MINNESOTA DEPARTMENT OF COMMERCE

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October 15, 2015

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-15-723

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> A Request by Minnesota Energy Resources Corporation (MERC or the Company) for Approval of a Change in Demand Entitlement for its Customers Served off of the Northern Natural Gas Company (Northern) System Effective in the Purchased Gas Adjustment (PGA) on November 1, 2015.

The filing was submitted on July 31, 2015. The petitioner is:

> Amber S. Lee
> Minnesota Energy Resources Corporation
> 1995 Rahncliff Court, Suite 200
> Eagan, MN 55122

Based on its investigation, the Department recommends that the Commission:

- **accept** MERC-NNG's peak-day analysis; and
- **approve** MERC-NNG's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2015.

The Department requests that MERC provide a detailed explanation in its Reply Comments of how it manages its non-heating season capacity given the fact that it appears to have a non-heating season capacity shortfall. Additionally, the Department anticipates reviewing MERC's updated cost analysis on the alternatives to the Bison contract after MERC's November 2, 2015 updated filing in the current docket.

The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

/s/ MICHELLE ST. PIERRE
Financial Analyst

SS/MS/lt
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G011/M-15-723

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation (MERC or the Company) filed a change in demand entitlement petition (Petition) on July 31, 2015 for its customers served off of the Northern Natural Gas Company (NNG or Northern) system.[1] MERC requested that the Minnesota Public Utilities Commission (Commission or PUC) approve the following changes in the Company's recovery of overall level of contracted capacity.[2]

Table 1: The Company's Proposed Total Entitlement Changes

Type of Entitlement	Proposed Changes: increase (decrease) (Dkt)[3]
TF 12 (month) Base	0
TF 12 (month) Variable	0
TFX 5 (month) (Max Rate)	(14,383)
Northwestern Energy	125
Total Entitlement Net Change	**(14,258)**

MERC proposed to reduce 5-month capacity by 14,383 Dkt and increase the Northwestern Energy firm capacity by 125 Dkt. The net change to the design-day capacity is a decrease of 14,258 Dkt. As discussed further below, MERC's projected 2015-2016 design-day

[1] In its December 21, 2012 Order in Docket No. G007,011/GR-10-977, the Commission approved consolidation of MERC's 4 PGA systems effective July 1, 2013. MERC named the PGA for the NNG customers "MERC-NNG." At the time, MERC's only other PGA system was named "MERC-Consolidated." Effective May 1, 2015, MERC acquired Interstate Power & Light Company's Minnesota natural gas operations and customers. The Commission required MERC to maintain the transitioned customers on a separate PGA until MERC's next rate case. MERC named the PGA for the transitioned customers "MERC NNG-Albert Lea." On July 31, 2015, MERC filed a demand entitlement request for MERC-Consolidated in Docket No. G011/M-15-722 and MERC NNG-Albert Lea in Docket No. G011/M-15-724.

[2] MERC noted in its July 31, 2015 cover letter that any updated information would be provided with the Company's November 1, 2015 filing. Since November 1, 2015 falls on a Sunday, the updated filing would be filed on November 2, 2015.

[3] Dekatherms (Dkt).

requirements (overall needs of its firm customers on a design day) decreased by 15,739 Dkt (or approximately 6.03 percent) from the previous year.

MERC described the factors contributing to the change in demand entitlements as follows:

- On MERC's NNG contract 112486, MERC decreased the capacity by 14,383 Dth. [4]

- Due to a new firm customer in [sic] and increased design day in Ortonville, MERC will be requesting to increase the firm capacity from 910 Dth to 1,035 Dth with Northwestern Energy, which is a 125 Dth increase.[5]

The Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) notes that MERC's Firm Deferred Delivery (storage) increased from a total Maximum Storage Quantity of 5,469,320 Dth to 5,569,320 Dth as indicated on MERC's Attachment 10. This is an increase of 100,000 Dth or approximately 1.83 (100,000/5,469,320) percent.

The Department concludes that MERC's proposed change appears to be reasonable, based on current information. As discussed below, the effect of the above-proposed changes is a decrease in demand costs for the General Service, Small and Large Volume Firm (Joint) customers.

