division of energy resources
Minnesota Department of Commerce

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March 4, 2013

Burl W. Haar
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. G007/M-12-1195

Dear Dr. Haar:

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-NMU (MERC-NMU, MERC, or the Company) for approval by the Minnesota Public Utilities Commission (Commission) of a change in demand entitlement for its MERC-NMU Transmission System Purchased Gas Adjustment (PGA) effective November 1, 2012.

The filing was submitted on November 1, 2012. The petitioner is:

> Gregory J. Walters
> Minnesota Energy Resources Corporation
> 3460 Technology Drive NW
> Rochester, MN 55901

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

- **allow** MERC to recover storage gas costs through the commodity portion of the PGA, rather than the demand portion;
- **accept** MERC-NMU's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis as mentioned herein;
- **accept** the corrected level of demand entitlement; and
- **allow** the proposed recovery of associated demand costs effective November 1, 2012.

The Department requests that, in future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the models if autocorrelation is present.

Additionally, for future demand entitlement filings, MERC should take additional care in its designation of trade secret data in its attachments. The Department puts MERC on notice that it may recommend rejection of any of the Company's future filings that are in the same or similar condition as the instant Petition.

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

Sincerely,

/s/ MICHELLE ST. PIERRE
Financial Analyst

/s/ SACHIN SHAH
Rates Analyst

MS/SS/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G007/M-12-1195

I. SUMMARY OF COMPANY'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2, Minnesota Energy Resources Corporation-Northern Minnesota Utilities (MERC-NMU, MERC, or the Company) filed a change in demand entitlement (capacity) petition (Petition) on November 1, 2012 for its MERC-NMU Transmission System Purchased Gas Adjustment (PGA). MERC-NMU has a consolidated PGA which includes the following four pipeline companies:

- Northern Natural Gas Co. (NNG) which also serves MERC-Peoples Natural Gas (MERC-PNG-NNG);
- Viking Gas Transmission Co. (VGT) which also serves MERC-PNG (MERC-PNG-VGT);
- Great Lakes Gas Transmission, L.P. (GLGT) which also serves MERC-PNG (MERC-PNG-GLGT); and
- Centra.

In its Petition, MERC requests that the Minnesota Public Utilities Commission (Commission) accept the following corrected changes in MERC-NMU's level of contracted capacity and recovery of related costs.[1]

[1] The Company initially proposed to increase the design-day winter entitlements by 1,252 Dekatherms (Dkt) (or approximately 2.02 percent) from the previous year's level. As discussed below, MERC-NMU overlooked a decrease in Centra FT-1 service of 358 Dkt/day. Thus, the corrected entitlement net change should be an increase of 894 Dkt (or approximately 1.44 percent) from the previous year. The Department incorporates this correction in its tables and attachments.

Table 1

The Company's Proposed Total Entitlement Changes	
Type of Entitlement	Proposed Changes: increase (decrease) (Dkt)
TF 12 Base and Variable	718
TF5	307
TFX-12	308
TFX-5	860
Sum of NNG winter capacity	2,193
NNG Zone GDD Call Option	(1,265)
NNG Subtotal	**928**
GLGT FT0016	(24)
GLGT FT16 155 (12)	(8)
GLGT FT16 155 (5)	(9)
GLGT FT15782	(22)
GLGT Subtotal	**(63)**
VGT AF0012	51
VGT AF0014	4
VGT AF0102	9
VGT AF0183	(1,852)
Sum of GLGT winter capacity	(1,788)
Wadena Option	2,175
VGT Subtotal	**387**
Sum of Increases	1,315
Sum of Decreases	(63)
Total Proposed Entitlement Net Change	**1,252**
Correction-Centra FT-1	(358)
Corrected Entitlement Net Change	**894**

The Company's corrected proposal would increase MERC-NMU's design-day (winter) capacity by 894 Dkt from the previous level. As discussed further below, MERC-NMU's 2012-2013 design-day requirements (overall needs of its customers on a design day) would increase by 2,276 Dkt (or approximately 3.92 percent) from the previous year.

MERC described the factors contributing to the change in demand entitlements as follows:[2]

- MERC-NMU's prorated share [3] of NNG winter capacity increased by 2,193 Dkt/day;
- MERC-NMU's prorated share of NNG Zone GDD Call Option decreased by 1,265 Dkt/day;
- MERC-NMU's prorated share of GLGT[4] winter capacity decreased by 63 Dkt/day;

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[2] MERC Petition pages 2-3.

[3] MERC's allocates its NNG, Bison Pipeline (Bison), and Northern Border Pipeline (NBPL) capacity between MERC-PNG and MERC-NMU based on design day numbers. For the 2012-13 heating season, MERC-PNG's prorated share of NNG capacity decreased from 89.88 percent to 88.93 percent while MERC-NMU's prorated share increased from 10.12 percent to 11.07 percent.

[4] Capacity on GLGT is allocated between MERC-NMU and MERC-PNG-GLGT based on design day numbers.

- MERC-NMU's prorated share of VGT[5] winter capacity decreased by 1,788 Dkt/day; and
- MERC-NMU's prorated share of Wadena Option increased by 2,175 Dkt/day.

The Company also proposed changes to non-capacity items in the November 2012 PGA compared to the October 2012 PGA as follows:

- MERC-NMU's prorated share of NNG non-winter capacity increased by 19 Dkt/day for both its TFX April and TFX October contracts;
- MERC-NMU's prorated share of Bison/NBPL non-winter capacity increased by 477 Dkt/day;[6]
- MERC-NMU reduced its AECO/Emerson swap contract by 17,958 Dkt/day; and
- MERC-NMU increased its Firm Deferred Delivery (FDD) storage contract.

The Minnesota Department of Commerce, Division of Energy Resources (Department or DOC) does not oppose any of the proposed changes. As discussed below, the effect of the above proposed changes is an increase in demand costs. The Company requested that the Commission allow recovery of the associated demand costs in its monthly PGA effective November 1, 2012.

