GREAT PLAINS
NATURAL GAS CO.
A Division of Montana-Dakota Utilities Co.

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August 29, 2019

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: Annual Report; Automatic Adjustment
Docket No. E, G999/AA-19-___

Dear Mr. Wolf:

Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota Utilities Co., herewith electronically submits its Annual Report of Automatic Adjustment of Gas Charges (AAA), pursuant to Minnesota Rule 7825.2800 – 7825.2830.

In support of the filing Great Plains has attached the following:

Exhibit A – Summary of Gas Costs Recovered
Degree Day and Volume Information
Exhibit B – Independent Auditor's Report reviewing the accounting procedures of Great Plains' purchased gas adjustment
Exhibit C – Schedule of Contractor Main Strikes
Exhibit D – Meter Testing Updates
Exhibit E – Curtailment and Penalties

If you have any questions regarding this filing, please contact me at (701) 222-7856, or Brian M. Meloy, at (612) 335-1451.

Sincerely,

/s/ *Tamie. A. Aberle*

Tamie A. Aberle
Director of Regulatory Affairs

cc: Brian M. Meloy

GREAT PLAINS NATURAL GAS CO.
AUTOMATIC PURCHASED GAS ADJUSTMENT REPORT
MINNESOTA RULE 7825.2800 - 7825.2830
FOR THE TWELVE MONTHS ENDING JUNE 30, 2019

Procurement Policy (7825.2800)

Great Plains Natural Gas Co.'s (Great Plains) distribution system is served by the Viking Gas Transmission Company (VGT) pipeline and the Northern Natural Gas Company (NNG) pipeline. The following is a summary of Great Plains' firm gas entitlement contracts in effect for the 2018-2019 heating season, which were reported in the Informational Update Filing on Great Plains' 2018 Demand Entitlement Filing (DEQ) in Docket No. G004/M-18-454 on October 31, 2018.

Supplier	Contract Type	Units	Expires
NNG	TF12 (Base & Variable)	7,535 dk/Day	10/31/19
NNG	TF5 (Seasonal)	3,410 dk/Day	10/31/19
NNG	TFX (Seasonal)	5,200 dk/Day	10/31/19
NNG	TFX (Negotiated)	1,000 dk/Day	3/31/25
NNG	TFX (Annual)	2,000 dk/Day	10/31/25
NNG	TFX (Annual)	13,000 dk/Day	3/31/24
NNG	TFX (Seasonal)	2,000 dk/Day	10/31/19
VGT	FT-A	8,000 dk/Day	10/31/22
VGT	FT-A	5,000 dk/Day	10/31/22
VGT	FT-A	5,000 dk/Day	10/31/23
VGT	FT-A (Seasonal)	2,000 dk/Day	10/31/22

Great Plains provides service to 18 communities located in western Minnesota and one community in eastern North Dakota. To meet its design day delivery obligation, Great Plains utilizes pipeline capacity on both VGT and NNG pipelines.

To serve customers connected to VGT, Great Plains delivers natural gas to city gates connected to VGT using a combination of two options. The first option is to deliver gas from the Ventura market area on NNG to Chisago, which serves as an interconnect between NNG and VGT. The second option is to purchase gas at VGT's Emerson location and deliver gas directly to VGT city gates.

To deliver gas from the Ventura market area, Great Plains utilizes 13,000 dk/day of annual capacity on a NNG TFX contract and 2,000 dk/day of seasonal capacity on a NNG TFX contract. These contracts deliver natural gas to Chisago. This gas is subsequently transported from Chisago to VGT city gates using corresponding VGT capacity of 13,000 dk/day of annual capacity and 2,000 dk/day of seasonal capacity.

Additionally, Great Plains may purchase natural gas at VGT's Emerson receipt location and deliver to city gates interconnecting with VGT. To transport this, Great Plains may use either (1) 5,000 dk/day of annual capacity incremental to the capacity stated in the preceding paragraph or (2) up to 5,000 dk/day of the previously mentioned 13,000 dk/day of annual VGT capacity.

Great Plains has a total of 19,145 dk per day of firm transportation capacity on NNG to meet its southwestern Minnesota design day delivery requirements. Although this amount of capacity exceeds current requirements, Great Plains continues to believe it will require this amount of capacity in the future and the opportunity to own contract capacity at present is more economical than future construction.

Great Plains also utilizes NNG's firm storage service. This service enables Great Plains to purchase gas during the summer months, when gas has historically been cheaper, for winter withdrawal. In addition to this service being an additional firm source of supply during the heating season, another benefit of this storage service is for real time nominations, whereby storage can be nominated on a 4-hour notice, which minimizes potential penalty situations.

Great Plains has contracted for 2,500 dk per day of VGT's Load Management Service (LMS) and 2,500 dk per day of NNG's System Management Service (SMS) to cover daily delivery variances. These variances may be caused by fluctuations from temperature forecasting or customer consumption changes.

Gas supply is contracted on a seasonal basis from suppliers on a least cost and demonstrated delivery reliability basis.

<u>Dispatching Policy (7825.2800)</u>

Great Plains continues to use telemetry and computer systems to monitor its pipeline deliveries. This has allowed the Company to minimize the use of daily contracts and minimize associated demand contract charges from suppliers.