II. THE DEPARTMENT'S ANALYSIS OF THE COMPANY'S PROPOSAL

The Department's analysis of the Company's request includes:

- MERC's Bison/Northern Border Pipeline (NBPL) contract;
- changes to capacity;
- design-day requirement;
- reserve margin; and
- purchased gas adjustment (PGA) cost recovery proposal.

A. BISON/NBPL CONTRACT

In its January 21, 2015 Order,[6] the Commission required that MERC, in its next demand entitlement filing, provide an evaluation and analysis of available gas supply alternatives to its Bison/NBPL contracts based on the concerns in the PUC Staff's Briefing Papers:

[4] Petition, page 17.
[5] *Id*.
[6] Docket Nos. G007/M-10-1166, G011/M-10-1167, G011/M-10-1168, and G011/M-10-1169.

> But as PUC staff first mentioned in its Docket No. 08-698 briefing papers, the gas supply market continues to change because of the increased supply generated from fracking and other drilling operations throughout the United States. This increase in the supply of gas has generated interest from interstate pipelines and producers/marketers to construct new pipelines to connect these new gas supplies to areas that were not previously served from those sources of gas. The new facilities and the new gas supply have created a gas market that provides new alternative sources of supply, is extremely competitive and has resulted in lower gas supply prices.
>
> Further, because of the availability of new and possibly lower priced gas supply options, PUC staff believes that the Bison/NBPL contract option may not currently be the best or least cost gas option to supply MERC's customers. While PUC staff firmly believes that a LDC should have a diversified gas supply, the cost of the diversification should not over-burden MERC's rate payers.
>
> PUC staff is not recommending any changes to the Department's recommendation regarding these contracts, but it is of the opinion that the Commission may wish to require MERC to address the Bison/NBPL contracts in MERC's 2015-2016 demand entitlement petitions, by requiring MERC to evaluate the available gas supply alternatives to its Bison/NBPL contracts and provide the parties with its analysis in its 2015-2016 demand entitlement petitions.

In its Petition, MERC did not provide an evaluation but stated:

> As MERC continues to plan for the 2015-2016 heating season, we will continue to analyze and evaluate alternatives to the Bison contract on a going-forward basis and also the availability and potential value of capacity releases. MERC will provide an updated cost analysis on the alternatives on or before November 1, 2015.[7]

The Department anticipates reviewing MERC's updated cost analysis on the alternatives to the Bison contract after MERC's November 2, 2015 updated filing in the current docket.

[7] Petition, page 16.

B. MERC'S PROPOSED CHANGES

1. Capacity

As indicated in DOC Attachments 1 and 2, the Company proposed to decrease its total entitlement level in Dkt as follows:

Table 2

Filing	Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	Change From Previous Year (%)
July 31, 2015	266,385	252,127	(14,258)	(5.35)%

As discussed below, the design-day requirement decreased by 15,739 Dkt. As also discussed below, MERC-NNG's reserve margin is reasonable. The Department concludes that MERC-NNG's proposed level of demand entitlement is reasonable and recommends approval of the proposed level of capacity. However, the Department notes that Attachment 3 of the Company's Petition, appears to indicate a capacity shortage for the non-heating season of 33,090 MMBtu. The Department requests that MERC provide a detailed explanation in its Reply Comments of how it manages its non-heating season capacity given the fact that it appears to have a non-heating season capacity shortfall.

2. Design-Day Requirement

As indicated in DOC Attachment 2, the Company proposed to decrease its total design day in Dkt as follows:

Table 3

Filing	Previous Design Day (Dkt)	Proposed Design Day (Dkt)	Design Day Changes (Dkt)	Change From Previous Year (%)
July 31, 2015	261,002	245,263	(15,739)	(6.03)%

MERC provided significant discussion regarding its design-day calculation. The Department notes that the Company's design-day analysis is similar to the process that it has used in prior demand entitlement filings. However, MERC performed regressions by pipeline and weather station in the present docket. Considering the July 1, 2013 rearrangement/consolidation of MERC's NNG entitlements and design day estimates, this approach seems reasonable.

