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

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August 31, 2020

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: Annual Report; Automatic Adjustment
Docket No. G999/AA-20-172

Dear Mr. Seuffert:

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) 222-7855, or Brian M. Meloy, at (612) 335-1451.

Sincerely,

/s/ Travis R. Jacobson

Travis R. Jacobson
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, 2020

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 2019-2020 heating season, which were reported in the Informational Update Filing on Great Plains' 2019 Demand Entitlement Filing (DEQ) in Docket No. G004/M-19-430 on November 1, 2019.

Supplier	Contract Type	Units	Expires
NNG	TF12 (Base & Variable)	7,535 dk/Day	10/31/24
NNG	TF5 (Seasonal)	3,410 dk/Day	10/31/24
NNG	TFX (Seasonal)	5,200 dk/Day	10/31/24
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	10/31/24
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.

Dispatching Policy (7825.2800)

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.

Actions to Minimize Cost (7825.2800)

Company personnel continuously monitor the industry markets to ensure 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' transmission capacity, including capacity releases as applicable, is discussed in its annual Demand Entitlement filing.

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 26, 2019, the Department approved Great Plains' Conservation Improvement Program (CIP) Extension Plan (2020 Extension) in Docket No. G004/CIP-16-121 with a budget of $902,858 in 2020 and with associated dk savings of 57,307 dk.

Similar to prior CIP plans, the Great Plains 2020 CIP Extension 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 2020 CIP Extension 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, 2020.

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

Great Plains transported 4,176,591 dk for Minnesota end-use customers on its distribution system for the twelve months ending June 30, 2020.

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

The total (over)under recovery for Minnesota for the twelve months ending June 30, 2020 was:

Recovered Costs	Actual Costs	(Over)Under Recovery	% of Actual
$13,880,150	$13,730,115	($150,035)	1.09%

Pipeline demand charges were under-recovered by $64,568 or 1.27 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.

- VGT and NNG implemented interim rate increases that resulted in higher demand costs beginning in January 1, 2020.
- Weather was 1.95 percent colder than normal for the twelve months ending June 30, 2020. Please see Exhibit A, page 5 for a monthly degree day analysis.

The commodity components of the PGA were over-recovered by $214,603 or 2.49 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)

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

Great Plains is on track to fill its storage level prior to the beginning of the upcoming heating season. Current supply and demand levels are expected to keep the commodity cost of gas in the $2.50 - $3.50 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 $776 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, Section 7 has been recently updated, specifically the combination of the Random Sampling Section and Large Capacity Meters Section. Great Plains has removed the Large Capacity Meters Section and combined small and large meter random sampling in the Random Sampling Section so that all meters are held to the same standards. 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, 2020
MINNESOTA SYSTEM

	Recovered Costs	Actual Costs	(Over)Under Recovery	% of Actual
Firm	$11,045,470	$10,928,026	($117,444)	1.07%
Interruptible	2,834,680	2,802,089	(32,591)	1.16%
Total	$13,880,150	$13,730,115	($150,035)	1.09%

	Beginning Balance	(Over) Under Recovery	GCR Recovery	Ending Balance
Firm	($640,239)	($117,444)	$565,999	($191,684)
Interruptible	(106,374)	(32,591)	35,778	(103,187)
Total	($746,613)	($150,035)	$601,777	($294,871)