<u>Actions to Minimize Cost (7825.2800)</u>

Company personnel continuously monitor the industry markets to insure its procurement policies will minimize gas costs without jeopardizing the Company's responsibility to deliver. Great Plains will continue to evaluate its gas supply portfolio to provide its firm customers with reliable gas supply on a best cost basis to ensure its procurement policies will minimize gas costs without jeopardizing the Company's responsibility to deliver.

Great Plains actively participates with a group of regional utility companies and municipalities on issues related to NNG. This group exists specifically to review and intervene in FERC matters that affect the cost of gas to the Company's service area.

Conservation (7825.2800)

On November 3, 2016, the Department approved Great Plains' 2017-2019 Triennial Energy Conservation Improvement Program (CIP) Plan in Docket No. G004/CIP-16-121 with a budget of $885,396 in 2017 increasing to $902,858 in 2019 and with associated dk savings of 56,904 dk in 2017 rising to 57,307 dk in 2019.

Similar to prior CIP plans, the Great Plains 2017-2019 Triennial CIP Plan includes programs applicable to residential, as well as commercial and industrial customers. In addition, the plan provides funding assistance to eligible low-income participants for weatherization and the emergency replacement or tune-up of a furnace or boiler. The 2017-2019 Triennial CIP Plan also offers a water heater temperature set-back program to eligible low-income participants.

Purchased Gas Adjustment Rule Variances (7825.2810 subpart 2(A))

Great Plains did not request a variance from the purchased gas adjustment rules for the twelve months ending June 30, 2019.

Level of Customer-owned Gas Volumes (7825.2810 subpart 2(C))

Great Plains transported 4,352,702 dk for Minnesota end-use customers on its distribution system for the twelve months ending June 30, 2019.

Explanation of Over/Under Recoveries (7825.2810 subpart 2(D))

The total (over)under recovery for Minnesota for the twelve months ending June 30, 2019 was:

Recovered Costs	Actual Costs	(Over)Under Recovery	% of Actual
$18,701,798	$18,070,263	($631,535)	3.49%

Pipeline demand charges were over-recovered by $369,867 or 9.37 percent due to the following:

- Great Plains recovers demand costs on a volumetric basis, while costs are assessed on a fixed monthly basis. Generally, demand costs are under-recovered during the summer months, when firm sales volumes are low and over-recovered during the winter months when sales volumes are high.

- Weather was 15.58 percent colder than normal for the twelve months ending June 30, 2018. Please see Exhibit A, page 5 for a monthly degree day analysis.

The commodity components of the PGA were over-recovered by $261,668 or 1.85 percent due to timing differences between the cost of gas recovered in rates and the actual gas costs.

The calculation of the GCR and details of each of the components of demand and commodity by month are included in Exhibit A.

Impact of Market Forces on Gas Costs (7825.2830)

Continued increases to domestic production have resulted in a low natural gas price environment this summer. While natural gas-fired generation has increased demand, both regionally and throughout the US, these continued production increases have allowed storage levels to rise significantly over last year's levels and return to near the five-year average.

Great Plains is on track to fill its storage level prior to the beginning of the upcoming heating season. The increases to domestic production are forecasted to keep the commodity cost of gas in the $2.50 - $3.00 range given average regional weather which should provide supply stability, thus keeping the price of natural gas from increasing significantly. Great Plains has and will continue to minimize its exposure to these short-term pricing spikes through its strategy of securing a majority of its monthly supply needs on a fixed or first-of-the-month index pricing.

The continuing shift of electric generation from coal to natural gas and new generation fueled by natural gas may result in higher natural gas prices in the longer term.

Contractor Main Strikes

Pursuant to the Order in Docket No. G-999/AA-10-885, the total cost of lost gas due to main strikes of $1,248 was credited to the cost of gas prior to the determination of the cost of gas charged to the customer classes. Therefore, there is not an amount allocated to firm and interruptible customers in this GCR. See Exhibit C for Great Plains' Contractor Main Strike information.

Meter Testing Updates

Great Plains' meter testing plan is set forth in Section 7 of its Gas Distribution Standards as originally submitted on June 4, 2012 in Docket No. E,G999/AA-10-885. Several minor modifications were made to the Gas Meter Testing Section of the Gas Distribution Standards in 2013, which were reported in an update to Docket No. G999/AA-14-580. Section 7 was again revised in 2015, however, the revisions did not affect the meter testing plan.

Section 7 of the Gas Distribution Standards was updated in 2016 to remove the reference to mechanical correcting indexes on Page 15, along with a clarifying change in the title of this section to "Indexes and Electronic Correctors."

The Gas Distribution Standards were again revised in 2018 and 2019. However, there were no updates regarding meter testing to Section 7 of the Gas Distribution Standards.

Great Plains continues to test meters based on random sampling of new and installed meters along with testing the large capacity meters on a periodic basis. See Exhibit D for Section 7 of the Gas Distribution Standards related to testing gas meters.

Curtailment Requirements and Penalties

Pursuant to the Order in Docket No. G999/AA-17-493, regulated natural gas utilities shall provide information on unauthorized gas use for each customer that did not comply with a called interruption(s) during the heating season. See Exhibit E for Great Plains' curtailment activities.

