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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IDAHO PUBLIC
UTILITIES COMMISSION

August 16, 2006

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington St.
P. O. Box 83720
Boise, ID 83720-0074

RE: Intermountain Gas Company
Case No. INT-G-06-04

Dear Ms. Jewell:

Enclosed for filing with this Commission is a signed original and seven copies of Intermountain Gas Company's Application and supporting Workpapers for Authority to change its Prices on October 1, 2006.

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

If you have any questions or require additional information regarding the attached, please contact me at 377-6168.

Very truly yours,

Michael P. McGrath
Director
Gas Supply and Regulatory Affairs

MPM/blf

Enclosures

cc W. C. Glynn
P. R. Powell
M. E. Rich
M. W. Richards, Jr.

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INTERMOUNTAIN GAS COMPANY

CASE NO. INT-G-06-04

APPLICATION,

EXHIBITS,

AND

WORKPAPERS

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY for Authority to Change Its Prices on October 1, 2006

(October 1, 2006 Purchased Gas Cost Adjustment Filing)

Morgan W. Richards, Jr.
ISB # 1913
804 East Pennsylvania Lane
Boise, Idaho 83706
Telephone (208) 345-8371
Attorney for Intermountain Gas Company

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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-06-04 **APPLICATION**

Intermountain Gas Company ("Intermountain"), an Idaho corporation with general offices located at 555 South Cole Road, Boise, Idaho, hereby requests authority, pursuant to Idaho Code Sections 61-307 and 61-622, to place in effect October 1, 2006 new rate schedules which will decrease its annualized revenues by $1.6 million, pursuant to the Rules of Procedure of the Idaho Public Utilities Commission ("Commission"). Because of changes in Intermountain's gas related costs, as described more fully in this Application, Intermountain's earnings will not be decreased as a result of the proposed changes in prices and revenues. Intermountain's current rate schedules showing proposed changes are attached hereto as Exhibit No. 1 and are incorporated herein by reference. Intermountain's proposed rate schedules are attached hereto as Exhibit No. 2 and are incorporated herein by reference.

Communications in reference to this Application should be addressed to:

Paul R. Powell
Executive Vice President & Chief Financial Officer
Intermountain Gas Company
Post Office Box 7608, Boise, ID 83707
and
Morgan W. Richards, Jr.
Attorney
804 East Pennsylvania Lane, Boise, ID 83706

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

I.

Intermountain is a gas utility, subject to the jurisdiction of the Idaho Public Utilities 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 - 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 Shelly;
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, Conda, 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, 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, a compressor station, a liquefied natural gas storage facility, 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 a change in gas related costs resulting from: 1) an increase in costs billed Intermountain pursuant to General Rate Cases filed by Northwest Pipeline Corporation ("Northwest" or "Northwest Pipeline") and Gas Transmission Northwest Corporation ("Gas Transmission Northwest" or

"GTN"), 2) benefits included in Intermountain's firm transportation and storage costs resulting from Intermountain's management of its storage and firm capacity rights on pipeline systems including Northwest Pipeline and GTN, 3) a decrease in Intermountain's Weighted Average Cost of Gas ("WACOG"), 4) an updated customer allocation of gas related costs pursuant to the Company's Purchased Gas Cost Adjustment provision, and 5) the inclusion of temporary surcharges and credits for one year relating to gas and interstate transportation costs from Intermountain's deferred gas cost account. Exhibit No. 3 contains pertinent excerpts from pipeline and related facilities' tariffs. 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-05-2. The aforementioned changes would result in an overall price decrease to Intermountain's RS-1, RS-2, GS-1, and LV-1 customers, a price decrease to Intermountain's T-1 customers, and an increase in Intermountain's T-2 Demand Charge and a decrease to the T-2 Commodity Charge.

These price changes are applicable to service rendered under rate schedules affected by and subject to Intermountain's Purchased Gas Cost Adjustment ("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 summarizes the price changes in: 1) Intermountain's base rate gas costs and its rate class allocation, and 2) adjusting temporary surcharges or credits flowing through to Intermountain's direct sales and transportation customers. Exhibit No.'s 3 and 4 are attached hereto and incorporated herein by reference.

III.

The current prices of Intermountain are those approved by this Commission in Order No. 29875, Case No. INT-G-05-2.

IV.

Intermountain's proposed prices incorporate all price changes impacting Intermountain's firm interstate transportation capacity including, but not limited to, any such changes implemented by Northwest and GTN which have occurred since Intermountain's last PGA filing in Case No. INT-G-05-2. Exhibit No. 4, Lines 1 through 23, details the proposed changes in

Intermountain's prices resulting from adjustments to Intermountain's cost of interstate and upstream capacity from its various suppliers.

On June 30, 2006, Northwest Pipeline Corporation filed a general system rate case with the Federal Energy Regulatory Commission ("FERC") in Docket No. RP06-416-000. This filing is the first general rate increase sought by Northwest in nearly ten years. The FERC suspended the effective date of Northwest's proposed rates until January 1, 2007, subject to refund and conditions and the outcome of the FERC hearing. Intermountain's proposed prices have been weighted to reflect this January 1, 2007 effective date. Intermountain has representation at FERC to intervene in Northwest's General Rate Case proceeding.

Intermountain transports natural gas from Alberta on the Gas Transmission Northwest system from the international border at Kingsgate to the interconnection with Northwest Pipeline at Stanfield. On June 30, 2006, GTN filed a general system rate case with the Federal Energy Regulatory Commission in Docket No. RP06-407-000. The FERC suspended the effective date of GTN's proposed rates until January 1, 2007, subject to refund and conditions and the outcome of the FERC hearing. Intermountain's proposed prices have been weighted to reflect this January 1, 2007 effective date. GTN's current rates are based on its last rate case, filed in 1994. Intermountain has representation at FERC to intervene in GTN's General Rate Case proceeding.

Intermountain is party to certain agreements whereby Intermountain manages its storage related assets in conjunction with a third party asset manager. Intermountain proposes to pass back to its customers the benefits generated from these agreements as included on Exhibit No. 4, Line 19.

V.

The WACOG reflected in Intermountain's proposed prices is $0.72400 per therm, as shown on Exhibit No. 4, Line 24, Column (f). This compares to $0.73219 per therm currently included in the Company's tariffs.

As stated in the Company's Customer Notice, despite a 30% increase in crude oil prices during this past year when the Company last changed its natural gas prices, the Company has not increased in its Application the natural gas cost to its customers. Natural gas prices have been moderated by historically high levels of natural gas stored in the nation's inventory; natural gas production, which was shut-in after the impact of Hurricane Katrina, has now largely come back on-line in the Gulf of Mexico and the outlook for the upcoming hurricane season is moderate as compared to last season; and price induced domestic natural gas rig counts and production are up as compared to a year ago.

The proposed WACOG includes the benefits to Intermountain's customers generated by Intermountain's management of significant natural gas storage assets whereby gas is procured during the traditionally lower priced summer season for withdrawal and use during the winter when prices would otherwise be substantially higher. Additionally, and in an effort to further stabilize the prices paid by our customers during the upcoming winter storage withdrawal period, Intermountain entered into hedging agreements to lock-in the price for 100% of the company's April 2006 to October 2006 storage injections.

Intermountain also believes that the WACOG proposed in this Application, subject to the effect of actual supply and demand, will likely materialize during the upcoming PGA period because Intermountain is planning to employ, in addition to those natural gas hedges already in place for the high winter demand, cost effective financial instruments to secure those prices embedded within the filed WACOG when and if those pricing opportunities materialize in the marketplace.

However, liquidity in the market is sustained by contrary opinions and natural gas prices could indeed realize levels different from those included in this Application. Although current commodity futures prices dictate the use of this $0.72400 per therm WACOG, Intermountain continues to remain vigilant in monitoring natural gas prices and is committed to come before this Commission prior to this winters heating season with an Application to further amend these proposed prices, should these forward prices materially deviate from the $0.72400 per therm.

Timely natural gas price signals and the accounting for any cost differences brought about by these volatile markets, facilitated through the use of the PGA mechanism, enhances our customers' ability to make timely and informed energy use decisions and ensures they only pay the actual cost of such supplies. It is important to continue to alert our customers in a timely manner to these impending increases before their higher natural gas usage is before them. By employing the use of customer mailings 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 our customers manage their energy budget, and pending natural gas unit price changes.

VI.

Pursuant to Case No. INT-G-05-2, Intermountain has included temporary surcharges and credits in its October 1, 2005 prices for the principal reason of collecting or passing back to its customers deferred gas cost charges and benefits, as outlined in Case No. INT-G-05-2. Line 29 of Exhibit No. 4 reflects the elimination of these temporary surcharges and 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, pursuant to the Company's approved cost of service methodology. Intermountain's proposed prices include a fixed cost collection adjustment pursuant to these PGA provisions, as outlined on Exhibit No. 5, Line 24. The price impact of this adjustment is included on Exhibit No. 4, Line No. 30. Exhibit No. 5 is attached hereto and incorporated herein by reference.

VIII.

Intermountain is party to certain agreements whereby Intermountain has released segmented portions of its firm capacity rights when not needed to meet its customer needs. Intermountain proposes to pass back to its customers the benefits generated from the capacity release agreements, totaling $3.5 million. Exhibit No. 6, Line 1, reflects the inclusion of the $3.5 million credit. Intermountain proposes to pass back this amount via the per therm credit as detailed on Exhibit No. 7. Exhibit No.'s 6 and 7 are attached hereto and incorporated herein by reference.

IX.

Intermountain proposes to allocate deferred gas costs from its Account No. 186 balance to its customers through temporary price adjustments to be effective during the 12-month period ending September 30, 2007, as follows:

1) Intermountain has been deferring in its Account No. 186 fixed gas costs. The credit amount shown on Exhibit No. 8, Line 9, Col. (b) of $3.1 million is predominantly attributable to the collection of interstate pipeline capacity costs and the true-up of expense issues previously ruled on by this Commission. Intermountain proposes to collect or pass back these balances via the per therm surcharges and credits, as detailed on Exhibit No. 8 and included on Exhibit No. 6, Line 2. Exhibit No. 8 is attached hereto and incorporated herein by reference.

2) Intermountain has been deferring in its Account No. 186 deferred gas cost debits of $14.1 million, as shown on Exhibit No. 9, Line 2, Col. (b), attributable to Intermountain's variable gas costs since September 1, 2005. Intermountain proposes to collect this debit balance via a per therm surcharge, as shown on Exhibit No. 9, Line 4, Col. (b) and included on Exhibit No. 6, Line 3. Exhibit No. 9 is attached hereto and incorporated herein by reference.

X.

Intermountain has allocated the proposed price changes to each of its customer classes based upon Intermountain's PGA provision. A straight cent-per-therm price decrease was not utilized for the T-1 tariff. No fixed costs are currently recovered in the tail block of Intermountain's T-1 tariff. Absent Williams' firm transportation TF-1 Commodity Charge, the proposed decrease in the T-1 tariff is fixed cost related, and therefore, a cent per therm decrease was made only to the first two blocks of the tariff for these fixed costs.

XI.

The proposed increase to the T-2 tariff Demand Charge is fixed cost related, and therefore, a cent per therm increase was made to the T-2 Demand Charge for these fixed costs. Additionally, the proposed decrease to the T-2 Commodity Charge incorporates the decrease in the Williams' firm transportation TF-1 Commodity Charge.

XII.

Exhibit No. 10 is an analysis of the overall price changes by class of customer. Exhibit No. 10 is attached hereto and incorporated herein by reference.

XIII.

The proposed overall price change herein requested among the classes of service of Intermountain will not affect Intermountain's earnings, and is just, fair, and equitable.

XIV.

This Application is filed pursuant to the applicable statutes and the Rules and Regulations of the Commission. 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.

XV.

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.

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

a. That the proposed rate schedules herewith submitted as Exhibit No. 2 be approved without suspension and made effective as of October 1, 2006 in the manner shown on Exhibit No. 2.

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 16th day of August, 2006.

INTERMOUNTAIN GAS COMPANY

By ______________________
Paul R. Powell
Executive Vice President & CFO

Morgan W. Richards, Jr.

By ______________________
Morgan W. Richards, Jr.
Attorney for Intermountain Gas Company

CERTIFICATE OF MAILING

I HEREBY CERTIFY that on this 16th day of August, 2006, I served a copy of the foregoing Case No. INT-G-06-04 upon:

Paula Pyron
Northwest Industrial Gas Users
4113 Wolf Berry Court
Lake Oswego, OR 97035

Edward A. Finklea
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Avenue, Suite 2000
Portland, Oregon 97204-1136

R. Scott Pasley
J. R. Simplot Company
PO Box 27
Boise, ID 83707

David Hawk
J. R. Simplot Company
PO Box 27
Boise, ID 83707

Conley E. Ward, Jr.
Givens, Pursley, Webb & Huntley
277 N. 6th St., Suite 200
PO Box 2720
Boise, ID 83701

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

Michael P. McGrath
Director
Gas Supply and Regulatory Affairs

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EXHIBIT NO. 1

CASE NO. INT-G-06-04

INTERMOUNTAIN GAS COMPANY

CURRENT TARIFFS

Showing Proposed Price Changes

(8 pages)

COMPARISON OF PROPOSED OCTOBER 1, 2006 PRICES TO OCTOBER 1, 2005 PRICES

Line No.	Rate Class (a)	October 1, 2005 Prices per INT-G-05-2 (b)	Proposed Adjustment (c)	Proposed October 1, 2006 Prices (d)
1	**RS-1**			
2	April - November	$ 1.25501	$ (0.00058)	$ 1.25443
3	December - March	1.14245	(0.00058)	1.14187
4	**RS-2**			
5	April - November	1.10648	(0.00100)	1.10548
6	December - March	1.07285	(0.00100)	1.07185
7	**GS-1**			
8	April - November			
9	Block 1	1.13515	(0.01209)	1.12306
10	Block 2	1.11342	(0.01209)	1.10133
11	Block 3	1.09240	(0.01209)	1.08031
12	December - March			
13	Block 1	1.08430	(0.01209)	1.07221
14	Block 2	1.06310	(0.01209)	1.05101
15	Block 3	1.04264	(0.01209)	1.03055
16	CNG Fuel	1.04264	(0.01209)	1.03055
17	**LV-1** (1)			
18	Block 1	0.88912	(0.00025) (2)	0.88887
19	Block 2	0.85063	(0.00025) (3)	0.85038
20	Block 3	0.77051	0.00916 (4)	0.77967
21	**T-1**			
22	Block 1	0.12929	(0.01110) (2)	0.11819
23	Block 2	0.09080	(0.01110) (3)	0.07970
24	Block 3	0.01068	(0.00169) (4)	0.00899
25	**T-2**			
26	Demand Block 1	1.70931	0.12103	1.83034
27	Demand Block 2	0.90773	0.12103	1.02876
28	Commodity Charge	0.00653	(0.00169)	0.00484
29	Over-Run Service	0.04912	(0.00169)	0.04743

(1) The LV-1 Adjustment is calculated by taking the figures in Lines 22 - 24, Col (c), plus removal of the TF-1 Commodity Charge change, plus the change in the WACOG, plus removal of the temporary variable surcharge from INT-G-05-2 of $0.03171, plus the temporary variable debit on Exhibit 9, Line 4, Col (b)

(2) See Workpaper No. 7, Line 13, Col (e)

(3) See Workpaper No. 7, Line 20, Col (e)

(4) See Workpaper No. 7, Line 21, Col (e)

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SEP 30 '05 OCT 1 - '05
Per. O.N. 29875
Jean D. Jewell SECRETARY

Rate Schedule RS-1
RESIDENTIAL SERVICE

AVAILABILITY:

Available to individually metered consumers not otherwise specifically provided for, using natural gas for residential purposes.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - ~~$1.25501~~ $1.25443 per therm*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge - ~~$1.14245~~ $1.14187 per therm*

***Includes:**

Temporary purchased gas cost adjustment of ~~$0.06562~~ $0.03422
Weighted average cost of gas of ~~$0.73219~~ $0.72400

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 Provision.