MERC also made some changes to its design-day analysis. Previously, MERC used a slightly different approach as follows:[8]

> Similar to the process used the prior year, the Team generated regressions of the daily throughput data available less the known daily meter readings for non-firm customers and adjusted those regressions for the estimated peak day impact of the other non-firm customers who do not have daily readings.

In the current Petition, MERC states the following in part:[9]

> A review of the data available also showed that we could use daily small volume interruptible data that came as a result of the Telemetry program as part of MERC's Interruptible Tariffs.
>
> The Team followed an approach generally consistent with the one used last year with one major change. By only using daily data, the Team removed the effects the monthly billing cycle data had on the Peak Day forecast.
>
> … The daily throughput data was provided by pipeline and meter, with each meter on each pipeline mapped to one of the weather stations shown in the above table. As noted above, some of the meters represented a TBS. Some meters were dedicated to a customer who is not a firm service customer. For example, certain transportation, interruptible, direct connect, and taconite customers have their own meter, but are not counted as firm service customers.
>
> The Team then gathered daily telemetered data from every remaining interruptible customer and mapped each customer's data to a pipeline and to one of the weather stations shown in the above table. This was a major new undertaking this year that was only made possible by the Telemetry program as part of MERC's Interruptible Tariffs.

Thus, as a result of MERC's telemetry program making it possible for all interruptible customers to have daily metered data, the Company no longer had to estimate their peak-day impact as it had previously done. This approach seems reasonable.

As previously discussed in the Department's December 8, 2014 Comments in Docket No. G011/M-14-660, the Department notes that in MERC's analysis for Ortonville the Company used a regression model with a negative intercept term without providing a reasonable

[8] See the Company's November 3rd, 2014 Compliance Filing – Revised Demand Entitlement Petition at page 5, Docket No. G011/M-14-660.
[9] Petition, pages 5 and 7.

explanation for why it would be appropriate to do so. Using a negative intercept term in a regression model, *ceteris paribus*, would tend to imply that MERC would not need any pipeline entitlements (capacity) for baseload usage; rather its customers are supplying the baseload natural gas to MERC which seems implausible.

The Department notes that MERC appropriately corrected its models for autocorrelation, as was discussed in the Department's March 4th, 2013 comments in Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194 and G011/M-12-1195 wherein the Department requested that, in future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the model if autocorrelation is present. The Department appreciates MERC's attention to this issue.

The Department recommends that the Commission accept MERC-NNG's peak-day analysis. Further, the Department requests that in its future demand entitlement filings, MERC check the regression models it ultimately uses to make sure the models appear reasonable, *e.g.*, that no negative intercept terms are in the models.

3. Reserve Margin

As indicated in DOC Attachment 2, the proposed reserve margin is 6,864 Dkt as follows:

Table 4

Filing	Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year
July 31, 2015	252,127	245,263	6,864	2.80%	0.74%

The proposed reserve margin of 2.80 percent represents an increase of 0.74 percent over last year's reserve margin of 2.06 percent.[10] Generally, a reserve margin of up to five percent is not unreasonable. Based on this information and the Department's assessment of the Company's design-day analysis, the Department concludes that the reserve margin appears to be reasonable at this time.

C. THE COMPANY'S PGA COST RECOVERY PROPOSAL

In its Petition, the Company compared its July 2015 PGA to its projected November 2015 PGA rates to highlight the changes in demand costs (MERC Attachment 4, Page 1 of 3).[11] The Company's demand entitlement proposal would result in the following annual demand cost impacts:

[10] MERC Attachment 3.
[11] MERC has similar information in its Attachment 11. On MERC's Attachment 12, the Company estimated the change in costs due to the November 1, 2015 decrease in entitlement levels of $1,077,728 and increase in related demand costs of $261,267.