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

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

- trade secret designation;
- timeline for filing the annual demand entitlement filing;
- storage costs allocated to commodity costs;
- changes to capacity;
- design-day requirement;
- reserve margin; and
- PGA cost recovery proposal.

A. TRADE SECRET DESIGNATION

Regarding the designation of trade secret data, the Department notes that in MERC's November 1, 2012 trade secret and public filings, the trade secret data is not identified in a manner that

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[5] Capacity on Viking is allocated between MERC-PNG's Viking PGA and MERC-NMU's PGA system.

[6] MERC previously contracted for 50,000 Dkt/day of capacity on Bison which went into service on January 14, 2011. The contracted capacity with NBPL went into effect at the in-service of Bison. This arrangement allows MERC to access gas supplies in the Rocky Mountain region. This agreement is discussed in greater detail in Docket No. G007,011/M-08-698 as well as in the Department's *Comments* in Docket Nos. G011/M-10-1168 and G007/M-10-1166.

satisfies the Commission's requirements. Further, such data appears to be inconsistently designated in the trade secret and public versions. MERC initially filed three trade secret attachments for each of its demand entitlement filings. Specifically, the Department identifies the following trade secret designation issues in the Company's attachments:

- On Attachment 1, page 1, the trade secret copy states "Non-public Document – Contains Trade Secret Data" but no indication of which words or numbers are considered trade secret was given; and
- No words or numbers are redacted from the public copy of Attachment 1, page 1.

When the Department asked MERC whether information was considered trade secret on Attachment 1, page 1, the response was that Attachment 1, page 1 should not have been marked trade secret. The Department cautions MERC about this erroneous designation of trade secret data. For future demand entitlement filings, MERC should take additional care in its designation of trade secret data in its attachments.

Additionally, the Department notes that MERC initially filed all of its attachments (approximately 13-15 attachments for each of its four demand entitlement filings) as electronic spreadsheets. While the Department appreciates spreadsheets that show formulas, some of the spreadsheets had no labels, certain pages seemed to be missing, and much formatting needed to be done in order to print paper copies. Rather than recommending rejection of the filing in this instance, the Department requested that the Company re-file its attachments in PDF format with the trade secret correctly marked and labels on every attachment so that the labels agreed with the references in the filing and could easily be printed. The Department puts MERC on notice that it may recommend rejection of any of the Company's future filings that are in the same or similar condition as the instant Petition.

B. TIMELINE FOR FILING

As stated above, MERC filed its Petition on November 1. In MERC's January 31, 2012 *Reply Comments* in Docket No. G011/M-11-1083, the Company stated that it would comply with the Department's recommended initial filing date of August 1 for its annual demand entitlement filings on a going-forward basis. The Department continues to conclude that July 1 or August 1 is an optimal filing time since it would enable any reliability issues to be identified and possibly resolved prior to the start of the heating season.

C. STORAGE COSTS

The Department has advocated in several recent demand entitlement filings[7] that demand costs associated with storage contracts be recovered through the commodity portion of the PGA since all customers, not just firm customers, benefit from stored gas. The Commission has not yet

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[7] See the Commission's February 6, 2008 Order in Docket No. E,G999/AA-06-1208, for more background.

determined whether storage-related costs are more appropriately recovered through the commodity or through the demand portion of MERC's PGAs.

The Department notes that the Commission allowed CenterPoint Energy to allocate a portion of its storage costs to commodity costs in CenterPoint Energy's PGA.[8] Similarly, the Department recommends that the Commission allow MERC to recover storage gas costs through the commodity portion of the PGA, rather than the demand portion.

While the Department has been recommending this rate design change since MERC's 2007 demand entitlement dockets, the Department is aware that it would be problematic to implement such changes retroactively; as a result, the Department urges the Commission to address this question of rate design and implement the change on a going-forward basis.

D. MERC'S PROPOSED CHANGES

1. Capacity

As indicated in DOC Attachments 1 and 2, the Company proposed to increase MERC-NMU's entitlement level in Dkt as follows:

Table 2

	Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	Change From Previous Year (%)
Proposed	62,100	63,352	1,252	2.02
Corrected	62,100	62,994	894	1.44

As stated above, MERC-NMU's share of NNG winter capacity increased by 2,193 Dkt/day. Additionally, MERC-NMU's share of NNG Zone GDD Call Option decreased by 1,265 Dkt/day due to the Company not purchasing a NNG Zone Delivery Call Option for the heating season. For the 2011-12 heating season, MERC purchased a NNG Zone Delivery Call Option totaling 12,500 Dkt (Docket No. G011/M-11-1084). In MERC's March 22, 2012 Reply Comments in that docket, the Company stated that the NNG Zone Delivery Call Option was a three-month contract to meet the 2011-2012 peak day:

> The gas daily call option delivered to MERC's EF Zone that MERC entered into was a short term contract for a period starting December 1, 2011, through February 29, 2012. The purpose of the contract was to replace the LS Power contract, meet the theoretical peak day and address the positive reserve margins that have

8 See the Commission's February 28, 2012 Order in Docket No. G008/M-07-561.

> occurred in the previous demand entitlement filings. . . .MERC did not call on the gas daily call option, so MERC incurred no volumetric charges.

Thus, MERC-NMU's net NNG winter capacity increased by 928 Dkt/day (2,193 Dkt – 1,265 Dkt).

As also stated above, MERC-NMU's share of VGT winter capacity decreased by 1,788 Dkt/day and the Company's share of Wadena Option increased by 2,175 Dkt/day. MERC stated that it was not able to purchase firm winter capacity only (November 2012 through March 2013) from VGT, so instead MERC purchased a Wadena Delivered Call Option.[9] The result is that MERC-NMU's net VGT winter capacity increased by 387 Dkt/day (2,175 Dkt – 1,788 Dkt).