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.

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Rate Schedule RS-2
MULTIPLE USE RESIDENTIAL SERVICE

AVAILABILITY:

Available to individually metered consumers using gas for several residential purposes including both water heating and space heating.

RATE:

Monthly minimum charge is the customer charge.

For billing periods ending April through November

Customer Charge - $2.50 per bill

Commodity Charge - ~~$1.10648~~ $1.10548 per therm*

For billing periods ending December through March

Customer Charge - $6.50 per bill

Commodity Charge ~~$1.07285~~ $1.07185 per therm*

***Includes:**

Temporary purchased gas cost adjustment of ~~$0.04838~~ $0.02786
Weighted average cost of gas of ~~$0.73219~~ $0.72400

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 Provision.

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.

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Rate Schedule GS-1
GENERAL SERVICE

AVAILABILITY:

Available to individually metered customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on 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.

For billing periods ending April through November

Customer Charge - $2.00 per bill

Commodity Charge - First 200 therms per bill @ ~~$1.13515*~~ $1.12306*
Next 1,800 therms per bill @ ~~$1.11342*~~ $1.10133*
Over 2,000 therms per bill @ ~~$1.09240*~~ $1.08031*

For billing periods ending December through March

Customer Charge - $9.50 per bill

Commodity Charge - First 200 therms per bill @ ~~$1.08430*~~ $1.07221*
Next 1,800 therms per bill @ ~~$1.06310*~~ $1.05101*
Over 2,000 therms per bill @ ~~$1.04264*~~ $1.03055*

***Includes:**

Temporary purchased gas cost adjustment of ~~$0.04984~~ $0.02520
Weighted average cost of gas of ~~$0.73219~~ $0.72400

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Per. O.N. 29875
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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

Commodity Charge - ~~$1.04264~~ $1.03055 per therm*

***Includes:**

Temporary purchased gas cost adjustment of ~~$0.04984~~ $0.02520
Weighted average cost of gas of ~~$0.73219~~ $0.72400

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 Provision.

SERVICE CONDITIONS:

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 borne 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.**

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.**

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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 schedules LV-1, T-1, or T-2, or any new customer 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:

Commodity Charge:

First 250,000 therms per bill @ ~~$0.88912*~~ $0.88887*
Next 500,000 therms per bill @ ~~$0.85063*~~ $0.85038*
Amount Over 750,000 therms per bill @ ~~$0.77051~~ $0.77967****

The above prices include weighted average cost of gas of ~~$0.73219~~ $0.72400
*** Includes temporary purchased gas cost adjustment of ~~$0.03032~~ $0.03084**
**** Includes temporary purchased gas cost adjustment of ~~$0.03171~~ $0.04906**

PURCHASED GAS COST ADJUSTMENT (PGA):

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

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. Any LV-1 customer who exits the LV-1 service at any time (including, but not limited to, the expiration of the contract term) will pay to Intermountain Gas Company, upon exiting the LV-1 service, all gas and/or interstate transportation related costs to serve the customer during the LV-1 contract period not borne by the customer during the LV-1 contract period. Any LV-1 customer will have refunded to them, upon exiting the LV-1 service, any excess gas and/or interstate transportation related payments made by the customer during the LV-1 contract period.

3. In the event that total deliveries to any customer within the last three contract periods met or exceeded the 200,000 therm threshold, but the customer during the current contract period used less than the contract minimum of 200,000 therms, an additional amount shall be billed. The additional amount shall be calculated by billing the deficit usage below 200,000 therms at the T-1 Block 1 rate. The customer's future eligibility for the LV-1 Rate Schedule will be renegotiated with the Company.

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Per. O.N. 29875
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Rate Schedule T-1
FIRM TRANSPORTATION 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 schedules LV-1, T-1, or T-2, upon execution of a one year minimum written service contract for firm transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Commodity Charge:

Block One:	**First 250,000 therms transported @ ~~$0.12929*~~ $0.11819***
Block Two:	**Next 500,000 therms transported @ ~~$0.09080*~~ $0.07970***
Block Three:	**Amount over 750,000 therms transported @ ~~$0.01068~~ $0.00899**

***Includes temporary purchased gas cost adjustment of ~~$(0.00139)~~ $(0.01822)**

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 Provision.

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 a Maximum Daily Firm Quantity (MDFQ) amount, which will be stated in and will be in effect throughout the term of the service contract. The MDFQ shall not exceed the customer's historical maximum daily usage, as agreed to by the Company.**

   In the event the Customer requires daily usage in excess of the MDFQ, and subject to the availability of firm interstate transportation to service Intermountain's system, all such usage may be transported and billed under either secondary rate schedule T-3 or T-4. The secondary rate schedule to be used shall be predetermined by negotiation between the Customer and Company, and shall be included in the service contract. All volumes transported under the secondary rate schedule are subject to the provisions of the applicable rate schedule T-3 or T-4.

IDAHO PUBLIC UTILITIES COMMISSION
APPROVED EFFECTIVE

SEP 30 '05 OCT 1 - '05
Per. O.N. 29875
Jean D. Jewell SECRETARY

Rate Schedule T-2
FIRM TRANSPORTATION SERVICE WITH MAXIMUM DAILY DEMANDS

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing T-2 customer whose daily contract demand for nonammonia therms on any given day meets or exceeds a predetermined level agreed to by the customer and the Company upon execution of a one-year minimum written service contract for firm transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Firm Service	**Rate Per Therm**
Demand Charge:	
Firm Daily Demand -	
First 15,000 therms	~~**$1.70931***~~ **$1.83034***
Amount over 15,000 therms	~~**$0.90773***~~ **$1.02876***
Commodity Charge:	
For Firm Therms Transported	~~**$0.00653**~~ **$0.00484**
Over-Run Service	
Commodity Charge:	
For Therms Transported In Excess Of MDFQ:	~~**$0.04912**~~ **$0.04743**

***Includes temporary purchased gas cost adjustment of ~~$(0.08920)~~ $(0.15687)**

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 Provision.

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 nominate a Maximum Daily Firm Quantity (MDFQ), which will be stated in and will be in effect throughout the term of the service contract.**

3. **The monthly Demand Charge will be equal to the MDFQ times the Firm Daily Demand rate. Firm demand relief will be afforded to those T-2 customers paying both demand and commodity charges for gas when, in the Company's judgment, such relief is warranted.**

4. **The actual therm usage for the month or the MDFQ times the number of days in the billing month, whichever is less, will be billed at the applicable commodity charge for firm therms.**

INTERMOUNTAIN GAS CO.

CASE NO. INT-G-06-04

EXHIBIT NO. 2

(PROPOSED TARIFFS)

HAS BEEN SCANNED

SEPARATELY

J

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UTILITIES COMMISSION

EXHIBIT NO. 3

CASE NO. INT-G-06-04

INTERMOUNTAIN GAS COMPANY

PERTINENT EXCERPTS FROM INTERSTATE PIPELINES AND RELATED FACILITIES

(49 pages)

Williams Northwest Pipeline Corporation ("Northwest Pipeline" or "Northwest")

Applicable Tariffs/Rate Schedules

Williams

NORTHWEST PIPELINE
P.O. Box 58900
Salt Lake City, UT 84158-0900
Phone: (801) 584-7155
FAX: (801) 584-7764

To: All Shippers on Northwest Pipeline Corporation's Transmission System
and Affected State Regulatory Commissions

On June 30, 2006, Northwest Pipeline Corporation filed a general system rate case with the Federal Energy Regulatory Commission. The attached is an abbreviated copy of the rate case filing. Please distribute to interested people within your organization. Upon request, Northwest will send a full copy of this filing to you or others within your organization.

Requests for full copies should be directed to Barbara Odland as follows:

Barbara Odland
Northwest Pipeline Corporation
P.O. Box 58900
Salt Lake City, Utah 84158-0900
(801) 584-6781
nwpratecase@williams.com

If you have any questions concerning this rate case filing, please give Barbara or me a call.

Jan Caldwell

Jan Caldwell
Manager, Cost of Service/Rate Design
Northwest Pipeline Corporation
(801) 584-7155
nwpratecase@williams.com

Williams

NORTHWEST PIPELINE
P.O. Box 58900
Salt Lake City, UT 84158-0900
Phone: (801) 584-7200
FAX: (801) 584-7764

June 30, 2006

Ms. Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Northwest Pipeline Corporation
Docket No. RP06-________

Dear Ms. Salas:

Pursuant to Section 4 of the Natural Gas Act, 15 U.S.C. § 717c, and Part 154 of the regulations of the Federal Energy Regulatory Commission ("Commission"), 18 CFR 154, Northwest Pipeline Corporation ("Northwest") tenders for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1, an original and twelve copies of certain revised tariff sheets to reflect a general rate increase and *pro forma* Sheet No. 5, together with supporting rate case statements and schedules. The revised tariff sheets, which are enumerated herein and included in the filing, are proposed to be effective August 1, 2006.

Statement of Nature, Reasons and Basis for the Filing – 18 CFR 154.7(a)(6)

I. Overview

This general rate case filing reflects various revisions to the rates for jurisdictional transportation and storage services contained in Northwest's Tariff along with supporting statements and schedules as required by the Commission's regulations. As background, this filing represents the first general rate increase that Northwest has filed since its Docket No. RP96-367 rate application, which was filed approximately ten years ago. Following a period of several years of "pancaked" rate case filings, Northwest entered into a Settlement Agreement in Docket No. RP96-367 with its customers which, among other things, was intended to help Northwest avoid filing repeated rate increases and provide rate stability for its customers.

In the ten years since the Settlement Agreement, many circumstances have changed that necessitate increases in the jurisdictional rates reflected in this filing to permit Northwest the opportunity to recover its cost of service. As shown in Statement G of this filing, revenues at current rates are inadequate to recover Northwest's cost of service and result in a revenue deficiency of approximately $119.1 million.

In compliance with 18 CFR 154.7(a)(6), the following table compares the cost of service, rate base and throughput underlying this filing with the same information underlying the most recently Commission-approved just and reasonable rates. For "the last rates found just and reasonable by the Commission," Northwest is using the cost of service, rate base and throughput in the Settlement Agreement approved in Docket No. RP96-367, and increasing such amounts by the incrementally priced expansion projects and cost of service projects which were certificated by the Commission after the March 1, 1997 effective date of the Docket No. RP96-367 rate case.

	Cost of Service	Rate Base	Annual Throughput (Dth)
RP96-367[1/]	$265,722,093	$812,305,958	723,000,000
Evergreen Expansion	41,960,705	180,588,786	85,794,583
Cost of Service Projects[2/]	5,570,826	21,419,552	-
"Last Rates" Approved	$313,253,624	$1,014,314,296	808,794,583
This Filing[3/]	$441,478,087	$1,506,923,947	801,353,958

The cost of service underlying this filing utilizes a base period for the twelve months ended March 31, 2006, adjusted for known and measurable changes through December 31, 2006, which, as shown above, results in an increase in Northwest's cost of service of approximately $128.2 million[4/] over the cost of service underlying the last rates found just and reasonable by the Commission. The major reasons for the increased cost of service are:

a) an increase of approximately $12.1 million included in the Certificate Application filed in Docket No. CP06-45 for the incrementally priced Parachute Lateral Project, which is anticipated to be placed in service on November 1, 2006;

[1/] Excludes approximately $2.3 million cost of service and approximately $8.7 million rate base related to the Tumwater and Olympia projects since Northwest was fully reimbursed for these two projects following the effective date of the Docket No. RP96-367 settlement.

[2/] The Cost of Service Projects include the Berwick (Docket No. CP03-196), Centralia (Docket No. CP03-196), and Elmore (Docket No. CP02-240) laterals and the Columbia Gorge 1999 Expansion (Docket No. CP98-554). The cost of service and rate base for Berwick, Centralia and Elmore are updated to reflect the current annual cost of service calculations pursuant to Section 21 of the General Terms and Conditions of Northwest's Tariff.

[3/] Includes the cost of service, rate base, and throughput related to the proposed incrementally priced Parachute Lateral Project.

[4/] This amount is higher than the revenue deficiency shown on Statement G of $119.1 million due primarily to the $12.1 million cost of service associated with the Parachute Lateral, partially offset by other minor differences, including throughput, and minor cost variances associated with each calculation.

b) an increase of approximately $61.6 million included in the Certificate in Docket No. CP05-32 for the rolled-in Capacity Replacement Project, which is anticipated to be placed in service on November 1, 2006;

c) an increase of approximately $21.8 million included in the Certificate in Docket No. CP01-438 for the rolled-in Rockies Displacement Project, net of approximately $16.7 million in escrow funds which were used to partially offset the capital cost of the project;

d) an increase of approximately $7.1 million included in the Certificate in Docket No. CP02-4 for the rolled-in portion of the Sumas-Chehalis and Columbia Gorge displacement facilities constructed as part of the Evergreen Expansion Project;

e) an increase of approximately $16.9 million related to the increase in the rate of return and associated income taxes (i.e. pre-tax return) on the approximately $1.507 billion rate base included in this filing;

f) an increase of approximately $13.9 million related to operation and maintenance expenses, including administrative and general expenses, ("O&M"), in addition to the O&M costs included in the total project costs enumerated above, including approximately $5.9 million associated with a required accounting change to expense pipeline assessment costs; and

g) a reduction of approximately $5.2 million related to the net effect of various other changes reflected in this filing, including normal rate base decline as a result of depreciation, partially offset by additional reliability and integrity-related expenditures.

II. Cost of Service

The cost of service in this filing, as indicated above and supported by the Statement P testimony of various Northwest witnesses submitted with the filing, is $441,478,087, which consists of the following cost components:

O&M Expenses	$106,272,899
Depreciation and Amortization	87,366,078
Taxes Other Than Income Taxes	16,925,100
Federal and State Income Taxes	68,737,002
Return	165,158,867
Revenue Credits	(2,981,859)
Total Cost of Service	$441,478,087

Northwest is requesting an overall after tax rate of return of 10.96 percent (15.47 percent pre-tax), including a rate of return on equity of 13.6 percent. Consistent with Commission policy, Northwest has used its projected capital structure as of the end of the test period comprised of debt capital of 45 percent and common stock equity of 55 percent.

The evidence in this rate proceeding supports a depreciation rate of 2.93 percent applied to transmission plant (exclusive of the facilities associated with the Evergreen Expansion 15 and 25 year contracts and the Cost of Service Projects), and a net negative salvage rate of 0.94 percent for a combined rate of 3.87 percent. However, Northwest is making a market adjustment to its net negative salvage rate as applied to such transmission plant to reduce it to 0.31 percent, but only to the extent that the combination of depreciation and net negative salvage rates would otherwise exceed 3.24 percent. Northwest has proposed certain other changes to the depreciation and net negative salvage rates as shown on Statement H-2 page 2 of this filing.

III. Other Proposed Changes

Northwest is proposing in this proceeding a two-part straight-fixed variable ("SFV") rate design for the Rate Schedule TF-1 (Large Customer) rates (but will maintain the levelized rate methodology for the Evergreen Expansion shippers and a one-part volumetric rate for Rate Schedule TF-1 (Small Customer)). While SFV rate design is a change from the rates that were implemented in the settlement of Northwest's last rate case in Docket No. RP96-367, SFV rates are consistent with the Commission's directives in Order No. 636 and with the rate design the Commission approved in Northwest's last litigated rate proceeding in Docket No. RP95-409.

The rate for service under Rate Schedule LS-2I associated with interruptible storage service at Northwest's Plymouth LNG storage facility is modified to provide for the inclusion of liquefaction and vaporization charges. Currently, a shipper under Rate Schedule LS-2I only pays a daily volumetric inventory charge. Northwest proposes to revise Rate Schedule LS-2I to reflect liquefaction and vaporization charges similar to such charges under Rate Schedules LS-1 and LS-2F.

