For Current PGA Interest from 7/1 through 9/30/18			9		
39	**Estimated Balance in Acct 1910.2360 at 9/30/18**				(514)	
40	**ESTIMATED ACCOUNT 1910 LOST AND UNACCOUNTED FOR GAS BALANCE AT 9/30/18**					$ 786,421

[1] See Workpaper No. 7, Line 22, Column (d)

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2018

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1910 FIXED AMOUNTS:**					
2	**Fixed Gas Cost Balance Approved in Prior PGA in Acct 1910.2050 at 10/1/17**			$ (16,214,897)		
3	RS Amortization in Acct 1910.2070 of Acct 1910.2050 Balance Approved in Prior PGA at 10/1/17		$ 50,801			
4	Amortization for RS in Acct 1910.2070 of Acct 1910.2050 Balance Approved in Prior PGA as of 6/30/18		10,298,023			
5	Estimated RS Therm Sales 7/1 through 9/30/18	15,671,828				
6	RS Amortization Rate	$ 0.04726	740,651			
7	Estimated RS Amortization in Acct 1910.2070 of Acct 1910.2050 Balance Approved in Prior PGA at 9/30/18			11,089,475		
8	GS-1 Amortization in Acct 1910.2080 of Acct 1910.2050 Balance Approved in Prior PGA at 10/1/17		$ 76,321			
9	Amortization for GS-1 in Acct 1910.2080 of Acct 1910.2050 Balance Approved in Prior PGA at 6/30/18		6,073,424			
10	Estimated GS-1 Therm Sales 7/1 through 9/30/18	8,994,498				
11	GS-1 Amortization Rate	$ 0.05619	505,401			
12	Estimated GS-1 Amortization in Acct 1910.2080 of Acct 1910.2050 Balance Approved in Prior PGA at 9/30/18			6,655,146		
13	LV-1 Amortization in Acct 1910.2090 of Acct 1910.2050 Balance Approved in Prior PGA at 10/1/17		$ 4,158			
14	Amortization for LV-1 in Acct 1910.2090 of Acct 1910.2050 Balance Approved in Prior PGA as of 6/30/18		118,043			
15	Estimated LV-1 Block 1 Therm Sales 7/1 through 9/30/18	1,449,015				
16	LV-1 Amortization Rate	$ 0.01996	28,922			
17	Estimated LV-1 Amortization Balance in Acct 1910.2090 of Acct 1910.2050 Balance Approved in Prior PGA at 9/30/18			151,123		
18	**Estimated Balance in Acct 1910.2050 at 9/30/18**				$ 1,680,847	
19	**Fixed Cost Collection Deferral of Current PGA Year Activity in Acct 1910.2200 at 10/1/17**			$ (1,720,257)		
20	Fixed Cost Collection Deferred in Acct 1910.2200 through 6/30/18			(19,090,712)		
21	Estimated Fixed Cost Collection Deferred from 7/1 through 9/30/18			11,859,078		
22	**Estimated Balance in Acct 1910.2200 of Current PGA Year Activity at 9/30/18**				(8,951,891)	
23	**Capacity Releases Deferral of Current PGA Year Activity in Acct 1910.2320 at 10/1/17**			$ (3,279,503)		
24	Capacity Releases Deferred in Acct 1910.2320 through 6/30/18			(4,939,800)		
25	Estimated Capacity Releases Deferred from 7/1 through 9/30/18			-		
26	**Estimated Balance in Acct 1910.2320 of Current PGA Year Activity at 9/30/18**				(8,219,303)	
27	**Current PGA Interest in Acct 1910.2430 at 10/1/17**			$ (215)		
28	Current PGA Interest Deferred in Acct 1910.2430 through 6/30/18			(50,284)		
29	Estimated Current PGA Interest from 7/1 through 9/30/18			(1,358)		
30	**Estimated Balance in Acct 1910.2430 at 9/30/18**				(51,857)	