GREAT PLAINS NATURAL GAS CO.
SUMMARY OF (OVER) UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2019
MINNESOTA SYSTEM

	Recovered Costs	Actual Costs	(Over)Under Recovery	% of Actual
Firm	$14,957,122	$14,449,540	($507,582)	3.51%
Interruptible	3,744,676	3,620,723	(123,953)	3.42%
Total	$18,701,798	$18,070,263	($631,535)	3.49%

	Beginning Balance	(Over) Under Recovery	GCR Recovery	Ending Balance
Firm	$1,285,788	($507,582)	($1,418,445)	($640,239)
Interruptible	413,160	(123,953)	(395,581)	(106,374)
Total	$1,698,948	($631,535)	($1,814,026)	($746,613)

Cost recovery by class and component:	Recovered Costs	Actual Costs	(Over)Under Recovery	% of Actual
Firm				
Viking Gas Transmission:				
FT-A - Zone 1-1 (Cat. 3)	$410,555	$394,713	($15,842)	4.01%
FT-A - Zone 1-1 (Cat. 3)	256,666	234,658	(22,008)	9.38%
FT-A - Zone 1-1 (Cat. 3)	224,525	139,025	(85,500)	61.50%
FT-A Seasonal	42,731	39,656	(3,075)	7.75%
BP Contract (Firm Demand)	4,602	0	(4,602)	
FT-A - Capacity Release	(23,787)	(23,140)	647	2.80%
FT-A - Capacity Release	(1,509)	(10,289)	(8,780)	85.33%
Northern Natural Gas:				
TFX - Winter/Seasonal	1,111,860	1,031,162	(80,698)	7.83%
TFX - Summer	505,876	458,151	(47,725)	10.42%
TF12 Base - Summer	153,562	160,330	6,768	4.22%
TF12 Base - Winter	197,700	177,241	(20,459)	11.54%
TF12 Variable - Summer	139,576	105,220	(34,356)	32.65%
TF12 Variable - Winter	243,144	233,757	(9,387)	4.02%
TF5	252,781	234,418	(18,363)	7.83%
TFX - Summer	77,691	70,485	(7,206)	10.22%
TFX - Winter	533,667	494,958	(38,709)	7.82%
TFX Negotiated Contract - Winter	131,476	121,999	(9,477)	7.77%
FDD-1 Reservation	93,232	85,399	(7,833)	9.17%
Interruptible Demand Credit	(381,528)	(344,790)	36,738	10.66%
Total Demand Costs	$3,972,820	$3,602,953	($369,867)	10.27%
Commodity Costs	10,984,302	10,846,587	(137,715)	1.27%
Total Firm Gas Costs	$14,957,122	$14,449,540	($507,582)	3.51%
Interruptible				
Commodity Costs	$3,399,886	$3,275,933	($123,953)	3.78%
Interruptible Demand Charge	344,790	344,790	0	0.00%
Total Interruptible Gas Costs	$3,744,676	$3,620,723	($123,953)	3.42%
Total Gas Costs	$18,701,798	$18,070,263	($631,535)	3.49%

GREAT PLAINS NATURAL GAS CO.
ANALYSIS OF (OVER)/UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2019
MINNESOTA SYSTEM - FIRM