IV. Tariff Sheets - 18 CFR 154.7(a)(5)

Appendix A contains the following revised tariff sheets which are being submitted in the instant filing:

Thirty-First Revised Sheet No. 5
Third Revised Sheet No. 5-B
Sixth Revised Sheet No. 5-C
First Revised Sheet No. 5-D
Fourteenth Revised Sheet No. 6
Fifteenth Revised Sheet No. 7
Seventeenth Revised Sheet No. 8
Fifteenth Revised Sheet No. 8.1
Fifth Revised Sheet No. 91
Third Revised Sheet No. 91-A

Proposed Sheet Nos. 5 through 8.1 are submitted to revise Northwest's Statement of Rates in its tariff to reflect the overall increase in Northwest's jurisdictional rates and to reflect new liquefaction and vaporization rates under Rate Schedule LS-2I on Sheet No. 8.1.

Sheet No. 91 is submitted to revise Rate Schedule LS-2I to provide for liquefaction and vaporization charges associated with interruptible storage services at Northwest's Plymouth LNG storage facility. Sheet No. 91-A is submitted due to pagination.

Northwest's certificate application in Docket No. CP06-45 for the construction and operation of the Parachute Lateral project anticipates an in-service date for the Parachute Lateral prior to January 1, 2007 and the anticipated costs associated with the Parachute Lateral project are reflected in the test period adjustments. *Pro forma* tariff sheets included in the certificate filing include recourse rates associated with service on the Parachute Lateral, and Northwest incorporates these *pro forma* tariff sheets by reference in the instant filing. Since Northwest is requesting an effective date of August 1, 2006 for the proposed tariff sheets submitted in the instant filing, the recourse rates for the Parachute Lateral project are not reflected on the proposed tariff sheets. Therefore, *pro forma* Sheet No. 5 also is submitted to show both the rates on proposed Thirty-First Revised Sheet No. 5 submitted herewith and the rates for the Parachute Lateral project under the new Parachute Lateral Rate Schedules TFL-1 and TIL-1. When Northwest submits a motion in December 2006 to move into effect on January 1, 2007 the tariff sheets in the instant filing, following an anticipated five month suspension period, Northwest will file Substitute Thirty-First Revised Sheet No. 5 to include the Parachute Lateral rates.

Proposed Effective Date and Waiver Request - 18 CFR 154.7(a)(3), (6), (8) and (9)

Pursuant to Section 154.7(a)(9) of the Commission's regulations, Northwest hereby moves that the proposed tariff sheets be made effective August 1, 2006, or at the end of any suspension period which may be imposed by the Commission. Although Northwest has requested an effective date of August 1, 2006, Northwest anticipates this filing will be suspended for the full five month period, with an effective date of January 1, 2007. For the reasons discussed above, Northwest requests that a waiver of Section 154.7(a)(9) or 154.206 of the Commission's regulations be granted, as necessary, and that the suspension order include a statement that Northwest may file Substitute Thirty-First Revised Sheet No. 5 reflecting the anticipated Parachute Lateral rates as shown on *pro forma* Sheet No. 5 when Northwest files a motion, pursuant to Section 154.206 of the Commission's regulations, to place the suspended rates into effect.

Material Submitted – 18 CFR 154.7(a)(1)

In accordance with Section 154.7(a)(1) of the Commission's regulations, the following material is submitted herewith:

i. a proposed form of notice for the instant filing suitable for publication in the Federal Register, and a diskette copy of such notice in accordance with 18 CFR 154.209;

ii. the revised tariff sheets and *pro forma* Sheet No. 5, and, pursuant to 18 CFR 154.4, a diskette copy of such sheets;

iii. a "redlined" version of both the revised tariff sheets and *pro forma* Sheet No. 5, pursuant to 18 CFR 154.201(a);

iv. documentation in the form of workpapers or otherwise, sufficiently detailed to support the changes proposed herein in accordance with to 18 CFR 154.201(b);

v. Statements A through J, L, M, O, P and related schedules in accordance with Part 154 of the Commission's regulations;

vi. the Statement of Northwest's Chief Accounting Officer pursuant 18 CFR 154.308; and

vii. a compact disk ("CD") containing Northwest's electronic version of its filing herein pursuant to 18 CFR 154.4.

Service and Communications – 18 CFR 154.2(d) and 154.208

An original and twelve copies of this filing are being provided to the Commission. Abbreviated copies of this filing have been served upon Northwest's customers and upon affected state regulatory commissions. Within two business days of receiving a request for a complete copy from Northwest's customers and/or interested state regulatory commissions, Northwest will serve a full copy of this filing to the requesting parties.

All communications regarding this filing should be served upon:

Laren M. Gertsch*
Director, Rates and Regulatory
(801) 584-7200
Northwest Pipeline Corporation
P.O. Box 58900
Salt Lake City, Utah 84158-0900
nwpratecase@williams.com

Steven W. Snarr*
General Counsel
(801) 584-7094
Northwest Pipeline Corporation
P.O. Box 58900
Salt Lake City, Utah 84158-0900
steven.w.snarr@williams.com

* Designated to receive service pursuant to 18 CFR 385.203.

Jan M. Caldwell
Manager, Cost of Service/Rate Design
(801) 584-7155
Northwest Pipeline Corporation
P.O. Box 58900
Salt Lake City, Utah 84158-0900
nwpratecase@williams.com

Gary K. Kotter
Manager, Certificates and Tariffs
(801) 584-7117
Northwest Pipeline Corporation
P.O. Box 58900
Salt Lake City, Utah 84158-0900
nwpratecase@williams.com

Questions regarding this filing should be directed to Laren M. Gertsch.

To the best of my knowledge and belief, the tariff sheets and statements and schedules are true and correct and contain the same information as the diskette and compact disk containing the tariff sheets and statements and schedules.

Respectfully submitted,

NORTHWEST PIPELINE CORPORATION

Laren M. Gertsch
Director, Rates and Regulatory

Enclosures

Northwest Pipeline Corporation
FERC Gas Tariff
Third Revised Volume No. 1

Thirty-First Revised Sheet No. 5
Superseding
Thirtieth Revised Sheet No. 5

STATEMENT OF RATES
Effective Rates Applicable to Rate Schedules TF-1, TF-2 and TI-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate Minimum	Base Tariff Rate Maximum	ACA(2)	Currently Effective Tariff Rate(3) Minimum	Currently Effective Tariff Rate(3) Maximum
Rate Schedule TF-1 (4)(5)					
Reservation					
(Large Customer)					
System-Wide	.00000	.43712	-	.00000	.43712
15 Year Evergreen Exp.	.00000	.41621	-	.00000	.41621
25 Year Evergreen Exp.	.00000	.39748	-	.00000	.39748
Volumetric					
(Large Customer)					
System-Wide	.00756	.00756	.00180	.00936	.00936
15 Year Evergreen Exp.	.00369	.00369	.00180	.00549	.00549
25 Year Evergreen Exp.	.00369	.00369	.00180	.00549	.00549
(Small Customer) (6)	.00756	.88180	.00180	.00936	.88360
Scheduled Overrun	.00756	.44468	.00180	.00936	.44648
Rate Schedule TF-2 (4)(5)					
Reservation	.00000	.43712	-	.00000	.43712
Volumetric	.00756	.00756	-	.00756	.00756
Scheduled Daily Overrun	.00756	.44468	-	.00756	.44468
Annual Overrun	.00756	.44468	-	.00756	.44468
Rate Schedule TI-1					
Volumetric (7)	.00756	.44468	.00180	.00936	.44648
Scheduled Overrun	.00756	.44468	.00180	.00936	.44648

Issued by: Laren M.Gertsch, Director
Issued on: June 30, 2006

Effective: August 1, 2006

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules TF-1, TF-2 and TI-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(3) The currently effective tariff rate is the sum of the base tariff rate and the applicable surcharges. To the extent Transporter discounts the maximum currently effective tariff rate, such discounts will be applied on a non-discriminatory basis, subject to the policies of Order No. 497.

Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

A "Facility Cost-of-Service Charge," as defined in Section 21 of the General Terms and Conditions, is payable in addition to all other rates and charges if such a charge is included in Exhibit C to a Shipper's Transportation Service Agreement.

In addition to the reservation rates and surcharges shown on Sheet No. 5, Shippers who contract for Columbia Gorge Expansion Project capacity are subject to a Facilities Reservation Surcharge pursuant to Section 3.4 of Rate Schedule TF-1. The Facilities Charge used in deriving the Columbia Gorge Expansion Project Facilities Reservation Surcharge has a minimum rate of $0 and a maximum rate during the indicated months or calendar years as follows:

August 1, 2006 - October 1, 2006 $0.18523
November 1, 2006 - December 1, 2006 $0.17819

Year	Rate	Year	Rate	Year	Rate
2007	$0.16990	2013	$0.12704	2019	$0.09634
2008	$0.16286	2014	$0.11979	2020	$0.09169
2009	$0.15605	2015	$0.11396	2021	$0.08753
2010	$0.14880	2016	$0.10926	2022	$0.08312
2011	$0.14155	2017	$0.10515	2023	$0.07872
2012	$0.13393	2018	$0.10075	2024	$0.07410

January 1, 2025 - March 31, 2025 $0.07300

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules TF-1, TF-2 and TI-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(4) All reservation rates are daily rates computed on the basis of 365 days per year, except that such rates for leap years are computed on the basis of 366 days.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion reservation and volumetric rates apply to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements. The System-Wide reservation and volumetric rates apply to Shippers receiving service under all other Rate Schedule TF-1 service agreements.

For Rate Schedule TF-1, the 15-Year and 25-Year Evergreen Expansion maximum base tariff reservation rates are comprised of $0.41094 and $0.39221 for transmission costs and $0.00527 and $0.00527 for storage costs, respectively. The System-Wide maximum base tariff reservation rates for Rate Schedule TF-1 and the maximum base tariff reservation rates for Rate Schedule TF-2 are comprised of $0.43185 for transmission costs and $0.00527 for storage costs.

For Rate Schedule TF-1 (Large Customer), the maximum base tariff volumetric rates applicable to Shippers receiving service under Rate Schedule TF-1 Evergreen Expansion service agreements are comprised of $0.00344 for transmission costs and $0.00025 for storage costs. The maximum base tariff volumetric rates for all other services under Rate Schedule TF-1 (Large Customer) and for services under Rate Schedule TF-2 are comprised of $0.00731 for transmission costs and $0.00025 for storage costs.

(5) Rates for Rate Schedules TF-1 and TF-2 are also applicable to capacity release service. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The reservation rate is the comparable volumetric bid reservation charge applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules TF-1, TF-2 and TI-1 (Continued)

(Dollars per Dth)

Footnotes (Continued)

(6) Rate Schedule TF-1 (Small Customer) one-part volumetric rate is based upon a 50% load factor, and the maximum base tariff rate is comprised of $0.87101 for transmission costs and $0.01079 for storage costs. Transporter will not transport gas for delivery for Small Customers subject to this Rate Schedule TF-1 under any interruptible Service Agreement or under any capacity release Service Agreement unless such Small Customer has exhausted its daily levels of firm service entitlement for that day.

(7) Rate Schedule TI-1 maximum base tariff volumetric rate is comprised of $0.43916 for transmission costs and $0.00552 for storage costs.

(8) Applicable to Rate Schedules TF-1, TF-2 and TI-1 pursuant to Section 15.5 of the General Terms and Conditions.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules SGS-2F and SGS-2I

(Dollars per Dth)

Rate Schedule and Type of Rate	Currently Effective Tariff Rate (1) Minimum	Currently Effective Tariff Rate (1) Maximum
Rate Schedule SGS-2F (2)		
Demand Charge	0.00000	0.01634
Capacity Demand Charge	0.00000	0.00060
Volumetric Bid Rates		
Withdrawal Charge	0.00000	0.01634
Storage Charge	0.00000	0.00060
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00120

Footnotes

(1) Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

Rates are also applicable to capacity release service. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The Withdrawal Charge and Storage Charge are applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedule LS-1

(Dollars per Dth)

Type of Rate	Currently Effective Tariff Rate (1)
Demand Charge (2)	0.03154
Capacity Charge (2)	0.00403
Liquefaction	0.64110
Vaporization	0.04184

Footnotes

(1) Shippers receiving service under this rate schedule are required to furnish fuel reimbursement in-kind at the rate specified on Sheet No. 14.

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

TransCanada Alberta System (or Nova Gas Transmission - "Nova")

Applicable Tariffs/Rate Schedules

TABLE OF RATES, TOLLS & CHARGES

Service	Rates, Tolls and Charges
1. Rate Schedule FT-R	Refer to Attachment "1" for applicable FT-R Demand Rate per month & Surcharge for each Receipt Point Average Firm Service Receipt Price (AFSRP) $141.42/$10^3m^3$
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	FT-D Demand Rate per month (Apr – Oct) $141.42/$10^3m^3$ FT-D Demand Rate per month (effective November 1, 2006) $ 3.74/GJ
4. Rate Schedule STFT	STFT Bid Price. Minimum bid of 100% of FT-D Demand Rate
5. Rate Schedule FT-DW	FT-DW Bid Price. Minimum bid of 125% of FT-D Demand Rate
6. Rate Schedule FT-A	FT-A Commodity Rate $ 0.48/10^3m^3
7. Rate Schedule FT-P	Refer to Attachment "2" for applicable FT-P Demand Rate per month
8. Rate Schedule LRS	Contract Term — Effective LRS Rate ($/$10^3m^3$/day) 1-5 years — 9.69 6-10 years — 8.10 15 years — 7.26 20 years — 6.45
9. Rate Schedule LRS-2	LRS-2 Rate per month $50,000
10. Rate Schedule LRS-3	LRS-3 Demand Rate per month (Jan – April) $196.32/$10^3m^3$ LRS-3 Demand Rate per month (effective May 1, 2006) $129.55/$10^3m^3$
11. Rate Schedule IT-R	Refer to Attachment "1" for applicable IT-R Rate & Surcharge for each Receipt Point
12. Rate Schedule IT-D	IT-D Rate (Apr – Oct) $ 5.12/10^3m^3 IT-D Rate (effective November 1, 2006) $ 0.1354/GJ
13. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment "1" to the applicable Schedule of Service
14. Rate Schedule PT	Schedule No — PT Rate — PT Gas Rate 9005-01000-0 — $ 164.91/d — 0.0 10^3m^3/d 9006-01000-0 — $ 15.05/d — 1.0 10^3m^3/d
15. Rate Schedule OS	Schedule No. — Charge 2003004522-2 — $ 83,333.00 / month 2003034359-2 — $ 899.00 / month 2004168619-1 — $ 437.50 / month 2006222805-2 — $ 8.00 / month 2006222973-1 — $ 856.00 / month 2006222974-1 — $ 66.00 / month 2006223044-1 — $ 171.00 / month 2006223045-1 — $ 1,576.00 / month 2006223046-1 — $ 294.00 / month 2006223047-1 — $ 68.00 / month 2006224148-1 — $ 92.00 / month 2006224149-1 — $ 536.00 / month 2006224337-1 — $ 66.00 / month 2006224475-1 — $ 111.00 / month 2006224607-1 — $ 3,588.00 / month
16. Rate Schedule CO_2	Tier — CO_2 Rate ($/$10^3m^3$) 1 — 674.38 2 — 532.41 3 — 390.43

TransCanada
In business to deliver

TransCanada Home ▸ Gas Transmission ▸ Alberta System

Border Heat Values, Empress, McNeill & A/BC

	Empress Border		McNeill Border		Alberta/BC Border	
Date	Posted HV (MJ/m3)	Actual HV (MJ/m3)	Posted HV (MJ/m3)	Actual HV (MJ/m3)	Posted HV (MJ/m3)	Actual HV (MJ/m3)
July 2006	37.40	-	37.50	-	37.90	-
June 2006	37.45	-	37.50	-	38.20	-
May 2006	37.50	37.44	37.55	37.98	37.85	37.92
Apr 2006	37.45	37.41	37.45	37.52	37.85	37.80
Mar 2006	37.45	37.40	37.45	37.51	37.85	37.90
Feb 2006	37.50	37.41	37.45	37.46	37.85	37.85
Jan 2006	37.55	37.37	37.60	37.46	37.85	37.82

Border Archives

TransCanada BC System (or Alberta Natural Gas - "ANG")

Applicable Tariffs/Rate Schedules

3 RATES STATEMENT AND CALCULATION METHODOLOGY

3.1 Statement of Effective Rates and Charges

	Effective Rates
FS-1 Firm Service	
Demand Rate (cents/GJ/Km/Month*)	1.2454355541
IS-1 Interruptible Service	
Commodity Rate (cents/GJ/Km*)	0.0450404091

* Total distance of pipeline is 170.7 km

Company Use Gas

Shipper's Share of Company Use Gas shall be determined pursuant to Section 10.5 of the General Terms and Conditions.

