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January 31, 2018

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Cost of Gas Adjustment (COG)
February 2018
Case No. PU-18-010

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (143rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (143rd Revised Sheet No. 8), showing the February 2018 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$1.2660 per dk for all customers.

Attachment B shows the calculations supporting the gas costs for February 2018, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$1.2660 per dk for all customers since the last COG filing due to an increase in the market price of gas. Great Plains contracts a portion of its gas requirements based on certain index prices. In late December 2017 and early January 2018, the actual index prices applicable to those natural gas purchases were much higher than the anticipated prices included in Great Plain's Purchased Gas Cost Adjustments for December and January. Great Plains is evaluating the impact and reviewing alternatives that may be available in order to address potential impacts to customers.

Attachment C explains the reasons for the change in the market price of gas.

Attachment D shows the calculation of the balancing account since April 30, 2017.

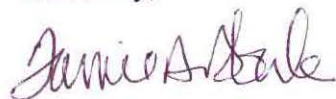
Great Plains submitted a check for \$600.00 on December 29, 2017 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with the monthly COG filings.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

If you have questions regarding this filing, please contact me at (701) 222-7856 or tamie.aberle@mdu.com

Sincerely,

A handwritten signature in purple ink that reads "Tamie A. Aberle". The signature is written in a cursive style with a large initial "T".

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2

143rd Revised Sheet No. 1.1

Canceling 142nd Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/dk
Firm Gas Service - General	2	\$3.50 per month	First 10 dk \$1.2869 Over 10 dk 1.0646	\$5.8814	\$7.1683 6.9460
Interruptible Gas Service - General	3	\$3.50 per month	First 400 dk \$1.1506 Next 2,600 dk 0.9021 Over 3,000 dk 0.7486	\$4.1925	\$5.3431 5.0946 4.9411
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All dk \$1.2516	\$4.1925	\$5.4441
Transportation Service	5	\$3.50 per month	First 400 dk \$1.1506 Next 2,600 dk 0.9021 Over 3,000 dk 0.7486		\$1.1506 0.9021 0.7486

Date Filed: January 31, 2018

Effective Date: Service rendered on and after February 1, 2018

Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Case No.: PU-18-010



GREAT PLAINS NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2
 143rd Revised Sheet No. 8
 Canceling 142nd Revised Sheet No. 8

COST OF GAS

Page 1 of 1

Summary:	Firm			Interruptible			
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	\$0.0662	\$5.1708	\$0.0000	\$5.2370	\$5.1708	\$0.0000	\$5.1708
Accumulated Adj.	1.3273	(2.3206)	0.3717	(0.6216)	(2.3206)	0.0763	(2.2443)
Current Adj.	0.0000	1.2660	0.0000	1.2660	1.2660	0.0000	1.2660
Total Adj.	1.3273	(1.0546)	0.3717	0.6444	(1.0546)	0.0763	(0.9783)
Total Rate	\$1.3935	\$4.1162	\$0.3717	\$5.8814	\$4.1162	\$0.0763	\$4.1925

Date Filed: January 31, 2018
Issued By: Tamie A. Aberle
 Director - Regulatory Affairs

Effective Date: Service rendered on and after February 1, 2018
Case No.: PU-18-010

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
PURCHASED GAS COST ADJUSTMENT
FEBRUARY 2018**