Description	Beginning Balance	July	August	September	October	November	December	January	February	March	April	May	June	Ending Balance
Recovered through PGA:														
FT-A - Zone 1-1 (Cat. 3)		$5,524	$5,816	$5,496	$14,908	$31,474	$54,205	$63,805	$77,257	$70,731	$43,916	$25,221	$12,202	$410,555
FT-A - Zone 1-1 (Cat. 3)		3,453	3,636	3,436	9,320	19,677	33,888	39,889	48,300	44,220	27,456	15,766	7,625	256,666
FT-A - Zone 1-1 (Cat. 3)						7,381	33,888	39,889	48,300	44,220	27,456	15,766	7,625	224,525
FT-A Seasonal		575	605	572	1,552	3,276	5,641	6,641	8,040	7,361	4,571	2,626	1,271	42,731
BP Contract (Firm Demand)		494	520	492	1,335	1,761	-	-	-	-	-	-	-	4,602
FT-A - Capacity Release						(782)	(3,590)	(4,226)	(5,117)	(4,684)	(2,909)	(1,671)	(808)	(23,787)
FT-A - Capacity Release												(584)	(925)	(1,509)
TFX - Winter/Seasonal		14,965	15,749	14,882	40,375	85,237	146,793	172,793	209,225	191,551	118,933	68,307	33,050	1,111,860
TFX - Summer		6,807	7,166	6,771	18,369	38,781	66,789	78,618	95,194	87,153	54,113	31,078	15,037	505,876
TF12 Base - Summer		2,541	2,675	2,528	6,858	13,317	19,606	23,079	27,946	25,584	15,886	9,125	4,417	153,562
TF12 Base - Winter		3,269	3,441	3,251	8,821	17,137	25,248	29,720	35,986	32,946	20,456	11,746	5,679	197,700
TF12 Variable - Summer		1,403	1,477	1,396	3,787	9,155	19,094	22,476	27,215	24,915	15,470	8,886	4,302	139,576
TF12 Variable - Winter		2,448	2,577	2,436	6,608	15,961	33,257	39,146	47,401	43,396	26,944	15,478	7,492	243,144
TF5		3,401	3,581	3,383	9,180	19,380	33,375	39,285	47,569	43,550	27,040	15,527	7,510	252,781
TFX - Summer		1,045	1,101	1,040	2,821	5,956	10,257	12,074	14,619	13,384	8,310	4,774	2,310	77,691
TFX - Winter		7,181	7,559	7,143	19,379	40,912	70,457	82,937	100,424	91,940	57,085	32,786	15,864	533,667
TFX Negotiated Contract - Winter		1,769	1,862	1,759	4,774	10,079	17,358	20,432	24,741	22,650	14,063	8,078	3,911	131,476
FDD-1 Reservation		1,254	1,320	1,248	3,386	7,147	12,309	14,489	17,544	16,061	9,972	5,729	2,773	93,232
Interruptible Demand Credit		(5,058)	(5,325)	(5,031)	(13,650)	(29,006)	(50,495)	(59,439)	(71,973)	(65,892)	(40,911)	(23,451)	(11,297)	(381,528)
Total Demand Cost		$51,071	$53,760	$50,802	$137,823	$296,843	$528,080	$621,608	$752,671	$689,086	$427,851	$245,187	$118,038	$3,972,820
Commodity Cost		108,479	116,428	112,581	315,553	764,203	1,642,968	2,066,228	2,229,497	1,930,785	995,611	483,630	218,339	10,984,302
Total Recovered Through PGA		$159,550	$170,188	$163,383	$453,376	$1,061,046	$2,171,048	$2,687,836	$2,982,168	$2,619,871	$1,423,462	$728,817	$336,377	$14,957,122
GCR Adjustment		7,028	7,398	11,618	52,722	111,305	191,688	225,638	273,213	250,133	155,307	89,213	43,182	1,418,445
Total Recovered		$166,578	$177,586	$175,001	$506,098	$1,172,351	$2,362,736	$2,913,474	$3,255,381	$2,870,004	$1,578,769	$818,030	$379,559	$16,375,567
Actual Cost of Gas:														
FT-A - Zone 1-1 (Cat. 3)		$33,225	$37,624	$36,855	$29,203	40,384	$14,303	$43,410	$48,452	$34,384	$31,770	$23,104	$21,999	$394,713
FT-A - Zone 1-1 (Cat. 3)		25,182	19,289	14,643	22,598	17,861	23,177	18,109	17,998	19,255	17,053	20,612	18,881	234,658
FT-A - Zone 1-1 (Cat. 3)						3,941	23,177	18,109	17,998	19,255	17,053	20,612	18,880	139,025
FT-A Seasonal						1,576	9,271	7,244	7,199	7,702	6,664			39,656
BP Contract (Firm Demand)														0
FT-A - Capacity Release						(999)	(5,873)	(4,589)	(4,561)	(4,880)	(2,238)			(23,140)
FT-A - Capacity Release											(2,066)	(4,292)	(3,931)	(10,289)
TFX - Winter/Seasonal						40,990	241,064	188,354	187,194	200,273	173,287			1,031,162
TFX - Summer		85,135	65,212	49,505	76,398	47,060					1,327	69,682	63,832	458,151
TF12 Base - Summer		31,786	24,349	18,484	28,526	17,572					390	20,471	18,752	160,330
TF12 Base - Winter						7,046	41,435	32,375	32,176	34,424	29,785			177,241
TF12 Variable - Summer		17,558	13,449	10,209	15,756	9,705					379	19,918	18,246	105,220
TF12 Variable - Winter						9,292	54,647	42,699	42,436	45,400	39,283			233,757
TF5						9,318	54,802	42,819	42,556	45,529	39,394			234,418
TFX - Summer		13,098	10,033	7,616	11,754	7,240					204	10,720	9,820	70,485
TFX - Winter						19,676	115,710	90,410	89,853	96,131	83,178			494,958
TFX Negotiated Contract - Winter						4,849	28,521	22,285	22,147	23,695	20,502			121,999
FDD-1 Reservation		9,165	7,020	5,329	8,224	6,501	8,435	6,590	6,550	7,007	6,206	7,501	6,871	85,399
Interruptible Demand Credit		(16,605)	(17,499)	(16,845)	(23,858)	(56,171)	(44,249)	(33,480)	(31,101)	(32,344)	(31,544)	(22,935)	(18,159)	(344,790)
Total Demand Cost		$198,544	$159,477	$125,796	$168,601	$185,841	$564,420	$474,335	$478,897	$495,831	$430,627	$165,393	$155,191	$3,602,953
Commodity Cost		107,869	117,625	77,487	318,014	750,780	1,662,627	1,968,299	2,208,932	1,779,117	1,201,072	462,852	191,913	10,846,587
Total Actual Gas Costs		$306,413	$277,102	$203,283	$486,615	$936,621	$2,227,047	$2,442,634	$2,687,829	$2,274,948	$1,631,699	$628,245	$347,104	$14,449,540
Total (Over)Under Recoveries		$139,835	$99,516	$28,282	($19,483)	($235,730)	($135,689)	($470,840)	($567,552)	($595,056)	$52,930	($189,785)	($32,455)	($1,926,027)
Cumulative Balance	$1,285,788	$1,425,623	$1,525,139	$1,553,421	$1,533,938	$1,298,208	$1,162,519	$691,679	$124,127	($470,929)	($417,999)	($607,784)	($640,239)	($640,239)