TransCanada
In business to deliver

Pricing & Tolls - BC System

TransCanada's - BC System Rates
2006 Interim Rates Effective Jan 1, 2006

Service	Tariff Rate		¢/GJ/d (Cdn)	Information P ¢/Mcf/d (Cdn)
FS-1 Firm Service (A/BC to Kingsgate)				
FS-1 Rate	1.2454355541	(¢/GJ/Month/Km)	7.0	7.4
IS-1 Interruptible Service (A/BC to Kingsgate)				
IS-1 Rate	0.0450404091	(¢/GJ/Km) *	7.7	8.2

* The IS-1 Interruptible Service Commodity Rate is calculated by taking the FS-1 Firm Service Demand Rate and multiplying by 110%

1. For information purposes, the maximum Shipper's Haul Distance used in the Shipper's monthly charge for Serv 170.7 km.
2. Rates are payable in Canadian dollars and GJ units are used for billing purposes. Mcf and MMbtu units a information purposes only.
3. Conversion Factors below have been used to calculate the rates provided for information purposes:
   Cdn$/US$ 1.15 - subject to change (updated Mar 2/06)
   ¢/GJ to ¢/MMBtu x 1.055056
4. Posted commodity rate is based on Effective Heating Value Forecast of 37.8 MJ/m³.
5. Rates do not include G.S.T.
6. Inquiries regarding the BC System may be directed to:
   Bruce Newberry at 403.920.5579
   Scott Yule at 403.920.5558

Other information for TransCanada's BC System:

Current

- Fuel Rates & Heating Values
- AB Border Heat Values

Archives

- Rates: 2005 | 2004
- Fuel Rates & Heating Values
- AB Border Heat Values

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TransCanada Home ▸ Gas Transmission ▸ BC System

Current Fuel Rates & Heating Values

Fuel Rate Effective July 1, 2006

Fuel Rate and MJ value on TransCanada's B.C. System for July, 2006

Please be advised that effective July 1, 2006 at 08:00 the fuel rate on TransCanada's B.C. System will **change to 1.1%.**

If you have any questions please contact Leslie Leroux at 403.920.2625

For the period of July 1, 2006, until further notice, a fuel rate of 0.006444% per GJ/km will be in effect. For scheduling purposes this rate is converted to 0.0104% per GJ/Mile. Applicable rates for the most common paths are provided here:

Current Fuel Rates

Gas Transmission Northwest ("GTN")
- formerly PGT -

Applicable Tariffs/Rate Schedules

TransCanada
In business to deliver

Gas Transmission Northwest Corporation
1400 SW Fifth Avenue, Suite 900
Portland, Oregon 97201

John A. Roscher
Director, Rates & Regulatory Affairs

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email John_Roscher@TransCanada.com
web www.gastransmissionnw.com

June 30, 2006

Ms. Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Gas Transmission Northwest Corporation
Docket No. RP06-___

Dear Secretary Salas:

Pursuant to Section 4(e) of the Natural Gas Act, as amended,[1]/ ("NGA") and Subpart D of Part 154 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2]/ Gas Transmission Northwest Corporation ("GTN") hereby submits for filing and acceptance the revised tariff sheets listed on Appendix A to be included in its FERC Gas Tariff, Third Revised Volume No. 1-A. The tariff sheets are proposed to become effective on August 1, 2006. GTN anticipates, however, that the rates proposed herein will be subject to a five-month suspension period and placed into effect on January 1, 2007.

Statement of Nature, Reasons and Basis

The purpose of this filing is to restate GTN's rates for service on its interstate transportation system. GTN's system extends approximately 612 miles from the International Boundary at Kingsgate, British Columbia, to the Oregon-California border, where it interconnects with Tuscarora Gas Transmission Company and Pacific Gas & Electric Company. GTN utilizes this pipeline to provide firm and interruptible transportation service to numerous shippers serving the Pacific Northwest, California, and Nevada markets. GTN also interconnects with facilities of Northwest Pipeline near Spokane and Palouse, Washington, and Stanfield, Oregon.

GTN's current rates for service were established more than 10 years ago by settlement in Docket No. RP94-149.[3]/ Since that time, the market in which GTN operates has undergone

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[1]/ 15 U.S.C. § 717c(e).
[2]/ 18 C.F.R. §§ 154.301 - 315 (2005).
[3]/ *See Pacific Gas Transmission Co.*, 76 FERC ¶ 61,246 (1996), *reh'g sub nom, PG&E Gas Transmission, Northwest Corp.*, 82 FERC ¶ 61,289 (1998).

significant, fundamental changes, including an increase in pipeline capacity into GTN's major market in California as well as an increase in pipeline capacity out of GTN's major supply area in the Western Canada Sedimentary Basin ("WCSB"). The changing competitive landscape has left GTN with substantial unsubscribed capacity as a result of capacity turnback and shipper defaults, and GTN has been forced to drastically discount the price of capacity to meet competitive demands. As further described in the testimony filed herein, GTN anticipates that, during the test period, it will have approximately 450,000 Dth per day of unsubscribed long-term capacity as the result of capacity turnback and/or defaults by customers. Also, as described in the testimony, GTN does not anticipate that it will be able to sell its unsubscribed capacity at or near GTN's tariff rate for the foreseeable future. In fact, for 290 days of the base period, GTN's capacity was worth less than zero, *i.e.*, the cost of transporting gas on GTN and upstream pipelines exceeded the difference between the price of gas in the supply and market areas.

As a result of the turnback of capacity and persistently poor market conditions, GTN is compelled to file to increase its rates to reflect the heightened risks it now faces and to allow GTN a fair opportunity to recover its costs and earn a fair return. To address the unique risks presented to the pipeline and its shippers by this level of capacity turnback and default, GTN proposes that it share with its shippers the costs associated with unsubscribed mainline capacity on a 10 percent/90 percent basis, respectively. GTN's proposal honors the Commission's objective that pipelines not shift 100 percent of the costs associated with turnback capacity to their shippers.[4]/

To the extent that GTN's efforts to remarket its unsubscribed capacity are successful, GTN proposes to share revenues generated from such unsubscribed mainline capacity sales with its shippers on a 25 percent/75 percent basis, respectively, after all costs allocated to long-term firm, short-term firm, seasonal and interruptible capacity services have been recovered. GTN will share revenues associated with mainline capacity sales regardless of their source, be it from long-term firm, short-term firm, seasonal, or interruptible capacity sales. Therefore, maximum rate, long-term firm shippers' ultimate cost responsibility will be reduced by the sale of GTN's unsubscribed capacity. By allowing GTN to retain 25 percent of the revenue from unsubscribed capacity sales, GTN will have an ongoing incentive to sell its unsubscribed capacity for the benefit of itself and its shippers.

GTN is also proposing a series of other changes designed to increase recovery of costs and reduce the burden on long-term firm shippers, including charging a market-based rate for full-haul interruptible transportation; implementing hub service rates that are similar to a 100 percent load factor interruptible transportation rate; and implementing a flexible service proposal designed to allow increased recovery of revenue from short-haul services. These proposals are addressed in greater detail below and in the testimony. Again, these services will inure to the benefit of long-term firm shippers through GTN's revenue sharing proposal.

The enclosed Statement P, in Volumes 3 of this filing, contains the prepared direct testimony and exhibits supporting GTN's proposed rate increase and tariff changes. A list of

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[4]/ *See Natural Gas Pipeline Co. of America*, 73 FERC ¶ 61,050, at 61,129 (1995) (citing *El Paso Natural Gas Co.*, 72 FERC ¶ 61,083, at 61,441 (1995)).

GTN's witnesses is set forth below, along with a brief summary of the principal topics addressed in each witness's testimony.

Witness	**Testimony**
Jeffrey R. Rush	Overview of GTN's system and major components of the rate case filing.
Amy Leong	Overall cost of service consisting of operations and maintenance expenses, depreciation and amortization, return allowance, income taxes and taxes other than income taxes, rate base and return, capital structure, cost of debt, and regulatory assets and liabilities.
John A. Roscher	Cost classification and rate design, treatment of turnback capacity, roll-in of 1998 and 2002 expansions, discount adjustments, market-based IT rate proposal and flexible services rate proposal.
Benjamin K. Johnson	Billing determinants and revenues, including Statement G, hub service rate design, and elimination of IT discount floor.
Kenneth W. Nichols	Revisions to creditworthiness tariff provisions.
Walter W. Haessel	WCSB gas supply projections to support the economic life of GTN's system.
Dan A. King	Cost analysis of retiring and removing facilities to support net negative salvage rate, and pipeline integrity costs.
Edward H. Feinstein	Depreciation rates.
Leslie Ferron-Jones	Commercial risk environment and turnback capacity issues.
Steven H. Levine	Business risk analysis, including analysis of proxy pipeline group.
Paul R. Moul	Range of return on equity.
Paul R. Carpenter	Market power analysis in support of GTN's market-based IT rate proposal.

Barry E. Sullivan	Consistency of GTN's market-based IT rate proposal with Commission policy.

Reasons for Proposed Rate Increase

GTN's cost-of-service and rate calculations are based upon the costs and throughput levels for the base period (twelve months ended March 31, 2006) as adjusted for known and measurable changes through the test period ending December 31, 2006. As a result of the changes proposed herein, GTN's maximum recourse full-haul unit rate for service under Rate Schedule FTS-1 will increase from $0.262787 per Dth to $0.449854 per Dth. However, as discussed above, under GTN's revenue sharing mechanism, the rate paid by long-term firm shippers could be significantly reduced if GTN is successful in remarketing unsubscribed capacity.

In compliance with section 154.7(a)(6) of the Commission's regulations, the following table compares the cost-of-service, rate base, and throughput contained in this filing with the same information underlying GTN's last rates found to be just and reasonable by the Commission:

	This Filing	Prior Rates [5]/
Mainline Cost-of-Service	$294,608,644	$206,019,324
Mainline Rate Base	$868,221,495	$951,237,958
Mainline Throughput	327,067,816,932 Dth-mi	367,128,864,763 Dth-mi

The proposed rates also incorporate an increase in return on equity, reflecting the increased business and financial risks GTN now faces. As detailed in the testimony of GTN Witness Amy Leong, GTN's proposed rates include an overall cost of capital of 11.33 percent. Witness Leong establishes GTN's overall cost of service for the twelve-month base period ending March 31, 2006, adjusted for known and measurable changes for the test period ending December 31, 2006, as $303.5 million. This cost of service is based on GTN's actual capital structure of 37.01 percent debt/62.99 percent equity and a transmission depreciation rate of 2.76 percent. GTN Witness Leong supports the use of GTN's own capital structure, which conforms to FERC's policy in that GTN issues its own non-guaranteed debt, has its own debt ratings separate from its parent, and has a common equity ratio in line with others previously approved by the Commission.

In addition, GTN Witness Paul R. Moul supports an appropriate return on common equity in the range of 13.0 to 15.0 percent. Based upon the investment risks unique to GTN, as detailed in the testimony of GTN Witnesses Moul, Steven H. Levine, and Leslie Ferron-Jones, GTN has justified a rate of return on equity of 14.5 percent.

[5]/ *See* n.3, *supra*.

The following table summarizes GTN's overall rate of return:

	Capitalization Ratio	Cost	Weighted Cost
Long-Term Debt	37.01%	5.96%	2.20%
Equity	62.99%	14.5%	9.13%
Overall Rate of Return			11.33%

GTN Witnesses demonstrate that GTN has above-average business risk relative to the relevant pipeline proxy group. GTN faces above-average supply risk due to its heavy dependence on gas supplies sourced from the WCSB, a basin where production has flattened out and is projected to remain flat or decline in the coming years. GTN also faces above-average market risk in its primary destination market in California because WCSB gas supplies transported to California via GTN compete with Rocky Mountain and San Juan gas supplies transported to California via numerous pipelines. Indeed, since 2001, there have been several expansions of pipeline capacity to California, which have resulted in excess interstate pipeline capacity to the state.

As a result of the competitive conditions in GTN's supply and market areas, GTN's pipeline capacity has been devalued significantly. GTN Witness Ferron-Jones describes how GTN has had difficulty selling its unsubscribed capacity even at sharply discounted rates due to these conditions.

As supported by GTN Witnesses Edward H. Feinstein, Walter W. Haessel and Dan A. King, GTN's rates also reflect an increase in the depreciation rate of GTN's transmission plant to 2.76 percent and the establishment of a negative salvage rate of 0.74 percent.

<u>Other Rate-Related Proposals</u>

Market-Based, Full-Haul IT Rate Proposal

Consistent with Commission policy and Commission cases approving or otherwise addressing market-based rates for transportation,[6]/ GTN is proposing to charge market-based rates for full-haul interruptible transportation ("IT") service from the International Boundary near Kingsgate, British Columbia, to Malin, Oregon. GTN Witness Dr. Paul R. Carpenter provides a market power analysis that concludes that GTN lacks market power over full-haul IT

[6]/ *See K N Interstate Gas Transmission Co.*, 76 FERC ¶ 61,134 (1996); *Rendezvous Gas Services, L.L.C.*, 112 FERC ¶ 61,141, at 61,792-94 pp. 26-40 (2005); *Koch Gateway*, 61 FERC ¶ 61,013 (1996).

service from Kingsgate to Malin, and thus the Commission can appropriately approve GTN's request to charge market-based rates for such service. Just as importantly, GTN is not filing for authority to charge market-based rates for IT services at any other delivery points on its system. After careful consideration, GTN has determined that customers at these other receipt and delivery points do not have the same quality of good alternatives available to them. GTN will continue to provide all other customers (at all other delivery points) with IT service at a capped, cost-based IT tariff rate.

Roll-In of 1998 and 2002 Expansion Projects

GTN is proposing to roll in the costs associated with the 1998 and 2002 expansions. The 1998 Expansion benefits from de minimis capital costs of only $6 million and easily meets the roll-in threshold of the Commission's 1995 Policy Statement[7]/ even after taking into account all changed circumstances. The rate impact of rolled-in treatment for the proposed expansion is below the 5 percent threshold established by the Commission. GTN's roll-in analysis demonstrates that there are rate reductions and system benefits associated with the 1998 Expansion.

The 2002 Expansion meets the roll-in test as set forth in the 1999 Policy Statement.[8]/ Consistent with Commission policy,[9]/ GTN calculated a rolled-down, stand-alone rate for the 2002 Expansion, utilizing all maximum rate post-expansion long-term firm capacity sales and permanent capacity releases, with the exception of those expected to terminate or default during the test period. The resulting rolled-down 2002 Expansion rate is lower than the filed-for mainline system rate without the 2002 Expansion costs and volumes. As such, the 2002 Expansion qualifies for rolled-in treatment under the 1999 Policy Statement because with roll in, existing shippers will not subsidize the expansion. GTN is also proposing to roll in fuel costs associated with the 2002 Expansion. GTN demonstrates that pipeline capacity sales and permanent releases since the inception of the roll-down mechanism warrant a rolling in of the 2002 Expansion fuel costs. Rolling-down the overall incremental fuel rate yields a current rate, expressed on a full-haul basis, of 1.14 percent, well below the roll-in threshold of 2.45 percent.