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2018

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**Pipeline Transportation Capacity Release Deferred Approved in Prior PGA in Acct 1910.2530 at 10/1/17**		$ -			
2	Pipeline Transportation Capacity Release Deferred Approved in Prior PGA in Acct 1910.2530 through 6/30/18		(3,740,000)			
3	Estimated Deferral in Acct 1910.2530 from 7/1 through 9/30/18		-			
4	Estimated Balance in Acct 1910.2530 at 9/30/18			$ (3,740,000)		
5	RS Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 6/30/18		$ 2,579,260			
6	Estimated RS Therm Sales from 7/1 through 9/30/18	15,671,828				
7	RS Amortization Rate	$ 0.01164	182,420			
8	Estimated RS Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/18		2,761,680			
9	GS-1 Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 6/30/18		$ 1,270,380			
10	Estimated GS-1 Therm Sales from 7/1 through 9/30/18	8,994,498				
11	GS-1 Amortization Rate	$ 0.01141	102,627			
12	Estimated GS-1 Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/18		1,373,007			
13	Estimated Core Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/18 (Sum of Lines 8 & 12, Column (c))			4,134,687		
14	LV-1 Amortization in Acct 1910.2550 of Acct 1910.2530 Balance Approved in Prior PGA at 6/30/18		$ 37,932			
15	Estimated LV-1 Block 1 Therm Sales from 7/1 through 9/30/18	1,449,015				
16	LV-1 Amortization Rate	$ 0.00617	8,940			
17	Estimated LV-1 Amortization in Acct 1910.2550 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/18		46,872			
18	Estimated Industrial Amortization in Acct 1910.2550 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/18			46,872		
19	**Estimated Balance in Acct 1910.2530 at 9/30/18**				$ 441,559	
20	**LNG Sales Credits Approved in Prior PGA Deferred in Acct 1910.2800 at 10/1/17**			$ (495,419)		
21	LNG Sales Credit Amortization in Acct 1910.2810 of Acct 1910.2800 Approved in Prior PGA at 10/1/17		$ 2,979			
22	Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA as of 6/30/18		471,031			
23	Estimated Amortization 7/1 through 9/30/18		63,194			
24	Estimated Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA at 9/30/18			537,204		
25	**LNG Sales Current PGA Interest Deferred in Acct 1910.2815 at 10/1/17**		$ 28			
26	LNG Sales Current PGA Interest Deferred in Acct 1910.2815 through 6/30/18		(116)			
27	Estimated LNG Sales Current PGA Interest from 7/1 through 9/30/18		(34)			
28	**Estimated Balance in Acct 1910.2815 at 9/30/18**			(122)		
29	LNG Sales Deferral - Margin Sharing Deferred in Acct 1910.2820 of Current PGA Year Activity through 6/30/18			(469,397)		
30	LNG Sales Deferral - O&M Recovery Deferred in Acct 1910.2825 of Current PGA Year Activity through 6/30/18			(101,711)		
31	**Estimated LNG Sales Credit Balance at 9/30/18**				$ (529,445)	

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2018

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**General Rate Case Cost Deferral in 1910.2600 at 10/1/17**			$ -		
2	**General Rate Case Intervenor Funding in Acct 1910.2610 at 10/1/17**			25,178		
3	Deferred Intervenor Funding Amortization in Acct 1910.2620 of Acct 1910.2610 Balance Approved in Prior PGA at 10/1/17		$ -			
4	Amortization in Acct 1910.2620 of Acct 1910.2610 Balance Approved in Prior PGA as of 6/30/18		(25,768)			
5	Estimated Amortization 7/1 through 9/30/18		(2,456)			
6	Estimated Amortization in Acct 1910.2620 of Acct 1910.2610 Balance Approved in Prior PGA at 9/30/18			(28,224)		
7	**Deferred General Rate Case Costs Approved for Recovery in Acct 1910.2630 at 10/1/17**			378,614		
8	Deferred GRC Costs Approved for Recovery Amortization in 1910.2640 of Acct 1910.2630 Balance Approved in Prior PGA at 10/1/17		-			
9	Amortization in Acct 1910.2640 of Acct 1910.2630 Approved in Prior PGA as of 6/30/18		(74,453)			
10	Estimated Amortization 7/1 through 9/30/18		(7,210)			
11	Estimated Amortization in Acct 1910.2640 of Acct 1910.2630 Balance Approved in Prior PGA at 9/30/18			(81,663)		
12	**Deferred General Rate Case Costs Approved for Recovery PGA Year Interest Deferred in 1910.2615 at 10/1/17**		-			
13	Deferred General Rate Case Costs Approved for Recovery PGA Year Interest Deferred in 1910.2615 through 6/30/18		25			
14	Estimated Deferred General Rate Case Costs Approved for Recovery Interest from 7/1 through 9/30/18		224			
15	**Estimated Balance in Acct 1910.2615 at 9/30/18**			249		
16	**Estimated Deferred General Rate Case Costs Approved for Recovery Balance at 9/30/18**				$ 294,154	
17	**ESTIMATED ACCOUNT 1910 FIXED BALANCE AT 9/30/18**					$ (15,335,936)
18	**TOTAL DEFERRED ACCOUNT 1910 BALANCE**					$ (19,590,217)

