MINNESOTA DEPARTMENT OF COMMERCE

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October 28, 2016

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-16-650

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) 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 or NNG) System Effective in the Purchased Gas Adjustment (PGA) on November 1, 2016.

The filing was submitted on August 1, 2016. The petitioner is:

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

The Department requests that MERC provide additional information in reply comments or if possible in the November 1, 2016 update. The Department will offer additional comments and recommendations in subsequent response comments after it has reviewed the additional information.

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

Sincerely,

/s/ MICHAEL RYAN
Rates Analyst

/s/ SACHIN SHAH
Rates Analyst

MR/SS/lt
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G011/M-16-650

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 August 1, 2016 for its customers served off of the NNG system.[1] MERC requested that the Minnesota Public Utilities Commission (Commission or PUC) approve no changes in the Company's recovery of overall level of contracted capacity.[2]

In terms of capacity, MERC proposed to maintain the same entitlement level as was in place last heating season, resulting in an estimated reserve margin of 1.54 percent. However, MERC's Firm Deferred Delivery (storage) increased from a total Maximum Storage Quantity of 5,469,320 Dth[3] to 5,869,320 Dth as indicated on MERC's Attachment 10. This is an increase of 400,000 Dth or approximately 7.31 (400,000/5,469,320) percent. Including the added storage, MERC's Firm Deferred Delivery makes up just over 30% of the anticipated usage for the upcoming winter (5,869,320Dth /18,029,851 Dth or 32.55%).

Using a similar design-day calculation methodology as has been used in the past, MERC proposed to increase its total design day by 1.44 percent.

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[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 August 1, 2016, MERC filed a demand entitlement request for MERC-Consolidated in Docket No. G011/M-16-651 and MERC NNG-Albert Lea in Docket No. G011/M-16-652.

[2] MERC noted in its August cover letter that any updated information would be provided with the Company's November 1, 2016 filing.

[3] Dekatherms.

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

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

- Changes to capacity;
- design-day requirement;
- reserve margin; and
- purchased gas adjustment (PGA) cost recovery proposal.

A. MERC'S PROPOSED CHANGES

1. Capacity

As an initial matter, the Department confirms that, as required by the Commission's Order Point 9 of its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, MERC provided separate data on its summer and winter demand entitlements.[4]

As indicated in DOC Attachments 1 and 2, the Company proposed to keep its total entitlement level in Dth the same as the prior year as follows:

Table 1: MERC's NNG Total Entitlement Levels

Filing	Previous Entitlement (Dth)	Proposed Entitlement (Dth)	Entitlement Changes (Dth)	Change From Previous Year (%)
August 1, 2016	252,127	252,127	0	0%

As discussed below, the design-day requirement increased by 3,533 Dth. MERC-NNG's proposed level of demand entitlement appears reasonable, but will provide final recommendations after reviewing the Company's November 1, 2016 update.

As noted above, MERC's Firm Deferred Delivery (storage) increased from a total Maximum Storage Quantity of 5,469,320 Dth to 5,869,320 Dth as indicated on MERC's Attachment 10. The Department followed up informally with MERC to gather additional information regarding the increased storage. According to the Company the new storage was added June 1, 2016, which allowed the Company to inject gas this summer for withdrawal during the upcoming winter. The Company also indicated that the opportunity to add storage on NNG is not often available since it is typically sold out. The Department requests that MERC provide a detailed explanation of the need for the proposed change to storage in reply comments. For instance, the Petition is unclear as to whether the decision to add storage was made for hedging purposes, anticipated growth, or another reason. Also, the Department requests that MERC provide detail regarding the term of the storage contract

[4] See MERC Attachment 3.

including whether it was added through an amendment to the current arrangement or through a separate agreement. Further, the Department requests that the Company provide a discussion regarding how frequently NNG has offered storage capacity in the past. Finally, in Attachment 4 of the Petition, storage contract number 118657 has 5,550 Dth/month at a Reservation rate of $3.3157/Dth and 64,000 Dth/month (winter only) at a Storage Cycle rate of $0.6901/Dth. The Department requests that the Company fully address why the contracted rates are above the NNG maximum tariff rate of $1.7140/Dth and $0.3567 for Reservation and Storage Cycle, respectively.