Attachment B
Page 1 of 8

	<u>Billing</u> <u>Determinants</u>	<u>Rate 1/</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per Dk</u>
<u>Viking Firm</u>					
FT-A - Zone 1-1 (Cat. 3)	8,000	\$4.3706	12	\$419,578	\$0.1371
FT-A - Zone 1-1 (Cat. 1)	5,000	4.3706	12	262,236	0.0857
FT-A Seasonal	2,000	4.3706	5	43,706	0.0143
BP Contract (Firm Demand) 3/	1,600	4.7120	5	37,696	0.0123
<u>Northern Natural Firm</u>					
TFX - Winter/Seasonal	15,000	15.1530	5	1,136,475	\$0.3714
TFX - Summer	13,000	5.6830	7	517,153	0.1690
TF12 Base - Summer	4,854	5.6830	7	\$193,097	0.0631
TF12 Base - Winter	4,854	10.2300	5	248,282	0.0811
TF12 Variable - Summer	2,681	5.6830	7	106,653	0.0349
TF12 Variable - Winter	2,681	13.8660	5	185,874	0.0608
TF5	3,410	15.1530	5	258,359	0.0844
TFX - Summer	2,000	5.6830	7	79,562	0.0260
TFX - Winter	7,200	15.1530	5	545,508	0.1783
TFX Negotiated Contract - Winter	1,000	26.8918	5	134,459	0.0439
FDD-1 Reservation	4,640	1.7140	12	95,436	0.0312
Total Demand Charges				<u>\$4,264,074</u>	<u>\$1.3935</u>
Estimated Weighted Average Commodity Cost	3,059,601 2/	4.1162		12,593,930	4.1162
Gas Cost Reconciliation Adjustment					0.3717
Total Current Firm Gas Cost				<u>\$16,858,004</u>	<u>\$5.8814</u>
Base Cost of Gas					<u>5.2370</u>
Accumulated Adjustment					<u>\$0.6444</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$4.1162
Gas Cost Reconciliation Adjustment					0.0763
Total Current Interruptible Gas Cost					<u>\$4.1925</u>
Base Cost of Gas					5.1708
Accumulated Adjustment					<u>(\$0.9783)</u>

1/ Effective February 1, 2018

2/ Annual demand volume including Minnesota.

3/ BP Contract (Firm Demand) Capacity Rate

$$\begin{array}{r}
 \$0.1550 \quad \text{Per dk} \\
 \times \quad 30.4 \quad \text{Average days in month} \\
 \hline
 \$4.7120
 \end{array}$$

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
ESTIMATED GAS COSTS
FEBRUARY 2018**

Attachment B
Page 2 of 8

	<u>Total System Supply</u>	<u>Cost per Dk</u>	<u>FDD-1 Storage</u>	<u>FDD-1 Capacity</u>	<u>SMS 1/</u>	<u>Viking Transport</u>
<u>Estimated Cost Per Dk</u>						
Commodity Cost of Gas		\$4.0696	\$2.8346			
Transportation - Northern Natural		\$0.0372	\$0.0372		\$0.0208	
Transportation - Viking						0.0129
Withdrawal Fee			0.0149			
Fuel Transportation 2/		0.0436	0.0414			
Transportation - Viking						0.0578
SMS Demand 3/		0.0139	0.0139			
LMS Demand 3/		0.0064	0.0064			
FDD-1 Capacity 4/				\$0.0202		
Total Cost Per Dk		\$4.1707	\$2.9484	\$0.0202	\$0.0208	\$0.0707
Total Estimated Dk Purchases 5/	674,950	611,662	63,288	0	0	378,279
Estimated Cost	\$2,778,233	\$2,551,059	\$186,598	\$13,634	\$198	\$26,744
Average Cost Per Dk		<u>\$4.1162</u>				

1/ Monthly requirement of 9,500 Dk.

	<u>NNG</u>	<u>Viking</u>
2/ Transportation Fuel Percentage of Field Area and Other	0.00%	0.00%
Market Area	1.06%	1.40%
Total	1.06%	1.40%

3/ Amount divided by the annual demand volume pursuant to Minnesota Rule 7825.2700 Subpart 5.

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per Dk</u>
SMS	2,500	\$2.1800	12	\$65,400	\$0.0139
LMS Demand	2,500	\$1.0000	12	\$30,000	\$0.0064

4/ Amount divided by the annual demand volume pursuant to Minnesota Rule 7825.2700 Subpart 5.

	<u>Billing Determinants</u>	<u>Rate</u>	<u>Demand Months</u>	<u>Amount</u>	<u>Amount Per Dk</u>
FDD-1 Demand Charge (Capacity Charge)	53,509	\$0.3567	5	\$95,433	\$0.0202

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
ESTIMATED GAS COSTS**

Attachment B
Page 3 of 8

5/ Dk requirements for February	<u>Required Monthly</u>	<u>Days in Month</u>	<u>Required Daily</u>	<u>Percent Supply</u>
Estimated Dk Purchases	611,662	28	21,845	91%
Storage Gas	63,288	28	2,260	9%
Total Dk Requirements	<u>674,950</u>		<u>24,105</u>	100%
	<u>NNG</u>	<u>Viking</u>		
<u>Transportation Fuel</u>				
Dk	611,662 ✓	378,279 ✓		
Adjusted for Fuel Dk	618,215	383,650		
Fuel Costs	\$26,668	\$21,858		
Fuel Cost Per Dk	\$0.0436	\$0.0578		
<u>Storage Fuel</u>				
Dk	63,288 ✓			
Adjusted for Fuel Dk	64,213			
Fuel Costs	\$2,622			
Fuel Cost Per Dk	\$0.0414			