INTERMOUNTAIN GAS COMPANY
Analysis of Account 2292 Credits
May 31, 2018

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 2292 TAX REFORM DEFERRAL, CASE NO. GNR-U-18-01:**					
2	Tax Reform Deferral in Acct 2292 at 10/1/17				$ -	
3	RS Tax Reform Deferral in Acct 2292 1/1 through 5/31/18				(1,794,100)	
4	GS-1 Tax Reform Deferral in Acct 2292 1/1 through 5/31/18				(675,992)	
5	LV-1 Tax Reform Deferral in Acct 2292 1/1 through 5/31/18				(9,593)	
6	T-3 Tax Reform Deferral in Acct 2292 1/1 through 5/31/18				(13,642)	
7	T-4 Tax Reform Deferral in Acct 2292 1/1 through 5/31/18				(238,514)	
8	**Balance in Acct 2292 at 5/31/18**					$ (2,731,841)

INTERMOUNTAIN GAS COMPANY
Analysis of LV-1 Tariff Block 1, Block 2, and Block 3 Adjustments

Line No.	Description	Block 1 Therm Sales	Block 2 Therm Sales	Block 3 Therm Sales		Total
	(a)	(b)	(c)	(d)		(e)
1	LV-1 Therm Sales (1/1/17 - 12/31/17)	7,373,615	0	0		7,373,615
2	Blocks 1 and 2 Therm Sales	7,373,615	0	0		7,373,615
3	Percent Therm Sales between Blocks 1 and 2	100.000%	0.000%	0.000%		100.000%
4	Proposed Adjustment to LV-1 Tariff [1]				$	(0.03556)
5	LV-1 Therm Sales (1/1/17 - 12/31/17)					7,373,615
6	Annualized Adjustment (Line 4 multiplied by Line 5)				$	(262,206)
7	Annualized Adjustment (Line 6)				$	(262,206)
8	Percent Annualized Sales included in Block 1 and Block 2					100.000%
9	Adjustment to Block 1 and 2 (Line 7 multiplied by Line 8)				$	(262,206)
10	Block 1 and 2 Therms					7,373,615
11	Price Adjustment/Therm Block 1 and 2 (Line 9 divided by Line 10)				$	(0.03556)
12	WACOG Commodity Charge Change [2]					(0.03296)
13	**Total Price Adjustment/Therm Block 1 and Block 2**				$	(0.06852)
14	Price Adjustment/Therm Block 3 [3]				$	(0.01521)
15	WACOG Commodity Charge Change [2]					(0.03296)
16	Eliminate INT-G-17-05 Variable Temporary [4]					(0.00629)
17	**Total Price Adjustment/Therm Block 3**				$	(0.05446)

[1] See Exhibit No. 5, Line 31, Column (k) minus the difference of Line 22, Column (f) minus Column (c)
[2] See Exhibit No. 5, Line 22, Column (f) minus Column (c)
[3] See Exhibit No. 7, Lines 3 - 7, Column (d)
[4] See Workpaper No. 8, Footnote 6

INTERMOUNTAIN GAS COMPANY
Lost and Unaccounted for Gas
(Volumes in Therms)