The reported level of Centra FT-1 was 9,858 Dkt/day in MERC-NMU's 2011-2012 demand entitlement filing. On page 17 of the Petition, MERC-NMU stated "There was no change in Centra firm entitlements." Also, MERC's Attachment 3, *Entitlement Levels Proposed to be Effective November 1, 2012*, shows no change to the current amount of 9,858 Dkt/day for Centra FT-1. However, MERC-NMU implemented 9,500 Dkt/day in its November 2012 PGA.[10] The Department discussed the inconsistency with Company personnel. The Company clarified that it overlooked a decrease in Centra FT-1 service of 358 Dkt/day from 9,858 to 9,500 Dkt/day.

As discussed below, MERC-NMU's projected 2012-2013 design day reflects an increase of 2,278 Dkt over the 2011-2012 level. As also discussed below, MERC-NMU's proposed reserve margin is reasonable. Therefore, the Department concludes that MERC-NMU's corrected level of demand entitlement is reasonable and recommends acceptance of the corrected level of capacity.

2. Design-Day Requirement

As indicated in DOC Attachments 1 and 2, the Company proposed to increase its design day in Dkt as follows:

Table 3

Previous Design Day (Dkt)	Proposed Design Day (Dkt)	Design Day Changes (Dkt)	Change From Previous Year (%)
57,989	60,265	2,276	3.92

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

9 Filing, page 17.
10 Docket No. G007/AA-12-1199.

demand entitlement filings. MERC once again explored the use of additional weather variables in its review of other design-day regression models but did not use the variables in the Company's final design-day analysis. The Department does not oppose MERC's evaluation of other weather determinants in its efforts to produce the most robust design-day estimates possible; however, the Department also notes that some of these additional data were taken from a proprietary source as was discussed in the Department's January 3rd, 10th , and March 12th, 2012 *Comments* in Docket Nos. G011/M-11-1082, G011/M-11-1083, and G011/M-11-1084 respectively. When a utility uses proprietary data in its analysis, the Department cannot fully verify that the results of the analysis are correct.

The Department notes that MERC's analysis and models had autocorrelation present in the regression analysis. The presence of autocorrelation in an Ordinary Least Squares (OLS) regression analysis implies that the errors are not independent of each other. This would violate one of the basic assumptions in typical regression analysis which is that one normally assumes that the errors are all independent of one another. Hence the presence of autocorrelation would affect the validity of the statistical tests that are typically applicable to OLS multiple regression analysis such as, for example, the coefficient of determination ("R-squared") test statistic, and the t-statistic. When forecasting with an OLS regression model, absence of autocorrelation between the errors is very important. Thus, in the Company's future demand entitlement filings, MERC should check the regression models it ultimately uses for autocorrelation and correct the models if autocorrelation is present.

The Department recommends that the Commission accept MERC's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis as mentioned above. Further, the Department requests that in its future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the models if autocorrelation is present.

3. Reserve Margin

As indicated in DOC Attachment 3, MERC-NMU's corrected reserve margin increased by 2,729 Dkt as follows:

Table 4

	Proposed Entitlement (Dkt)	**Proposed Design Day (Dkt)**	**Difference (Dkt)**	**Reserve Margin (%)**	**Change From Prior Year (%)**
Proposed	63,352	60,265	3,087	5.12	-1.97
Corrected	62,994	60,265	2,729	4.53	-2.56

The corrected reserve margin of 4.53 percent represents a decrease of 2.56 percent over last year's reserve margin of 7.09 percent. Generally, a reserve margin up to five percent is not unreasonable. Based on this information and the Department's analysis of the Company's design-day analysis, the Department concludes that the reserve margin is reasonable at this time.

E. THE COMPANY'S PGA COST RECOVERY PROPOSAL

The demand entitlement amounts listed in DOC Attachment 1 represent the demand entitlements for which the Company's firm customers would pay. In its Petition, the Company compared its October 2012 PGA to its November 2012 PGA as a means of highlighting its changes in demand costs (MERC-NMU's Attachment 4, Page 1 of 6).[11] The Company's demand entitlement proposal would result in the following annual demand cost impacts as shown in DOC Attachment 4:

- an annual bill increase of $5.12 related to demand costs, or approximately 4.43 percent, for the average General Service - Residential customer consuming 90 Dkt annually;
- an annual bill increase of $280.84 related to demand costs, or approximately 4.43 percent, for the average Large General Service customer consuming 4,932 Dkt annually;
- no demand cost impacts related to MERC-NMU's other rate classes.

Based on its analysis, the Department recommends that the Commission allow the proposed recovery of associated demand costs effective November 1, 2012.

III. THE DEPARTMENT'S RECOMMENDATIONS

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

- allow MERC to recover storage gas costs through the commodity portion of the PGA, rather than the demand portion;
- accept MERC-NMU's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis as mentioned herein;
- accept the corrected level of demand entitlement; and
- allow the proposed recovery of associated demand costs effective November 1, 2012.

The Department requests that, in future demand entitlement filings, MERC check the regression models it ultimately uses for autocorrelation and correct the models if autocorrelation is present.

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[11] MERC's Attachment 4 included the correct demand level for Centra FT-1.

Additionally, for future demand entitlement filings, MERC should take additional care in its designation of trade secret data in its attachments. The Department puts MERC on notice that it may recommend rejection of any of the Company's future filings that are in the same or similar condition as the instant Petition.