GREAT PLAINS NATURAL GAS CO.
ANALYSIS OF (OVER)/UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2019
MINNESOTA SYSTEM - INTERRUPTIBLE

Description	Beginning Balance	July	August	September	October	November	December	January	February	March	April	May	June	Total
Recovered thru PGA:														
Commodity Cost		$131,970	$141,654	$139,718	$202,724	$520,168	$514,819	$439,990	$356,787	$357,840	$288,405	$175,942	$129,869	$3,399,886
Interruptible Demand Charge		16,605	17,499	16,845	23,858	56,171	44,249	33,480	31,101	32,344	31,544	22,935	18,159	344,790
Total		$148,575	$159,153	$156,563	$226,582	$576,339	$559,068	$473,470	$387,888	$390,184	$319,949	$198,877	$148,028	$3,744,676
GCR Adjustment		(3,290)	(3,466)	4,772	32,700	76,761	59,575	45,075	41,873	43,546	42,470	30,941	24,624	395,581
Total Recovered		$145,285	$155,687	$161,335	$259,282	$653,100	$618,643	$518,545	$429,761	$433,730	$362,419	$229,818	$172,652	$4,140,257
Actual Cost of Gas:														
Commodity Cost of Gas		$131,805	$143,261	$119,334	$201,291	$557,584	$523,930	$406,876	$325,388	$345,228	$255,388	$150,145	$115,703	$3,275,933
Interruptible Demand Charge		16,605	17,499	16,845	23,858	56,171	44,249	33,480	31,101	32,344	31,544	22,935	18,159	344,790
Total Actual Gas Costs		$148,410	$160,760	$136,179	$225,149	$613,755	$568,179	$440,356	$356,489	$377,572	$286,932	$173,080	$133,862	$3,620,723
Current Month Under/(Over) Recovery		$3,125	$5,073	($25,156)	($34,133)	($39,345)	($50,464)	($78,189)	($73,272)	($56,158)	($75,487)	($56,738)	($38,790)	($519,534)
Cumulative Balance	$413,160	$416,285	$421,358	$396,202	$362,069	$322,724	$272,260	$194,071	$120,799	$64,641	($10,846)	($67,584)	($106,374)	($106,374)

GREAT PLAINS NATURAL GAS CO.
ANALYSIS OF (OVER)/UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2019
MINNESOTA SYSTEM