Line No.	Description	Oct 2014 - Sept 2015	Oct 2015 - Sept 2016	Oct 2016 - Sept 2017
	(a)	(b)	(c)	(d)
1	Core Customer Purchased Gas	293,930,590	339,592,192	373,355,527
2	Transportation Customer Gas	293,573,841	345,348,399	354,152,074
3	LNG Storage Withdrawals	1,702,854	1,795,842	1,292,372
4	Under Deliveries of Gas from Pipeline (Draft)	2,723,140	-	523,910
5	Total Deliveries to System	591,930,425	686,736,433	729,323,883
6	Core Customer Billed Gas	294,800,808	324,902,426	369,157,907
7	Unbilled Adjustment	1,443,092	815,526	3,800,799
8	Transportation Customer Billed Gas	293,573,841	345,348,399	354,152,074
9	Company Use Gas	442,552	529,408	297,147
10	LNG Storage Injections	1,491,905	11,370,008	1,190,801
11	Line Breaks - Found Gas	-	-	231,195
12	Over Deliveries of Gas from Pipeline (Pack)	-	2,026,730	-
13	Total Deliveries to Customers	591,752,198	684,992,497	728,829,923
14	**Lost/(Found) Gas (Line 5 minus 13)**	178,227	1,743,936	493,960
15	Average Purchase WACOG	$ 0.40007	$ 0.28657	$ 0.28349
16	Cost of Lost/(Found) Gas (Line 14 times Line 15)	$ 71,302	$ 499,763	$ 140,033
17	**Lost Gas $/Therm (Line 16 divided by Line 5)**	$ 0.00012	$ 0.00073	$ 0.00019
18	Lost/(Found) Gas (Line 14)	178,227	1,743,936	493,960
19	Lost/(Found) Gas Therms Deferred	2,325,824	1,033,736	1,617,866
20	Lost/(Found) Gas Adjustment (Line 18 minus Line 19)	(2,147,597)	710,200	(1,123,906)
21	Actual Lost Gas Rate (Line 14 divided by Line 5)	0.0301% [1]	0.2539% [2]	0.0677%
22	**3-Year Average Lost Gas Rate**			0.1172% [3]

[1] See Case No. INT-G-16-03
[2] See Case No. INT-G-17-05
[3] Current PGA Year L&U Rate

Exhibit No. 1, Page 2 (INT-G-17-05)
Compliance Filing in Case Nos.
INT-G-16-02, INT-G-17-03, & INT-G-17-05
Intermountain Gas Company

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Tariff Components

Line No.	Description (a)	RS (b)	GS-1 (c)	LV-1 (d)	T-3 (e)	T-4 (f)
1	**Cost of Gas:**					
2	Temporary purchased gas cost adjustment [1]	$ (0.05425)	$ (0.06300)	$ (0.01984) [6]	$ (0.00063)	$ (0.01908)
3	Weighted Average Cost of Gas [2]	0.26020	0.26020	0.26020	-	-
4	Gas Transportation Cost [3]	0.19964	0.20127	0.10545	-	-
5	**Total Proposed Cost of Gas**	$ 0.40559	$ 0.39847	$ 0.34581	$ (0.00063)	$ (0.01908)
6	Energy Efficiency Charge [4]	0.00367				
7	**Distribution Cost:** [5]					
8	Block 1	$ 0.17849	$ 0.19801	$ 0.03309	$ 0.04082	$ 0.02713
9	Block 2		0.17283	0.01336	0.01662	0.00959
10	Block 3		0.14852	0.00339	0.00612	0.00294
11	Block 4		0.07500			
12	Demand Charge			0.30000		0.30000
13	**Proposed Prices**					
14	Block 1	$ 0.58775	$ 0.59648	$ 0.37890	$ 0.04019	$ 0.02713
15	Block 2		0.57130	0.35917	0.01599	0.00959
16	Block 3		0.54699	0.26988 [7]	0.00549	0.00294
17	Block 4		0.47347			
18	Demand Charge			0.30000		0.28092

[1] See Exhibit No. 6, Line 7, Columns (b) - (f)
[2] See Exhibit No. 4, Line 22, Column (f)
[3] See Exhibit No. 5, Line 29, Columns (e) - (g)
[4] See Case No. INT-G-17-03
[5] See Case No. INT-G-16-02 (Settlement Order No. 33879)
[6] LV-1 Block 3 temporary is Exhibit No. 6, Column (d), Lines 3 through 6 only. A surcharge of $0.00629.
[7] LV-1 Block 3 price is Column (d); Line 10 plus Line 3 plus the $0.00629 from footnote 5.