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)	$373,569	$366,218	($7,351)	2.01%
FT-A - Zone 1-1 (Cat. 3)	233,523	227,063	(6,460)	2.85%
FT-A - Zone 1-1 (Cat. 3)	233,523	227,063	(6,460)	2.85%
FT-A Seasonal	38,961	39,355	394	1.00%
FT-A - Capacity Release	(43,639)	(34,855)	8,784	25.20%
FT-A - Capacity Release	(3,871)	(32,174)	(28,303)	87.97%
Northern Natural Gas:				
TFX - Winter/Seasonal	1,454,284	1,503,402	49,118	3.27%
TFX - Summer	661,689	519,846	(141,843)	27.29%
TF12 Base - Summer	199,010	154,261	(44,749)	29.01%
TF12 Base - Winter	256,008	265,338	9,330	3.52%
TF12 Variable - Summer	184,397	147,050	(37,347)	25.40%
TF12 Variable - Winter	321,416	331,507	10,091	3.04%
TF5	330,565	341,847	11,282	3.30%
TFX - Summer	101,702	80,299	(21,403)	26.65%
TFX - Winter	697,990	721,788	23,798	3.30%
TFX Negotiated Contract - Winter	119,695	121,313	1,618	1.33%
FDD-1 Reservation	138,164	120,703	(17,461)	14.47%
Interruptible Demand Credit	(691,223)	(429,693)	261,530	60.86%
Total Demand Costs	$4,605,763	$4,670,331	$64,568	1.38%
Commodity Costs	6,439,707	6,257,695	(182,012)	2.91%
Total Firm Gas Costs	$11,045,470	$10,928,026	($117,444)	1.07%
Interruptible				
Commodity Costs	$2,404,987	$2,372,396	($32,591)	1.37%
Interruptible Demand Charge	429,693	429,693	0	0.00%
Total Interruptible Gas Costs	$2,834,680	$2,802,089	($32,591)	1.16%
Total Gas Costs	$13,880,150	$13,730,115	($150,035)	1.09%