- annual bill decrease of $4.56 related to demand costs, or approximately -0.72 percent, for the average General Service customer consuming 93 Dkt annually;
- annual bill decrease of $4.28 related to demand costs, or approximately -0.01 percent, for the average Small Volume Firm customer consuming 6,699 Dkt annually;
- annual bill decrease of $12.83 related to demand costs, or approximately -0.01 percent, for the average Large Volume Firm customer consuming 42,000 Dkt annually;
- no demand cost impacts related to MERC-NNG's interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

Based on its investigation, the Department recommends that the Commission:

- **accept** MERC-NNG's peak-day analysis; and
- **approve** MERC-NNG's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2015.

The Department also requests that MERC provide a detailed explanation in its Reply Comments of how it manages its non-heating season capacity given the fact that it appears to have a non-heating season capacity shortfall. Additionally, the Department anticipates reviewing MERC's updated cost analysis on the alternatives to the Bison contract after MERC's November 2, 2015 updated filing in the current docket.

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	13-670 NNG Total	14-660 NNG Total	15-723 NNG Total	July Change
NNG Design Day	**245,878**	**261,002**	**245,263**	**(15,739)**
Customer Requirements moving to Transportation	**0**	**0**	**0**	**0**
Adjusted NNG Design Day	**245,878**	**261,002**	**245,263**	**(15,739)**
Adjusted NNG Design Day Percentages	**100.00%**	**100.00%**	**100.00%**	**0**
Total NNG Design Day Capacity	**256,385**	**266,385**	**252,127**	**(14,258)**
Total NMU Design Day Capacity				
Entitlements in PGA				
TF12B	**47,044**	**55,019**	**55,019**	**0**
TF12V	**29,035**	**21,060**	**21,060**	**0**
net change				**0**
TF5	**31,515**	**31,515**	**31,515**	**0**
TFX12 (112486)	**10,822**	**10,822**	**10,822**	**0**
TFX(5) (112486)	**60,271**	**66,271**	**51,888**	**(14,383)**
TFX(5) (112561)	**6,000**	**0**	**0**	**0**
TFX(5) (112486)	**1,800**	**1,800**	**1,800**	**0**
TFX(5) (12-V)	**0**	**0**	**0**	**0**
TFX(5) (127852)	**0**	**30,000**	**30,000**	**0**
TFX12 (111866)	**1,283**	**1,283**	**1,283**	**0**
TFX12 (111866)	**8,271**	**8,271**	**8,271**	**0**
TFX5 (111866)	**25,013**	**25,013**	**25,013**	**0**
Total Entitlements in PGA	**221,054**	**251,054**	**236,671**	**(14,383)**
Entitlements in PGA (NNG)				
	0	**0**	**0**	**0**
Windom	**2,500**	**2,500**	**2,500**	**0**
LS Power	**0**	**0**	**0**	**0**
Northwestern Energy (Ortonville)	**910**	**910**	**1,035**	**125**
NNG Zone GDD Call Option	**20,000**	**0**	**0**	**0**
	0	**0**	**0**	**0**
	0	**0**	**0**	**0**
	0	**0**	**0**	**0**
TFX7 chg to TFX12 (111866)*	**11,921**	**11,921**	**11,921**	**0**
Total	**35,331**	**15,331**	**15,456**	**125**
Total Capacity before Peak Shaving	**256,385**	**266,385**	**252,127**	**(14,258)**
LP Peak Shaving	**0**	**0**	**0**	**0**
Total Design Day Capacity w/o Contract Demand	**256,385**	**266,385**	**252,127**	**(14,258)**
Total Transp. (with TFX Offpeak less LSP)	**256,385**	**266,385**	**252,127**	**(14,258)**
Total Annual Transportation	**111,786**	**111,786**	**111,911**	**125**
Total Seasonal Transportation	**144,599**	**154,599**	**140,216**	**(14,383)**
Total Percent Seasonal	**56.4%**	**58.0%**	**55.6%**	**-2.42%**
LS Power as % of Total DD Capacity	**0.0%**	**0.0%**	**0.0%**	**0.00%**
Reserve Margin	**4.27%**	**2.06%**	**2.80%**	**0.74%**
Total Design Day Capacity w/ contract demand	**256,385**	**266,385**	**266,385**	**0**
Factors	**100.00%**	**100.00%**	**100.00%**	**0.00%**
				0
Other: Storage levels not included in Peak Day Deliverability				**0**
TFX Oct	**2,000**	**2,000**	**2,000**	**0**
TFX Apr	**2,000**	**2,000**	**2,000**	**0**
FDD Storage reservation (112490)	**75,437**	**75,437**	**75,437**	**0**
FDD Storage capacity MSQ **1/**	**4,349,320**	**4,349,320**	**4,349,320**	**0**
FDD Storage reservation (113704)	**5,550**	**5,550**	**5,550**	**0**
FDD Storage capacity MSQ **2/**	**200,000**	**650,000**	**650,000**	**0**
FDD Storage reservation (118215)	**13,008**	**2,602**	**2,602**	**0**
FDD Storage capacity MSQ **3/**	**750,000**	**150,000**	**150,000**	**0**
FDD Storage reservation (118657)	**3,468**	**11,274**	**11,274**	**0**
FDD Storage capacity MSQ **4/**	**320,000**	**320,000**	**320,000**	**0**
FDD Storage reservation (2015)			**1,735**	**1,735**
FDD Storage capacity MSQ **5/**			**100,000**	**100,000**
FDD Storage reservation total	**97,463**	**94,863**	**96,598**	**1,735**
FDD Storage capacity total	**5,619,320**	**5,469,320**	**5,569,320**	**100,000**
SMS	**22,680**	**22,680**	**22,680**	**0**
Bison/NBPL (FT0003 & T8673F)	**50,000**	**50,000**	**50,000**	**0**
AECO Storage	**648,265**	**648,265**	**648,265**	**0**
FDD				
1/ Cycled Volumes =	**869,864**	**869,864**	**869,864**	**0**
2/ Cycled Volumes =	**40,000**	**130,000**	**130,000**	**0**
3/ Cycled Volumes =	**150,000**	**30,000**	**30,000**	**0**
4/ Cycled Volumes =	**64,000**	**64,000**	**64,000**	**0**
5/ Cycled Volumes =			**20,000**	**20,000**