2. Design-Day Requirement

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

Table 2: MERC's NNG Design Day Levels

Filing	Previous Design Day (Dth)	Proposed Design Day (Dth)	Design Day Changes (Dth)	Change From Previous Year (%)
August 1, 2016	245,263	248,796	3,533	1.44%

At page 2 of its Petition, MERC stated the following:

> For the Demand Entitlement filing effective November 1, 2016, the total Design-Day requirement for MERC NNG is 248,701 Dth (Attachment 1).

However, the design day requirement of 248,701 Dth is not supported by the Company's Attachment 1. MERC's Attachment 1 correctly shows the proposed design-day requirement of 248,796 Dth.

MERC used a similar approach to what it used in last year's filing for its design-day analysis. 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 interruptible customers' peak-day impact. MERC obtained the daily large volume transportation, interruptible and joint interruptible volumes by pipeline and weather station (Data A). In addition, MERC obtained the daily small volume interruptible volumes by pipeline and weather station (Data B). MERC calculated the daily firm volumes by subtracting both Data A and Data B from the total throughput volumes.

In addition, MERC made some adjustments to its data, for example for the NNG pipeline, for its regression analysis. In its Petition MERC stated the following:[5]

[5] Petition at page 6.

> Review daily total metered throughput, Data A, and Data B and identify missing or bad reads, and to the extent possible, fix missing or bad reads. To the extent that the data could not be fixed, it was not included in the regressions.

MERC's approach does not seem unreasonable. However, the Department observed discrepancies in the historical data for MERC's Rochester regression analysis. The discrepancies' related to the data MERC submitted *In The Matter of the Application of Minnesota Energy Resources Corporation For Authority of Rider Recovery for the Rochester Natural Gas Extension For Natural Gas Service in Minnesota* in Docket No. G011/M-15-895 and the data MERC provided in the instant docket. For example, please see table 3 below.

Table 3: MERC Data Discrepancies

Filing	Day	Total Throughput (Dth)	Total Vol. Interruptible (Dth)	Net Throughput (Dth)
Aug 1, 2016	01/06/14	112,774	21,593	91,181
Docket 15-895[6]		85,138	7,291	77,847
difference		*27,636*	*14,302*	*13,334*
Aug 1, 2016	02/05/14	112,565	33,122	79,443
Docket 15-895		84,877	18,873	66,004
difference		*27,688*	*14,249*	*13,439*
Aug 1, 2016	02/18/15	116,775	32,410	84,365
Docket 15-895		76,717	10,414	66,303
difference		*40,058*	*21,996*	*18,062*

The Department requests that MERC reconcile all of the information and provide a detailed explanation, in sufficient detail to permit duplication, for any and all difference(s) that are identified in Table 3 above and any other discrepancies identified by MERC. The information can be provided concurrently with MERC's November 1, update or in the Company's Reply Comments. Further, the Department requests that the Company explain if the reconciliation requested above will impact the Company's design-day analysis and/or Exhibits A through D filed by the Company on August 1, 2016. If the reconciliation does impact MERC's August 1, 2016 petition, then the Department requests that MERC provide the corrected Exhibits and design-day analysis.

The Commission's April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, at Order point 10, stated in part the following:

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[6] The data in Docket No. 15-895 was totaled for all of the Town Border Stations (TBS's) and was obtained from MERC's electronic file titled, "Rochester Design Peak Day Analysis Sept 2015 Regressions corrected for AutoCor.xlsx". Please see July 1, 2016 Direct Testimony of Adam Heinen at DOC Ex. ___ AJH-7 (Heinen Direct).

> Required MERC to verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis attempts to explain.

In its Petition, MERC stated the following[7]:

> Order Point 10 of the Commission's April 28, 2016, Order in Docket No. G011/M-15-723 required that MERC verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis attempts to explain. MERC has carefully reviewed the results of its regression analysis and verified that the results are consistent with the underlying theory the analysis attempts to explain. Please see MERC's May 31, 2016, compliance filing in Docket Nos. G011/M-15-722, G011/M-15 723, and G011/M-15-724 for further discussion of this issue.

In MERC's analysis for Ortonville, the Company used a regression model with a negative intercept term. The Department concludes that, while MERC's use of a zero intercept in its Ortonville regression analysis is not ideal, our concerns remain somewhat mitigated as described in our previous comments.[8] Thus, MERC complied with the Commission's April 28, 2016 Order described above.

The Department notes that MERC appropriately corrected its models for autocorrelation, as required by the Commission's February 4, 2015 Order in Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194, and G011/M-12-1195 wherein the Commission required that, in its future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the model if autocorrelation is present.