STATEMENT OF RATES
 (Rates Per Dekatherm)

Attachment B
 Page 4 of 8

Currently Effective Term-Differentiated Rates

Rate Schedule	Base Tariff Rate
<u>Category 1 (Contract Term of Less than 3 Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$4.7507
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate 1/	\$5.7394
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$3.3143
Zone 2-2 Minimum Rate	\$0.0000
<u>Category 2 (Contract Term of 3 Years to less than 5 Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$4.5607
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$5.5494
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$3.1243
Zone 2-2 Minimum Rate	\$0.0000
<u>Category 3 (Contract Term of 5 or more Years)</u>	
Monthly Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	\$4.3706
Zone 1-1 Minimum Rate	\$0.0000
Zone 1-2 Maximum Rate	\$5.3593
Zone 1-2 Minimum Rate	\$0.0000
Zone 2-2 Maximum Rate	\$2.9343
Zone 2-2 Minimum Rate	\$0.0000

1/ Throughout Viking's Statement of Rates and Tariff, "Zone 1-2" shall mean Transportation Service for quantities received in Zone 1 and delivered in Zone 2 or received in Zone 2 and delivered in Zone 1 whether by transport, exchange, or Displacement.

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	\$0.0116	1.40%
Zone 1-2	\$0.0116	1.65%
Zone 2-2	\$0.0116	0.25%
Minimum Rate	\$0.0116	
IT and AOT		
Zone 1-1	\$0.1678	1.40%
Zone 1-2	\$0.2003	1.65%
Zone 2-2	\$0.1206	0.25%
Minimum Rate	\$0.0116	

- 1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at <http://www.ferc.gov>.
- 2/ The Fuel and Loss Retention Percentages shall be applicable to all transportation rate schedules and includes the following Gas Lost and Unaccounted For Percentages: 0.00% for Zone 1-1, 0.00% for Zone 1-2, and 0.00% for Zone 2-2. Transportation entirely by Displacement will incur only the Gas Lost and Unaccounted For Percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	\$1.00		\$1.00
LMS – Daily Overrun Rate	\$0.2003		\$0.2003
LMS – Load Management Cost Reconciliation Adjustment		(\$0.0051)	

- 1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

Rate Schedule	Maximum Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	\$0.2003	\$0.0000
RPL Service:		
Daily Reservation Rate	\$0.2003	\$0.0000

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12		TF5	TFE
	TF12 Base	Variable		
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/		Market Area 3/ 6/		Field Mileage 5/		Carlton Surcharges 4/		Out-of-Balance 3/	
TF12 Base	TF12 Var., TF5 & TFE	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

- 1/ The minimum reservation rate is equal to zero.
- 2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the maximum Field Area throughput commodity rates for any transaction involving MIDs.
- 3/ The Maximum and Minimum rates include the Market Area Electric Compression charge of \$0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where applicable, the Field Area Electric Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.
- 6/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.

RATE SCHEDULES TFX and LFT

RESERVATION RATES		MARKET-TO-MARKET		FIELD-TO-FIELD					
		Apr-Oct	Nov-Mar	Apr-Oct	Nov-Mar	Apr-Oct	Nov-Mar		
Base Tariff Rates 1/		\$5.683	\$15.153	\$5.473	\$9.853				

COMMODITY RATES 2/ TFX and LFT		Market Area 3/ 7/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0359	0.0190			0.0175	0.0000	0.0359	0.0190
Field	Market	0.0359	0.0190	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

GULF COAST		Reservation 1/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Other Gulf Coast		4.8169	0.0000	0.0000	0.0000	0.0000	0.0000

- 1/ The minimum reservation rate is equal to zero.
- 2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the maximum Field Area throughput commodity rates for any transaction involving MIDs.
- 3/ The Maximum and Minimum rates include the Market Area Electric Compression charge of \$0.0000 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where applicable, the Field Area Compression charge of \$0.0000 and the ACA unit surcharge as set forth on FERC's website at <http://www.ferc.gov> will be added to the mileage based rates.
- 6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at <http://www.ferc.gov>.
- 7/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	<u>Percentages</u>
FUEL PERCENTAGES:	1/ 7/
Market Area (including Out-of-Balance)	0.87%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.19% 4/ 5/ 7/
FDD Storage Fuel	1.44%