Flexible Services Rate Proposal

GTN is proposing to facilitate the recovery of unsubscribed capacity costs by allowing GTN to apply higher rates to new contracts for services not sold on an annual, uniform MDQ basis. Such services would include seasonal long-term firm, variable MDQ long-term firm, short-term firm and interruptible transportation other than full-haul (collectively referred to as "flexible services"). GTN proposes to set the maximum rate for flexible services equal to 2.5 times the maximum reservation component of the recourse rate that applies to long-term firm, uniform MDQ shippers, plus the delivery component applicable to long-term firm, uniform

[7]/ *Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines*, 71 FERC ¶ 61,914 (1995).
[8]/ *Certificate of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,225 (1999), *clarified*, 90 FERC ¶ 61,128 (2000).
[9]/ *PG&E Gas Transmission, Northwest Corp.*, 82 FERC ¶ 61,289, at 62,123 n.29 (1998).

MDQ shippers. These flexible service rates can be assessed at any time during the year and revenues from flexible services will be shared on an annual basis to the extent that overall pipeline revenues for mainline service exceed what would have been collected had the maximum recourse rates for long-term, uniform MDQ shippers applied to all mainline volumes transported during the annual period. GTN proposes that revenues above this threshold be shared among GTN and its shippers on a 25 percent/75 percent basis, consistent with the revenue sharing percentage GTN is proposing for unsubscribed capacity sales.

Hub Service Rates

Consistent with Commission precedent,[10]/ GTN is also proposing to charge a postagestamp rate for hub services which is similar to a 100 percent load factor IT rate. By approving this proposal, the Commission will level the playing field for pipelines serving western markets by allowing GTN the opportunity to charge similar rates for similar services.

Summary of Proposed Tariff Changes

GTN is also proposing to implement the following tariff changes reflected on the revised tariff sheets in Appendix A, to be effective August 1, 2006:

Revised Base Rates

As explained above, GTN is updating its cost-of-service and proposing to increase its base transportation rates (maximum recourse rates) for Rate Schedule FTS-1. In addition, GTN is seeking authorization to charge market-based rates for full-haul interruptible transportation service under Rate Schedule IT from one receipt point (Kingsgate) to one delivery point (Malin). As noted, GTN is also requesting authorization to implement a flexible service rate proposal that will allow GTN to set the maximum rate for new sales of seasonal long-term firm, variable MDQ long-term firm, short-term firm, and interruptible transportation other than full-haul at levels higher than their respective maximum recourse rates, subject to a cap of 2.5 times the maximum reservation component of the recourse rate that applies to long-term firm, uniform MDQ shippers, plus the delivery component applicable to such long-term firm, uniform MDQ shippers.

Creditworthiness

As detailed in the testimony of GTN Witness Kenneth W. Nichols, GTN proposes to make four tariff changes related to credit provisions:

First, GTN proposes to modify General Terms and Conditions ("GT&C") ¶ 18.1(e) to allow GTN to consider a shipper's credit quality when evaluating bids and awarding capacity in an open season for long-term firm capacity based on specific, objective criteria that will be posted prior to the commencement of each open season. As explained by GTN Witness Nichols, this change is necessary given GTN's unique experience with non-creditworthy shippers, and is

[10]/ *Mojave Pipeline Co.*, 79 FERC ¶ 61,347 (1997).

also consistent with FERC's Policy Statement on Creditworthiness Issues for Interstate Natural Gas Pipelines. [11]/

Second, GTN proposes to modify GT&C ¶ 18.3(A)(2)(b) and ¶ 18.3(D)(3) of its Tariff to give GTN the discretion to determine whether to allow a shipper to replace its original credit assurance with an alternative assurance. This proposal would prevent a shipper from using a superior form of credit assurance to secure capacity in an open season and then substituting an inferior form of security thereafter.

Third, GTN proposes to clarify GT&C ¶ 18.3(A)(2)(b)(i) and ¶ 18.3(D)(3)(a) to ensure that GTN has the authority to request additional assurances when a shipper provides GTN with a guarantee and the guarantor has become noncreditworthy or no longer has a sufficient credit limit.

Fourth, GTN is proposing to eliminate its current strict "10 percent of tangible net worth test" for establishing shipper credit limits in GT&C ¶ 18.3(A)(2)(b) and to replace it with a more flexible approach that considers a shipper's specific circumstances in determining credit limits.

Reservation of Capacity for Future Expansions

GTN is proposing to revise GT&C ¶ 32 to permit GTN to reserve unsubscribed firm capacity, or capacity under existing or expiring firm transportation agreements that are not subject to the right of first refusal ("ROFR"), for use in connection with a future expansion project. GTN will only be permitted to reserve capacity for a future expansion project for which an open season has been held or will be held within one year of posting the capacity as reserved. Capacity may only be reserved for up to one year prior to GTN's filing a certificate application for the proposed expansion, and thereafter until the expansion is placed into service. GTN submits that its proposed tariff revisions with respect to the reservation of capacity for future expansions are consistent with the capacity reservation tariff provisions that the Commission has approved for several other pipelines.[12]/

Open Seasons for Expansion Capacity and ROFR Capacity

GTN Witness Roscher describes how GTN's currently-effective ROFR procedures have exposed GTN and it long-term shippers to the risk of prospective capacity turnback. For example, in 2001 an open season for ROFR capacity generated contract extensions of 2 to 5 years while contemporaneous open seasons for GTN's 2002 Expansion Project generated binding bids for terms ranging from 10 to 52 years.[13]/ GTN awarded the expansion capacity to

[11]/ *See Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, 111 FERC ¶ 61,412 (2005).
[12]/ *See Texas Gas Transmission, LLC*, 111 FERC ¶ 61,380 (2005); *Dominion Transmission, Inc.*, 111 FERC ¶ 61,135 (2005); *Tennessee Gas Pipeline Co.*, 84 FERC ¶ 61,304 (1998), *reh'g and clarification*, 86 FERC ¶ 61,066 (1999).
[13]/ *See* Exh. GTN-6 at 41-45.

two shippers for contract terms of 52 and 40 years.[14]/ According to Mr. Roscher, shippers and potential shippers have been reluctant to bid on ROFR capacity because of the uncertainty inherent in the ROFR shipper's right to retain the capacity by matching the highest bid.[15]/

In order to promote allocative efficiency, rationalize demand for expansion capacity with existing capacity and reduce the risk of prospective capacity turnback, GTN is proposing to add a new ¶ 33.11 to its ROFR procedures that will permit GTN to hold one open season for an expansion project and a shipper's ROFR capacity when GTN has announced an expansion project and a shipper has notified GTN of its intent to exercise its right of first refusal. Under the proposed ¶ 33.11, in order to continue to receive transportation service following the expiration of its contract term, a ROFR shipper may be required to match the lowest acceptable bid that meets the minimum terms and conditions of the expansion open season.

GTN submits that this matching requirement is consistent with the Commission's allocative efficiency principle that holds that pipeline capacity should be allocated to shippers that value the capacity most as reflected by the NPV of their bids. If an expansion shipper places greater value on the existing capacity than the ROFR shipper, then the existing capacity should be used to satisfy this new demand. By satisfying new demand with existing capacity, GTN's proposal also rationalizes capacity by reducing the pipeline's need to construct additional capacity. Finally, GTN's proposal would benefit GTN and its shippers by reducing the risk of prospective capacity turnback. Allocating ROFR capacity and expansion capacity in one open season would mitigate the risk of future capacity turnback by ensuring that the longest possible term for the capacity is obtained.

Finally, GTN submits that its proposal to require the ROFR shipper to match the minimum terms and conditions in the expansion open season is consistent with Commission precedent. In *Kern River Gas Transmission Co.*, for example, the Commission relied on its earlier decision in *Tennessee Gas Pipeline Co.* to find that "if a pipeline has already announced an expansion project, the Commission will allow the pipeline to impose the same minimum terms and conditions on the posting of unsubscribed capacity that it anticipates it will impose in the future expansion project open season."[16]/ Thus, in these cases the Commission has endorsed the concept that, when the pipeline has announced an expansion project, in allocating expired capacity, the pipeline may impose the same minimum terms and conditions that it will use to allocate the expansion capacity.

ROFR Notice Period When Expansion Project is Proposed

Under the ROFR procedures set forth in GT&C ¶ 33, in order to exercise the ROFR, a shipper must notify GTN one year prior to the primary election date whether it elects to

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[14]/ *See id.* at 44.
[15]/ *See id.* at 43-44.
[16]/ 105 FERC ¶ 61,114, at P 14 (2003) (citing *Tennessee*, 84 FERC at 62,347, in which the Commission permitted the pipeline to impose the same minimum terms and conditions in the posting of "expired contract capacity" that it received from shippers "as a result of an expansion open season").

terminate or not to terminate its service agreement. If the shipper elects not to terminate its contract, then the ROFR process will be triggered and the shipper will be permitted to retain its capacity if it agrees to match any acceptable bid that may be received by GTN. In light of its proposal to rationalize the allocation of ROFR capacity with allocation of expansion of capacity, GTN is also proposing to revise its ROFR procedures to provide that, when GTN has proposed an expansion the sizing of which could be affected by the shipper's decision on whether or not to exercise its ROFR to continue service, GTN may notify a shipper that its election to terminate or not to terminate its service agreement must be provided up to 36 months prior to the expiration date of the shipper's term of service. GTN's proposed language with respect to the 36-month notice requirement is virtually identical to language that the Commission has approved for Northern Border Pipeline Company.[17]

Materials Submitted

Consistent with the relevant provisions of Sections 154.7, 154.201, *et seq.*, and 154.301 of the Commission's regulations, GTN is submitting the original and 12 copies of this filing comprised of the following:

1) Transmittal Letter including Statement of Nature, Basis and Reasons for Filing;

2) A Form of Notice for this filing suitable for publication in the Federal Register, including one diskette containing a copy of the Form of Notice;

3) A certificate of service;

4) Statement of Authorized Accounting Representative pursuant to § 154.308 of the Commission's regulations;

5) Appendix A -- List of Revised Tariff Sheets in clean and marked versions;

6) Statements A - O; and

7) Statement P -- Prepared Direct Testimony/Exhibits.

Electronic Filing Requirement

Pursuant to Section 154.4 of the Commission's regulations, this filing includes a disk containing all statements and schedules contained in this filing in electronic media in the same format generated by the spreadsheet software used in developing the statements.

[17]/ *See* Northern Border, FERC Gas Tariff, First Rev. Vol. 1, Rate Schedule T-1 § 5.1, Third Rev. Sheet No. 102A.

Proposed Effective Date and Motion to Place Rates Into Effect

The revised tariff sheets filed herein have a proposed effective date of August 1, 2006. Because this filing reflects a rate increase, however, GTN expects the Commission to suspend the effectiveness of the tariff sheets until January 1, 2007. Pursuant to section 154.7(a)(9), GTN hereby moves to place the tariff sheets set forth in Appendix A into effect August 1, 2006. In the event the Commission elects to accept and suspend the tariff sheets, GTN will file a separate motion pursuant to section 154.206 to place the tariff sheets into effect at the end of the suspension period.

Requests for Waivers

Pursuant to section 154.7(a)(7), GTN respectfully requests that the Commission grant all waivers necessary to allow the tariff sheets to become effective as proposed herein, including any necessary waivers of Parts 154, 284 and 385, as well as any other rule, policy, pronouncement or order.

Posting and Certification of Service

In accordance with section 154.2(d) of the Commission's regulations, GTN has made copies of this filing available for public inspection, during regular business hours, in a convenient form and place at GTN's main offices located at 1400 SW 5th Avenue, Suite 900, Portland, Oregon 97201. In addition, GTN has posted a complete copy of the filing on its internet website http://www.gastransmissionnw.com. Finally, GTN is serving copies of this filing on interested state regulatory commissions, GTN's affected customers, and other interested parties. Such service meets or exceeds the requirements of section 154.208 of the Commission's regulations.

Communications

All correspondence and communications concerning this filing should be addressed to the following:

Carl M. Fink,
Associate General Counsel
* John A. Roscher
Director, Rates and Regulatory Affairs
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(202) 637-5526
e-mail: LAAlexander@hhlaw.com

* Denotes person designated to receive official service pursuant to Rule 203 of the Commission's Rules of Practice and Procedure.

The undersigned hereby certifies that he has read this filing and knows (i) the contents of the paper copies and electronic media; (ii) that the paper copies contain the same information contained on the electronic media; (iii) that the contents as stated in the copies and on the electronic media are true to the best of his knowledge and belief; and (iv) that he possesses full power and authority to sign this filing.

Respectfully submitted,

/s

John A. Roscher
Director, Rates and Regulatory Affairs
Gas Transmission Northwest Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Gas Transmission Northwest Corporation	)))	**Docket No. RP06-___**

NOTICE OF PROPOSED CHANGES IN FERC GAS TARIFF

Take notice that on June 30, 2006, Gas Transmission Northwest Corporation ("GTN") tendered for filing as part of its FERC Gas Tariff, Third Revised Volume No. 1-A, revised tariff sheets listed below. GTN proposes that the tariff sheets become effective on August 1, 2006.

Ninth Revised Sheet No. 4
Fourth Revised Sheet No. 5
Eighth Revised Sheet No. 6
Fourth Revised Sheet No. 12
Sixth Revised Sheet No. 100
Second Revised Sheet No. 108
Second Revised Sheet No. 109
First Revised Sheet No. 129
First Revised Sheet No. 130
Second Revised Sheet No. 133
First Revised Sheet No. 133A
Second Revised Sheet No. 134
Second Revised Sheet No. 135
First Revised Sheet No. 135A
Second Revised Sheet No. 136
First Revised Sheet No. 136A
Second Revised Sheet No. 137
Second Revised Sheet No. 138
Second Revised Sheet No. 139
First Revised Sheet No. 140
Third Revised Sheet No. 141
First Revised Sheet No. 141A
First Revised Sheet No. 210
Original Sheet No. 210A
Third Revised Sheet No. 211
Original Sheet No. 211A
Third Revised Sheet No. 212
Fourth Revised Sheet No. 213
Second Revised Sheet No. 214

GTN states that the purpose of this filing is to effectuate an increase in the base tariff rates applicable to GTN's jurisdictional services and to implement certain related tariff revisions. GTN further states that the filing is necessary to allow GTN an opportunity to recover its costs and earn a fair return in light of the increased risks that GTN now faces as a result of significant capacity turnback on its system and its inability to remarket such capacity at or near its maximum recourse rate.

GTN states that a copy of this filing has been served upon its customers and interested state regulatory commissions.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR § 385.211 and § 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed in accordance with the provisions of Section 154.210 of the Commission's regulations (18 C.F.R. § 154.210). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date, need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on [DATE].

Magalie R. Salas
Secretary

STATEMENT OF AUTHORIZED ACCOUNT REPRESENTATIVE

RATE FILING OF GAS TRANSMISSION NORTHWEST CORPORATION

OF JUNE 30, 2006

TO THE FEDERAL ENERGY REGULATORY COMMISSION:

I, Gregory A. Lohnes, Chief Financial Officer for Gas Transmission Northwest Corporation, do hereby represent that the cost statements and supporting data submitted as part of the above-mentioned filing by Gas Transmission Northwest Corporation, together with working papers required therein, which purport to reflect the books of the Company, do, in fact, set forth the results shown by such books.