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Heating Season	No. of Design Day Customers	Change from Previous Year	% Change From Previous Year	Design Day (Mcf)	Change from Previous Year	% Change From Previous Year	Total Entitlement (Mcf)*	Change from Previous Year	% Change From Previous Year	% of Reserve Margin [(7)-(4)]/(4)
2015-2016	181,460	3,072	1.72%	245,263	(15,739)	-6.03%	252,127	-14,258	-5.35%	2.80%
2014-2015	178,388	-190	-0.11%	261,002	15,124	6.15%	266,385	10,000	3.90%	2.06%
2013-2014	178,578	1,641	0.93%	245,878	19,995	8.85%	256,385	22,900	9.81%	4.27%
2012-2013	176,937	1,696	0.97%	225,883	(9,172)	-3.90%	233,485	-12,500	-5.08%	3.37%
2011-2012	175,241	-786	-0.45%	235,055	16,842	7.72%	245,985	-15,690	-6.00%	4.65%
2010-2011	176,027	799	0.46%	218,213	(9,827)	-4.31%	261,675	7,000	2.75%	19.92%
2009-2010	175,228	1,266	0.73%	228,040	(19,148)	-7.75%	254,675	4,227	1.69%	11.68%
2008-2009	173,962	1,846	1.07%	247,188	23,434	10.47%	250,448	0	0.00%	1.32%
2007-2008	172,116	7,063	4.28%	223,754	1,635	0.74%	250,448	2036	0.82%	11.93%
2006-2007	165,053			222,119			248,412			11.84%
Average:			1.07%			1.33%			0.28%	7.38%

Columns (1) and (4) were provided by MERC in Attachment 1, page 3.