/jl

DOC Attachment 1
Allocation and Direct Assignment of MERC-NMU's Demand

Docket No. G007/M-11-1088	**10-1166 NMU GS**	Proposed Change	**11-1088 NMU GS**	Proposed Change	**12-559 NMU GS**	Proposed Change	**12-1195 NMU GS**	Proposed Change
NNG Design Day	**23,615**		**23,778**		**23,778**		**25,003**	
Customer Requirements moving to Transportation	**0**		**0**		**0**		**0**	
Adjusted Design Day	**23,615**	(1,065)	**23,778**	163	**23,778**	0	**25,003**	1,225
Total NMU Design Day Capacity	**57,662**	(3,254)	**57,989**	327	**57,989**	0	**60,265**	2,276
<u>NNG Allocated Entitlements in PGA</u>								
TF12B	**4,232**	(3,281)	**4,774**	542	**4,774**	0	**6,014**	1,240
TF12V	**3,919**	(1,324)	**2,848**	(1,071)	**2,848**	0	**2,326**	(522)
TF(5)	**3,493**	1,502	**3,267**	(226)	**3,267**	0	**3,574**	307
TFX12 (112486)	**1,171**	1,171	**1,095**	(76)	**1,095**	0	**1,198**	103
TFX(5) (112486)	**6,208**	69	**5,806**	(402)	**5,806**	0	**6,370**	564
TFX(5) (112561)	**649**	649	**607**	(42)	**607**	0	**664**	57
TFX(5) (112486)	**195**	195	**182**	(13)	**182**	0	**182**	0
TFX(5) (12-V)	**0**	0	**0**	0	**0**	0	**0**	0
TFX12 (111866)	**139**	139	**130**	(9)	**130**	0	**142**	12
TFX12 (111866)	**895**	895	**837**	(58)	**837**	0	**916**	79
TFX5 (111866)	**2,707**	2,707	**2,531**	(176)	**2,531**	0	**2,770**	239
Windom	**0**	0	**0**	0	**0**	0	**0**	0
LS Power	**3,149**	424	**0**	(3,149)	**0**	0	**0**	0
Northwestern Energy (Ortonville)	**0**	0	**0**	0	**0**	0	**0**	0
NNG Zone GDD Call Option	**0**	0	**1,265**	1,265	**1,265**	0	**0**	(1,265)
TFX7 chg to TFX12 (111866)*	**1,290**	1,290	**1,206**	(84)	**1,206**	0	**1,320**	114
Total NNG Allocated Entitlements in PGA	**28,047**	4,436	**24,548**	-3,499	**24,548**	0	**25,476**	928
<u>Other Pipelines Entitlements in PGA</u>								
Viking FT-A (AF 0012)	**7,966**	0	**7,711**	(255)	**7711**	0	**7,762**	51
Viking FT-A backhaul	**0**	(5,902)	**0**	0	**0**	0	**0**	0
Viking FT-A (AF 0014)	**0**	0	**678**	678	**678**	0	**682**	4
Viking FT-A (AF 0102)	**0**	0	**1,234**	1,234	**1,234**	0	**1,243**	9
Viking FT-A (AF 0183)	**0**	0	**1,852**	1,852	**1,852**	0	**0**	(1,852)
Viking Chisago TF 12 (112495) B	**0**	(1,368)	**0**	0	**0**	0	**0**	0
Viking Chisago TF 12 (112495) V	**0**	(955)	**0**	0	**0**	0	**0**	0
Viking Chisago TF 5 (112495)	**0**	(563)	**0**	0	**0**	0	**0**	0
Viking Chisago TF 12 (112486)	**0**	(2,089)	**0**	0	**0**	0	**0**	0
Viking Chisago TF 5 (112486)	**0**	(926)	**0**	0	**0**	0	**0**	0
Great Lakes T-16 & T-155 -12	**11,308**	0	**8,445**	(2,863)	**8,445**	0	**8,413**	(32)
Great Lakes T-16 & T-155 -5	**2,138**	0	**2,238**	100	**2,238**	0	**2,229**	(9)
Great Lakes FT8466-12	**3,000**	0	**0**	(3,000)	**0**	0	**0**	0
Great Lakes FT15782-12	**0**	0	**5,536**	5,536	**5,536**	0	**5,514**	(22)
Centra FT-1	**9,858**	0	**9,858**	0	**9,858**	0	**9,500**	(358)
Centra -Boise	**0**	0	**0**	0	**0**	0	**0**	0
Nexen Storage	**0**	0	**0**	0	**0**	0	**0**	0
Tenaska PSO GL	**0**	0	**0**	0	**0**	0	**0**	0
Wadena Delivered Option	**5,902**	5,902	**0**	(5,902)	**0**	0	**2,175**	2,175
Tenaska PSO Centra	**0**	0	**0**	0	**0**	0	**0**	0
ANR Storage	**0**	0	**0**	0	**0**	0	**0**	0
Total Capacity	**68,219**	4,437	**62,100**	-6,119	**62,100**	0	**62,994**	894
Total NNG Transportation	**28,047**	4,436	**24,548**	-3,499	**24,548**	0	**25,476**	928
Total Transportation	**57,878**	-1,465	**55,865**	-217	**55,865**	0	**57,574**	1,709
Total Seasonal Transportation	**12,408**	8,617	**11,604**	-1,086	**11,604**	0	**12,714**	1,110
Percent Seasonal on NNG	**44.2%**		**47.3%**		**47.3%**	0	**49.9%**	0
Reserve Margin	**18.31%**		**7.09%**		**7.09%**	0	**4.53%**	(0)
<u>Other Entitlements not included in Peak Day Deliverability</u>								
Field TF (TFF) (NMU direct assigned)	**0**	0	**0**	0	**0**	0	**0**	0
TFX Offpeak Old Oct. (60,000)	**0**	0	**0**	0	**0**	0	**0**	0
TFX Offpeak Old Oct. (35,000)	**0**	0	**0**	0	**0**	0	**0**	0
TFX Offpeak New Oct. (14,600)	**0**	0	**0**	0	**0**	0	**0**	0
TFX Offpeak New Apr. (39,600)	**0**	0	**0**	0	**0**	0	**0**	0
TFX Oct	**216**	216	**202**	(14)	**202**	0	**221**	19
TFX Apr	**216**	216	**202**	(14)	**202**	0	**221**	19
TFX7 chg to TFX12 (111866)*	**0**	0	**0**	0	**0**	0	**0**	0
TFX Apr-Oct	**0**	0	**0**	0	**0**	0	**0**	0
TFX May-Sept	**0**	0	**0**	0	**0**	0	**0**	0
FDD Storage reservation (112490)	**8,164**	1,331	**7,634**	(530)	**7,634**	0	**8,354**	720
FDD Storage capacity MSQ **1/**	**470,684**	76,735	**440,149**	(30,535)	**440,149**	0	**481,629**	41,480
FDD Storage reservation (113704)	**0**	0	**0**	0	**351**	351	**384**	33
FDD Storage capacity MSQ **2/**	**0**	0	**0**	0	**20,245**	20,245	**22,150**	1,905
FDD Storage reservation (118215)	**751**	269	**702**	(49)	**1,317**	615	**1,441**	124
FDD Storage capacity MSQ **3/**	**43,301**	15,479	**40,491**	(2,811)	**75,920**	35,429	**83,072**	7,152
FDD Storage reservation (118657)	**601**	86	**562**	(39)	**562**	0	**615**	53
FDD Storage capacity MSQ **4/**	**34,630**	4,965	**32,385**	(2,245)	**32,385**	0	**35,435**	3,050
ANR Capacity	**0**	0	**0**	0	**0**	0	**0**	0
Nexen PSO	**0**	(684,604)	**0**	0	**0**	0	**0**	0
Tenaska PSO	**0**	0	**0**	0	**0**	0	**0**	0
NGPL	**0**	0	**0**	0	**0**	0	**0**	0
SMS	**2,454**	351	**2,295**	(159)	**2,295**	0	**2,512**	217
SBA	**0**	0	**0**	0	**0**	0	**0**	0
Upstream Demand per Mo	**0**	0	**0**	0	**0**	0	**0**	0
Bison/NBPL (FT0003 & T8673F)	**5,411**	5,411	**5,060**	(351)	**5,060**	0	**5,537**	477
AECO Storage	**665,043**	665,043	**666,223**	1,180	**666,223**	0	**648,265**	(17,958)
1/ Cycled Volumes =	**94,137**	15,347	**88,030**	(6,107)	**88,030**	0	**96,326**	8,296
2/ Cycled Volumes =	**0**	0	**0**	0	**4,048**	4,048	**4,429**	381
3/ Cycled Volumes =	**8,658**	3,095	**8,096**	(562)	**15,180**	7,084	**16,610**	1,430
4/ Cycled Volumes =	**6,926**	993	**6,477**	(449)	**6,477**	0	**7,087**	610