The Department requests that MERC provide the reconciliation, explanation, and the resulting information for its Rochester regression in either it's Reply Comments or in its November 1 update. As a result, the Department anticipates it will provide its recommendation to the Commission at a later date.

3. Reserve Margin

As indicated in DOC Attachment 2, the proposed reserve margin is 3,331 Dth, or 1.34 percent, as follows:

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[7] Petition at page 11.
[8] Please see the Department's February 22, 2016 Response Comments in Docket No. G011/M-15-723 at pages 3-4.

Table 4: MERC's NNG Reserve Margin

Filing	Total Entitlement (DthDth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
August 1, 2016	252,127	248,796	3,331	1.34%	(1.46)%

The proposed reserve margin of 1.34 percent represents a decrease of 1.46 percentage points as compared to last year's reserve margin of 2.80 percent.[9] Table 5 below lists MERC-NNG reserve margins for the past 5 years.

Table 5: MERC's NNG Proposed and Historical Reserve Margins

2016-2017	1.34%
2015-2016	2.80%
2014-2015	2.06%
2013-2014	4.27%
2012-2013	3.37%

Generally, a reserve margin of up to 5 percent is not unreasonable. While MERC-NNG's reserve margin has been below 5 percent in recent years, it is not clear that a reserve margin of less than 2 percent is reasonable. In reply comments the Department requests further information on the driver of the low reserve margin, including any actions that MERC may be contemplating to address the relatively low NNG reserve margin.

B. THE COMPANY'S PGA COST RECOVERY PROPOSAL

In its Petition, the Company compared its July 2016 PGA to its projected November 2016 PGA rates to highlight the changes in demand costs (MERC Attachment 4, Page 1 of 3).[10] The Company's demand entitlement proposal would result in the following annual demand cost impacts:

- annual bill increase of $0.02 related to demand costs, or less than .02 percent, for the average General Service customer consuming 89 Dth annually;

- annual bill increase of $0.05 related to demand costs, or approximately 0.02 percent, for the average Small Volume Firm customer consuming 5,543 Dth annually;

[9] MERC Attachment 3.
[10] MERC has similar information in its Attachment 11.

- annual bill decrease of $0.15 related to demand costs, or approximately 0.02 percent, for the average Large Volume Firm customer consuming 42,000 Dth annually;

- no demand cost impacts related to MERC-NNG's interruptible rate classes.

III. THE DEPARTMENT'S RECOMMENDATIONS

The Department will provide its recommendations to the Commission in Response Comments, after MERC files Reply Comments and the November 1, 2016 update. If possible, the preferred method would be to have MERC file Reply Comments in the November 1, 2016 update.

The Department requests that MERC provide a detailed explanation on the following information:

- Storage Capacity Additions – provide further detail on the decision to add additional storage capacity.

- Design-Day Analysis - in sufficient detail to permit duplication, reconciliation of any and all difference(s) that are identified in Table 3 above of discrepancies in the historical data for MERC's Rochester regression analysis. The Company should also explain if the reconciliation requested above will impact the Company's design day analysis and/or Exhibits A through D filed by the Company on August 1, 2016. If so, the Department requests that MERC provide the corrected Exhibits and design-day analysis reflecting the Company's reconciliation.

- Reserve Margin – provide further information on the driver of the low reserve margin. Describe any actions that MERC may be contemplating to address the relatively low NNG reserve margin.

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Department Attachment 1
Docket No. G011/M-16-650
MERC NNG Demand Entitlement Historical and Current Proposal

	Historical Demand Entitlements			Proposed 8/1/16			
Contract Type	2013-2014 Quantity (Mcf)	2014-2015 Quantity (Mcf)	2015-2016 Quantity (Mcf)	2016-2017 Quantity (Mcf)	Change in Quantity (Mcf)	Change in Capacity (%)	Change in Design Day (%)
TF12B	49,153	55,019	45,026	45,026	0		
TF12V	26,926	21,060	30,290	30,290	0		
TF5	31,515	31,515	32,278	32,278	0		
TFX12	32,297	32,297	32,297	32,297	0		
TFX(5)	93,084	123,084	108,701	108,701	0		
TFX (April Only)*	2,000	2,000	2,000	2,000	0		
TFX (October Only)*	2,000	2,000	2,000	2,000	0		
Windom	2,500	2,500	2,500	2,500	0		
Northwestern Energy	910	910	1,035	1,035	0		
NNG Zone Delivery Call Option	20,000	0	0	0	0		
Bison**	50,000	50,000	50,000	50,000	0		
NBPL**	50,000	50,000	50,000	50,000	0		
Total Entitlement	**256,385**	**266,385**	**252,127**	**252,127**	**0**	**0.00%**	**1.44%**
Total Annual Transportation	**131,786**	**111,786**	**111,148**	**111,148**	**0**	**0.00%**	
Total Winter Only Transport	**124,599**	**154,599**	**140,979**	**140,979**	**0**	**0.00%**	
Percent of Winter Only Capacity	48.60%	58.04%	55.92%	55.92%			