GREAT PLAINS NATURAL GAS CO.
ANALYSIS OF (OVER)/UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2020
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)		$6,709	$5,431	$6,369	$12,588	$32,504	$52,936	$73,084	$63,932	$58,137	$34,987	$18,577	$8,315	$373,569
FT-A - Zone 1-1 (Cat. 3)		4,193	3,393	3,979	7,867	20,312	33,087	45,692	39,961	36,345	21,880	11,616	5,198	233,523
FT-A - Zone 1-1 (Cat. 3)		4,193	3,393	3,979	7,867	20,312	33,087	45,692	39,961	36,345	21,880	11,616	5,198	233,523
FT-A Seasonal		698	565	663	1,311	3,385	5,519	7,629	6,668	6,065	3,651	1,939	868	38,961
FT-A - Capacity Release		(445)	(360)	(422)	(834)	(2,883)	(6,445)	(8,559)	(7,536)	(7,275)	(5,022)	(2,665)	(1,193)	(43,639)
FT-A - Capacity Release		(508)	(412)	(482)	(954)	(1,515)	-	-	-	-	-	-	-	(3,871)
TFX - Winter/Seasonal		18,173	14,707	17,248	34,097	88,043	140,166	235,587	289,274	279,279	192,752	102,329	42,629	1,454,284
TFX - Summer		8,268	6,691	7,847	15,513	40,056	63,770	107,188	131,621	127,074	87,703	46,560	19,398	661,689
TF12 Base - Summer		2,429	1,965	2,305	4,556	11,884	19,221	32,314	39,687	38,316	26,445	14,039	5,849	199,010
TF12 Base - Winter		3,122	2,527	2,963	5,859	15,283	24,724	41,569	51,059	49,295	34,022	18,062	7,523	256,008
TF12 Variable - Summer		2,365	1,914	2,245	4,438	11,331	17,714	29,782	36,582	35,318	24,376	12,940	5,392	184,397
TF12 Variable - Winter		4,119	3,334	3,909	7,729	19,747	30,905	51,934	63,755	61,552	42,482	22,553	9,397	321,416
TF5		4,129	3,341	3,919	7,747	20,004	31,848	53,543	65,765	63,493	43,821	23,264	9,691	330,565
TFX - Summer		1,271	1,028	1,206	2,384	6,155	9,799	16,473	20,231	19,533	13,482	7,157	2,983	101,702
TFX - Winter		8,723	7,059	8,278	16,365	42,257	67,275	113,073	138,837	134,040	92,511	49,112	20,460	697,990
TFX Negotiated Contract - Winter		2,150	1,740	2,041	4,034	10,416	16,584	21,997	19,318	18,651	12,872	6,834	3,058	119,695
FDD-1 Reservation		1,524	1,234	1,447	2,860	7,387	11,759	21,561	28,827	27,831	19,209	10,197	4,328	138,164
Interruptible Demand Credit		(6,211)	(5,895)	(9,131)	(18,052)	(45,957)	(71,871)	(116,167)	(135,001)	(129,233)	(87,610)	(46,512)	(19,583)	(691,223)
Total Demand Cost		$64,902	$51,655	$58,363	$115,375	$298,721	$480,078	$772,392	$892,941	$854,766	$579,441	$307,618	$129,511	$4,605,763
Commodity Cost		116,944	85,060	98,218	183,810	506,901	965,075	1,370,675	1,131,811	992,451	577,705	271,380	139,677	6,439,707
Total Recovered Through PGA		$181,846	$136,715	$156,581	$299,185	$805,622	$1,445,153	$2,143,067	$2,024,752	$1,847,217	$1,157,146	$578,998	$269,188	$11,045,470
GCR Adjustment		23,744	19,215	11,731	(21,491)	(55,491)	(88,343)	(118,813)	(107,051)	(103,352)	(71,331)	(37,869)	(16,948)	(565,999)
Total Recovered		$205,590	$155,930	$168,312	$277,694	$750,131	$1,356,810	$2,024,254	$1,917,701	$1,743,865	$1,085,815	$541,129	$252,240	$10,479,471
Actual Cost of Gas:														
FT-A - Zone 1-1 (Cat. 3)		$31,929	$31,484	$30,095	$26,574	32,469	$39,520	($1,471)	$55,972	$40,823	$31,666	$19,807	$27,350	$366,218
FT-A - Zone 1-1 (Cat. 3)		21,550	20,761	21,049	17,686	18,601	19,192	24,921	17,570	20,028	17,669	16,301	11,735	227,063
FT-A - Zone 1-1 (Cat. 3)		21,550	20,761	21,049	17,686	18,601	19,192	24,921	17,570	20,028	17,669	16,301	11,735	227,063
FT-A Seasonal		-				1,664	7,677	9,968	7,028	8,011	5,007			39,355
FT-A - Capacity Release		(2,333)	(2,248)	(2,279)	(1,915)	(2,598)	(4,773)	(6,066)	(4,124)	(4,945)	(3,574)			(34,855)
FT-A - Capacity Release		(2,154)	(2,075)	(2,104)	(1,768)	(2,398)	(4,406)	(5,600)	(3,807)	(4,564)	(3,298)			(32,174)
TFX - Winter/Seasonal						37,507	199,616	324,878	305,308	366,039	270,054			1,503,402
TFX - Summer		72,854	70,187	71,162	59,793	48,816					35,409	103,072	58,553	519,846
TF12 Base - Summer		21,403	20,619	20,905	17,565	14,341					10,680	31,088	17,660	154,261
TF12 Base - Winter						7,637	35,227	57,328	53,871	64,586	46,689			265,338
TF12 Variable - Summer		20,825	20,063	20,341	17,092	13,954					9,844	28,654	16,277	147,050
TF12 Variable - Winter						9,542	44,009	71,623	67,306	80,694	58,333			331,507
TF5						9,838	45,379	73,856	69,407	83,213	60,154			341,847
TFX - Summer		11,208	10,798	10,948	9,199	13,280						15,857	9,009	80,299
TFX - Winter						20,773	95,816	155,941	146,548	175,699	127,011			721,788
TFX Negotiated Contract - Winter						5,120	23,617	30,016	20,407	24,466	17,687			121,313
FDD-1 Reservation		7,843	7,556	7,661	6,437	6,769	6,984	12,434	12,674	15,195	15,507	13,453	8,190	120,703
Interruptible Demand Credit		(15,664)	(16,355)	(16,082)	(18,531)	(44,391)	(81,535)	(41,614)	(44,246)	(50,437)	(48,702)	(28,629)	(23,507)	(429,693)
Total Demand Cost		$189,011	$181,551	$182,745	$149,818	$209,525	$445,515	$731,135	$721,484	$838,836	$667,805	$215,904	$137,002	$4,670,331
Commodity Cost		107,710	82,528	103,322	188,535	540,839	983,976	1,264,226	1,085,882	934,531	593,444	253,445	119,257	6,257,695
Total Actual Gas Costs		$296,721	$264,079	$286,067	$338,353	$750,364	$1,429,491	$1,995,361	$1,807,366	$1,773,367	$1,261,249	$469,349	$256,259	$10,928,026
Total (Over)Under Recoveries		$91,131	$108,149	$117,755	$60,659	$233	$72,681	($28,893)	($110,335)	$29,502	$175,434	($71,780)	$4,019	$448,555
Cumulative Balance	($640,239)	($549,108)	($440,959)	($323,204)	($262,545)	($262,312)	($189,631)	($218,524)	($328,859)	($299,357)	($123,923)	($195,703)	($191,684)	($191,684)