DOC Attachment 2
Allocation and Direct Assignment
of Demand Entitlements between
MERC-PNG and MERC-NMU

	10-1168 PNG GS	10-1166 NMU GS	Total	11-1084 PNG GS	11-1088 NMU GS	Total	12-558 PNG GS	12-559 NMU GS	Total	12-1193 PNG GS	12-1195 NMU GS	Total
NNG Design Day	194,598	23,615	218,213	211,182	23,778	234,960	211,182	23,778	234,960	200,785	25,003	225,788
Customer Requirements moving to Transportation	0	0	0	0	0	0	0	0	0	0	0	0
For NMU - VGT Design Day		10,835			11,046			11,046			11,523	
For NMU - GLGT Design Day		14,964			14,870			14,870			15,825	
For NMU - Centra Deisgn Day		8,248			8,295			8,295			7,914	
Adjusted NNG Design Day	194,598	23,615	218,213	211,182	23,778	234,960	211,182	23,778	234,960	200,785	25,003	225,788
Adjusted NNG Design Day Percentages	89.18%	10.82%	100.00%	89.88%	10.12%	100.00%	89.88%	10.12%	100.00%	88.93%	11.07%	100.00%
Total NNG Design Day Capacity	233,627	23,615	257,242	221,436	23,778	245,214	221,436	23,778	245,214	208,007	25,003	233,010
Total NMU Design Day Capacity		57,662			57,989			57,989			60,265	
Less: NGPL adjusted for nonrecallable releases	0	0	0	0	0	0	0	0	0	0	0	0
Less: Windom	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500
Less: LS Power	25,951	3,149	29,100	0	0	0	0	0	0	0	0	0
Less: Northwestern Energy (Ortonville)	0	0	0	910	0	910	910	0	910	910	0	910
Less: Chisago delivery to Viking	0	0	0	0	0	0	0	0	0	0	0	0
Less: TF12B	0	0	0	0	0	0	0	0	0	0	0	0
Less: TF5	0	0	0	0	0	0	0	0	0	0	0	0
Less: TFX(5)	0	0	0	0	0	0	0	0	0	0	0	0
Less: Contract Demand Units	0	0	0	0	0	0	0	0	0	0	0	0
Total Design Day Capacity (excluding direct assignments)	205,176	84,426	289,602	219,846	81,767	301,613	219,846	81,767	301,613	206,417	85,268	291,685
Factors for All Winter Capacity	70.85%	29.15%	100.00%	72.89%	27.11%	100.00%	72.89%	27.11%	100.00%	70.77%	29.23%	100.00%
Allocated Entitlements in PGA												
TF12B	34,875	4,232	39,107	42,396	4,774	47,170	42,396	4,774	47,170	41,156	6,014	47,170
TF12V	32,290	3,919	36,209	25,298	2,848	28,146	25,298	2,848	28,146	25,820	2,326	28,146
TF5	28,785	3,493	32,278	29,011	3,267	32,278	29,011	3,267	32,278	28,704	3,574	32,278
TFX12 (112486)	9,651	1,171	10,822	9,727	1,095	10,822	9,727	1,095	10,822	9,624	1,198	10,822
TFX(5) (112486)	51,163	6,208	57,371	51,383	5,806	57,189	51,383	5,806	57,189	50,819	6,370	57,189
TFX(5) (112561)	5,351	649	6,000	5,393	607	6,000	5,393	607	6,000	5,336	664	6,000
TFX(5) (112486)	1,605	195	1,800	1,800	182	1,982	1,800	182	1,982	1,800	182	1,982
TFX(5) (12-V)	0	0	0	0	0	0	0	0	0	0	0	0
TFX12 (111866)	1,144	139	1,283	1,153	130	1,283	1,153	130	1,283	1,141	142	1,283
TFX12 (111866)	7,376	895	8,271	7,434	837	8,271	7,434	837	8,271	7,355	916	8,271
TFX5 (111866)	22,306	2,707	25,013	22,482	2,531	25,013	22,482	2,531	25,013	22,243	2,770	25,013
Total Allocated Entitlements in PGA	194,546	23,608	218,154	196,077	22,077	218,154	196,077	22,077	218,154	193,998	24,156	218,154
Direct Assigned Entitlements in PGA (NNG)												
NGPL	0	0	0	0	0	0	0	0	0	0	0	0
Windom	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500
LS Power	25,951	3,149	29,100	0	0	0	0	0	0	0	0	0
Northwestern Energy (Ortonville)	0	0	0	910	0	910	910	0	910	910	0	910
NNG Zone GDD Call Option	0	0	0	11,235	1,265	12,500	11,235	1,265	12,500	0	0	0
TFX(5)	0	0	0	0	0	0	0	0	0	0	0	0
TFX(7)	0	0	0	0	0	0	0	0	0	0	0	0
TFX(5)	0	0	0	0	0	0	0	0	0	0	0	0
TFX7 chg to TFX12 (111866)*	10,631	1,290	11,921	10,715	1,206	11,921	10,715	1,206	11,921	10,601	1,320	11,921
Total Direct Assignments	39,082	4,439	43,521	25,360	2,471	27,831	25,360	2,471	27,831	14,011	1,320	15,331
Total Capacity before Peak Shaving	233,628	28,047	261,675	221,437	24,548	245,985	221,437	24,548	245,985	208,009	25,476	233,485
LP Peak Shaving	0	0	0	0	0	0	0	0	0	0	0	0
Total Design Day Capacity w/o Contract Demand	233,628	28,047	261,675	221,437	24,548	245,985	221,437	24,548	245,985	208,009	25,476	233,485
Total Transp. (with TFX Offpeak less LSP)	207,677			221,437			221,437			208,009		
Total Annual Transportation	67,165			67,694			67,694			66,976		
Total Seasonal Transportation	52,696			53,293			53,293			52,747		
Total Percent Seasonal	22.6%			24.1%			24.1%			25.4%		