*Total entitlement is calculated during the heating season, which includes the five months of November-March. April- and October-only contracts do not meet this criteria.
**Entitlement for Bison and NBPL is not included in the total as it does not add incremental capacity due to the fact that NNG capacity would still be required.
Source: MERC's Attachments 3 & 7

Department Attachment 2
Docket No. G011/M-16-650
MERC NNG Demand Entitlement Analysis

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve (7) - (4)	% Reserve [(7)-(4)]/(4)
2016-2017	184,577	3,251	1.79%	248,796	3,533	1.44%	252,127	0	0.00%	3,331	1.34%
2015-2016	181,326	2,938	1.65%	245,263	(15,739)	-6.03%	252,127	(14,258)	-5.35%	6,864	2.80%
2014-2015	178,388	(190)	-0.11%	261,002	15,124	6.15%	266,385	10,000	3.90%	5,383	2.06%
2013-2014	178,578	1,641	0.93%	245,878	19,995	8.85%	256,385	22,900	9.81%	10,507	4.27%
2012-2013	176,937	1,696	0.97%	225,883	(9,172)	-3.90%	233,485	(12,500)	-5.08%	7,602	3.37%
2011-2012	175,241	(786)	-0.45%	235,055	16,842	7.72%	245,985	(15,690)	-6.00%	10,930	4.65%
2010-2011	176,027	799	0.46%	218,213	(9,827)	-4.31%	261,675	7,000	2.75%	43,462	19.92%
2009-2010	175,228	1,266	0.73%	228,040	(19,148)	-7.75%	254,675	4,227	1.69%	26,635	11.68%
2008-2009	173,962	1,846	1.07%	247,188	23,434	10.47%	250,448	0	0.00%	3,260	1.32%
2007-2008	172,116	7,063	4.28%	223,754	1,635	0.74%	250,448	2,036	0.82%	26,694	11.93%
2006-2007	165,053			222,119			248,412			26,293	11.84%
Average			1.13%			1.34%			0.25%		6.83%

	Firm Peak-Day Sendout*			Per Customer Metrics			
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak-Day Sendout (Dth)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak-Day Send per Customer (12)/(1)
2016-2017	unknown			0.0180	1.3479	1.3660	unknown
2015-2016	204,444	10,596	5.47%	0.0379	1.3526	1.3905	1.1275
2014-2015	193,848	(18,958)	-8.91%	0.0302	1.4631	1.4933	1.0867
2013-2014	212,806			0.0588	1.3769	1.4357	1.1917
2012-2013				0.0430	1.2766	1.3196	
2011-2012				0.0624	1.3413	1.4037	
2010-2011				0.2469	1.2397	1.4866	
2009-2010				0.1520	1.3014	1.4534	
2008-2009				0.0187	1.4209	1.4397	
2007-2008				0.1551	1.3000	1.4551	
2006-2007				0.1593	1.3457	1.5050	
Average			-1.72%	0.0893	1.3424	1.4317	1.1353

*Effective 7/1/13 MERC PGAs were consolidated from four down to two (NNG and Consolidated). Prior to 2013, no Peak-Day was calculated for only the NNG PGA.
Source: MERC's Attachment 1

Department Attachment 3
Docket No. G011/M-16-650
MERC NNG Rate Impacts

General Service-Residential	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 7/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.3217	$3.3879	$2.8907	$2.8630	-33.75%	-15.49%	-0.96%	($0.0277)
Demand Cost	$0.9226	$0.9003	$0.9317	$0.9319	1.01%	3.51%	0.02%	$0.0002
Commodity Margin	$2.3980	$2.1806	$2.3980	$2.3980	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$7.6423	$6.4688	$6.2204	$6.1929	-18.97%	-4.27%	-0.44%	($0.0275)
Average Annual Use	89	89	89	89				
Average Annual Cost of Gas*	$683.22	$578.31	$556.10	$553.65	-18.97%	-4.27%	-0.44%	($2.46)