/s

Gregory A. Lohnes
Chief Financial Officer
Gas Transmission Northwest Corporation

Dated: June 22, 2006

APPENDIX A
REVISED TARIFF SHEETS

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR
TRANSPORTATION OF NATURAL GAS
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)	
	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
BASE	0.000616	0.000000	0.049918	0.000000	0.000037	0.000037	0.0050%	0.0000%
STF(e)	0.001540	0.000000	0.124795	0.000000	0.000037	0.000037	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1(f)	0.003917	0.000000	0.014747	0.000000	0.000024	0.000024	---	---
E-2(g) (WWP)	0.189234	0.000000	---	---	0.000000	0.000000	---	---
E-2(h) (Diamond 1)	0.090388	0.000000	---	---	0.000000	0.000000	---	---
E-2(h) (Diamond 2)	0.035477	0.000000	---	---	0.000000	0.000000	---	---
COYOTE SPRINGS								
E-3(i)	0.001878	0.000000	0.003652	0.000000	0.000000	0.000000	---	---
OVERRUN CHARGE(j)	---	---	---	---	---	---	---	---
SURCHARGES								
ACA (k)	---	---	---	---	0.001800	0.001800	---	---

Issued by: John A Roscher, Director of Rates & Regulatory Affairs
Issued on: June 30, 2006
Effective on: August 1, 2006

STATEMENT OF EFFECTIVE RATES AND CHARGES FOR
TRANSPORTATION OF NATURAL GAS (a)
Rate Schedule ITS-1

	MILEAGE (n) (Dth-Mile)		NON-MILEAGE (o) (Dth)		FUEL (d) (Dth)	
	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
BASE	0.001577	0.000037	0.124795	0.000000	0.0050%	0.0000%
EXTENSION CHARGES						
MEDFORD						
E-1 (Medford) (f)	0.003941	0.000024	0.014747	0.000000	----	----
COYOTE SPRINGS						
E-3 (Coyote Springs) (i)	0.001878	0.000000	0.003652	0.000000	----	----
SURCHARGES						
ACA (k)	---	---	0.001800	0.001800	---	---

(Continued)

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS

Notes:

(a) The mileage component shall be applied per pipeline mile to gas transported by GTN for delivery to shipper based on the primary receipt and delivery points in Shipper's contract. Consult GTN's system map on Sheet 3 for receipt and delivery point and milepost designations.

(b) The non-mileage component is applied per Shipper's MDQ at Primary Point(s) of Delivery on Mainline Facilities.

(c) The delivery rates are applied per pipeline mile to gas transported by GTN for delivery to shipper based on distance of gas transported. Consult GTN's system map on Sheet No. 3 for receipt and delivery point and milepost designations.

(d) Fuel Use: Shipper shall furnish gas used for compressor station fuel, line loss, and other utility purposes, plus other unaccounted-for gas used in the operation of GTN's combined pipeline system in an amount equal to the sum of the current fuel and line loss percentage and the fuel and line loss percentage surcharge in accordance with Paragraph 37 of this tariff, multiplied by the distance in pipeline miles transported from the receipt point to the delivery point multiplied by the transportation quantities of gas received from Shipper under these rate schedules. The current fuel and line loss percentage shall be adjusted each month between the maximum rate of 0.0050% per Dth per pipeline mile and the minimum rate of 0.0000% per Dth per mile. The fuel and line loss percentage surcharge is 0.0000% per Dth per pipeline mile. No fuel use charges will be assessed for backhaul service. The incremental fuel surcharge, initially established for Shippers utilizing capacity constructed as part of GTN's 2002 Pipeline Expansion Project at 0.000854% per Dth per pipeline mile, shall be adjusted downward as new long-term Shippers take capacity that is subject to the incremental fuel surcharge pursuant to Paragraph 38 of GTN's General Terms and Conditions. Currently effective fuel charges, including GTN's currently effective incremental fuel surcharge, may be found on GTN's Internet website under "Informational Postings."

(e) Maximum reservation rates for Short-Term Firm service under Rate Schedule FTS-1 are equal to two and one-half times the applicable non-mileage and mileage FTS-1 Base Reservation components.

(f) Applicable to firm service on GTN's Medford Extension.

(Continued)

STATEMENT OF EFFECTIVE RATES AND CHARGES
FOR TRANSPORTATION OF NATURAL GAS FOR
PARKING AND AUTHORIZED IMBALANCE SERVICES
($/Dth)

Rate Schedule and Type of Charge	Base Tariff Rate Minimum	Maximum
PS-1 Parking Service:	0.0	0.353377/d
AIS-1 Authorized Imbalance Service:	0.0	0.353377/d

Notes:

(Continued)

Questar Pipeline Company
(for Clay Basin Storage)

Applicable Tariffs/Rate Schedules

FERC GAS TARIFF

FIRST REVISED VOLUME NO. 1

(SUPERSEDES ORIGINAL VOLUME NOS. 1, 1-A, 2 AND 2-A)

of

QUESTAR PIPELINE COMPANY

Filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications regarding this tariff should be addressed to:

L. G. Wright, Director, Regulatory Affairs
Questar Regulated Services Company
180 East 100 South
P. O. Box 45360
Salt Lake City, Utah 84145-0360
Telephone: (801) 324-2459
FAX: (801) 324-5935

STATEMENT OF RATES

Base Rate Schedule/ Type of Charge (a)	Annual Tariff Rate (b) $	Currently Charge Adjustment 4/ (c) $	Effective Rate (d) $
PEAKING STORAGE			
Monthly Reservation Charge			
Maximum	2.87375	-	2.87375/Dth
Minimum	0.00000	-	0.00000/Dth
Usage Charge			
Injection	0.03872	-	0.03872/Dth
Withdrawal	0.03872	-	0.03872/Dth
CLAY BASIN STORAGE			
Firm Storage Service - FSS			
Monthly Reservation Charge			
Deliverability			
Maximum	2.85338	-	2.85338/Dth
Minimum	0.00000	-	0.00000/Dth
Capacity			
Maximum	0.02378	-	0.02378/Dth
Minimum	0.00000	-	0.00000/Dth
Usage Charge			
Injection	0.01049	0.00180	0.01229/Dth
Withdrawal	0.01781	-	0.01781/Dth
Authorized Overrun Charge			
Maximum	0.30315	0.00180	0.30495/Dth
Minimum	0.01781	0.00180	0.01961/Dth
Interruptible Storage Service - ISS			
Usage Charge			
Inventory 1/			
Maximum	0.05927	-	0.05927/Dth
Minimum	0.00000	-	0.00000/Dth
Injection	0.01049	0.00180	0.01229/Dth
Withdrawal	0.01781	-	0.01781/Dth
OPTIONAL VOLUMETRIC RELEASES 2/			
Peaking Storage Service - PKS			
Maximum	3.40890	-	3.40890/Dth
Minimum	0.00000	-	0.00000/Dth
Firm Storage Service - FSS			
Maximum	0.57068	-	0.57068/Dth
Minimum	0.00000	-	0.00000/Dth
Storage Usage Charges Applicable to Volumetric Releases 3/			
Peaking Storage Service - PKS:			
Injection	0.03872	-	0.03872/Dth
Withdrawal	0.03872	-	0.03872/Dth
Clay Basin Storage Service - FSS:			
Injection	0.01049	0.00180	0.01229/Dth
Withdrawal	0.01781	-	0.01781/Dth
PARK AND LOAN SERVICE - PAL1			
Daily Charge			
Maximum	0.30315	-	0.30315/Dth
Minimum	0.00000	-	0.00000/Dth
Delivery Charge	0.02830	0.00180	0.03010/Dth

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

FOOTNOTES

1/Applied to the average monthly working gas balance.

2/Released capacity may be sold at a volumetric rate. Shippers releasing capacity on a volumetric basis must specify a rate between the maximum and minimum volumetric rate stated on this Statement of Rates and notify Questar of the criteria by which bids are to be evaluated.

3/Storage usage charges are applicable to storage services that are released at a volumetric rate and will be billed to the replacement shipper according to § 18.2 of the General Terms and Conditions of Part 1 of this tariff.

4/The annual charge adjustment (ACA) as specified by the Commission will be billed according to §§ 4(f) and 3(d) of Rate Schedule FSS and ISS, respectively, and § 17 of the General Terms and Conditions of Part 1 of this tariff.

NOTE: The monthly rates stated on Questar's Statement of Rates may be converted to a daily rate by multiplying the monthly base tariff rate times the number of months in the rate period and dividing the result by the number of days in the rate period. The result is rounded to the fourth decimal place.

Niska Gas Storage for AECO Storage – ("AECO") - formerly Encana -

Applicable Tariffs/Rate Schedules

ENCANA™

AECO Gas Storage Partnership

Ben Ledene

1800, 855 – 2nd Street SW
PO Box 2850
Calgary AB T2P 2S5

Tel (403) 645-3092
Fax (403) 290-8192
Ben.Ledene@encana.com

April 25, 2006

Duke Energy Marketing Limited Partnerhip
257 East 200 South, Suite 1000
Salt Lake City, UT 84111
United States

Attention: Jim McArthur
Director, Gas Marketing

Dear Sir/Madam:

RE: Natural Gas Storage Agreement Firm Service for a Reserved Inventory of 2750 TJ dated as of May 1, 1994 (the "Storage Agreement") between Duke Energy Marketing Limited Partnership (formerly Grand Valley Gas Company) and AECO Gas Storage Partnership (successor in interest to EnCana Gas Storage, a business unit of EnCana Midstream & Marketing).

The Commodity Rate and the Demand Rate of the Storage Agreement are indexed each April 1st in accordance with the formulas given on Schedules "A" and "B" of that contract respectively. The index for the Commodity Rate is GPI(2006)/GPI(1993). Based on the definition of GPI, GPI (1993) is shown in the Canadian Gas Price Reporter as $1.50/GJ and GPI (2006) is shown in that publication as $8.4419/GJ. Therefore, the index is 5.6279 and the Commodity Rate effective April 1, 2006 to March 31, 2007 will be $0.2814/GJ.

The Demand Rate index in the Storage Agreement is CPI(2006)/CPI(1993). Based on the definition of CPI, CPI (1993) as published by Statistics Canada is 129.9 and CPI (2006) is 165.6. Therefore, the index is 1.2748 and the Demand Rate effective April 1, 2006, under your contract, will be $17.210/TJ per month.

Also, as per Section 2.8 of the Storage Agreement, notice is hereby given that effective April 1, 2006, EnCana Corporation maximum daily injection and withdrawal requirements from the Storage Facility are as follows:

Maximum Injection Rate is 0 TJ/day
Maximum Withdrawal Rate is 0 TJ/day

If you have any questions regarding these matters, please call me at (403) 645-3092.

Yours truly,

B Ledene

Ben Ledene
Advisor, Market Development

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IDAHO PUBLIC
UTILITIES COMMISSION

EXHIBIT NOS. 4-10

CASE NO. INT-G-06-04

INTERMOUNTAIN GAS COMPANY

(7 pages)

INTERMOUNTAIN GAS COMPANY
Summary of Gas Cost Changes

									Cost of Service Allocation of Gas Cost Adjustment[1]					
Line No.	Description	Annual Therms/ Billing Determinants INT-G-05-2	10/1/2005 Prices INT-G-05-2	Total Annual Cost INT-G-05-2	Annual Therms/ Billing Determinants INT-G-06-04	10/1/2006 Prices INT-G-06-04	Total Annual Cost INT-G-06-04	Annual Difference	RS-1	RS-2	GS-1	T-1	T-2 Demand	T-2 Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	**DEMAND CHARGES:**													
2	**Transportation:**													
3	NWP TF-1 Demand 1 (Full Rate)[2]	625,880,100	$ 0.02862	$ 17,909,560	625,880,100	$ 0.04023	$ 25,179,524	$ 7,269,964	$ 859,191	$ 3,792,033	$ 2,240,281	$ 271,918	$ 106,541	$ -
4	NWP TF-1 Demand 1 (Discounted)[3]	197,204,400	0.02062	4,065,679	197,204,400	0.02831	5,582,403	1,516,724	179,252	791,127	467,387	56,730	22,228	-
5	Upstream Capacity[4]	1,119,314,160	0.00929	10,403,983	1,054,254,440	0.01184	12,477,894	2,073,911	245,102	1,081,759	639,087	77,570	30,393	-
6	**Storage:**													
7	SGS-1													
8	Demand	303,370 [5]	0.00169	187,023 [6]	303,370 [5]	0.00165	182,705 [6]	(4,318)	(510)	(2,252)	(1,331)	(162)	(63)	-
9	Capacity Demand	10,920,990 [5]	0.00006	247,142 [6]	10,920,990 [5]	0.00006	239,170 [6]	(7,972)	(942)	(4,158)	(2,457)	(298)	(117)	-
10	TF-2 Reservation	10,920,990 [5]	0.02776	303,167	10,920,990 [5]	0.03969	433,454	130,287	15,398	67,958	40,149	4,873	1,909	-
11	TF-2 Redelivery Charge	10,920,990 [5]	0.00300	32,763	10,920,990 [5]	0.00132	14,416	(18,347)	(2,286)	(9,858)	(6,203)	-	-	-
12	LS-1													
13	Demand	720,000 [5]	0.00260	683,280 [6]	720,000 [5]	0.00301	791,028 [6]	107,748	12,734	56,202	33,203	4,030	1,579	-
14	Capacity	7,705,200 [5]	0.00033	928,091 [6]	7,705,200 [5]	0.00039	1,096,835 [6]	168,744	19,943	88,017	51,999	6,312	2,473	-
15	Liquefaction	7,705,200 [5]	0.05569	429,103	7,705,200 [5]	0.06199	477,645	48,542	5,737	25,320	14,958	1,816	711	-
16	Vaporization	7,705,200 [5]	0.00303	23,347	7,705,200 [5]	0.00389	29,973	6,626	783	3,456	2,042	248	97	-
17	TF-2 Reservation	7,705,200 [5]	0.02776	213,895	7,705,200 [5]	0.03969	305,819	91,924	10,864	47,948	28,327	3,438	1,347	-
18	TF-2 Redelivery Charge	7,705,200 [5]	0.00300	23,116	7,705,200 [5]	0.00132	10,171	(12,945)	(1,613)	(6,956)	(4,376)	-	-	-
19	Other Storage Facilities							(1,093,942) [7]	(129,286)	(570,603)	(337,104)	(40,917)	(16,032)	-
20	**COMMODITY CHARGES:**													
21	**Transportation:**													
22	T-1 Industrial Transportation	26,921,955	0.00407	109,572	26,921,955	0.00238	64,074	(45,498)	-	-	-	(45,498)	-	-
23	T-2 Industrial Transportation	18,091,581	0.00407	73,633	18,091,581	0.00238	43,058	(30,575)	-	-	-	-	-	(30,575)
24	**Total Producer/Supplier Purchases Including Storage**	285,362,652	0.73219	208,939,680	285,362,652	0.72400	206,602,560	(2,337,120)	(291,240)	(1,255,775)	(790,105)	-	-	-
25	**TOTAL ANNUAL COST DIFFERENCE**							$ 7,863,753	$ 923,127	$ 4,104,218	$ 2,375,857	$ 340,060	$ 151,066	$ (30,575)
26	**Normalized Sales/CD Vols. (10/1/04 - 9/30/05)**								35,560,504	153,330,230	96,471,918	26,921,955	660,840	18,091,581
27	**Average Base Rate Change**								$ 0.02596	$ 0.02677	$ 0.02463	$ 0.01263	$ 0.22860	$ (0.00169)
28	**Other Permanent Changes Proposed:**													
29	Elimination of Temporary Credits and Surcharges from Case No. INT-G-05-2								(0.06562)	(0.04838)	(0.04984)	0.00139	0.08920	-
30	Adjustment to Fixed Cost Collection Rate (see Exhibit 5, Line 24)								0.00486	(0.00725)	(0.01208)	(0.00690)	(0.03990)	-
31	**Total Permanent Changes Proposed (Lines 27 through 30):**								(0.03480)	(0.02886)	(0.03729)	0.00712	0.27790	(0.00169)
32	**Temporary Surcharge (Credit) Proposed (Exhibit No. 6, Line 4, Cols (b)-(f))**								0.03422	0.02786	0.02520	(0.01822)	(0.15687)	-
33	**Proposed Average Per Therm/CD Change in Intermountain Gas Company Tariff**								$ (0.00058)	$ (0.00100)	$ (0.01209)	$ (0.01110)	$ 0.12103	$ (0.00169)

[1] See Workpaper No. 5, Line 10
[2] See Workpaper No. 1
[3] See Workpaper No. 2
[4] See Workpaper No. 3
[5] Represents Non-Additive Demand Charge Determinants
[6] Price Reflects Daily Charge; Annual Charge (Col d&g) equals Price (Col c&f) times Annual Therms/Billing Determinants (Col b&e) times 365
[7] See Workpaper No. 4, Line 33, Column (d)