LS Power as % of Total DD Capacity	11.1%			0.0%			0.0%			0.0%		
Reserve Margin	20.06%			4.86%			4.86%			3.60%		
Direct Assigned Entitlements in PGA (NMU)												
Viking FT-A (AF 0012)		7,966			7,711			7,711			7,762	
Viking FT-A backhaul		0			0			0			0	
Viking FT-A (AF 0014)		0			678			678			682	
Viking FT-A (AF 0102)		0			1,234			1,234			1,243	
Viking FT-A (AF 0183)		0			1,852			1,852			0	
Viking Chisago TF 12 (112495) B		0			0			0			0	
Viking Chisago TF 12 (112495) V		0			0			0			0	
Viking Chisago TF 5 (112495)		0			0			0			0	
Viking Chisago TF 12 (112486)		0			0			0			0	
Viking Chisago TF 5 (112486)		0			0			0			0	
Great Lakes T-16 & T-155 -12		11,308			8,445			8,445			8,413	
Great Lakes T-16 & T-155 -5		2,138			2,238			2,238			2,229	
Great Lakes FT8466-12		3,000			0			0			0	
Great Lakes FT15782-12		0			5,536			5,536			5,514	
Centra FT-1		9,858			9,858			9,858			9,500	
Centra -Boise		0			0			0			0	
Nexen Storage		0			0			0			0	
Tenaska PSO GL		0			0			0			0	
Wadena Delivered Option		5,902			0			0			2,175	
Tenaska PSO Centra		0			0			0			0	
ANR Storage	0	0	0	0	0	0	0	0	0	0	0	0
Total Capacity		68,219			62,100			62,100			62,994	
Total NNG transportation		28,047			24,548			24,548			25,476	
Total Annual Transportation		57,878			55,865			55,865			57,574	
Total Seasonal Transportation NNG		12,408			11,604			11,604			12,714	
Total Percent Seasonal on NNG		44.2%			47.3%			47.3%			49.9%	
Reserve Margin		18.31%			7.09%			7.09%			4.53%	
Direct Assigned Demand Not in PGA												
TF-12-B Contract Demand	0	0	0	0	0	0	0	0	0	0	0	0
Total Design Day Capacity w/ contract demand	233,628	28,047	261,675	221,437	24,548	245,985	221,437	24,548	245,985	208,009	25,476	233,485
Factors	89.18%	10.82%	100.00%	89.88%	10.12%	100.00%	89.88%	10.12%	100.00%	88.93%	11.07%	100.00%
Other Entitlements not included in Peak Day Deliverability												
Field TF (TFF) (NMU direct assigned)	0	0	0	0	0	0	0	0	0	0	0	0
TFX Offpeak Old Oct. (60,000)	0	0	0	0	0	0	0	0	0	0	0	0
TFX Offpeak Old Oct. (35,000)	0	0	0	0	0	0	0	0	0	0	0	0
TFX Offpeak New Oct. (14,600)	0	0	0	0	0	0	0	0	0	0	0	0
TFX Offpeak New Apr. (39,600)	0	0	0	0	0	0	0	0	0	0	0	0
TFX Oct	1,784	216	2,000	1,798	202	2,000	1,798	202	2,000	1,779	221	2,000
TFX Apr	1,784	216	2,000	1,798	202	2,000	1,798	202	2,000	1,779	221	2,000
TFX7 chg to TFX12 (111866)*	0	0	0	0	0	0	0	0	0	0	0	0
TFX Apr-Oct	0	0	0	0	0	0	0	0	0	0	0	0
TFX May-Sept	0	0	0	0	0	0	0	0	0	0	0	0
FDD Storage reservation (112490)	67,273	8,164	75,437	67,803	7,634	75,437	67,803	7,634	75,437	67,803	8,354	76,157
FDD Storage capacity MSQ 1/	3,878,642	470,684	4,349,326	3,909,172	440,149	4,349,321	3,909,172	440,149	4,349,321	3,867,692	481,629	4,349,321
FDD Storage reservation (113704)	0	0	0	0	0	0	3,118	351	3,469	3,085	384	3,469
FDD Storage capacity MSQ 2/	0	0	0	0	0	0	179,755	20,245	200,000	177,850	22,150	200,000
FDD Storage reservation (118215)	6,187	751	6,938	6,236	702	6,938	11,692	1,317	13,009	4,935	1,441	6,376
FDD Storage capacity MSQ 3/	356,700	43,301	400,002	359,510	40,491	400,001	674,081	75,920	750,001	57,838	83,072	140,910
FDD Storage reservation (118657)	4,949	601	5,550	4,988	562	5,550	4,988	562	5,550	133,390	615	134,005
FDD Storage capacity MSQ 4/	285,370	34,630	320,000	287,615	32,385	320,000	287,615	32,385	320,000	284,565	35,435	320,000
ANR Capacity	0	0	0	0	0	0	0	0	0	0	0	0
Nexen PSO	0	0	0	0	0	0	0	0	0	0	0	0
Tenaska PSO	0	0	0	0	0	0	0	0	0	0	0	0
NGPL	0	0	0	0	0	0	0	0	0	0	0	0
SMS	20,226	2,454	22,680	20,385	2,295	22,680	20,385	2,295	22,680	20,168	2,512	22,680
SBA	0	0	0	0	0	0	0	0	0	0	0	0
Upstream Demand per Mo	0	0	0	0	0	0	0	0	0	0	0	0
Bison/NBPL (FT0003 & T8673F)	44,589	5,411	50,000	44,940	5,060	50,000	44,940	5,060	50,000	44,463	5,537	50,000
AECO Storage	0	665,043	665,043	0	666,223	666,223	0	666,223	666,223	0	648,265	648,265
1/ Cycled Volumes =	775,728	94,137	869,865	781,834	88,030	869,864	781,834	88,030	869,864	773,538	96,326	869,864
2/ Cycled Volumes =	0	0	0	0	0	0	35,952	4,048	40,000	35,571	4,429	40,000
3/ Cycled Volumes =	71,342	8,658	80,000	71,904	8,096	80,000	134,820	15,180	150,000	11,568	16,610	28,178
4/ Cycled Volumes =	57,074	6,926	64,000	57,523	6,477	64,000	57,523	6,477	64,000	56,913	7,087	64,000