RATES AND COSTS	June	July	August	September	October	November	December	January	February	March	April	May	June	Total
Rates Utilized in PGA (per dk)														
Viking Gas Transmission:														
FT-A - Zone 1-1 (Cat. 3)	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1374	$0.1373	$0.1373	
FT-A - Zone 1-1 (Cat. 3)	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0858	0.0858	
FT-A - Zone 1-1 (Cat. 3)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0859	0.0859	0.0859	0.0859	0.0859	0.0859	0.0858	0.0858	
FT-A Seasonal	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	
BP Contract (Firm Demand)	0.0123	0.0123	0.0123	0.0123	0.0123	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
FT-A - Capacity Release	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0091)	(0.0091)	(0.0091)	(0.0091)	(0.0091)	(0.0091)	(0.0091)	(0.0091)	
FT-A - Capacity Release	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0104)	(0.0104)	
Northern Natural Gas:														
TFX - Winter/Seasonal	0.3721	0.3721	0.3721	0.3721	0.3721	0.3721	0.3721	0.3721	0.3721	0.3721	0.3721	0.3719	0.3719	
TFX - Summer	0.1693	0.1693	0.1693	0.1693	0.1693	0.1693	0.1693	0.1693	0.1693	0.1693	0.1693	0.1692	0.1692	
TF12 Base - Summer	0.0632	0.0632	0.0632	0.0632	0.0632	0.0497	0.0497	0.0497	0.0497	0.0497	0.0497	0.0497	0.0497	
TF12 Base - Winter	0.0813	0.0813	0.0813	0.0813	0.0813	0.0640	0.0640	0.0640	0.0640	0.0640	0.0640	0.0639	0.0639	
TF12 Variable - Summer	0.0349	0.0349	0.0349	0.0349	0.0349	0.0484	0.0484	0.0484	0.0484	0.0484	0.0484	0.0484	0.0484	
TF12 Variable - Winter	0.0609	0.0609	0.0609	0.0609	0.0609	0.0843	0.0843	0.0843	0.0843	0.0843	0.0843	0.0843	0.0843	
TF5	0.0846	0.0846	0.0846	0.0846	0.0846	0.0846	0.0846	0.0846	0.0846	0.0846	0.0846	0.0845	0.0845	
TFX - Summer	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	
TFX - Winter	0.1786	0.1786	0.1786	0.1786	0.1786	0.1786	0.1786	0.1786	0.1786	0.1786	0.1786	0.1785	0.1785	
TFX Negotiated Contract - Winter	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	
FDD-1 Reservation	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	
TFX - Capacity Release	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
TF12 - Capacity Release	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Interruptible Demand Credit	(0.1258)	(0.1258)	(0.1258)	(0.1258)	(0.1258)	(0.1280)	(0.1280)	(0.1280)	(0.1280)	(0.1280)	(0.1280)	(0.1271)	(0.1271)	
Total Recovered in PGA per dk:		$1.2702	$1.2702	$1.2702	$1.2702	$1.3386	$1.3386	$1.3386	$1.3386	$1.3386	$1.3386	$1.3282	$1.3282	
Interruptible Demand Charge	$0.3392	$0.3392	$0.3392	$0.3392	$0.3392	$0.3453	$0.3453	$0.3453	$0.3453	$0.3453	$0.3453	$0.3428	$0.3428	
Weighted Avg. Commodity:	$2.6869	$2.7191	$2.8060	$2.8300	$3.0041	$3.8892	$4.7292	$3.9536	$3.9871	$3.2662	$2.7276	$2.4218	$2.5395	
GCR Adjustment														
Firm	$0.1748	$0.1748	$0.1748	$0.4859	$0.4859	$0.4859	$0.4859	$0.4859	$0.4859	$0.4859	$0.4859	$0.4859	$0.4859	
Interruptible	(0.0672)	(0.0672)	(0.0672)	0.4649	0.4649	0.4649	0.4649	0.4649	0.4649	0.4649	0.4649	0.4649	0.4649	
Billed Dk Sales														
Firm		40,205.9	42,324.7	39,994.5	108,504.2	229,069.1	394,499.9	464,371.1	562,282.4	514,782.4	319,626.7	183,603.9	88,872.7	2,988,137.5
Interruptible		48,954.6	51,589.1	49,662.3	70,336.8	165,112.0	128,145.7	96,957.3	90,069.5	93,667.6	91,353.3	66,554.5	52,966.9	1,005,369.6
Total Dk		89,160.5	93,913.8	89,656.8	178,841.0	394,181.1	522,645.6	561,328.4	652,351.9	608,450.0	410,980.0	250,158.4	141,839.6	3,993,507.1
% Firm to Total dk Sales		45.09%	45.07%	44.61%	60.67%	58.11%	75.48%	82.73%	86.19%	84.61%	77.77%	73.40%	62.66%	74.82%
% Interruptible to Total dk Sales		54.91%	54.93%	55.39%	39.33%	41.89%	24.52%	17.27%	13.81%	15.39%	22.23%	26.60%	37.34%	25.18%

**GREAT PLAINS NATURAL GAS CO.
ANNUAL REPORT OF AUTOMATIC ADJUSTMENT
DEGREE DAY AND VOLUME ANALYSIS
MINNESOTA**

	Weighted Average Degree Days			Percent
	Normal	Actual	Difference	(Warmer)/Colder
July 2018	0	0	0	0.00%
August	0	2	2	0.00%
September	7	19	12	171.43%
October	151	304	153	101.32%
November	658	806	148	22.49%
December	1,055	1,096	41	3.89%
January 2019	1,402	1,242	(160)	-11.41%
February	1,422	1,743	321	22.57%
March	1,063	1,380	317	29.82%
April	718	781	63	8.77%
May	333	416	83	24.92%
June 2019	32	118	86	268.75%
Total	6,841	7,907	1,066	15.58%

	Authorized Volumes 1/	Actual Dk	Dk Difference	% Difference
Volumes	2,771,045.0	2,988,137.5	217,092.5	7.83%

1/ Authorized Residential and Firm General volumes per Docket Nos. G004/GR-15-879 and G004/MR-16-834.

Exhibit B

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INDEPENDENT ACCOUNTANTS' REPORT

To the Managing Committee of
Great Plains Natural Gas Co.:

We have examined the accompanying Schedule of Automatic Adjustment Clause for the Purchased Gas Cost (the "Schedule") included in the monthly filings of Great Plains Natural Gas Co. (the "Company"), a division of Montana-Dakota Utilities Co., a subsidiary of MDU Resources Group Inc., for the twelve-month period from July 1, 2018 to June 30, 2019. The Company's management is responsible for calculation of the purchased gas cost factors in the Schedule in accordance with the criteria established by the Minnesota Public Utilities Commission (the "Commission") based upon Minnesota Administrative Rules Chapter 7825.2700. Our responsibility is to express an opinion on the Schedule based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the examination to obtain reasonable assurance about whether the Schedule is in accordance with the criteria, in all material respects. An examination involves performing procedures to obtain evidence about the Schedule. The nature, timing, and extent of the procedures selected depend on our judgment, including an assessment of the risks of material misstatement of the Schedule, whether due to fraud or error. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

In our opinion, the Schedule of Automatic Adjustment Clause for the Purchased Gas Cost included in the monthly filings of Great Plains Natural Gas Co. for the twelve-month period from July 1, 2018 to June 30, 2019, presents the purchased gas cost factors in accordance with the Minnesota Administrative Rules Chapter 7825.2700, in all material respects.

This report is intended solely for the information and use of the Company and the Commission, and is not intended to be, and should not be, used by anyone other than the specified parties.