GREAT PLAINS NATURAL GAS CO.
ANALYSIS OF (OVER)/UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2020
MINNESOTA SYSTEM - INTERRUPTIBLE

Description	Beginning Balance	July	August	September	October	November	December	January	February	March	April	May	June	Total
Recovered thru PGA:														
Commodity Cost		$110,300	$102,626	$99,529	$108,886	$275,584	$608,141	$302,841	$208,587	$218,509	$184,305	$92,229	$93,450	$2,404,987
Interruptible Demand Charge		15,664	16,355	16,082	18,531	44,391	81,535	41,614	44,246	50,437	48,702	28,629	23,507	429,693
Total		$125,964	$118,981	$115,611	$127,417	$319,975	$689,676	$344,455	$252,833	$268,946	$233,007	$120,858	$116,957	$2,834,680
GCR Adjustment		21,244	22,181	14,122	(5,487)	(13,294)	(25,033)	(11,214)	(8,472)	(9,711)	(9,574)	(5,628)	(4,912)	(35,778)
Total Recovered		$147,208	$141,162	$129,733	$121,930	$306,681	$664,643	$333,241	$244,361	$259,235	$223,433	$115,230	$112,045	$2,798,902
Actual Cost of Gas:														
Commodity Cost of Gas		$98,046	$97,023	$95,654	$110,217	$297,583	$648,869	$277,744	$202,881	$201,670	$174,055	$87,192	$81,462	$2,372,396
Interruptible Demand Charge		15,664	16,355	16,082	18,531	44,391	81,535	41,614	44,246	50,437	48,702	28,629	23,507	429,693
Total Actual Gas Costs		$113,710	$113,378	$111,736	$128,748	$341,974	$730,404	$319,358	$247,127	$252,107	$222,757	$115,821	$104,969	$2,802,089
Current Month Under/(Over) Recovery		($33,498)	($27,784)	($17,997)	$6,818	$35,293	$65,761	($13,883)	$2,766	($7,128)	($676)	$591	($7,076)	$3,187
Cumulative Balance	($106,374)	($139,872)	($167,656)	($185,653)	($178,835)	($143,542)	($77,781)	($91,664)	($88,898)	($96,026)	($96,702)	($96,111)	($103,187)	($103,187)