DOC Attachment 3
Demand Entitlement Analysis
As Proposed by MERC-NMU

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
Heating Season	(1) DD No.of Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (Mcf)*	(8) Change from Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2012-2013	40,900	430	1.06%	60,265	2,276	3.92%	62,994	894	1.44%	4.53%
2011-2012	40,470	70	0.17%	57,989	327	0.57%	62,100	(6,119)	-8.97%	7.09%
2010-2011	40,400	(735)	-1.79%	57,662	(3,256)	-5.34%	68,219	4,436	6.95%	18.31%
2009-2010	41,135	2,023	5.17%	60,918	(2,808)	-4.41%	63,783	(1,052)	-1.62%	4.70%
2008-2009	39,112	854	2.23%	63,726	2,718	4.46%	64,835	415	0.64%	1.74%
2007-2008	38,258	(225)	-0.58%	61,008	(52)	-0.09%	64,420	1,639	2.61%	5.59%
2006-2007	38,483	275	0.72%	61,060	(922)	-1.49%	62,781	(1,553)	-2.41%	2.82%
2005-2006	38,208	(1,608)	-4.04%	61,982	1,279	2.11%	64,334	2,668	4.33%	3.79%
2004-2005	39,816	2,740	7.39%	60,703	(1,491)	-2.40%	61,666	(2,672)	-4.15%	1.59%
2003-2004	37,076	612	1.68%	62,194	7,968	14.69%	64,338	7,945	14.09%	3.45%
2002-2003	36,464	362	1.00%	54,226	(344)	-0.63%	56,393	260	0.46%	4.00%
2001-2002	36,102	415	1.16%	54,570	(1,099)	-1.97%	56,133	0	0.00%	2.86%
2000-2001	35,687	717	2.05%	55,669	1,118	2.05%	56,133	1,210	2.20%	0.83%
1999-2000	34,970	1,097	3.24%	54,551	119	0.22%	54,923	151	0.28%	0.68%
1998-1999	33,873	968	2.94%	54,432	1,551	2.93%	54,772	3,918	7.70%	0.62%
1997-1998	32,905	1,362	4.32%	52,881	2,176	4.29%	50,854	0	0.00%	-3.83%
1996-1997	31,543	790	2.57%	50,705	1,342	2.72%	50,854	(10,270)	-16.80%	0.29%
1995-1996	30,753			49,363			61,124			23.83%
Average:			1.72%			1.27%			0.40%	3.47%
Average (Ex. 2003-2004):			1.73%			0.43%			-0.46%	3.48%