Exhibit No. 5
Case No. INT-G-06-04
Intermountain Gas Company

INTERMOUNTAIN GAS COMPANY
Summary of Fixed Gas Cost Charges

Line No.	Description	Annual Therms/ Billing Determinants INT-G-05-2	10/1/2005 Prices INT-G-05-2	Annual Cost INT-G-05-2	Cost of Service Allocation of Gas Cost Adjustment [1] RS-1	RS-2	GS-1	T-1	T-2
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**DEMAND CHARGES:**								
2	**Transportation:**								
3	NWP TF-1 Demand 1 (Full Rate)	625,880,100	$ 0.02862	$ 17,909,560	$ 2,116,618	$ 9,341,673	$ 5,518,933	$ 669,871	$ 262,465
4	NWP TF-1 Demand 1 (Discounted)	197,204,400	0.02062	4,065,679	480,497	2,120,668	1,252,862	152,069	59,583
5	Upstream Capacity	1,119,314,160	0.00929	10,403,983	1,229,581	5,426,745	3,206,047	389,140	152,470
6	**Storage:**								
7	SGS-1								
8	Demand	303,370	0.00169	187,023 [2]	22,103	97,552	57,632	6,995	2,741
9	Capacity Demand	10,920,990	0.00006	247,142 [2]	29,208	128,910	76,158	9,244	3,622
10	TF-2 Reservation	10,920,990	0.02776	303,167	35,829	158,133	93,423	11,339	4,443
11	TF-2 Redelivery Charge	10,920,990	0.00300	32,763	4,083	17,604	11,076	-	-
12	LS-1								
13	Demand	720,000	0.00260	683,280 [2]	80,753	356,400	210,557	25,557	10,013
14	Capacity	7,705,200	0.00033	928,091 [2]	109,685	484,095	285,997	34,713	13,601
15	Liquefaction	7,705,200	0.05569	429,103	50,713	223,820	132,231	16,050	6,289
16	Vaporization	7,705,200	0.00303	23,347	2,759	12,178	7,195	873	342
17	TF-2 Reservation	7,705,200	0.02776	213,895	25,279	111,568	65,913	8,000	3,135
18	TF-2 Redelivery Charge	7,705,200	0.00300	23,116	2,881	12,420	7,815	-	-
19	Other Storage Facilities			5,914,467	698,994	3,085,000	1,822,577	221,219	86,677
20	Total Fixed Gas Cost Charges			$ 41,364,616	$ 4,888,983	$ 21,576,766	$ 12,748,416	$ 1,545,070	$ 605,381
21	Normalized Sales/CD Vols. (INT-G-06-04 Estimated Volumes)				33,652,624	175,908,456	103,203,086	28,017,449	660,840
22	Fixed Cost Collection per Therm (Row 20 divided by Row 21)				$ 0.14528	$ 0.12266	$ 0.12353	$ 0.05515	$ 0.91608
23	Current Fixed Cost Collection per Therm				$ 0.14042	$ 0.12991	$ 0.13561	$ 0.06205	$ 0.95598
24	Difference (Row 22 minus Row 23)			$ (2,578,166)	$ 0.00486	$ (0.00725)	$ (0.01208)	$ (0.00690)	$ (0.03990)

(1) See Workpaper No. 5, Line 10
(2) Price Reflects Daily Charge; Annual Charge (Col d) equals Price (Col c) times Annual Therms (Col b) times 365.

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Temporary Surcharges (Credits)

Line No.	Description	COST OF SERVICE ALLOCATION OF DEFERRED GAS COSTS				
		RS-1	RS-2	GS-1	T-1	T-2
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market Segmentation Credit [1]	$ (0.01176)	$ (0.01204)	$ (0.01130)	$ (0.00492)	$ (0.07846)
2	Proposed Temporary Surcharge (Credit) -Fixed Deferral [2]	(0.00308)	(0.00916)	(0.01256)	(0.01330)	(0.07841)
3	Proposed Temporary Surcharge (Credit) -Variable Deferral [3]	0.04906	0.04906	0.04906	-	-
4	**Total Proposed Temporary Surcharge (Credit)**	$ 0.03422	$ 0.02786	$ 0.02520	$ (0.01822)	$ (0.15687)

[1] See Exhibit No. 7, Line 3, Cols. (c) - (g)
[2] See Exhibit No. 8, Line 11, Col. (c) - (g)
[3] See Exhibit No. 9, Line 4, Col. (b)

INTERMOUNTAIN GAS COMPANY
Allocation of Annualized Segmentation Credits

			COST OF SERVICE ALLOCATION OF DEFERRED GAS COSTS [1]				
Line No.	Description	Total	RS-1	RS-2	GS-1	T-1	T-2
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Segmentation Credits	$ (3,538,166)	$ (418,154)	$ (1,845,516)	$ (1,090,306)	$ (132,338)	$ (51,852)
2	Normalized Sales/CD Vols. (10/1/04 - 9/30/05)		35,560,504	153,330,230	96,471,918	26,921,955	660,840
3	Proposed Price Adjustment Per Therm/CD		$ (0.01176)	$ (0.01204)	$ (0.01130)	$ (0.00492)	$ (0.07846)

[1] See Workpaper No. 5, Line 10

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

Line No.	Description	Deferred Account 1860 Estimated Sept. 30, 2006 Balance [1]	COST OF SERVICE ALLOCATION OF DEFERRED GAS COSTS [2]				
			RS-1	RS-2	GS-1	T-1	T-2
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Fixed Costs:**						
2	From INT-G-05-2 (Accounts 1860.2050 - 2090)	$ (325,863)	$ 106,442	$ (297,952)	$ (113,463)	$ (21,064)	$ 174
3	Fixed Cost Collection Adjustment (Accounts 1860.2200-2210)	(1,515,545)	(25,548)	(459,510)	(685,255)	(314,611)	(30,621)
4	Statoil Revenue Deferral (Account 1860.2260)	(180,823)	(21,370)	(94,318)	(55,722)	(6,763)	(2,650)
5	Capacity Releases & Purchases (Account 1860.2320)	(986,305)	(116,565)	(514,459)	(303,936)	(36,891)	(14,454)
6	Interest (Accounts 1860.2420, 2430)	(170,160)	(20,110)	(88,756)	(52,436)	(6,364)	(2,494)
7	Market Segmentation (Account 1860.2530)	(2,467,146)	(306,111)	(1,247,553)	(789,140)	(86,611)	(37,731)
8	Amortization of 1860.2530 (Accounts 1860.2540 - 1860.2550)	2,510,834	273,758	1,298,658	788,247	114,209	35,962
9	**Total Fixed Costs**	$ (3,135,008)	$ (109,504)	$ (1,403,890)	$ (1,211,705)	$ (358,095)	$ (51,814)
10	**Normalized Sales/CD Vols. (10/1/04 - 9/30/05)**		35,560,504	153,330,230	96,471,918	26,921,955	660,840
11	**Proposed Temporary Surcharge (Credit)-Fixed Costs**		$ (0.00308)	$ (0.00916)	$ (0.01256)	$ (0.01330)	$ (0.07841)

[1] See Workpaper No. 6
[2] See Workpaper No. 5, Line 10

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

Line No.	Description	Amount
	(a)	(b)
1	**Account 1860 Amounts Which Apply to RS-1, RS-2, GS-1, and LV-1:**	
2	Account 1860 Variable Costs [1]	$ 14,136,240
3	Normalized Sales/CD Vols. (10/1/04 - 9/30/05)	288,115,588
4	**Proposed Temporary Surcharge(Credit) - Variable Costs**	$ 0.04906

(1) See Workpaper No. 6, Page 1, Line 17, Col (f)

Exhibit No. 10
Case No. INT-G-06-04
Intermountain Gas Company
Page 1 of 1

INTERMOUNTAIN GAS COMPANY
Analysis of Annualized Price Change by Class of Service
Normalized Volumes for Twelve Months Ended September 30, 2005

			Average Prices Effective per Case No. INT-G-05-2 Commission Order No. 29875		Proposed Adjustments Effective 10/1/2006		Proposed Average Prices Effective 10/1/2006		
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-1 Residential	35,560,504	$ 44,766,407	$ 1.25888	$ (20,625)	$ (0.00058)	$ 44,745,782	$ 1.25830	-0.05%
3	RS-2 Residential	153,330,230	174,773,463	1.13985	(153,330)	(0.00100)	174,620,133	1.13885	-0.09%
4	GS-1 General Service	96,471,918	105,777,599	1.09646	(1,166,345)	(0.01209)	104,611,254	1.08437	-1.10%
5	LV-1 Large Volume	2,752,936	2,447,195	0.88894	(688)	(0.00025)	2,446,507	0.88869	-0.03%
6	Total Gas Sales	288,115,588	327,764,664	1.13762	(1,340,988)	(0.00465)	326,423,676	1.13297	-0.41%
7	T-1 Transportation	24,169,019	2,679,136	0.11085	(268,276)	(0.01110)	2,410,860	0.09975	-10.01%
8	T-2 Transportation (Demand)	660,840	572,803	0.86678	79,981	0.12103	652,784	0.98781	13.96%
9	T-2 Transportation (Commodity)	18,091,581	118,138	0.00653	(30,575)	(0.00169)	87,563	0.00484	-25.88%
10	Total T-2 (1)	18,091,581	690,941	0.03819	49,406	0.00273	740,347	0.04092	7.15%
11	Total	330,376,188	$ 331,134,741	$ 1.00230	$ (1,559,858)	$ (0.00472)	$ 329,574,883	$ 0.99758	-0.47%

(1) Demand volumes removed from the $/therm calculations

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NEWS RELEASE

August 16, 2006

Contact: Mike Huntington
Vice President
Marketing & External Affairs
(208) 377-6059

Today, Intermountain Gas Company ("Intermountain") filed its annual purchased gas cost adjustment application with the Idaho Public Utilities Commission ("IPUC"). This type of application is filed each year to ensure that the costs that Intermountain is incurring on behalf of its customers are properly reflected in its sales price. In its application, Intermountain requests permission to adjust its prices to reflect the prices of natural gas supplies that it expects to incur.

William C. "Bill" Glynn, President of Intermountain Gas Company, said, "Despite increases in some other energy prices like crude oil that has increased 30% during the past year, the Company expects to be able to manage its natural gas purchases such that it will not need to raise customer prices for this next winter season." Commenting further Glynn said, "The forces behind this expectation include the increase in natural gas production resulting from additional drilling, the return of Gulf Coast production which was shut-in from hurricane Katrina, and purchasing and pricing strategies the Company has employed, including the use of significant summer storage injections for winter deliveries."

Glynn, however, went on to say, "We are pleased to be able to offer this additional price stability, however, Intermountain continues to urge all its customers to be conscious of their energy usage and use it wisely. Helpful tips on ways to do that and how to request government payment energy assistance are provided through bill inserts and on the Company's website (www.intgas.com). We also have a number of programs to help our customers level out their energy bills over the year, and stabilize the potential impact that cold weather will have during periods of higher natural gas usage."

If approved as filed, all residential and commercial customer's unit prices will be essentially unchanged for natural gas used this next year and the Company's total net revenue will decrease by approximately $1.6 million (.5%). The proposed effective date is October 1, 2006. This proposal is subject to public review and approval by the IPUC. A copy of Intermountain's application is available at the offices of both the Idaho Public Utilities Commission and the Company.

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WORKPAPER NOS. 1-7

CASE NO. INT-G-06-04

INTERMOUNTAIN GAS COMPANY

(8 pages)

INTERMOUNTAIN GAS COMPANY
Northwest Pipeline TF-1 Full Rate Demand Workpaper

Line No.	Transportation (a)	INT-G-05-2 Annual Therms (b)	INT-G-05-2 Prices (c)	INT-G-05-2 Annual Cost (d)
1	TF-1 Demand 1 Contract #1	412,537,600	$ 0.028615	$ 11,804,763
2	TF-1 Demand 1 Contract #2	25,550,000	0.028615	731,113
3	TF-1 Demand 1 Contract #3	73,000,000	0.028615	2,088,895
4	TF-1 Demand 1 Contract #4	23,542,500	0.028615	673,669
5	TF-1 Demand 1 Contract #5	54,750,000	0.028615	1,566,672
6	TF-1 Demand 1 Contract #6	36,500,000	0.028615	1,044,448
7	Total Annual Cost	625,880,100	$ 0.028615	$ 17,909,560

Line No.	Transportation (a)	INT-G-06-04 Annual Therms (b)	INT-G-06-04 Prices (c)	INT-G-06-04 Annual Cost (d)
8	TF-1 Demand 1 Contract #1	412,537,600	$ 0.040362	$ 16,650,843
9	TF-1 Demand 1 Contract #2	25,550,000	0.040224	1,027,723
10	TF-1 Demand 1 Contract #3	73,000,000	0.040027	2,921,971
11	TF-1 Demand 1 Contract #4	23,542,500	0.039691	934,425
12	TF-1 Demand 1 Contract #5	54,750,000	0.039906	2,184,854
13	TF-1 Demand 1 Contract #6	36,500,000	0.039992	1,459,708
14	Total Annual Cost	625,880,100	$ 0.040362	$ 25,179,524
15	**Total Annual Cost Difference (Row 14 minus Row 7)**			**$ 7,269,964 (1)**

(1) See Exhibit 4, Line 3, Column (h)

INTERMOUNTAIN GAS COMPANY
Northwest Pipeline TF-1 Discounted Demand Workpaper

Line No.	Transportation (a)	INT-G-05-2 Annual Therms (b)	INT-G-05-2 Prices (c)	INT-G-05-2 Annual Cost (d)
1	TF-1 Demand 1 Contract #1	43,680,000	$ 0.027760	$ 1,212,557
2	TF-1 Demand 1 Contract #2	28,470,000	0.016656	474,196
3	TF-1 Demand 1 Contract #3	29,404,400	0.014724	432,950
4	TF-1 Demand 1 Contract #4	22,650,000	0.027760	628,764
5	TF-1 Demand 1 Contract #5	36,500,000	0.016656	607,944
6	TF-1 Demand 1 Contract #6	36,500,000	0.019432	709,268
7	Total Annual Cost	197,204,400	$ 0.020617	$ 4,065,679

Line No.	Transportation (a)	INT-G-06-04 Annual Therms (b)	INT-G-06-04 Prices (c)	INT-G-06-04 Annual Cost (d)
8	TF-1 Demand 1 Contract #1	43,680,000	$ 0.035650	$ 1,557,192
9	TF-1 Demand 1 Contract #2	28,470,000	0.023810	677,871
10	TF-1 Demand 1 Contract #3	29,404,400	0.021090	620,139
11	TF-1 Demand 1 Contract #4	22,650,000	0.037270	844,166
12	TF-1 Demand 1 Contract #5	36,500,000	0.023810	869,065
13	TF-1 Demand 1 Contract #6	36,500,000	0.027780	1,013,970
14	Total Annual Cost	197,204,400	$ 0.028308	$ 5,582,403
15	**Total Annual Cost Difference (Row 14 minus Row 7)**			**$ 1,516,724 (1)**

(1) See Exhibit 4, Line 4, Column (h)

INTERMOUNTAIN GAS COMPANY
Upstream Capacity Workpaper

Line No.	Transportation (a)	INT-G-05-2 Annual Therms (b)	INT-G-05-2 Prices (c)	INT-G-05-2 Annual Cost (d)
1	Upstream Agreement #1	198,089,150	$ 0.012756	$ 2,526,825
2	Upstream Agreement #2	155,624,370	0.005498	855,623
3	Upstream Agreement #3	155,025,220	0.013122	2,034,241
4	Upstream Agreement #4	193,282,100	0.012756	2,465,506
5	Upstream Agreement #5	273,100,300	0.005254	1,434,869
6	Upstream Agreement #6	144,193,020	0.013161	1,897,724
7	Total Annual Cost			$ 11,214,788
8	Estimated Upstream Capacity Release Credits			$ (810,805)
9	Total Annual Cost Including Capacity Release Credits			$ 10,403,983