GREAT PLAINS NATURAL GAS CO.
ANALYSIS OF (OVER)/UNDER RECOVERIES
TWELVE MONTHS ENDING JUNE 30, 2020
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)	$0.1373	$0.1373	$0.1373	$0.1373	$0.1373	$0.1373	$0.1465	$0.1400	$0.1400	$0.1150	$0.1150	$0.1150	$0.1150	
FT-A - Zone 1-1 (Cat. 3)	0.0858	0.0858	0.0858	0.0858	0.0858	0.0858	0.0916	0.0875	0.0875	0.0719	0.0719	0.0719	0.0719	
FT-A - Zone 1-1 (Cat. 3)	0.0858	0.0858	0.0858	0.0858	0.0858	0.0858	0.0916	0.0875	0.0875	0.0719	0.0719	0.0719	0.0719	
FT-A Seasonal	0.0143	0.0143	0.0143	0.0143	0.0143	0.0143	0.0153	0.0146	0.0146	0.0120	0.0120	0.0120	0.0120	
FT-A - Capacity Release	(0.0091)	(0.0091)	(0.0091)	(0.0091)	(0.0091)	(0.0171)	(0.0171)	(0.0165)	(0.0165)	(0.0165)	(0.0165)	(0.0165)	(0.0165)	
FT-A - Capacity Release	(0.0104)	(0.0104)	(0.0104)	(0.0104)	(0.0104)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Northern Natural Gas:														
TFX - Winter/Seasonal	0.3719	0.3719	0.3719	0.3719	0.3719	0.3719	0.3719	0.6334	0.6334	0.6334	0.6334	0.6334	0.4598	
TFX - Summer	0.1692	0.1692	0.1692	0.1692	0.1692	0.1692	0.1692	0.2882	0.2882	0.2882	0.2882	0.2882	0.2093	
TF12 Base - Summer	0.0497	0.0497	0.0497	0.0497	0.0497	0.0510	0.0510	0.0869	0.0869	0.0869	0.0869	0.0869	0.0631	
TF12 Base - Winter	0.0639	0.0639	0.0639	0.0639	0.0639	0.0656	0.0656	0.1118	0.1118	0.1118	0.1118	0.1118	0.0811	
TF12 Variable - Summer	0.0484	0.0484	0.0484	0.0484	0.0484	0.0470	0.0470	0.0801	0.0801	0.0801	0.0801	0.0801	0.0582	
TF12 Variable - Winter	0.0843	0.0843	0.0843	0.0843	0.0843	0.0820	0.0820	0.1396	0.1396	0.1396	0.1396	0.1396	0.1014	
TF5	0.0845	0.0845	0.0845	0.0845	0.0845	0.0845	0.0845	0.1440	0.1440	0.1440	0.1440	0.1440	0.1045	
TFX - Summer	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0260	0.0443	0.0443	0.0443	0.0443	0.0443	0.0322	
TFX - Winter	0.1785	0.1785	0.1785	0.1785	0.1785	0.1785	0.1785	0.3040	0.3040	0.3040	0.3040	0.3040	0.2207	
TFX Negotiated Contract - Winter	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0440	0.0423	0.0423	0.0423	0.0423	0.0423	0.0423	
FDD-1 Reservation	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0312	0.0631	0.0631	0.0631	0.0631	0.0631	0.0502	
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	(0.1271)	(0.1271)	(0.1969)	(0.1969)	(0.1969)	(0.1897)	(0.1926)	(0.2956)	(0.2956)	(0.2879)	(0.2879)	(0.2879)	(0.2203)	
Total Recovered in PGA per dk:		$1.3282	$1.2584	$1.2584	$1.2584	$1.2673	$1.2862	$1.9552	$1.9552	$1.9041	$1.9041	$1.9041	$1.4568	
Interruptible Demand Charge	$0.3428	$0.3428	$0.3428	$0.3428	$0.3428	$0.3302	$0.3352	$0.5301	$0.5301	$0.5163	$0.5163	$0.5163	$0.3950	
Weighted Avg. Commodity:	$2.5395	$2.1498	$2.1534	$2.0432	$1.9558	$2.4377	$2.7959	$2.5375	$2.3464	$2.0525	$1.5765	$1.9583	$1.8532	
GCR Adjustment														
Firm	$0.4859	$0.4859	$0.4859	($0.2344)	($0.2344)	($0.2344)	($0.2344)	($0.2344)	($0.2344)	($0.2344)	($0.2344)	($0.2344)	($0.2344)	
Interruptible	0.4649	0.4649	0.4649	(0.1015)	(0.1015)	(0.1015)	(0.1015)	(0.1015)	(0.1015)	(0.1015)	(0.1015)	(0.1015)	(0.1015)	
Billed Dk Sales														
Firm		48,865.1	39,545.6	46,378.3	91,684.0	236,737.3	376,891.1	506,883.2	456,700.4	440,921.2	304,312.4	161,555.2	72,305.4	2,782,779.2
Interruptible		45,696.0	47,711.3	46,914.0	54,057.4	130,977.3	246,634.4	110,487.4	83,467.2	95,676.9	94,329.0	55,450.0	48,368.5	1,059,769.4
Total Dk		94,561.1	87,256.9	93,292.3	145,741.4	367,714.6	623,525.5	617,370.6	540,167.6	536,598.1	398,641.4	217,005.2	120,673.9	3,842,548.6
% Firm to Total dk Sales		51.68%	45.32%	49.71%	62.91%	64.38%	60.45%	82.10%	84.55%	82.17%	76.34%	74.45%	59.92%	72.42%
% Interruptible to Total dk Sales		48.32%	54.68%	50.29%	37.09%	35.62%	39.55%	17.90%	15.45%	17.83%	23.66%	25.55%	40.08%	27.58%