Firm Peak Day Sendout

Heating Season	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess/Def. per Cust. [(7) - (4)]/(1)	(16) Design Day per Customer* (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18)*** Peak Day Sendout per PD Customer (12)/(11)	(19) Peak Day Sendout per DD Customer (12)/(1)
2012-2013	unknown	unknown			0.0667	1.4735	1.5402	unknown	unknown
2011-2012	40,470	46,380	2,731	6.26%	0.1016	1.4329	1.5345	1.1460	1.1460
2010-2011	40,400	43,649	(4,284)	-8.94%	0.2613	1.4273	1.6886	1.0804	1.0804
2009-2010**	40,588	47,933	1,532	3.30%	0.0696	1.4809	1.5506	1.1810	1.1653
2008-2009	40,694	46,401	(7,714)	-14.25%	0.0284	1.6293	1.6577	1.1402	1.1864
2007-2008	38,258	54,115	24,019	79.81%	0.0892	1.5946	1.6838	1.4145	1.4145
2006-2007	38,483	30,096	(16,324)	-35.17%	0.0447	1.5867	1.6314	0.7821	0.7821
2005-2006	38,208	46,420	5,014	12.11%	0.0616	1.6222	1.6838	1.2149	1.2149
2004-2005	38,394	41,406	2,123	5.40%	0.0242	1.5246	1.5488	1.0784	1.0399
2003-2004	37,632	39,283	(5,858)	-12.98%	0.0578	1.6775	1.7353	1.0439	1.0595
2002-2003	37,076	45,141	10,769	31.33%	0.0594	1.4871	1.5465	1.2175	1.2380
2001-2002	36,500	34,372	(9,950)	-22.45%	0.0433	1.5116	1.5548	0.9417	0.9521
2000-2001	35,956	44,322	3,967	9.83%	0.0130	1.5599	1.5729	1.2327	1.2420
1999-2000	35,822	40,355	(8,001)	-16.55%	0.0106	1.5599	1.5706	1.1265	1.1540
1998-1999	34,970	48,356	8,320	20.78%	0.0100	1.6069	1.6170	1.3828	1.4276
1997-1998	33,873	40,036	(7,904)	-16.49%	-0.0616	1.6071	1.5455	1.1819	1.2167
1996-1997	33,064	47,940	16,790	53.90%	0.0047	1.6075	1.6122	1.4499	1.5198
1995-1996	32,112	31,150			0.3824	1.6051	1.9876	0.9700	1.0129
Average:				5.99%	0.0704	1.5553	1.6257	1.1520	1.1678
Average (Ex. 2003-2004):				7.26%	0.0711	1.5481	1.6192	1.1588	1.1745

* The total entitlement includes the 864 Mcf/day of entitlement permanently released to Cornerstone in 2002-2003.
** The number of peak day customers is calculated using firm customer count numbers provided in MERC-NMU's *Initial Filing*, Attachment 12.
*** The number of design day customers are used when the number of firm peak day customers is unknown (18=19).

DOC Attachment 4
Rate Impact of MERC-NMU's PGA System Proposed Demand Entitlement Changes

1) General Service-Residential: Avg. Annual Use:			**90 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change M-12-559	Most Recent PGA 10/1/12	PGA 11/1/12 with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$5.6422	$2.3990	$3.1724	$3.5309	-37.42%	47.18%	11.30%	$0.3585
Demand Rate	$1.3841	$1.2787	$1.2862	$1.3431	-2.96%	5.04%	4.43%	$0.0569
Margin	$2.1759	$2.1759	$2.1759	$2.1759	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.2022	$5.8536	$6.6345	$7.0499	-23.39%	20.44%	6.26%	$0.4154
Avg. Annual Bill*	$828.20	$526.82	$597.11	$634.49	-23.39%	20.44%	6.26%	$37.3891
Effect of proposed commodity change on average annual bills:								$32.2644
Effect of proposed demand change on average annual bills:								$5.1248
2) Large General Service: Avg. Annual Use:			**4,932 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change M-12-559	Most Recent PGA 10/1/12	PGA 11/1/12 with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$5.6422	$2.3990	$3.1724	$3.5309	-37.42%	47.18%	11.30%	$0.3585
Demand Rate	$1.3841	$1.2787	$1.2862	$1.3431	0.00%	0.00%	4.43%	$0.0569
Margin	$1.9660	$1.9660	$1.9660	$1.9660	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$8.9923	$5.6437	$6.4246	$6.8400	-23.93%	21.20%	6.47%	$0.4154
Avg. Annual Bill*	$44,350.02	$27,834.73	$31,686.13	$33,735.05	-23.93%	21.20%	6.47%	$2,048.9254
Effect of proposed commodity change on average annual bills:								$1,768.0875
Effect of proposed demand change on average annual bills:								$280.8379
3) SV Interruptible Service: Avg. Annual Use:			**6,068 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change M-12-559	Most Recent PGA 10/1/12	PGA 11/1/12 with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$5.6422	$2.3990	$3.1724	$3.5309	-37.42%	47.18%	11.30%	$0.3585
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.9560	$0.9560	$0.9560	$0.9560	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.5982	$3.3550	$4.1284	$4.4869	-32.00%	33.74%	8.68%	$0.3585
Avg. Annual Bill*	$40,037.88	$20,358.14	$25,051.13	$27,226.47	-32.00%	33.74%	8.68%	$2,175.3355
Effect of proposed commodity change on average annual bills:								$2,175.3355
Effect of proposed demand change on average annual bills:								$0.0000
4) LV Interruptible Service: Avg. Annual Use:			**40,821 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change M-12-559	Most Recent PGA 10/1/12	PGA 11/1/12 with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$5.6422	$2.3990	$3.1724	$3.5309	-37.42%	47.18%	11.30%	$0.3585
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.2846	$0.2846	$0.2846	$0.2846	0.00%	0.00%	0.00%	$0.0000
TotalCost of Gas	$5.9268	$2.6836	$3.4570	$3.8155	-35.62%	42.18%	10.37%	$0.3585
Avg. Annual Bill*	$241,937.90	$109,547.24	$141,118.20	$155,752.24	-35.62%	42.18%	10.37%	$14,634.0428
Effect of proposed commodity change on average annual bills:								$14,634.0428
Effect of proposed demand change on average annual bills:								$0.0000

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)	Total Change (Percent)
General Service-Residential	$0.3585	11.30%	$0.0569	4.43%	0.4154	6.26%
Large General Service	$0.3585	11.30%	$0.0569	4.43%	0.4154	6.47%
Small Vol. Inter. Service	$0.3585	11.30%	$0.0000	0.00%	0.3585	8.68%
Large Vo. Inter. Service	$0.3585	11.30%	$0.0000	0.00%	0.3585	10.37%

*** The average annual bill shown does not include customer charges.**

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. G007/M-12-1195

Dated this **4th** of **March, 2013**

/s/Sharon Ferguson

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