Line No.	Transportation (a)	INT-G-06-04 Annual Therms (b)	INT-G-06-04 Prices (c)	INT-G-06-04 Annual Cost (d)	
10	Upstream Agreement #1	197,567,200	0.012525	$ 2,474,529	
11	Upstream Agreement #2	155,624,370	0.006641	1,033,501	
12	Upstream Agreement #3	155,025,220	0.019310	2,993,537	
13	Upstream Agreement #4	192,891,550	0.012525	2,415,967	
14	Upstream Agreement #5	189,573,700	0.006637	1,258,201	
15	Upstream Agreement #6	163,572,400	0.017131	2,802,159	
16	Total Annual Cost			$ 12,977,894	
17	Estimated Upstream Capacity Release Credits			$ (500,000)	
18	Total Annual Cost Including Capacity Release Credits			$ 12,477,894	
19	**Total Annual Cost Difference (Row 18 minus Row 9)**			**$ 2,073,911**	**(1)**

(1) See Exhibit 4, Line 5, Column (h)

INTERMOUNTAIN GAS COMPANY
Other Storage Facilities

Line No.	Storage Facilities (a)	INT-G-05-2 Monthly Billing Determinant (b)		INT-G-05-2 Prices (c)	INT-G-05-2 Monthly Cost (d)	INT-G-05-2 Annual Cost (e)
1	**Demand Costs -**					
2	Clay Basin I Reservation	266,250	(1)	$ 0.285340	$ 75,972	$ 911,664
3	Clay Basin II Reservation	221,840	(1)	0.285340	63,300	759,600
4	Clay Basin III Reservation	213,010	(1)	0	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	60,782	729,384
8	AECO Demand	26,064,970	(2)	0.001432	37,325	447,900
9	Total Demand Costs	110,199,970	(3)		$ 437,450	$ 5,249,400
10	**Cycling Costs -**					
11	Clay Basin I & II Cycling Costs	58,575,000		$ 0.001581	$ 92,594	$ 1,111,126
12	Clay Basin III Cycling Costs	25,560,000		0	35,468	425,611
13	AECO Cycling Costs	26,064,970		0.001536	40,023	480,272
14	Total Cycling Costs	84,639,970			$ 168,085	$ 2,017,009
15	Storage Demand Charge Credit					$ (1,351,942)
16	Total Costs Including Storage Credit					$ 5,914,467

Line No.	Storage Facilities (a)	INT-G-06-04 Monthly Billing Determinant (b)		INT-G-06-04 Prices (c)	INT-G-06-04 Monthly Cost (d)	INT-G-06-04 Annual Cost (e)
17	**Demand Costs -**					
18	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652
19	Clay Basin II Reservation	221,840	(1)	0.285338	63,299	759,588
20	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360
21	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724
22	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768
23	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384
24	AECO Demand	26,064,970	(2)	0.001634	42,590	511,080
25	Total Demand Costs	110,199,970	(3)		$ 442,713	$ 5,312,556
26	**Cycling Costs -**					
27	Clay Basin I & II Cycling Costs	58,575,000		$ 0.001196	$ 70,060	$ 840,715
28	Clay Basin III Cycling Costs	25,560,000		0.001187	30,339	364,062
29	AECO Cycling Costs	26,064,970		0.002227	58,039	696,465
30	Total Cycling Costs	110,199,970			$ 158,438	$ 1,901,242
31	Estimated Storage Demand Charge Credit					$ (2,393,273)
32	Total Costs Including Storage Credit					$ 4,820,525
33	**Total Annual Cost Difference Including Storage Credit (Row 32 minus Row 16)**					**$ (1,093,942)** (4)

(1) Charge Based on Maximum Daily Withdrawal

(2) Charge Based on Maximum Contractual Capacity

(3) Non Additive Billing Determants; Includes only Capacity Volumes

(4) See Exhibit 4, Line 19, Column (h)

INTERMOUNTAIN GAS COMPANY
Peak Day Analysis for Demand Allocators in Case No. INT-G-06-04

Line No.	Description (a)	Core RS-1 (b)	Core RS-2 (c)	Core GS-1 (d)	Total Core (e)	Firm Transportation T-1 (f)	Firm Transportation T-2 (g)	Total Firm Transportation (h)	Total Peak (i)
1	DEMAND ALLOCATORS PER CASE NO. INT-G-05-2:								
2	Peak Day Therms	446,782	1,820,855	1,151,783	3,419,420	126,412	55,070	181,482	3,600,902
3	Percent of Total	12.40750%	50.56664%	31.98596%	94.96010%	3.51056%	1.52934%	5.03990%	100.0000%
4	PROPOSED DEMAND ALLOCATORS PER CASE NO. INT-G-06-04:								
5	Peak Day Therms (Line 2)	446,782	1,820,855	1,151,783	3,419,420				
6	Customers Embedded within Line 2	61,967	175,928	26,029	263,924				
7	Peak Day Usage Per Customer (Line 5 divided by Line 6)	7.21	10.35	44.25					
8	January 2006 Actual Customers	61,596	189,378	26,169	277,143				
9	INT-G-06-04 Peak Day Therms (Line 7 mulitplied by Line 8)	444,107	1,960,062	1,157,978	3,562,147	140,552	55,070	195,622 [1]	3,757,769
10	Percent of Total	11.81837%	52.16026%	30.81557%	94.79420%	3.74030%	1.46550%	5.20580%	100.0000%

[1] FY07 Forecast Contract Therms

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1860 Surcharges (Credits)
Estimated September 30, 2006

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	**ACCOUNT 1860 VARIABLE AMOUNTS:**					
2	**Net Cumulative Deferred Gas Balance in 1860.2010 as of 10/1/05**			$ 8,730,036.39		
3	Amortization in 1860.2020 as of 6/30/06		$ (8,439,685.43)			
4	Estimated Therm Sales 7/1 through 9/30/06	20,454,611				
5	Amortization Rate	$ (0.03171)	(648,615.71)			
6	Estimated Amortization in 1860.2020 at 9/30/06			(9,088,301.14)		
7	**Estimated Balance in 1860.2010 at 9/30/06**				$ (358,264.75)	
8	**Deferred Gas Costs From Producers/Suppliers In 1860.2180 at 10/1/05**			$ 6,652,733.74		
9	Deferred Gas Costs From Producers/Suppliers in 1860.2180 through 6/30/06			13,729,873.58		
10	Estimated Deferred Costs in 1860.2180 from 7/1 through 9/30/06			(6,939,145.30)		
11	**Estimated Balance in 1860.2180 at 9/30/06**				13,443,462.02	
12	**Daily Gas Excess Sales Deferred in 1860.2240 at 6/30/06**				-	
13	**Interest Deferred in 1860.2340 at 10/1/05**			$ 42,589.74		
14	Deferred Interest in 1860.2340 through 6/30/06			821,916.10		
15	Estimated Interest from 7/1 through 9/30/06			186,536.43		
16	**Estimated Balance in 1860.2340 at 9/30/06**				1,051,042.27	
17	**ESTIMATED ACCOUNT 1860 VARIABLE BALANCE AT 9/30/06**					$ 14,136,239.54
18	**ACCOUNT 1860 FIXED AMOUNTS:**					
19	**Net Cumulative Deferred Gas Balance In 1860.2050 at 10/1/05**			$ 7,538,702.52		
20	RS-1 Deferred Gas Balance in 1860.2060 at 10/1/05		$ (3,912.78)			
21	Amortization for RS-1 in 1860.2060 at 6/30/06		(1,354,959.76)			
22	Estimated RS-1 Therm Sales 7/1 through 9/30/06	628,360				
23	RS-1 Amortization Rate	$ (0.04208)	(26,441.39)			
24	Estimated RS-1 Balance in 1860.2060 at 9/30/06			(1,385,313.93)		
25	RS-2 Deferred Gas Balance in 1860.2070 at 10/1/05		$ (7,309.82)			
26	Amortization for RS-2 in 1860.2070 at 6/30/06		(3,616,637.03)			
27	Estimated RS-2 Therm Sales 7/1 through 9/30/06	9,979,480				
28	RS-2 Amortization Rate	$ (0.02489)	(248,389.26)			
29	Estimated RS-2 Balance in 1860.2070 at 9/30/06			(3,872,336.11)		
30	GS-1 Deferred Gas Balance in 1860.2080 at 10/1/05		$ 924.76			
31	Amortization for GS-1 in 1860.2080 at 6/30/06		(2,313,609.11)			
32	Estimated Therm Sales 7/1 through 9/30/06	9,268,189				
33	GS-1 Amortization Rate	$ (0.02612)	(242,085.10)			
34	Estimated GS-1 Balance in 1860.2080 at 9/30/06			(2,554,769.45)		
35	Industrial Deferred Gas Balance in 1860.2090 at 10/1/05		$ 984.59			
36	Amortization for T-1 & T-2 in 1860.2090 at 6/30/06		(45,630.50)			
37	Estimated T-1 Block 1 & 2 Therm Sales 7/1 through 9/30/06	4,823,806				
38	T-1 Amortization Rate	$ (0.00276)	(13,313.70)			
39	Estimated T-2 Contract Demand Volumes 7/1 through 9/30/06	165,210				
40	T-2 Amortization Rate	$ 0.03519	5,813.74			
41	Estimated Industrial Balance in 1860.2090 at 9/30/06			(52,145.87)		
42	**Estimated Cumulative Balance in 1860.2050 at 9/30/06**				$ (325,862.84)	

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1860 Surcharges (Credits)
Estimated September 30, 2006

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Sub-Total (e)	Total (f)
1	**Fixed Cost Collection Deferred in 1860.2200 at 10/1/05**			$ 281,454.57		
2	Fixed Cost Collection Deferred in 1860.2200 through 6/30/06			(7,205,535.42)		
3	Estimated Fixed Cost Collection Deferred from 7/1 through 9/30/06			5,416,474.81		
4	**Estimated Balance in 1860.2200 at 9/30/06**				(1,507,606.04)	
5	**T-4 Exit Fee Adjustment Deferred in 1860.2210 at 10/1/05**			$ (2,036.88)		
6	T-4 Exit Fee Adjustment Deferred in 1860.2210 through 6/30/06			(4,427.57)		
7	Estimated T-4 Exit Fee Adjustment Deferred from 7/1 through 9/30/06			(1,474.52)		
8	**Estimated Balance in 1860.2210 at 9/30/06**				(7,938.97)	
9	**Statoil Revenue Deferred in 1860.2260 at 10/1/05**			$ 34.50		
10	Statoil Revenue Deferred in 1860.2260 through 6/30/06			(180,857.67)		
11	Estimated Statoil Revenue Deferred from 7/1 through 9/30/06			-		
12	**Estimated Balance in 1860.2260 at 9/30/06**				(180,823.17)	
13	**Capacity Released/Purchased Deferred in 1860.2320 at 6/30/06**				(986,304.81)	
14	**Interest Deferred in 1860.2420 at 10/1/05**			$ (157.38)		
15	Deferred Interest in 1860.2420 through 6/30/06			160.08		
16	Estimated Interest from 7/1 through 9/30/06			(169.29)		
17	**Estimated Balance in 1860.2420 at 9/30/06**				(166.59)	
18	**Interest in 1860.2430 at 10/1/05**			$ 21,157.24		
19	Deferred Interest in 1860.2430 through 6/30/06			(136,190.96)		
20	Estimated Interest from 7/1 through 9/30/06			(54,959.88)		
21	**Estimated Balance in 1860.2430 at 9/30/06**				(169,993.60)	
22	**Market Segmentation Deferred in 1860.2530 at 10/1/05**		$ (21,363.19)			
23	Market Segmentation Deferred in 1860.2530 through 6/30/06		(1,829,308.28)			
24	Estimated Deferral in 1860.2530 from 7/1 through 9/30/06		(616,475.00)			
25	Estimated Balance in 1860.2530 at 9/30/06			$ (2,467,146.47)		
26	RS-1 Amortization in 1860.2540 at 6/30/06		$ 268,624.45			
27	Estimated RS-1 Therm Sales from 7/1 through 9/30/06	628,360				
28	RS-1 Amortization Rate	$ 0.00817	5,133.70			
29	Estimated RS-1 Amortization in 1860.2540 at 9/30/06		273,758.15			
30	RS-2 Amortization in 1860.2540 at 6/30/06		$ 1,216,627.07			
31	Estimated RS-2 Therm Sales from 7/1 through 9/30/06	9,979,480				
32	RS-2 Amortization Rate	$ 0.00822	82,031.33			
33	Estimated RS-2 Amortization in 1860.2540 at 9/30/06		1,298,658.40			
34	GS-1 Amortization in 1860.2540 at 6/30/06		$ 714,193.87			
35	Estimated GS Therm Sales from 7/1 through 9/30/06	9,268,189				
36	GS-1 Amortization Rate	$ 0.00799	74,052.83			
37	Estimated GS-1 Amortization in 1860.2540 at 9/30/06		788,246.70			
38	Estimated Core Amortization in 1860.2540 at 9/30/06			2,360,663.25		
39	T-1 Amortization in 1860.2550 at 6/30/06		$ 94,190.25			
40	Estimated T-1 Block 1&2 Therm Sales from 7/1 through 9/30/06	4,823,806				
41	T-1 Amortization Rate	$ 0.00415	20,018.79			
42	Estimated T-1 Amortization in 1860.2550 at 9/30/06		114,209.05			
43	T-2 Amortization in 1860.2550 at 6/30/06		$ 27,039.03			
44	Estimated T-2 Contract from 7/1 through 9/30/06	165,210				
45	T-2 Amortization Rate	$ 0.05401	8,922.99			
46	Estimated T-2 Amortization in 1860.2550 at 9/30/06		35,962.02			
47	Estimated Industrial Amortization in 1860.2550 at 9/30/06			150,171.07		
48	**Estimated Balance in 1860.2530 at 9/30/06**				43,687.85	
49	**ESTIMATED ACCOUNT 1860 FIXED BALANCE AT 9/30/06**					$ (3,135,008.17)
50	**TOTAL DEFERRED ACCOUNT 1860 BALANCE**					$ 11,001,231.37

INTERMOUNTAIN GAS COMPANY
T-1 Tariff Block 1, Block 2, and Block 3 Adjustment

Line No.	Description (a)	Block 1 Therm Sales (b)	Block 2 Therm Sales (c)	Block 3 Therm Sales (d)		Total (e)
1	Industrial Therm Sales (10/1/04 - 9/30/05)	21,188,505	5,733,450	0		26,921,955
2	Blocks 1 and 2 Therm Sales	21,188,505	5,733,450			26,921,955
3	Percent Therm Sales between Blocks 1 and 2	78.703%	21.297%			100.000%
4	Proposed Adjustment to T-1 Tariff [(1)]				$	(0.00941)
5	Industrial Therm Sales (10/1/04 - 9/30/05)					26,921,955
6	Annualized Adjustment (Line 4 multiplied by Line 5)				$	(253,336)
7	Annualized Adjustment (Line 4 multiplied by Line 5)				$	(253,336)
8	Percent Annualized Sales included in Block 1					78.703%
9	Adjustment to Block 1 (Line 7 mulitplied by Line 8)				$	(199,383)
10	Block 1 Therms					21,188,505
11	Price Adjustment/Therm Block 1 (Line 9 divided by Line 10)				$	(0.00941)
12	Northwest Pipeline TF-1 Commodity Charge Change [(2)]					(0.00169)
13	Total Price Adjustment/Therm Block 1				$	(0.01110)
14	Annualized Adjustment (Line 4 multiplied by Line 5)				$	(253,336)
15	Percent Annualized Sales included in Block 2					21.297%
16	Adjustment to Block 2 (Line 14 multiplied by Line 15)				$	(53,953)
17	Block 2 Therms					5,733,450
18	Price Adjustment/Therm Block 2 (Line 16 divided by Line 17)				$	(0.00941)
19	Northwest Pipeline TF-1 Commodity Charge Change [(2)]					(0.00169)
20	Total Price Adjustment/Therm Block 2				$	(0.01110)
21	Total Price Adjustment/Therm Block 3				$	(0.00169)

[(1)] See Exhibit No. 4, Line 33, Col. (l) minus the difference of Line 22, Col. (f) minus Line 22, Col. (c)

[(2)] See Exhibit No. 4, Line 22, Col. (f) minus Line 22, Col. (c)