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 2019	0	3	3	0.00%
August	0	0	0	0.00%
September	5	19	14	280.00%
October	160	198	38	23.75%
November	654	826	172	26.30%
December	856	865	9	1.05%
January 2020	1,455	1,333	(122)	-8.38%
February	1,422	1,378	(44)	-3.09%
March	1,066	1,005	(61)	-5.72%
April	763	783	20	2.62%
May	322	386	64	19.88%
June 2020	30	68	38	126.67%
Total	6,733	6,864	131	1.95%

	Authorized Volumes 1/	Actual Dk	Dk Difference	% Difference
Volumes	2,771,045.0	2,782,779.2	11,734.2	0.42%

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 Energy Capital, LLC (a wholly-owned subsidiary of MDU Resources Group, Inc.) for the twelve-month period from July 1, 2019 to June 30, 2020. 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, 2019 to June 30, 2020, 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 28, 2020

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, 2019 TO JUNE 30, 2020

Month	Firm	Interruptible
July	0.2448	0.0976
August	0.1786	0.1012
September	(0.6519)	(0.5754)
October	(0.7393)	(0.6628)
November	(0.2485)	(0.1935)
December	0.1286	0.1697
January	0.4051	(0.0146)
February	0.2140	(0.2057)
March	(0.1310)	(0.5134)
April	(0.6070)	(0.9894)
May	(0.2252)	(0.6076)
June	(0.7776)	(0.8340)

GREAT PLAINS NATURAL GAS CO.
CONTRACTOR MAIN STRIKES
JULY 2019 - JUNE 2020

Date	Party Involved	Location	Repair Cost 1/	Dk Gas Lost	Gas Cost 2/
07/16/19	Contractor	Redwood Falls	$4,822	223.2	$776
			$4,822		$776

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

Exhibit D

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.

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.

5. 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.

INDEXES AND ELECTRONIC CORRECTORS

1. 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.

RETIREMENT OF GAS METERS AND REGULATORS

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.

3. The Meter Shop may complete appropriate documentation as directed by the Fixed Assets department to retire regulators, gas modules, or meters.

4. Destroy retired regulators and meters unless there is special authorization for alternate disposal or sale. A designee of either the Meter Shop, Region Director, or District Manager shall witness and certify to the destruction of retired equipment.

   Comply with the procedure in the Environmental Regulatory Compliance Manual when retiring regulators and meters

GREAT PLAINS NATURAL GAS CO.

CURTAILMENT REQUIREMENTS AND PENALTIES

JULY 2019 – JUNE 2020

Great Plains' curtailment requirements and penalties information:

a. One transmission-level curtailment events occurred during the period beginning July 2019 through June 2020. This event resulted from insufficient upstream transmission capacity to provide service to interruptible customers. That event was:

   1) 9:00 a.m. on 9/26/2019 until 6:00 p.m. on 09/27/2019
      - Three 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
9/26/19	9/27/19	No grain dryers receiving service off the VGT Vergas Lateral allowed to take deliveries (VGT Mainline Outage)	None
10/30/19	10/31/19	Due to limited capacity on NNG that we were maxing out due to colder than normal temperatures, resulted in any NNG grain dryers who called to run after gas was purchased not being allowed to run. (NNG summer capacity limits)	None
11/6/19	11/7/2019	Vergas Lateral pressure issues, dryers allowed to run per rotating schedule from the field with different start/end times (VGT)	None
11/10/19	11/14/19	Vergas Lateral pressure issues, dryers allowed to run per rotating schedule from the field with different start/end times (VGT)	None
11/20/19	11/22/19	Extreme operating conditions (VGT)	None
12/9/19	12/11/19	Extreme operating conditions (VGT)	None
12/9/19	12/11/19	Extreme operating conditions (NNG)	None
12/10/19	12/11/19	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None

1/10/20	1/10/20	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
1/15/20	1/16/20	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
1/18/20	1/21/20	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
2/12/20	2/14/20	No grain dryers receiving service from NNG city gates allowed to take deliveries (NNG SOL)	None
2/19/20	2/19/20	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, 2019 through June 30, 2020.

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.