	<u>Electric Compression</u>
COMMODITY RATES:	1/ 7/
Market Area	\$0.0000
Field Area	\$0.0000

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2016. For deliveries subject only to UAF, if the above UAF rate is negative, the UAF rate is zero; provided, however Northern will issue a volume credit on the Shipper's monthly imbalance statement equivalent to the negative Unaccounted For Percentage for such deliveries during the period in which the UAF rate is less than zero.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

7/ There will be no fuel, electric compression or UAF charges for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no fuel, electric compression or UAF charges for transportation as set forth in Sheet Nos. 141, 142C and 147.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
February 2018**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published at the beginning of each month.

The February monthly price for the NNG-Ventura Index is expected to increase significantly from the previous month's index. Periods of cold weather have increased demand throughout the United States. Furthermore; national storage levels have continued to fall at a record pace since the final days of December 2017. The EIA reported nationwide storage levels as of January 19, 2018 at 17.5 percent below the five-year average and 18.4 percent below last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: <http://www.eia.doe.gov>.

**GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM**

	(Over) Under Recovery	Refunds & Other	Interest 1/	Total Net Additions	Actual Dk Sales	Adjustment Per Dk	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2017									<u>\$106,098</u>
May 2017	(\$4,276)	\$0	\$45	(\$4,231)	16,178	\$0.1086	\$1,757	(\$5,988)	100,110
June	2,652	0	47	2,699	9,545	0.3717	1,760 2/	939	101,049
July	12,995	0	52	13,047	5,723	0.3717	2,127	10,920	111,969
August	21,473	0	55	21,528	6,045	0.3717	2,247	19,281	131,250
September	344	0	66	410	5,627	0.3717	2,092	(1,682)	129,568
October	6,138	0	68	6,206	8,076	0.3717	3,002	3,204	132,772
November	3,212	0	80	3,292	20,484	0.3717	7,614	(4,322)	128,450
December	38,727	0	83	38,810	36,968	0.3717	13,741	25,069	153,519
Total	<u>\$81,265</u>	<u>\$0</u>	<u>\$496</u>	<u>\$81,761</u>	<u>108,646</u>		<u>\$34,340</u>	<u>\$47,421</u>	
Balance @ December 31, 2017									<u>\$153,519</u>

1/ Interest calculated at the 3 Month Treasury Bill Rate.

2/ Reflects 6,795.0 dk @ \$0.1086 and 2,750.2 dk @ \$0.3717.

**GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	<u>(Over) Under Recovery</u>	<u>Refunds & Other</u>	<u>Interest 1/</u>	<u>Total Net Additions</u>	<u>Actual Dk Sales</u>	<u>Adjustment Per Dk</u>	<u>Total Adjustment Amount</u>	<u>Net Change- Additions less Adjustment</u>	<u>Cumulative Balance</u>
Balance @ April 30, 2017									<u>\$54,406</u>
May 2017	(\$17,828)	\$0	\$23	(\$17,805)	79,689	(\$0.2861)	(\$22,799)	\$4,994	59,400
June	(66,080)	0	28	(66,052)	78,654	0.0763	(16,397) 2/	(49,655)	9,745
July	(5,428)	0	1	(5,427)	25,157	0.0763	1,919	(7,346)	2,399
August	(4,244)	0	(3)	(4,247)	64,510	0.0763	4,922	(9,169)	(6,770)
September	(69,431)	0	(8)	(69,439)	33,125	0.0763	2,527	(71,966)	(78,736)
October	313	0	(50)	263	16,118	0.0763	1,230	(967)	(79,703)
November	572	0	(58)	514	35,727	0.0763	2,726	(2,212)	(81,915)
December	48,855	0	(64)	48,791	77,834	0.0763	5,939	42,852	(39,063)
Total	<u>(\$113,271)</u>	<u>\$0</u>	<u>(\$131)</u>	<u>(\$113,402)</u>	<u>410,814</u>		<u>(\$19,933)</u>	<u>(\$93,469)</u>	<u>(\$39,063)</u>

1/ Interest calculated at the 3 Month Treasury Bill Rate.

2/ Reflects 61,806.8 dk @ (\$0.2861) and 16,847.3 dk @ \$0.0763.