Deloitte & Touche LLP

August 29, 2019

GREAT PLAINS NATURAL GAS CO.
SCHEDULE OF AUTOMATIC ADJUSTMENT CLAUSE FOR THE PURCHASED GAS COST ADJUSTMENT IN DOLLARS PER DECATHERM
FOR THE PERIOD FROM JULY 1, 2018 TO JUNE 30, 2019

Month	Firm	Interruptible
July	0.4450	0.1312
August	0.5319	0.2181
September	0.8670	0.7742
October	1.0411	0.9483
November	1.9946	1.8395
December	2.8346	2.6795
January	2.0590	1.9039
February	2.0925	1.9374
March	1.3716	1.2165
April	0.8330	0.6779
May	0.5168	0.3696
June	0.6345	0.4873

GREAT PLAINS NATURAL GAS CO.
CONTRACTOR MAIN STRIKES
JULY 2018 - JUNE 2019

Date	Party Involved	Location	Repair Cost 1/	Dk Gas Lost	Gas Cost 2/
07/12/18	Contractor	Montevideo	$1,048	3.8	$15
08/09/18	Contractor	Marshall	1,174	14.9	61
08/14/18	Contractor	Marshall	2,131	122.2	498
09/18/18	Contractor	Marshall	486	62.2	255
10/04/18	Contractor	Sacred Heart	642	17.7	75
02/07/19	Contractor	Marshall	4,544	50.4	268
05/10/19	Contractor	Montevideo	961	20.4	76
06/25/19	Contractor	Pelican Rapids	1,912	N/A	N/A
			$12,898		$1,248

1/ Reimbursement is recorded as credit to Acct. 887, maintenance of mains.
2/ Credited to cost of gas.

Exhibit D

Table C (Cont.)
METER SPECIFICATIONS

Meter Make & No.	Style of Case	Case Working Pressure-PSI	Capacity-CFH 1/2" W.C. Diff.	Capacity-CFH 2" W.C. Diff.
ROCKWELL				
175	AL.	5 & 10	175	--
R200	AL.	5 & 10	200	--
250	AL.	5 & 10	250	--
R275	AL.	5 & 10	275	--
310	AL.	5 & 10	310	--
415	AL.	10 & 25	415	--
750	AL.	20	750	1,600
1,000	AL.	25	1,000	2,200
1,600	AL.	100	800	1,600
3,000	AL.	100	1,450	3,000
5,000	AL.	100	2,500	5,000
10,000	AL.	100	5,000	10,000
ROCKWELL				
Rotoseal R-3	--	125 to 1,440	--	3,000
Rotoseal R-5	--	125 to 1,440	--	5,000
Rotoseal R-8	--	125 to 1,440	--	8,000
Rotoseal R-11	--	125 to 1,440	--	11,000
ROCKWELL				
Turbo-meter T-18	--	125 to 1,440	--	18,000
Turbo-meter T-30	--	125 to 1,440	--	30,000
Turbo-meter T-60	--	125 to 1,440	--	60,000
Turbo-meter T-140	--	125 to 1,440	--	140,000
SPRAGUE				
S250, SL250	AL.	5	275	--
400, 400A	AL.	10 & 25	397	--

TESTING GAS METERS

DOMESTIC METERS

1. When testing domestic gas meters, the term "check" rate is flow at approximately 20% of the meter's rated capacity. "Open" rate is approximately 100% of the rated flow capacity at ½" differential.

2. Accuracy refers to a meter's degree of measurement error. A 100% accurate meter has 0% error. Spread is the range between check and open test results.

3. All new domestic meters purchased will have temperature compensation. Manufacturer settings shall be within +/-0.25% accuracy at the open and check rates. They shall have 1/2 X 2-foot test dials. Circular dials shall be preferred.

4. The Meter Shop shall randomly test five meters or five percent (5%) of all meters received whichever is greater, on each purchase order. They will be considered satisfactory if all meters are within +/-1% accuracy with less than 0.60% spread between the check and open rates. If one or more of the meters in the sample do not pass, the Meter Shop will test a second random sample. If the second sample fails, the meter shop will immediately notify the General Office Gas Measurement Manager to determine the course of action.

5. When receiving a new shipment of domestic meters or indexes, remove and check five indexes from the shipment for proper registration.

   On circular dial indexes, rotate the two-foot test dial manually 50 revolutions and the hand should then be at digit "1" on the "1 thousand foot" circle (1 ccf) if the index is registering properly.

6. The Meter Shop will not release any meter, from a new shipment, for service meters before successfully performing all acceptance tests.

RANDOM SAMPLING

1. Meters with synthetic diaphragms will be tested on a Random Sample basis according to test programs filed in each State.

2. Meters removed from service that in-test within +/-0.5% accuracy on both open and check rates with less than 0.60% spread, have an acceptable differential and that pass the "low light" test are satisfactory and may return to service without adjustment and/or repair. The "low light" rate is approximately the same as an appliance pilot light load.

3. Meters tested and repaired in the Meter Shop shall be adjusted to test within +/-0.5% accuracy with less than 0.60% spread.

LARGE CAPACITY METERS

1. Large capacity meters shall be tested on a periodic basis in accordance with the rules in each state or more frequently based on test results.