	Firm Peak Day Sendout							
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Number of Peak Day Customers	Firm Peak Day Sendout (Mcf)	Change from Previous Year	% Change From Previous Year	**Excess/Def. per Cust. [(7) - (4)]/(1)**	**Design Day per Customer (4)/(1)**	**Entitlement per Customer (7)/(1)**	**Peak Day Sendout per PD Customer (12)/(11)****
2015-2016	unknown	unknown			0.04	1.35	1.39	
2014-2015	178,388	193,848	(18,958)	-8.91%	0.03	1.46	1.49	1.0867
2013-2014	178,578	212,806	unknown	unknown	0.06	1.38	1.44	1.1917
2012-2013	176,937	unknown	#VALUE!	#VALUE!	0.04	1.28	1.32	#VALUE!
2011-2012	175,241	unknown	#VALUE!	#VALUE!	0.06	1.34	1.40	#VALUE!
2010-2011	176,027	unknown	#VALUE!	#VALUE!	0.25	1.24	1.49	#VALUE!
2009-2010	175,228	unknown	#VALUE!	#VALUE!	0.15	1.30	1.45	#VALUE!
2008-2009	173,962	unknown	#VALUE!	#VALUE!	0.02	1.42	1.44	#VALUE!
2007-2008	172,116	unknown	#VALUE!	#VALUE!	0.16	1.30	1.46	#VALUE!
2006-2007	165,053	unknown	#VALUE!	#VALUE!	0.16	1.35	1.51	#VALUE!
Average:				-8.91%	0.10	1.34	1.44	1.1392

Consolidation of the four into two PGAs (MERC-NNG and MERC-CON) was effective 7/1/13.
*** MERC-PNG NNG added to MERC-NMU NNG areas from DOC's prior Attachment 2 for each company.**
**** The number of design day customers are used when the number of firm peak day customers is unknown (18=19).**

DOC Attachment 3
Rate Impact of MERC-NNG PGA System Proposed Demand Entitlement Changes

1) General Service - Residential: Avg. Annual Use: 93 Mcf

Recovery	Last Base Cost of Gas G011/MR-13-732	Last Demand Change Nov. '14 M-14-660	Most Recent PGA 7/1/15	Nov-15 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.3407	$4.3034	$3.6498	$3.6498	-15.92%	-15.19%	0.00%	$0.0000
Demand Rate	$1.7568	$1.6999	$0.9947	$0.9457	-46.17%	-44.37%	-4.93%	($0.0490)
Margin	$2.1806	$2.2290	$2.1806	$2.1806	0.00%	-2.17%	0.00%	$0.0000
Total Recovery	$8.2781	$8.2323	$6.8251	$6.7761	-18.14%	-17.69%	-0.72%	($0.0490)
Avg. Annual Bill*	$769.86	$765.60	$634.73	$630.18	-18.14%	-17.69%	-0.72%	($4.5570)
Effect of proposed commodity change on average annual bills:								$0.00
Effect of proposed demand change on average annual bills:								($4.5570)

2) Small Volume Interruptible: Avg. Annual Use: 6,699 Mcf

Recovery	Last Base Cost of Gas G011/MR-13-732	Last Demand Change Nov. '14 M-14-660	Most Recent PGA 7/1/15	Nov-15 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.3407	$4.3034	$3.6498	$3.6498	-15.92%	-15.19%	0.00%	$0.0000
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.8490	$1.2014	$0.8490	$0.8490	0.00%	-29.33%	0.00%	$0.0000
Total Recovery	$5.1897	$5.5048	$4.4988	$4.4988	-13.31%	-18.27%	0.00%	$0.0000
Avg. Annual Bill*	$34,765.80	$36,876.66	$30,137.46	$30,137.46	-13.31%	-18.27%	0.00%	$0.00
Effect of proposed commodity change on average annual bills:								$0.00
Effect of proposed demand change on average annual bills:								$0.0000

3) Large Volume Interruptible: Avg. Annual Use: 42,000 Mcf

Recovery	Last Base Cost of Gas G011/MR-13-732	Last Demand Change Nov. '14 M-14-660	Most Recent PGA 7/1/15	Nov-15 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.3407	$4.3034	$3.6498	$3.6498	-15.92%	-15.19%	0.00%	$0.0000
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.4553	$0.4026	$0.4553	$0.4553	0.00%	13.09%	0.00%	$0.0000
Total Recovery	$4.7960	$4.7060	$4.1051	$4.1051	-14.41%	-12.77%	0.00%	$0.0000
Avg. Annual Bill*	$201,432.00	$197,652.00	$172,414.20	$172,414.20	-14.41%	-12.77%	0.00%	$0.00
Effect of proposed commodity change on average annual bills:								$0.00
Effect of proposed demand change on average annual bills:								$0.00