SV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 7/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.3217	$3.3879	$2.8907	$2.8630	-33.75%	-15.49%	-0.96%	($0.0277)
Commodity Margin	$0.9336	$0.8490	$0.9336	$0.9336	0.00%	9.96%	0.00%	$0.0000
Total Cost of Gas	$5.2553	$4.2369	$3.8243	$3.7966	-27.76%	-10.39%	-0.72%	($0.0277)
Average Annual Use	5,543	5,543	5,543	5,543				
Average Annual Cost of Gas*	$29,130.13	$23,485.14	$21,198.09	$21,044.55	-27.76%	-10.39%	-0.72%	($153.54)

LV Interruptible Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 7/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.3217	$3.3879	$2.8907	$2.8630	-33.75%	-15.49%	-0.96%	($0.0277)
Commodity Margin	$0.5007	$0.4553	$0.5007	$0.5007	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$4.8224	$3.8432	$3.3914	$3.3637	-30.25%	-12.48%	-0.82%	($0.0277)
Average Annual Use	42,000	42,000	42,000	42,000				
Average Annual Cost of Gas*	$202,540.80	$161,414.40	$142,438.80	$141,275.40	-30.25%	-12.48%	-0.82%	($1,163.40)

SV Firm Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 7/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.3217	$3.3879	$2.8907	$2.8630	-33.75%	-15.49%	-0.96%	($0.0277)
Demand Cost	$10.1722	$10.0707	$10.2650	$10.2670	0.93%	1.95%	0.02%	$0.0020
Commodity Margin	$0.9336	$0.8490	$0.9336	$0.9336	0.00%	9.96%	0.00%	$0.0000
Demand Margin	$2.7493	$2.5000	$2.7493	$2.7493	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$5.2553	$4.2369	$3.8243	$3.7966	-27.76%	-10.39%	-0.72%	($0.0277)
Total Demand Cost	$12.9215	$12.5707	$13.0143	$13.0163	0.73%	3.54%	0.02%	$0.0020
Average Annual Use	5,543	5,543	5,543	5,543				
Average Annual Demand Units	25	25	25	25				
Average Annual Cost of Gas*	$29,453.17	$23,799.40	$21,523.45	$21,369.96	-27.44%	-10.21%	-0.71%	($153.49)

LV Firm Service	Base Cost of Gas Change G011/MR-15-748 1/1/16	Last Demand Change 11/1/2015	Most Recent PGA 7/1/2016	Proposed Demand Changes 11/1/2016	% Change From Last Base Cost of Gas Change	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.3217	$3.3879	$2.8907	$2.8630	-33.75%	-15.49%	-0.96%	($0.0277)
Demand Cost	$10.1722	$10.0707	$10.2650	$10.2670	0.93%	1.95%	0.02%	$0.0020
Commodity Margin	$0.5007	$0.4553	$0.5007	$0.5007	0.00%	9.97%	0.00%	$0.0000
Demand Margin	$2.7493	$2.5000	$2.7493	$2.7493	0.00%	9.97%	0.00%	$0.0000
Total Cost of Gas	$4.8224	$3.8432	$3.3914	$3.3637	-30.25%	-12.48%	-0.82%	($0.0277)
Total Demand Cost	$12.9215	$12.5707	$13.0143	$13.0163	0.73%	3.54%	0.02%	$0.0020
Average Annual Use	42,000	42,000	42,000	42,000				
Average Annual Demand Units	75	75	75	75				
Average Annual Cost of Gas*	$203,509.91	$162,357.20	$143,414.87	$142,251.62	-30.10%	-12.38%	-0.81%	($1,163.25)

Change Summary	Commodity Change $/Mcf	Demand Change $/Mcf	Total Monthly Change $/Mcf	Total Monthly Change %	Average Annual Change
General Service	($0.0277)	$0.0002	($0.0275)	-0.44%	($2.46)
SV Interruptible Service	($0.0277)	$0.0000	($0.0277)	-0.72%	($153.54)
LV Interruptible Service	($0.0277)	$0.0000	($0.0277)	-0.82%	($1,163.40)
SV Firm Service	($0.0277)	$0.0020	($0.0257)	-0.71%	($153.49)
LV Firm Service	($0.0277)	$0.0020	($0.0257)	-0.81%	($1,163.25)

* Average Annual Bill amount does not include customer charges.

Prepared by the Minnesota Department of Commerce

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-16-650

Dated this 28th day of October 2016

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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