2. Meters tested or repaired in the Meter Shop shall be adjusted to within +/-0.5% accuracy with less than 0.60% spread.

3. Either the field office or the Meter Shop will enter meter test results, including accuracy data for all meters, differential data for rotary meters and spin test data for turbine meters, into meter history. Field operations can record data on Meter History Test Results Form 20141 and submit to the General Office Gas Measurement Manager.

4. New large capacity diaphragm meters purchased will be temperature compensated. They shall be set at the factory between -0.5% to 0.0% accuracy. All large capacity positive displacement meters shall be flow tested before installation.

5. All rotary meters shall be flow tested before installation or reinstallation. Differential pressure tests in accordance with the manufacturer's recommendation shall be made at the recommended mileage intervals or on a five-year basis, whichever occurs first. This test shall also include an oil change and

TC unit calibration check. If there are unacceptable differential pressures, flush or make repairs as necessary to obtain a satisfactory differential test or replace the meter. Visually inspect the strainer.

6. All turbine meters shall be flow tested before installation or reinstallation. A "Spin Test", in accordance with manufacturer's instructions, shall be made and recorded with the original test data. "Spin Tests" shall be made at the recommended mileage intervals or six calendar months, whichever occurs first. In the event that unacceptable spin times are found, repairs shall be made immediately. A cartridge change requires a spin test but not a flow test. A flow test should be made after turbine blade or change gear replacement. Bearings for the turbine meters should be lubricated every 6 months at a minimum.

7. To verify the index to meter drive ratio on large meters, a final flow test must be made with the service index installed. The service index is the index that will be recording the customer usage when the meter is in service.

   The only exception is when an integrating and/or recording instrument is installed in the field after the meter leaves the Meter Shop. In this case, make the final flow test with the proper standard index that is on the meter until installing the instrument. When making the instrument installation, the installer must verify that the instrument drive corresponds to the standard index on the meter. Meters set on pounds shall be checked onsite within two months for regulation accuracy and meter registration on the corrector. The proper factors on the customer account cut-in shall be verified with CIS billing information.

8. Orifice meters in service shall be calibrated and adjusted, if necessary, monthly.

INDEXES AND ELECTRONIC CORRECTORS

1. Electronic correcting indexes shall be calibrated annually not to exceed 13 calendar months. Within two months of being set, verification of proper set up shall be made on the meter and CIS billing. All electronic correction devices shall be set to read in Mcf for the corrected read and CCF for the uncorrected electronic read. It is also advised that the electronic uncorrected read be set to match the mechanical read to assist in identifying drive ratio errors. Site information files shall be printed and filed for reference.

2. Check correction factors at least twice yearly for reasonable operation by comparing the actual corrected factor to a calculated correction factor.

3. When the test or repair of a meter also includes the replacement of an index, it is permissible to set the new or repaired index at all zeros after a satisfactory test of the new index shows it to be in good operating order.

RETIREMENT OF METERS AND REGULATORS

RETIREMENT OF GAS REGULATORS AND METERS

1. Transfer gas modules (ERT's) and meters for retirement (because of obsolescence, damage or other cause) to the Bismarck Gas Meter Shop for examination and testing. In the Region, the Region Director or District Manager shall designate an employee to make the examination and determine the disposition of the material(s).

2. On a monthly basis, Regions and Districts shall report the retirement of regulators through the developed "On-Line" process. The Gas Measurement Manager shall review for approval.

GREAT PLAINS NATURAL GAS CO.

CURTAILMENT REQUIREMENTS AND PENALTIES

JULY 2018 – JUNE 2019

Great Plains' curtailment requirements and penalties information:

a. Two transmission-level curtailment events occurred during the period beginning July 2018 through June 2019. These events resulted from insufficient upstream transmission capacity to provide service to interruptible customers. Those events were:

1) 9:00 a.m. on 1/29/2019 until 9:00 a.m. on 1/30/2019
   - Four customers were requested to curtail gas usage
   - All customers complied with the request
2) 9:00 a.m. on 1/30/2019 until 9:00 a.m. on 1/31/2019
   - Four customers were requested to curtail gas usage
   - All customers complied with the request

Grain Drying customers were not allowed to run during the following gas days due to the operating conditions described below:

Start Date	End Date	Description	Non-Compliant Customers
1/18/19	2/1/19	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
1/19/19	1/19/19	Extreme operating conditions (VGT)	None
1/24/19	2/19/19	Extreme operating conditions (VGT)	None
2/7/19	2/8/19	Extreme operating conditions (VGT)	None
2/7/19	2/19/19	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
2/23/19	3/7/19	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
3/9/19	3/11/19	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None

b. There were no issues of non-compliance against curtailment orders from July 1, 2018 through June 30, 2019.

c. The specific commodity rate charged for the unauthorized gas used and how that rate is determined.

   Not Applicable.

d. The financial penalty, if any, assessed by the company to the customer, including calculations in determining the penalty or penalties.

   Not Applicable.

e. A discussion about utility communication with each customer regarding noncompliance with interruptions (excluding invoices).

   Each year, prior to the heating season, all customers that receive natural gas service under any interruptible rate schedule are provided a letter describing their level of service. The letter describes means of notification and penalty for failure to curtail.