4) Small Volume Firm: Avg. Annual Use: 6,699 Mcf
Avg. Annual CD Volumes: 25 Mcf

Recovery	Last Base Cost of Gas G011/MR-13-732	Last Demand Change Nov. '14 M-14-660	Most Recent PGA 7/1/15	Nov-15 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.3407	$4.3034	$3.6498	$3.6498	-15.92%	-15.19%	0.00%	$0.0000
Demand Rate	$20.0712	$17.2971	$10.3446	$10.1736	-49.31%	-41.18%	-1.65%	($0.1710)
Comm. Margin	$0.8490	$1.2014	$0.8490	$0.8490	0.00%	-29.33%	0.00%	$0.0000
SV Dem. Margin	$2.5000	$2.5953	$2.5000	$2.5000	0.00%	-3.67%	0.00%	$0.0000
Total Commodity Cost	$5.1897	$5.5048	$4.4988	$4.4988	-13.31%	-18.27%	0.00%	$0.0000
Total Demand Cost	$22.5712	$19.8924	$12.8446	$12.6736	-43.85%	-36.29%	-1.33%	($0.1710)
Avg. Annual Bill*	$35,330.08	$37,373.97	$30,458.58	$30,454.30	-13.80%	-18.51%	-0.01%	($4.2750)
Effect of proposed commodity change on average annual bills:								$0.00
Effect of proposed demand change on average annual bills:								($4.2750)

5) Large Volume Firm: Avg. Annual Use: 42,000 Mcf
Avg. Annual CD Units: 75 Mcf

Recovery	Last Base Cost of Gas G011/MR-13-732	Last Demand Change Nov. '14 M-14-660	Most Recent PGA 7/1/15	Nov-15 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.3407	$4.3034	$3.6498	$3.6498	-15.92%	-15.19%	0.00%	$0.0000
Demand Rate	$20.0712	$17.2971	$10.3446	$10.1736	-49.31%	-41.18%	-1.65%	($0.1710)
Comm. Margin	$0.4553	$0.4026	$0.4553	$0.4553	0.00%	13.09%	0.00%	$0.0000
LV Dem. Margin	$2.5000	$2.5953	$2.5000	$2.5000	0.00%	-3.67%	0.00%	$0.0000
Total Commodity Cost	$4.7960	$4.7060	$4.1051	$4.1051	-14.41%	-12.77%	0.00%	$0.0000
Total Demand Cost	$22.5712	$19.8924	$12.8446	$12.6736	-43.85%	-36.29%	-1.33%	($0.1710)
Avg. Annual Bill*	$203,124.84	$199,143.93	$173,377.55	$173,364.72	-14.65%	-12.95%	-0.01%	($12.8250)
Effect of proposed commodity change on average annual bills:								$0.00
Effect of proposed demand change on average annual bills:								($12.8250)

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Monthly Demand Change ($/Mcf)	Monthly Demand Change (Percent)	Annual Total Change ($/Mcf)		Annual Total Change (Percent)
All Firm	$0.0000	0.00%	($0.0490)	-4.93%	-$4.56		-0.72%
Sm Vol Inter. Service	$0.0000	0.00%	$0.0000	0.00%	$0.00		0.00%
Lrg Vol Inter. Service	$0.0000	0.00%	$0.0000	0.00%	$0.00		0.00%
Sm Vol Joint Service	$0.0000	0.00%	($0.1710)	-1.65%	-$4.27	**	-0.01%
Lrg Vol Joint Service	$0.0000	0.00%	($0.1710)	-1.65%	-$12.83	**	-0.01%

*** The average annual bill shown does not include customer charges.**
**** The total change for Joint customers includes only commodity change since not all joint customers purchase CD units.**

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. G011/M-15-723

Dated this 15th day of October 2015

/s/Sharon Ferguson

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